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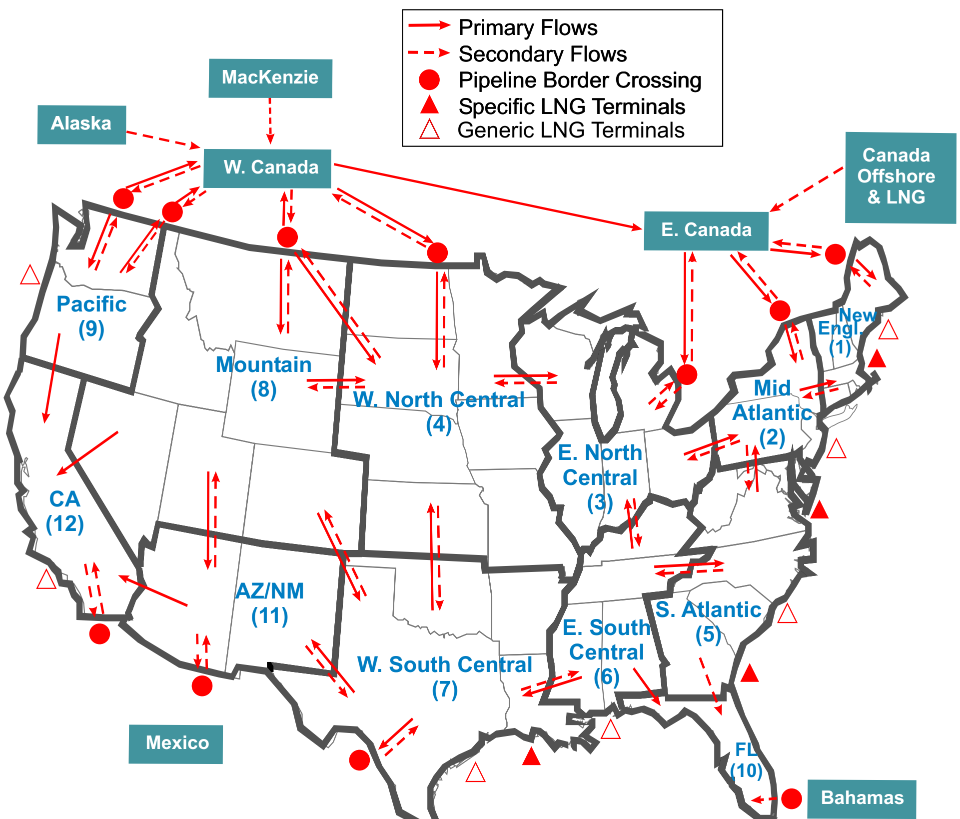
Natural Gas Transmission and Distribution Module

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 the regional interstate network, for both a peak (December through March) and off peak period during each forecast year. These 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 8). The major assumptions used within the NGTDM are grouped into five general categories. They relate to (1) structural components of the model, (2) capacity expansion and pricing of transmission and distribution services, (3) Arctic pipelines, and (4) imports and exports. A complete listing of NGTDM assumptions and in-depth methodology descriptions are presented in *Model Documentation: Natural Gas Transmission and Distribution Model of the National Energy Modeling System, Model Documentation 2005,* DOE/EIA-M062(2005) (Washington, DC, 2005).

Figure 8. Natural Gas Transmission and Distribution Model Regions



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting

Key Assumptions

Structural Components

The primary and secondary region-to-region flows represented in the model are shown in Figure 8. Primary flows are determined, along with nonassociated 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 generally set exogenously. Liquefied natural gas imports are also not directly part of the equilibration process, but our set at the beginning of each NEMS iteration in response to the price from the previous iteration. 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 offpeak 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. 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 an 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. Delivered prices for each sector are set by adding an endogenously estimated markup (generally a distributor tariff) to the regional representative citygate price. Production 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.

Capacity Expansion and Pricing of Transmission and Distribution Services

For the first 2 forecast years, announced pipeline and storage capacity expansions (that 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 demand, 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 it is determined 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 costs of recent comparable expansions and range from $1.48 to $6.84 in 2004 dollars per daily thousand cubic feet and miles.

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

Pricing of Services

While transportation tariffs for interstate pipeline services are initially based on a regulated cost-of-service calculation, an adjustment to the tariffs is applied which is dependent on the realized utilization rate, to reflect a more market-based approach. Transportation 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.

End-use prices by sector and season are derived by adding a markup to the average regional market price of natural gas in both peak and off-peak periods. (Prices are reported on an annual basis and represent quantity-weighted averages of the two seasons.) These markups include the cost of service provided by intraregional interstate pipelines, intrastate pipelines, and local distributors. The intrastate tariffs are accounted for endogenously through historical model benchmarking. Distributor tariffs represent the difference between the regional end-use and citygate price, independent of whether or not a customer class typically purchases gas through a local distributor.

The distribution tariffs for residential, commercial, and industrial customers are projected using econometrically estimated equations, primarily in response to changes in consumption levels. An assumed differential is used to divide the industrial price into one for noncore customers (refineries and industrial boiler users) and one for core customers who have less alternative fuel options. For electric generators, these markups are adjusted each forecast year by a fraction (0.27) of the annual percentage change in the associated electric generator consumption. This adjustment is intended to reflect anticipated additional infrastructure devoted to serving electric generation consumption growth.

The vehicle natural gas (VNG) sector is divided into fleet and non-fleet vehicles. The distributor tariffs for natural gas to fleet vehicles are set to *EIA's Natural Gas Annual* historical end-use prices minus citygate prices plus Federal and State VNG taxes. The price to non-fleet vehicles is based on the industrial sector core price plus an assumed $4.46 (2004 dollars per thousand cubic feet) dispensing charge plus Federal and State taxes, held constant in nominal dollars. It is assumed that the retailer will lower the dispensing charge by up to 20 percent if needed to be competitive with gasoline prices.

Pipelines from Arctic Areas into Alberta

The outlook for natural gas production from the North Slope of Alaska is affected strongly by the unique circumstances regarding its transport to market. Unlike virtually all other identified deposits of natural gas in the United States, North Slope gas lacks a means of economic transport to major commercial markets. The lack of viable marketing potential at present has led to the use of Prudhoe Bay gas to maximize crude oil recovery in that field. Recent high natural gas prices and the passage of legislation in support of a major Alaska pipeline from the North Slope into Alberta, Canada, raised the potential economic viability of such a project. The primary assumptions associated with estimating the cost of North Slope Alaskan gas in Alberta, as well as for MacKenzie Delta gas into Alberta, are shown in Table 56. A calculation is performed to estimate a regulated, levelized, tariff for each pipeline. Additional items are added to account for the wellhead price, treatment costs, pipeline fuel costs, and a risk premium to reflect market price uncertainty.

For the Alaska pipeline the uncertainty associated with the initial capitalization is captured by applying a value that is 20 percent higher than the expected value. Finally, for comparison purposes, a price differential of $0.64 (2004 dollars per Mcf) is assumed between the price in Alberta and the average lower 48 price. The resulting cost of Alaska gas, relative to the lower 48 wellhead price, is approximately $3.42 (2004 dollars per Mcf), with some variation across the forecast due to changes in gross domestic product. Construction of an Alaska-to-Alberta pipeline is forecast to commence if the assumed total costs for Alaska gas in the lower 48 States exceeds the average lower 48 gas price in each of the previous 2 years, on average over the previous 5 years (with greater weight applied to more recent years), and as expected to average over the next 3 years. An adjustment is made if prices were declining over the previous 5 years. Once the assumed 4-year construction period is complete, expansion can occur if the price exceeds the initial trigger price by $0.71 (2004 dollars per Mcf). When the Alaska to Alberta pipeline is built in the model, additional pipeline capacity is added to bring the gas across the border into the United States. For accounting purposes, the model assumes that all of the Alaska gas will be consumed in the United States and that sufficient economical supplies are available at the North Slope to fill the pipeline over the depreciation period.

Natural gas production from the MacKenzie Delta is assumed to be sufficient to fill a pipeline over the projection period should one be built connecting the area to markets in the south. The basic methodology used to represent the decision to build a MacKenzie pipeline is similar to the process used for an Alaska-to-lower 48 pipeline, using the primary assumed parameters listed in Table 56. One exception is that the uncertainty associated with the initial capitialization is captured in the risk premium.

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. U.S. natural gas exports from the United States to Canada are set exogenously in NEMS at 291 billion cubic feet per year, post 2006. Canadian production and U.S. import flows from Canada are determined endogenously within the model.

It is initially assumed that Mexican natural gas production grows at an average annual rate of 1.7 percent through 2030 and that consumption grows at an average annual rate of 3.0 percent. It is further assumed that domestic production will be supplemented by LNG from receiving terminals constructed on both the east

Table 56. Primary Assumptions for Natural Gas Pipelines from Alaska and MacKenzie Delta into Alberta, Canada

	Alaska to Alberta	MacKenzie Delta to Alberta
Initial flow into Alberta	3.9 Bcf per day	1.1 Bcf per day
Expansion potential	22 percent	58 percent
Initial capitalization	14.6 billion (2004 dollars)	5.1 billion (2004 dollars)
Cost of Debt (premium over AA bond rate)	0.0 percent	1.0 percent
Cost of equity (premium over AA bond rate)	5.0 percent	8.0 percent
Debt fraction	80 percent	70 percent
Depreciation period	15 years	15 years
Minimum wellhead price	$0.85 (2004 dollars per Mcf)	$1.06 (2004 dollars per Mcf)
Treatment and fuel costs	$0.44 (2004 dollars per Mcf)	$0.43 (2004 dollars per Mcf)
Risk Premium	$0.36 (2004 dollars per Mcf)	$0.28 (2004 dollars per Mcf)
Additional cost for expansion	$0.71 (2004 dollars per Mcf)	$0.11 (2004 dollars per Mcf)
Construction period	4 years	3 years
Planning period	5 years	2 years
Earliest start year	2015	2011

Note: The MacKenzie risk premium partially reflects the potential of capital cost overruns, whereas this is represented for the Alaska pipeline by using an initial capitalization that is 20 percent bigger than the expected estimate.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Alaska pipeline data are partially based on information from British Petroleum/ExxonMobil/Conoco Phillips and reflect assumed impact on Alaska pipeline finances as a result of the American Jobs Creation Act of 2004 and the Military Construction Appropriations Act, 2004.

and west coasts of Mexico that serve only the Mexican market. Receiving terminal(s) in Baja California, Mexico, that serve both Mexico and the United States can be constructed if the regional LNG price exceeds a trigger price. The difference between production and consumption in any year is assumed to be either imported from, or exported to, the United States. Adjustments to these figures are made endogenously within the model to reflect response to price fluctuations within the market.

Canadian consumption and production in Eastern Canada are set exogenously in the model and are shown in Table 57. Production in the Western Canadian Sedimentary Basin (WCSB) is calculated endogenously to the model using annual supply curves based on beginning-of-year proved reserves and an expected production-to-reserve ratio. Reserve additions are set equal to the product of successful natural gas wells (based on an econometric estimation) and a finding rate (set as a function of the number of successful wells drilled and the assumed economically recoverable resource base). The unconventional and conventional WCSB economically recoverable resource base estimates assumed in the model for the beginning of 2004 are 70 trillion cubic feet and 96 trillion cubic feet, respectively.[91] For conventional gas, the initial resource level is assumed to grow by 0.5 percent per year throughout the projection period to reflect improvements in

Table 57. Exogenously Specified Canadian Production and Consumption
(billion cubic feet per year)

Year	Consumption	Production Eastern Canada
2000	3,301	142
2005	3,200	182
2010	3,800	355
2015	4,200	800
2020	4,400	830
2025	4,400	730
2030	4,400	730

Source: Consumption - EIA, International Energy Outlook 2005, DOE/EIA-0484(2005); Production - Based on projections from *Canada's Energy Future, Scenarios for Supply and Demand to 2025*, National Energy Board, Calgery, Alberta, 2003.

and penetration of technology. Production from unconventional 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 forecast year.

Annual U.S. exports of liquefied natural gas (LNG) to Japan are assumed to be constant at 64.3 billion cubic feet per year through March of 2009, when the export license expires, and 0.0 through the remainder of the forecast. LNG imports are determined endogenously within the model. The model provides for the construction of new facilities should gas prices be high enough to make construction economic — the prices (including regasification) that are needed to initially trigger new LNG construction in the United States and the Bahamas vary by region and, at the beginning of the forecast, range from $3.19 to $4.80/Mcf (2004 dollars).

Currently there are five LNG facilities in operation, located at Everett, Massachusetts; Lake Charles, Louisiana; Cove Point, Maryland; Elba Island, Georgia; and off the coast of Louisiana (Gulfport Energy Bridge). These five facilities including expansions currently in progress have a combined design capacity of 4,435 million cubic feet per day (1.8 trillion cubic feet per year) and an assumed combined sustainable sendout of 1.3 trillion cubic feet per year. Further expansion is triggered when the regional LNG tailgate[92] price meets or exceeds a trigger price as determined in the model.

The model also has a provision for the construction of new facilities in all United States coastal regions, in eastern Canada, and in Baja California, Mexico. Supplies from a Baja California, Mexico, facility are assumed to enter the United States as pipeline imports from Mexico destined for Southwestern markets. A 1 Bcf per day facility, currently under construction, is assumed to come online in 2008 with one-half of its supplies available to the United States. As with expansion of existing facilities, construction of additional facilities is triggered when the regional LNG tailgate price meets or exceeds a trigger price. The trigger price for initial construction of a Baja California, Mexico, LNG facility starts at $4.93/Mcf (2004 dollars). LNG is represented similarly in eastern Canada, with the trigger price for initial construction at the terminal starting at $5.77/mcf (2004 dollars). These trigger prices are increased by a factor representing the difference between the world market price for LNG and the cost to bring it to the U.S. market. This factor is specified based on the assumed growth in world natural gas consumption from the *International Energy Outlook 2005* and the annual change in the world oil price.

Since LNG does not compete directly with wellhead prices, trigger prices are compared with regional prices in the vicinity of the LNG facility (i.e., the tailgate price) rather than with wellhead prices. With the exception of the Canada and Baja facilities, the individual trigger prices represent the least cost feasible combination of production, liquefaction, and transportation costs to the facility plus the regasification cost at the facility. Regasification costs at new facilities include capital costs for construction of the facility. A range of cost components used in determining trigger prices at new facilities is shown in Table 58. Regional risk premiums are determined based on regional specific factors that include proposal and site identification activity, population density, housing values, income values, and availability of deepwater ports.

Table 58. LNG Cost Components
(2004 dollars per mcf)

	Low		High	
2004 Production	$0.33	Nigeria	$1.50	Peru
2004 Liquefaction	$1.38	All facilities	$1.38	All facilities
Shipping	$0.32	Venezuala to the Bahamas	$1.73	Qatar to Gulf Mexico
Regasification	$0.35	Gulf of Mexico	$1.11	Florida
Risk Premium	$0.16	Western Gulf	$1.23	South Atlantic

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Gas supply costs are based on a March 31, 2003 report produced under contract to EIA by the Gas Technology Institute (GTI), using a conversion factor of 1,100 Btus/cf. Regasification costs are based on Project Technical Liaison, Inc. estimates. Shipping costs are based on various sources, including www.dataloy.com for transportation distances, the GTI Report, and EIA judgement. Liquefaction costs are based on data from Bear Sterns and Wood MacKenzie. Liquefaction, shipping, and regasification costs are determined endogenously in the NGTDM.

The production costs reflect assumed market prices entering the liquefaction facility for various stranded gas[93] locations and average about $0.55 Mcf (2004 dollars). Different supply factors are estimated based on the existing and potential upstream projects for each supply source, and are applied to the average supply cost to arrive at the production cost by source.[94]

Liquefaction costs are estimated based on a declining liquefaction capital cost function for one train (3.9 million metric tons of LNG or 186 Bcf per year) starting at $276 per ton of plant capacity in 2004 and gradually declining to $245 per ton in 2030. The capital cost is to be amortized over a 20-year period with a 18 percent average cost of equity, 60 percent debt fraction, and 30 percent corporate tax rate. The cost of debt is assumed to equal the AA utility bond rate. These liquefaction costs are adjusted to account for individual plant factors such as the plant's age and location. The liquefaction plant utilization rate is assumed to be 93 percent.

LNG shipment costs from a supply source to a receiving terminal are a function of the distance between these two locations, an average per unit-mile shipment cost, and a port cost. The per unit-mile shipment cost is computed as a function of the return on invested capital for the tanker, number of round trips per year, distance between a supply source and an LNG terminal, average tanker capacity, estimated fuel cost, and administrative and general expenses for the tanker serving that route. Taxes are embedded in the administrative and general expenses.

Shipment costs are based on distances, an assumed average capital cost for all the newly built tankers, an average rate of return on the invested capital, tanker fuel costs, administrative and general expenses, an assumed average tanker capacity per trip, and the assumed number of round trips per year for a tanker serving a particular route. The estimated shipment costs, in 2004 dollars/Mcf, were divided by the route distances to arrive at initial transportation costs. On average these calculations provide a result of $0.000173/Mcf-mile in 2004 dollars (i.e., roughly $0.17/Mcf per 1,000 nautical miles). Finally, an assumed $0.05/Mcf port cost is added to each of these transportation costs to arrive at the final shipment costs.

Regasification costs include a fixed and variable component. Variable costs include administrative and general expenses, operating and maintenance expenses, taxes and insurance, electric power costs, and fuel usage and loss. The fixed costs reflect the expected annual return on capital and are based on the assumed capital cost, a 60 percent debt fraction, the cost of debt and equity, a 38 percent corporate tax rate, and a 20-year economic life. The capital costs are based on the cost of storage tanks, vaporizer units, marine facilities, site improvements and roads, buildings and services, installation, engineering and project management, land, contingency, and the capacity of the plant. The cost of debt is tied to the AA utility bond rate and the cost of equity is tied to the 10-year treasury note yield plus a 10-percent risk premium. A per-unit regasification charge for a given size facility is obtained by dividing total costs by an assumed annual throughput. Regional specific factors are applied to account for differences in costs associated with land purchase, labor, site specific permitting, special land and waterway preparation and/or acquisition, and other general construction and operating cost differences.

It is assumed that LNG facilities are developed with an initial design capacity along with a capability for future expansion. For existing terminals, original capital expenditures are considered sunk costs. Costs were additionally determined for expansion beyond documented expansion capability at existing facilities under the assumption that if prices reached sustained levels at which new facilities would be constructed, additional expansion at existing facilities would likely be considered. The costs of expansion at existing facilities within a region are in general lower that those for the construction of new facilities. If market prices warrant, additional capacity can be added in a region either through expansion or construction of new facilities.

Legislation and Regulation

The methodology for setting reservation fees for transportation services is consistent with FERC's alternative ratemaking and capacity release position in that it allows flexibility in the rates pipelines charge. The methodology is market-based in that prices for transportation services will respond positively to increased demand for services while prices will decline (reflecting discounts to retain customers) should the demand for services decline. The Pipeline Safety Improvement Act of 2002 is not explicitly represented, but is expected to raise transportation costs by an insignificant amount.

Section 116 of the Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2004 (H.R.4837) gives the Secretary of Energy the authority to issue Federal loan guarantees for an Alaska natural gas transportation project, including the Canadian portion, that would carry natural gas from northern Alaska, through the Canadian border south of 68 degrees north latitude, into Canada, and to the lower-48 States. This authority would expire 2 years after the final certificate of public convenience and necessity is issued. In aggregate the loan guarantee would not exceed: (1) 80 percent of total capital costs (including interest during construction); (2) $18 billion dollars (indexed for inflation at the time of enactment); or (3) a term of 30 years. The Act also promotes streamlined permitting and environmental review, an expedited court review process, and protection of rights-of-way for the pipeline. The loan guarantee was represented in the model by lowering the cost of debt by a percentage point and increasing the debt fraction fro 70 percent to 80 percent.

Section 706 of the American Jobs Creation Act of 2004 (H.R.4520) provides a 7-year cost-of-investment recovery period for the Alaska natural gas pipeline, as opposed to the currently allowed 15-year recovery period, for tax purposes. The provision would be effective for property placed in service after 2013, or treated as such. The provision was represented in the model by lowering the cost of equity by 3 percentage points.

Section 707 of the American Jobs Creation Act would extend the 15-percent tax credit currently applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant that supplies natural gas to a 2 trillion Btu per day pipeline, lies in Northern Alaska, and produces carbon dioxide for injection into hydrocarbon-bearing geological formations. A gas treatment plan on the North Slope that feeds gas into an Alaska pipeline to Canada is expected to satisfy this requirement. The provision would be effective for costs incurred after 2004. The provision was represented in the model by lowering the rate charge for natural gas treatment by $0.05 per Mcf.

High and Low Liquefied Natural Gas Import Cases

Two cases were created to assess the impact of a range of liquefied natural gas (LNG) imports on the domestic natural gas market. The future level of LNG imports into the United States is highly uncertain. The levels will depend on such things as the ability and motivation of companies to site regasification facilities domestically, the ability and motivation of companies to site liquefaction facilities throughout the world, the world market for natural gas shipped via pipeline and in liquid form, the relative need for consuming the available natural gas in other parts of the world, the potential other uses for the gas (e.g., its conversion into liquid fuel), and finally the price of LNG on the world market, which in turn is impacted by the cost of producing, liquefying, shipping, and regasifying the gas. These cases are intended to highlight the impact if LNG imports were actually much different than under the reference case, for whatever reason. The high and low liquefied natural gas import cases were formulated by setting the LNG import levels to 30 percent more and 30 percent less than the LNG import levels determined within the low price and the high price cases, respectively.

Notes and Sources

[91] For unconventional -- Average undiscovered resources under the National Energy Board's Supply Push and Techno-vert scenarios in "Canada's Energy Future, Scenarios for Supply and Demand to 2025," 2003. For conventional -- "Canada's Conventioal Natural Gas Resources -- A Status Report," April 2004.

[92] Tailgate LNG prices represents the price when natural gas exists the regasification facility.

[93] Gas reserves that have been located but are isolated from potential markets, commonly referred to as “stranded” gas, are likely to provide most of the natural gas for LNG in the future. Reserves that can be linked to sources of demand via pipeline are unlikely candidates to be developed for LNG.

[94] Largely based on information from Gas Technology Institute, “Liquefied Natural Gas (LNG) Methodology Enhancements in NEMS,” Report submitted to Energy Information Administration, March 31, 2003.