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This report documents the archived version of the NGTDM that was used to produce the natural gas forecasts presented in the *Annual Energy Outlook 2014*, (DOE/EIA-0383(2014). The purpose of this report is to provide a reference document for model analysts, users, and the public that defines the objectives of the model, describes its basic approach, and provides detail on the methodology employed.

The model documentation is updated annually to reflect significant model methodology and software changes that take place as the model develops. The next version of the documentation is planned to be released in the first quarter of 2016.

Update Information

This edition of the model documentation of the Natural Gas Transmission and Distribution Module (NGTDM) reflects changes made to the module over the past year for the *Annual Energy Outlook 2014*. Aside from general data and parameter updates, the notable changes include the following:

- Limit the number of new liquefied natural gas trains in North America to three per year rather than one per year, allow export capacity utilization to decline if relative prices warrant, and exogenously set liquefied natural gas exports out of Canada.
- Base natural gas regional flow decisions on variable rates (i.e., excluding reservation charges) and set rates based on historical differentials between representative regional spot prices (i.e., basis differentials)
- Allow for reversal of pipeline flows on specifically identified arcs deemed likely for this to occur.
- Set delivered prices to electric generators based on regional spot prices, not city gate prices.
- Assign prices for compressed natural gas and liquefied natural gas use in trains and ships.

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Abbreviations and acronyms

AEO	Annual Energy Outlook
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
Btu	British thermal unit
DTS	Distributor Tariff Submodule
EMM	Electricity Market Module
GAMS	Gas Analysis Modeling System
gas	natural gas
IFFS	Integrated Future Forecasting System
INGM	International Natural Gas Model
ITS	Interstate Transmission Submodule
LFMM	Liquid Fuels Market Module
MEFS	Mid-term Energy Forecasting System
MMBtu	Million British thermal units
Mcf	Thousand cubic feet
MMcf	Million cubic feet
MMcfd	Million cubic feet per day
MMbbl	Million barrels
NEMS	National Energy Modeling System
NGA	Natural Gas Annual
NGM	Natural Gas Monthly
NGTDM	Natural Gas Transmission and Distribution Module
OGSM	Oil and Gas Supply Module
PIES	Project Independence Evaluation System
PTS	Pipeline Tariff Submodule
STEO	Short-Term Energy Outlook
Tcf	Trillion cubic feet
WCSB	Western Canadian Sedimentary Basin

1. Background/Overview

Background

The Natural Gas Transmission and Distribution Module (NGTDM) is the component of the National Energy Modeling System (NEMS) that is used to represent the U.S. domestic natural gas transmission and distribution system. NEMS was developed by the former Office of Integrated Analysis and Forecasting of the U.S. Energy Information Administration (EIA) and is the third in a series of computer-based, midterm energy modeling systems used since 1974 by EIA and its predecessor, the Federal Energy Administration, to analyze and project U.S. domestic energy-economy markets. From 1982 through 1993, the Intermediate Future Forecasting System (IFFS) was used by EIA for its integrated analyses. Prior to 1982, the Midterm Energy Forecasting System (MEFS), an extension of the simpler Project Independence Evaluation System (PIES), was employed. NEMS was developed to enhance and update EIA's modeling capability. Greater structural detail in NEMS permits the analysis of a broader range of energy issues. While NEMS was initially developed in 1992, the model is updated each year, from simple historical data updates to complete replacements of submodules.

The time horizon of NEMS is the midterm period that extends approximately 25 years, currently to year 2040. In order to represent the regional differences in energy markets, the component modules of NEMS function at regional levels appropriate for the markets represented, with subsequent aggregation/disaggregation to the Census Division level for reporting purposes. The projections in NEMS are developed assuming that energy markets are in equilibrium[1] using a recursive price adjustment mechanism.[2] For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for the economic competition between the various fuels and sources. NEMS is organized and implemented as a modular system.[3] The NEMS modules represent each of the fuel supply markets, conversion sectors (e.g., refineries and power generation), and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The system includes a routine that simulates a carbon emissions cap and trade system with annual fees to limit carbon emissions from energy-related fuel combustion. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, Census Division, and end-use sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production activity, and international petroleum supply availability.

The integrating routine of NEMS controls the execution of each of the component modules. The modular design provides the capability to execute modules individually, thus allowing independent analysis with, as well as development of, individual modules. This modularity allows the use of the methodology and level of detail most appropriate for each energy sector. Each forecasting year, NEMS

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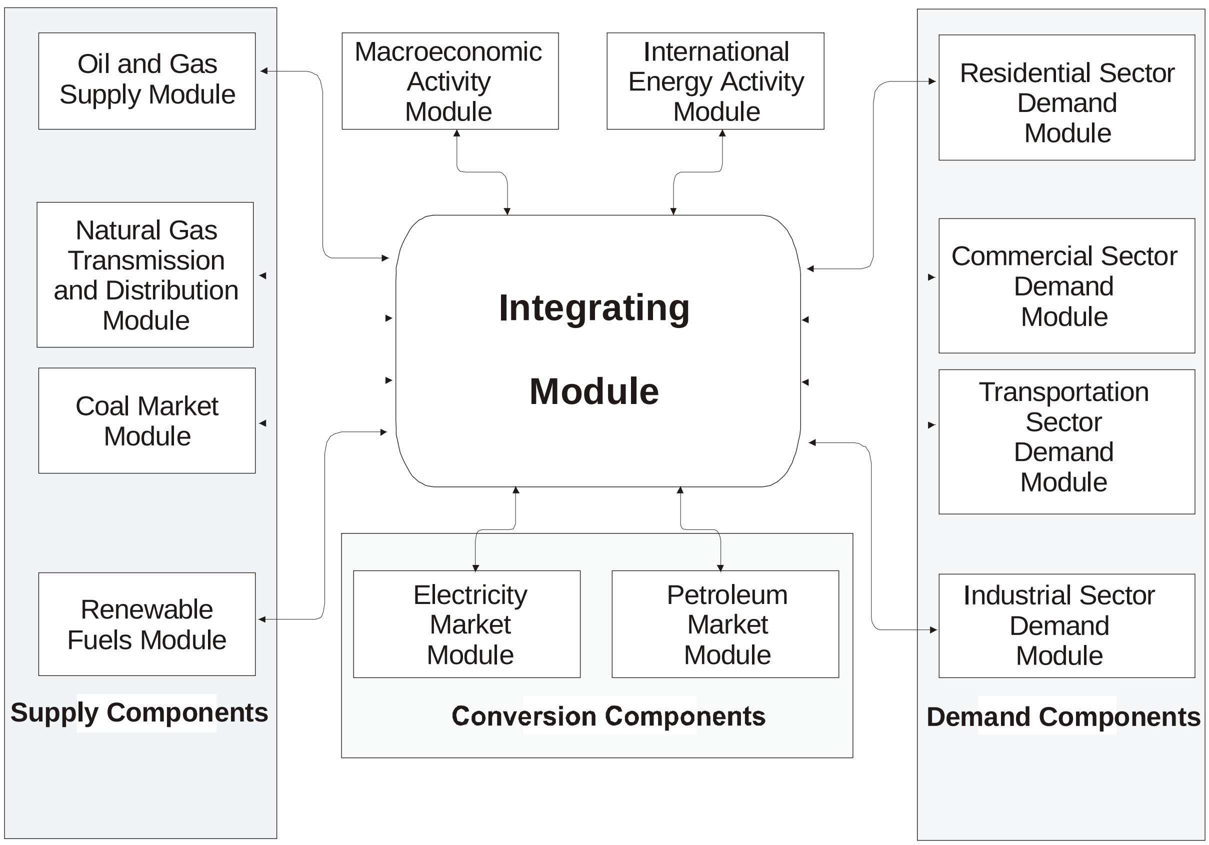
[1] Markets are said to be in equilibrium when the quantities demanded equal the quantities supplied at the same price; that is, at a price that sellers are willing to provide the commodity and consumers are willing to purchase the commodity.

[2] The central theme of the approach used is that supply and demand imbalances will eventually be rectified through an adjustment in prices that eliminates excess supply or demand.

[3] NEMS is composed of 13 modules including a system integration routine.

solves by iteratively calling each module in sequence (once in each NEMS iteration) until the delivered prices and quantities of each fuel in each region have converged within tolerance between the various modules, thus achieving an economic equilibrium of supply and demand in the consuming sectors. For some applications the model is also run in multiple cycles, generally to converge on a solution that involves the need to look ahead at other projected values for future years when solving the current forecasting year. Module solutions are reported annually through the midterm horizon. A schematic of NEMS is provided in **Figure 1-1**, while a list of the associated model documentation reports is in Appendix C, including a report providing an overview of the whole system.

Figure 1-1. Schematic of the National Energy Modeling System



NGTDM overview

The NGTDM module within NEMS represents the transmission, distribution, and pricing of natural gas. Based on information received from other NEMS modules, the NGTDM also includes representations of the end-use demand for natural gas, the production of domestic natural gas, and the availability of natural gas traded on the international market. The NGTDM links natural gas suppliers (including importers) and consumers in the Lower 48 states, including liquefied natural gas (LNG) export terminals, and across the Mexican and Canadian borders via a natural gas transmission and distribution network, while determining the flow of natural gas and the regional market clearing prices between suppliers and end-users. For two seasons of each forecast year, the NGTDM determines the production, flows, and prices of natural gas within an aggregate representation of the U.S./Canadian pipeline network, connecting domestic and foreign supply regions with 12 U.S. and 2 Canadian demand regions. Since

NEMS operates on an annual (not a seasonal) basis, NGTDM results are generally passed to other NEMS modules as annual totals or quantity-weighted annual averages. Since the Electricity Market Module has a seasonal component, peak and off-peak[4] prices are also provided for natural gas to electric generators.

Natural gas pricing and flow patterns are derived by obtaining a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The methodology employed allows for the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of primary pipeline and storage capacity expansion requirements. Key components of interstate pipeline tariffs are projected, along with distributor tariffs.

The Lower 48 demand regions represented are the 12 NGTDM regions (**Figure 1-2**). These regions are an extension of the nine Census Divisions, with Census Division 5 split into South Atlantic and Florida, Census Division 8 split into Mountain and Arizona/New Mexico, Census Division 9 split into California and Pacific, and Alaska and Hawaii handled independently. Within the U.S. regions, consumption is represented for five end-use sectors: residential, commercial, industrial, electric generation, and transportation (or natural gas vehicles), with the industrial and electric generator sectors further distinguished by core and noncore segments. The transportation sector is separated into compressed and liquefied natural gas for use in vehicles (retail and fleet), ships, and trains.

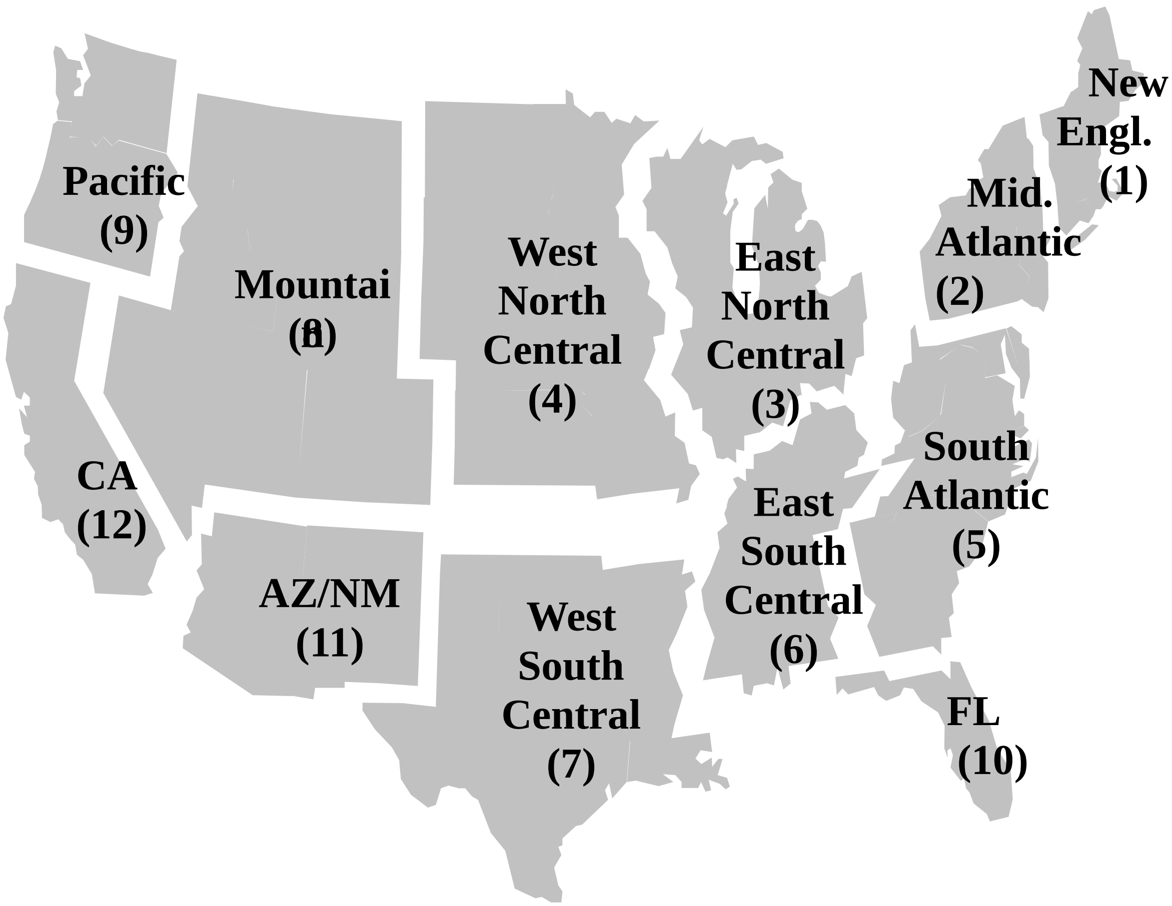
One or more domestic supply region is represented in each of the 12 NGTDM regions. Canadian supply and demand are represented by two interconnected regions -- East Canada and West Canada -- which connect to the Lower 48 regions via seven border crossing nodes. The demarcation of East and West Canada is at the Manitoba/Ontario border. In addition, the model accounts for the potential construction of a pipeline from Alaska to Alberta and one from the Mackenzie Delta to Alberta, if market prices are high enough to make the projects economic. The representation of the natural gas market in Canada is much less detailed than for the United States since the primary focus of the model is on the domestic U.S. market. Potential LNG imports into and LNG exports out of North America are modeled for each of the coastal regions represented in the model, including seven regions in the United States, a potential import point in the Bahamas, potential import/export points in eastern and western Canada, and imports into western Mexico (if destined for the United States).[5] Any LNG facilities in existence or under construction are included in the model. While the model does not project the construction of any additional import facilities, the construction of LNG export facilities are projected. Finally, imports and exports with Mexico are projected at three border crossings.

The module consists of three major components: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS), as well as several satellite components to establish various market elements not represented elsewhere in NEMS such as: a coal-to-gas conversion component, an Alaska demand component, a Canadian supply/demand component, a Mexico supply/demand component, and an LNG supply/demand component. The ITS is the integrating submodule of the NGTDM. It simulates the natural gas price determination process by bringing together

[4] The peak period covers the period from December through March; the off-peak period covers the remaining months.
[5] Maximum LNG imports into Mexico to serve the Mexico market are set exogenously.

all major economic factors that influence regional natural gas trade in the United States, including pipeline and storage capacity expansion decisions. The Pipeline Tariff Submodule (PTS) generates a representation of tariffs for interstate transportation and storage services, both existing and expansions. The Distributor Tariff Submodule (DTS) generates markups for distribution services provided by local distribution companies and for transmission services provided by intrastate pipeline companies. The modeling techniques employed are a heuristic/iterative process for the ITS, an accounting algorithm for the PTS, and a series of historically based and econometrically based equations for the DTS.

Figure 1-2. Natural Gas Transmission and Distribution Module (NGTDM) Regions



NGTDM objectives

The primary purpose of the NGTDM is to derive natural gas delivered and supply prices, as well as flow patterns for movements of natural gas through the regional interstate network. Although NEMS operates on an annual basis, the NGTDM was designed to be a two-season model, to better represent important features of the natural gas market. The prices and flow patterns are derived by obtaining a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The representations of the key features of the transmission and distribution network are the focus of the various components of the NGTDM. These key modeling objectives/capabilities include:

- Represent interregional flows of gas and pipeline capacity constraints
- Represent regional and import supplies, as well as demands for exports
- Determine the amount and the location of required additional pipeline and storage capacity on a regional basis
- Provide a peak/off-peak or seasonal analysis capability
- Represent transmission and distribution service pricing

Overview of the documentation report

The archived version of the NGTDM that was used to produce the natural gas forecasts used in support of the *Annual Energy Outlook 2014*, DOE/EIA-0383(2014) is documented in this report. The purpose of this report is to provide a reference document for model analysts, users, and the public that defines the objectives of the model, describes its basic design, provides detail on the methodology employed, and describes the model inputs, outputs, and key assumptions. It is intended to fulfill the legal obligation of EIA to provide adequate documentation in support of its models (Public Law 94-385, Section 57.b.2). Subsequent chapters of this report provide:

- A description of the interface between NEMS and the NGTDM and the representation of demand and supply used and established in the module (Chapter 2)
- An overview of the solution methodology of the NGTDM (Chapter 3)
- The solution methodology for the Interstate Transmission Submodule (Chapter 4)
- The solution methodology for the Distributor Tariff Submodule (Chapter 5)
- The solution methodology for the Pipeline Tariff Submodule (Chapter 6)
- A description of module assumptions, inputs, and outputs (Chapter 7)

The archived version of the model is available through the National Energy Information Center (202-586-8800, infoctr@eia.gov) and is identified as NEMS2014 (part of the National Energy Modeling System archive package as archived for the Annual Energy Outlook 2014, DOE/EIA-0383(2014)).

The document includes a number of appendices to support the material presented in the main body of the report. Appendix A presents the module abstract. Appendix B lists the major references used in developing the NGTDM. Appendix C lists the various NEMS Model Documentation Reports for the various modules that are mentioned throughout the NGTDM documentation. A mapping of equations presented in the documentation to the relevant subroutine in the code is provided in Appendix D. Appendix E provides a mapping between the variables that are assigned values through READ statements in the module and the data input files that are read. The input files contain detailed descriptions of the input data, including variable names, definitions, sources, units and derivations.[6] Appendix F documents the derivation of all empirical estimations used in the NGTDM. Variable cross-reference tables are provided in Appendix G. Finally, Appendix H contains a description of the algorithm used to project new coal-to-gas plants and the pipeline-quality gas produced.

[6] The NGTDM data files are available upon request by contacting Joe Benneche at Joseph.Benneche@eia.gov or (202) 586-6132. Alternatively, an archived version of the NEMS model (source code and data files) can be downloaded from http://www.eia.gov/forecasts/aeo/info_nems_archive.cfm.

2. Demand and Supply Representation

This chapter describes how supply and demand are represented within the NGTDM and the basic function that the Natural Gas Transmission and Distribution Module (NGTDM) fulfills in NEMS. First, a general description of NEMS is provided, along with an overview of the NGTDM. Second, the data passed to and from the NGTDM and other NEMS modules is described along with the methodology used within the NGTDM to transform the input values prior to their use in the model. The natural gas demand representation used in the module is described, followed by a section on the natural gas supply interface and representation, and concluding with a section on the representation of demand and supply in Alaska.

A brief overview of NEMS and the NGTDM

NEMS represents all of the major fuel markets (crude oil and petroleum products, natural gas, coal, electricity, and imported energy) and iteratively solves for an annual supply/demand balance for each of the nine Census Divisions, accounting for the price responsiveness in both energy production and end-use demand, and for the interfuel substitution possibilities. NEMS solves for an equilibrium in each forecast year by iteratively operating a series of fuel supply and demand modules to compute the end-use prices and consumption of the fuels represented, effectively finding the intersection of the theoretical supply and demand curves reflected in these modules.[7] The end-use demand modules (for the residential, commercial, industrial, and transportation sectors) are detailed representations of the important factors driving energy consumption in each of these sectors. Using the delivered prices of each fuel, computed by the supply modules, the demand modules evaluate the consumption of each fuel, taking into consideration the interfuel substitution possibilities, the existing stock of fuel and fuel conversion burning equipment, and the level of economic activity. Conversely, the fuel conversion and supply modules determine the end-use prices needed in order to supply the amount of fuel demanded by the customers, as determined by the demand modules. Each supply module considers the factors relevant to that particular fuel, for example: the resource base for oil and gas, the transportation costs for coal, or the refinery configurations for petroleum products. Electric generators and refineries are both suppliers and consumers of energy.

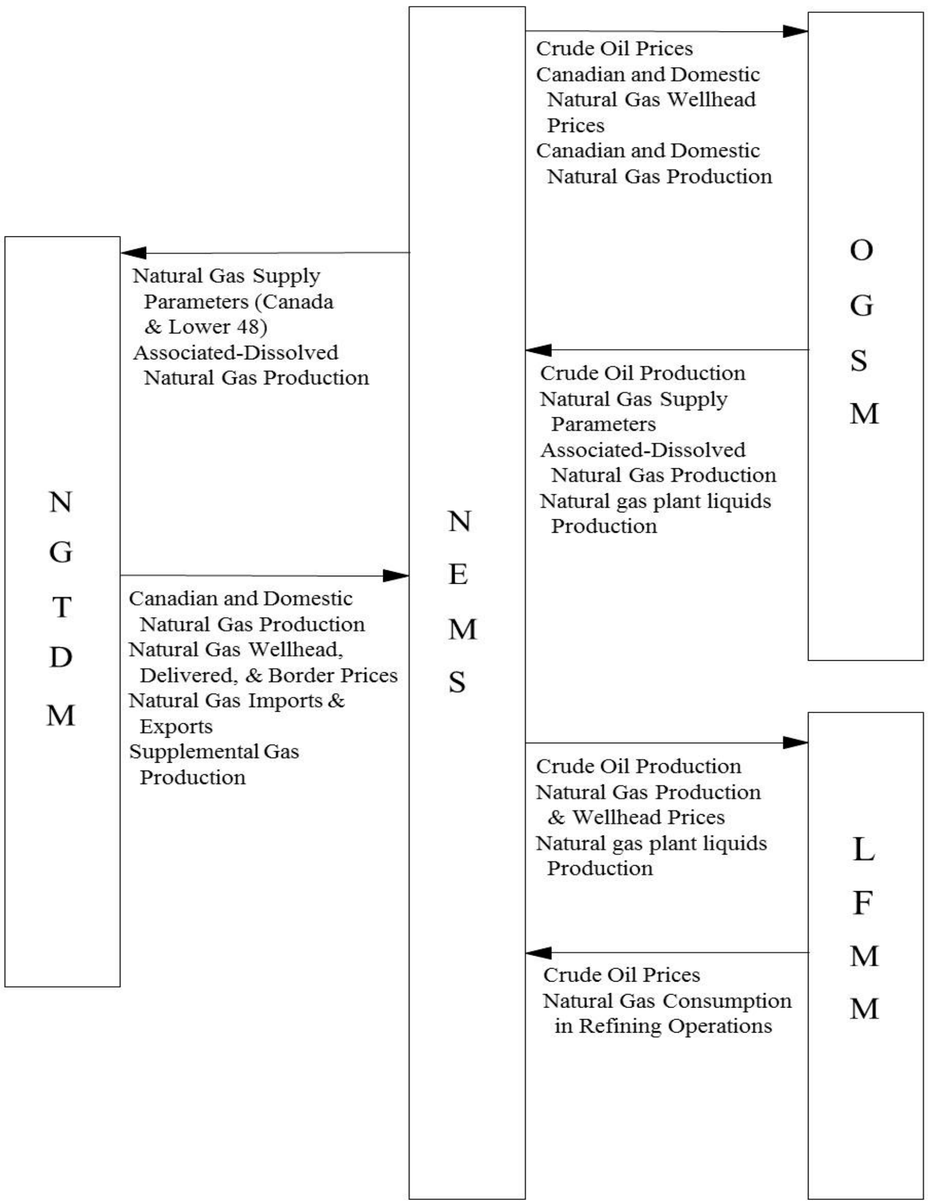
Within the NEMS system, the NGTDM provides the interface for natural gas between the Oil and Gas Supply Module (OGSM) and the demand modules in NEMS, including the Electricity Market Module (EMM). Since the other modules provide little, if any, information on markets outside of the United States, the NGTDM uses supply curves for liquefied natural gas (LNG) imports based on output results from EIA's separate International Natural Gas Model (INGM) and includes a simple representation of natural gas markets in Canada and Mexico in order to project LNG and pipeline import levels into the United States. It similarly represents/projects exports via pipeline and as LNG. The NGTDM estimates the price and flow of dry natural gas supplied internationally from the contiguous U.S. border[8] or domestically from the wellhead (and indirectly from natural gas processing plants) to the domestic end-

[7] A more detailed description of the NEMS system, including the convergence algorithm used, can be found in "Integrating Module of the National Energy Modeling System: Model Documentation 2013." DOE/EIA-M057(2013), June 2013 or "The National Energy Modeling System: An Overview 2009," DOE/EIA-0581(2009), October 2009.

[8] Natural gas exports are also accounted for within the model.

user. In so doing, the NGTDM models the markets for the transmission (pipeline companies) and distribution (local distribution companies) of natural gas in the contiguous United States.[9] The primary data flows between the NGTDM and the other oil and gas modules in NEMS, the Liquid Fuels Market Module (LFMM) and the OGSM are depicted in **Figure 2-1**.

Figure 2-1. Primary Data Flows between Oil and Gas Modules of NEMS



[9] Because of the distinct separation in the natural gas market between Alaska, Hawaii, and the contiguous United States, natural gas consumption in, and the associated supplies from, Alaska are modeled separately from the contiguous United States within the NGTDM. Since volumes associated with Hawaii are relatively small, they are just considered part of the NGTDM region for California.

In each NEMS iteration, the demand modules in NEMS provide the level of natural gas that would be consumed at the burner-tip in each region by the represented sector at the delivered price set by the NGTDM in the previous NEMS iteration. At the beginning of each forecast year during a model run, the OGSM provides an expected annual level of natural gas produced at the wellhead in each region represented, given the oil and gas wellhead prices from the previous forecast year. (Some supply sources (e.g., Canada) are modeled directly in the NGTDM.) The NGTDM uses this information to build "short-term" (annual or seasonal) supply and demand curves to approximate the supply or demand response to price. Given these short-term demand and supply curves, the NGTDM solves for the delivered, hub or spot,[10] wellhead, and border prices that represent a natural gas market equilibrium, while accounting for the costs and market for transmission and distribution services (including its physical and regulatory constraints).[11] These solution prices, and associated production levels, are in turn passed to the OGSM and the demand modules, including the EMM, as primary input variables for the next NEMS iteration and/or forecast year. Most of the calculations within OGSM are performed only once each NEMS iteration, before NEMS begins the process of converging to an equilibrium solution. Information from OGSM is then passed as needed to the NGTDM to solve for the forecast year.

The NGTDM is composed of three primary components or submodules: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS). The ITS is the central module of the NGTDM, since it is used to derive network flows and prices of natural gas in conjunction with a peak[12] and off-peak natural gas market equilibrium. Conceptually the ITS is a simplified representation of the natural gas transmission and distribution system, structured as a network composed of nodes and arcs. The other two primary components serve as satellite submodules to the ITS, providing parameters which define the tariffs to be charged along each of the interregional, intraregional, intrastate, and distribution segments. Data are also passed back to these satellite submodules from the ITS. Other parameters for defining the natural gas market (such as supply and demand curves) are derived based on information passed primarily from other NEMS modules. However in some cases, supply (e.g., synthetic gas production) and demand (e.g., pipeline fuel) components are modeled exclusively in the NGTDM.

The NGTDM is called once each NEMS iteration, but all submodules are not run for every call. The PTS is executed only once for each forecast year, on the first iteration for each year. The ITS and the DTS are executed once every NEMS iteration. The calling sequence of and the interaction among the NGTDM modules is as follows for each forecast year executed in NEMS:

First Iteration:

- The PTS determines the revenue requirements associated with interregional/interstate pipeline company transportation and storage services, using a cost-based approach, and uses this

[10] Regional hub prices are reflective of a representative regional spot price.

[11] Parameters are provided by OGSM for the construction of supply curves for domestic non-associated natural gas production. The NGTDM establishes a supply curve for tight/other Western Canada. The use of demand curves in the NGTDM is an option; the model can also respond to fixed consumption levels.

[12] The peak period covers the period from December through March; the off-peak period covers the remaining months.

information and cost of expansion estimates as a basis in establishing fixed rates and volume-dependent tariff curves (variable rates) for pipeline and storage usage.

- The ITS establishes supply levels (e.g., for supplemental supplies) and supply curves for production and LNG imports based on information from other modules.

Each Iteration:

- The DTS sets markups for intrastate transmission and for distribution services using econometric relationships based on historical data, largely driven by changes in consumption levels.
- The ITS establishes projected values for supporting components, generally set as a function of prices from the previous iteration, for such things as LNG imports and exports, consumption in Alaska, coal-to-gas production, imports and exports from Mexico, and exports to Canada.
- The ITS processes consumption levels from NEMS demand modules as required, (e.g., annual consumption levels are disaggregated into peak and off-peak levels) before determining a market equilibrium solution across the two-period NGTDM network.
- The ITS employs an iterative process to determine a market equilibrium solution which balances the supply and demand for natural gas across a U.S./Canada network, thereby setting prices throughout the system and production and import levels. This operation is performed simultaneously for both the peak and off-peak periods.

Last Iteration:

- In the process of establishing a network/market equilibrium, the ITS also determines the associated pipeline and storage capacity expansion requirements. These expansion levels are passed to the PTS and are used in the revenue requirements calculation for the next forecast year. One of the inputs to the NGTDM is “planned” pipeline and storage expansions. These are based on reported pending and commenced construction projects and analysts’ judgment as to the likelihood of the project’s completion. For the first two forecast years, the model does not allow builds beyond these planned expansion levels.
- Other outputs from NGTDM are passed to report-writing routines.

For the historical years (1990 through 2012), a modified version of the above process is followed to calibrate the model to history. Most, but not all, of the model components are known for the historical years. In a few cases, historical levels are available annually, but not for the peak and off-peak periods (e.g., the interstate flow of natural gas and regional supply prices). The primary unknowns are pipeline and storage tariffs and regional market prices. When prices are translated from the supply nodes, through the network to the end-user (or city gate) in the historical years, the resulting prices are compared against published values for city gate prices. These differentials (benchmark factors) are carried through and applied during the forecast years as a calibration mechanism. In the most recent historical year (2012) even fewer historical values are known, and the process is adjusted accordingly.

The primary outputs from the NGTDM, which are used as input in other NEMS modules, result from establishing a natural gas market equilibrium solution: delivered prices, spot, wellhead and border crossing prices, and non-associated natural gas production. In addition, the NGTDM provides a forecast of natural gas imports and exports, lease and plant fuel consumption, and pipeline fuel use, as well as pipeline and distributor tariffs, pipeline and storage capacity expansion, and interregional natural gas flows.

Natural gas demand representation

Natural gas produced within the United States is consumed in lease and plant operations, delivered to consumers, exported internationally, or consumed as pipeline fuel. Within the NGTDM, natural gas demand in the United States is represented for the five primary consuming sectors (residential, commercial, industrial, electric generators, and transportation) based on projected values set in the NEMS demand modules. In addition, the NGTDM internally represents natural gas consumed for lease, plant, and pipeline fuel, as well as pipeline and liquefied natural gas exported out of the United States and the rest of North America (discussed in a later section, along with assumptions used for natural gas consumption in Canada and Mexico). In order to deal with the distinct natural gas markets between Alaska and the Lower 48 region, natural gas consumption in Alaska is estimated separately in the NGTDM (also discussed later) although it is already included in projected volumes for the Pacific Census Division.

Classification of natural gas consumers

Natural gas that is delivered to consumers is represented within NEMS at the Census Division level and by five primary end-use sectors: residential, commercial, industrial, transportation, and electric generation.[13] These demands are further distinguished by customer class (core or non-core), reflecting the type of natural gas transmission and distribution service that is assumed to be predominantly purchased. A “core” customer is expected to generally require guaranteed or firm service, particularly during peak days/periods during the year. A “non-core” customer is expected to require a lower quality of transmission services (non-firm service) and therefore, consume gas under a less-certain and/or less-continuous basis. While customers are distinguished by customer class for the purpose of assigning different delivered prices, the NGTDM does not explicitly distinguish firm versus non-firm transmission service. Currently in NEMS, all customers in the transportation, residential, and commercial sectors are classified as core.[14] Within the industrial sector the non-core segment is made up of the energy-intensive industries, while the core is made up of the non-energy-intensive industries. The electric generating units defining each of the two customer classes modeled are as follows: (1) core − gas steam

[13] Natural gas burned in the transportation sector is defined as compressed natural gas or liquefied natural gas that is burned in natural gas vehicles, including ships and trains; and the electric generation sector includes all electric power generators whose primary business is to sell electricity, or electricity and heat, to the public, including combined heat and power plants, small power producers, and exempt wholesale generators.

[14] NEMS is structurally able to classify a segment of these sectors as non-core, but currently sets the non-core consumption at zero for the residential, commercial, and transportation sectors.

units or gas combined-cycle units, (2) non-core − dual-fired turbine units, gas turbine units, or dual-fired steam plants (consuming both natural gas and residual fuel oil). [15]

For any given NEMS iteration and forecast year, the demand modules in NEMS determine the level of natural gas consumption for each region and customer class given the delivered price for the same region, class, and sector, as calculated by the NGTDM in the previous NEMS iteration. Within the NGTDM, each of these consumption levels (and its associated price) is used in conjunction with an assumed price elasticity as a basis for building an annual demand curve. (The price elasticities are set to zero if fixed consumption levels are to be used.) These curves are used within the NGTDM to minimize the required number of NEMS iterations by approximating the demand response to a different price. In so doing, the price where the implied market equilibrium would be realized can be approximated. Each of these market equilibrium prices is passed to the appropriate demand module during the next NEMS iteration to determine the consumption level that the module would actually forecast at this price. Once NEMS converges, the difference between the actual consumption, as determined by the NEMS demand modules, and the approximated consumption levels in the NGTDM are insignificant.

For all but the electric sector, the NGTDM disaggregates the annual Census division regional consumption levels into the regional and seasonal representation that the NGTDM requires. The regional representation for the electric generation sector differs from the other NEMS sectors as described below.

Regional/seasonal representations of demand

Natural gas consumption levels by all non-electric[16] sectors areprovided by the NEMS demand modules for the nine Census divisions, the primary integrating regions represented in NEMS. Alaska and Hawaii are included within the Pacific Census Division. The EMM represents the electricity generation process for 22 electricity supply regions (**Figure 2-2**). Within the EMM, the electric generators' consumption of natural gas is disaggregated into subregions that can be aggregated into Census Divisions or into the regions used in the NGTDM.

With the following few exceptions, the regional detail provided at a Census division level is adequate to build a simple network representative of the contiguous U.S. natural gas pipeline system. First, Alaska is not connected to the rest of the Nation by pipeline and is therefore treated separately from the contiguous Pacific Division in the NGTDM. Second, Florida receives its gas via a distinctly different route than the rest of the South Atlantic Division and is therefore isolated. A similar statement applies to Arizona and New Mexico relative to the Mountain Division. Finally, California is split off from the contiguous Pacific Division because of its relative size coupled with its unique energy-related regulations. The resulting 12 primary regions represented in the NGTDM are referred to as the "NGTDM Regions" (**Figure 1-2**).

[15] Currently natural gas prices for the core and non-core segments of the electric generation sector are set to the same average value.

[16] The term "non-electric sectors" refers to sectors (other than commercial and industrial combined heat and power generators) that do not produce electricity using natural gas (i.e., the residential, commercial, industrial, and transportation demand sectors).

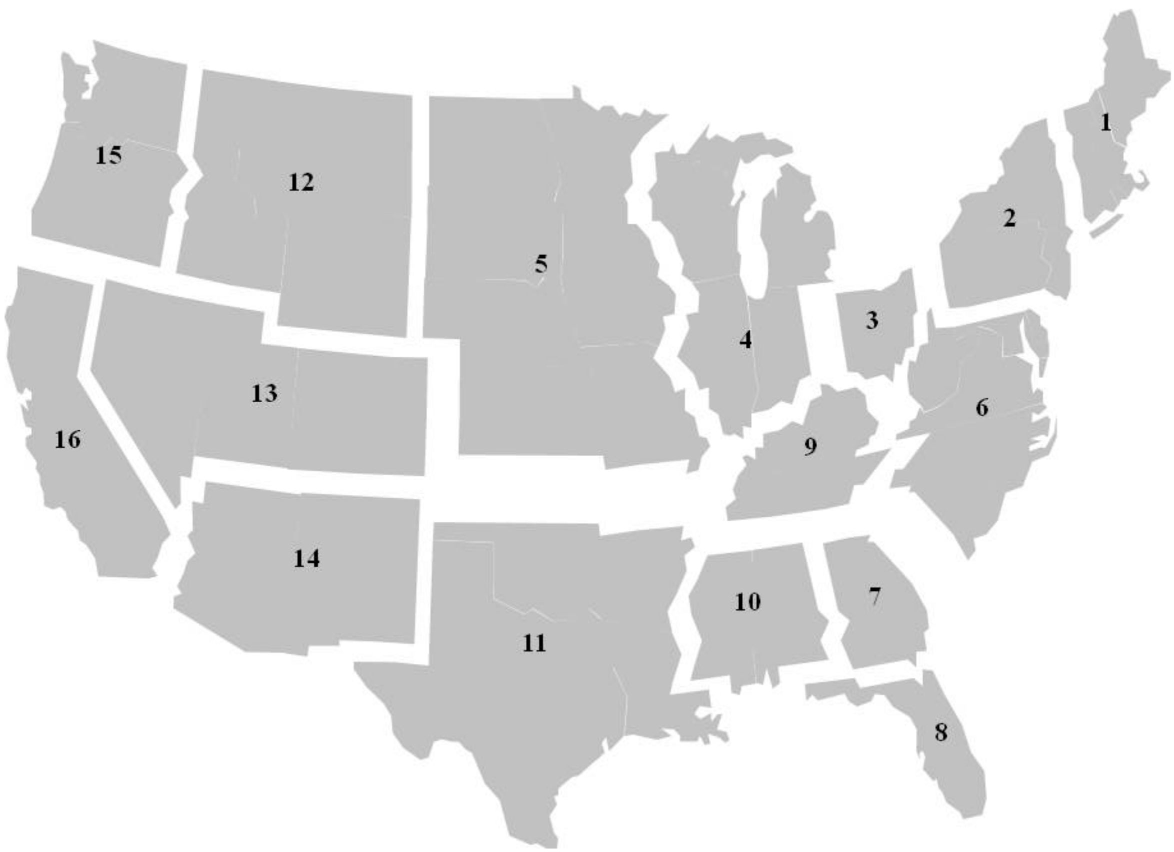
Figure 2-2. Electricity Market Module (EMM) Regions

The regions represented in the EMM do not always align with State borders and generally do not share common borders with the Census divisions or NGTDM regions. Therefore, demand in the electric generation sector is represented in the NGTDM at a 17-subregional (NGTDM/EMM) level which allows for a reasonable regional mapping between the EMM and the NGTDM regions (**Figure 2-3**). The seventeenth region is Alaska. Within the EMM, the disaggregation into subregions is based on the relative geographic location (and natural gas-fired generation capacity) of the current and proposed electricity generation plants within each region.

Annual consumption levels for each of the non-electric sectors are disaggregated from the nine Census divisions to the two seasonal periods and the twelve NGTDM regions by applying average historical shares (2001 to 2012) that are held constant throughout the forecast (census − NG_CENSHR, seasons − PKSHR_DMD). For the Pacific Division, natural gas consumption estimates for Alaska are first subtracted to establish a consumption level for just the contiguous Pacific Division before the historical share is applied. The consumption of gas in Hawaii was considered to be negligible and is not handled separately. Within the NGTDM, a relatively simple series of equations (described later in the chapter) was included for approximating the consumption of natural gas by each non-electric sector in Alaska. These estimates, combined with the levels provided by the EMM for consumption by electric generators in Alaska, are used in the calculation of the production of natural gas in Alaska.

Unlike the non-electric sectors, the factors (core − PKSHR_UDMD_F, non-core − PKSHR_UDMD_I) for disaggregating the annual electric generator sector consumption levels (for each NGTDM/EMM region and customer type − core and non-core) into seasons are adjusted over the forecast period. Initially average historical shares (1994 to 2012, except New England − 1997 to 2012) are established as base-level shares. The peak-period shares are increased each year of the forecast by 0.5% (with a corresponding decrease in the off-peak shares) not to exceed 32% of the year.[17]

Figure 2-3. NGTDM/EMM Regions



Natural gas demand curves

While the primary analysis of energy demand takes place in the NEMS demand modules, the NGTDM itself directly incorporates price-responsive demand curves to speed the overall convergence of NEMS and to improve the quality of the results obtained when the NGTDM is run as a stand-alone model. The NGTDM may also be executed to determine delivered prices for fixed consumption levels (represented

[17] The peak period covers 33% of the year.

by setting the price elasticity of demand in the demand curve equation to zero). The intent is to capture relatively minor movements in consumption levels from the provided base levels in response to price changes, not to accurately mimic the expected response of the NEMS demand modules. The form of the demand curves for the firm transmission service type for each non-electric sector and region is:

$$NGDMD\_CRVF_{s,r} = BASQTY\_F_{s,r} * (PR / BASPR\_F_{s,r})^{NONU\_ELAS\_F_s} \tag{1}$$

where,

$BASPR\_F_{s,r}$	=	delivered price to core sector s in NGTDM region r in the previous NEMS iteration (1987 dollars per Mcf)
$BASQTY\_F_{s,r}$	=	natural gas quantity which the NEMS demand modules indicate would be consumed at price BASPR_F by core sector s in NGTDM region r (Bcf)
$NONU\_ELAS\_F_s$	=	short-term price elasticity of demand for core sector s (set to zero for *AEO2014* or to represent fixed consumption levels)
PR	=	delivered price at which demand is to be evaluated (1987 dollars per Mcf)
$NGDMD\_CRVF_{s,r}$	=	estimate of the natural gas which would be consumed by core sector s in region r at the price PR (Bcf)
s	=	core sector (1-residential, 2-commercial, 3-industrial, 4- transportation)

The form of the demand curves for the non-electric interruptible transmission service type is identical, with the following variables substituted: NGDMD_CRVI, BASPR_I, BASQTY_I, and NONU_ELAS_I (all set to zero for *AEO2014*). For the electric generation sector the form is identical as well, except there is no sector index and the regions represent the 16 NGTDM/EMM lower 48 regions, not the 12 NGTDM regions. The corresponding set of variables for the core and non-core electric generator demand curves are [NGUDMD_CRVF, BASUPR_F, BASUQTY_F, UTIL_ELAS_F] and [NGUDMD_CRVI, BASUPR_I, BASUQTY_I, UTIL_ELAS_I], respectively. For *AEO2014* all of the electric generator demand curve elasticities were set to zero.

Lease, plant, and pipeline fuel

The consumption of gas as lease, plant, and pipeline fuel is determined within the NGTDM. Gas used in well, field, and lease operations and in natural gas processing plants is set equal to an historically observed percentage of dry gas production.[18] In addition, natural gas consumed in the process of liquefying natural gas for export out of the lower 48 region and for liquefied natural gas vehicles was added to the lease and plant fuel category and set as a percent of liquefied natural gas exported (PERLIQFUEL, Appendix E) or a percent of the natural gas entering the liquefaction plant associated with vehicle use (LNGV_LOSS, Appendix E), respectively. Pipeline fuel use depends on the amount of gas flowing through each region, as described in Chapter 4.

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[18] The regional factors used in calculating lease and plant fuel consumption (PCTLP) are initially based on historical averages (2008 through 2012) and held constant throughout the forecast period. However, a model option allows for these factors to be scaled in the first one or two forecast years so that the resulting national lease and plant fuel consumption will match the annual published values presented in the latest available *Short-Term Energy Outlook* (STEO), DOE/EIA-0202, (Appendix E, STQLPIN). The adjustment attributable to benchmarking to STEO (if selected as an option) is phased out by the year STPHAS_YR (Appendix E). For *AEO2014* these factors were phased out by 2016. A similar adjustment is performed on the factors used in calculating pipeline fuel consumption using STEO values from STQGPTR (Appendix E).

Domestic natural gas supply interface and representation

The primary categories of natural gas supply represented in the NGTDM are non-associated and associated-dissolved gas from onshore and offshore U.S. regions; pipeline imports from Mexico; eastern, western (shale/coalbed and tight/other), and Arctic Canada production; LNG imports; natural gas production in Alaska (including that which is transported through Canada via pipeline[19]); synthetic natural gas produced from coal and from liquid hydrocarbons; and other supplemental supplies. Outside of Alaska (which is discussed in a later section) the only supply categories from this list that are allowed to vary within the NGTDM in response to a change in the current year's natural gas price are the non-associated gas from onshore and offshore U.S. regions, tight/other gas from the western Canada region, and LNG imports.[20] The supply levels for the remaining categories are fixed at the beginning of each forecast year (i.e., before market clearing prices are determined), with the exception of associated-dissolved gas (determined in OGSM).[21] With the exception of LNG imports, which have a peak and off-peak representation, the NGTDM applies average historical relationships to convert annual "fixed" supply levels to peak and off-peak values. These factors are held constant throughout the forecast period.

Within the OGSM, natural gas supply activities are modeled for 12 U.S. supply regions (6 onshore, 3 offshore, and 3 Alaskan geographic areas). The six onshore OGSM regions within the contiguous United States, shown in **Figure 2-4**, do not generally share common borders with the NGTDM regions. The NGTDM represents onshore supply for the 17 regions resulting from overlapping the OGSM and NGTDM regions (**Figure 2-5**). A separate component of the NGTDM models the foreign sources of gas that are transported via pipeline from Canada and Mexico. Seven Canadian and three Mexican border crossings demarcate the foreign pipeline interface in the NGTDM. Potential LNG imports are represented at each of the coastal NGTDM regions; however, import volumes will only be projected based on where existing or exogenously set additional regasification capacity exists (e.g., if a facility is under construction or deemed highly likely to be constructed).[22]

[19] Several different options have been proposed for bringing stranded natural gas in Alaska to market (e.g., by pipeline, as LNG, and as liquids). In previous AEOs the Petroleum Market Module forecast the potential conversion of Alaska natural gas into liquids, but this option was not included in *AEO2014*. While the NGTDM allows for the building of a generic pipeline from Alaska's North Slope into Alberta (although not at the same time as a Mackenzie Valley pipeline), it also evaluates the viability of building a new LNG export facility in Alaska (also supplied by North Slope gas) and under most scenerios the LNG facility is the more clear choice. Therefore, the export facility is assumed to have first access to the currently proved reserves in Alaska which are assumed to be producible at a relatively low cost given their association with oil production.

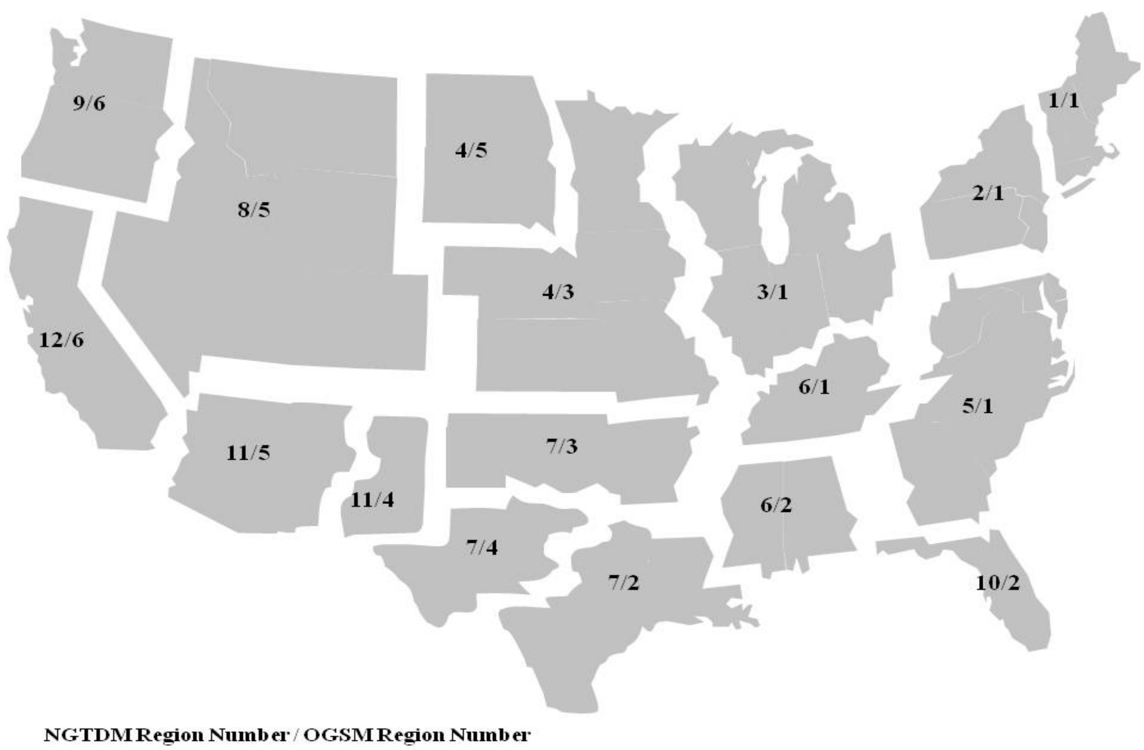
[20] Liquefied natural gas imports are set based on the price in the previous NEMS iteration and are effectively "fixed" when the NGTDM determines a natural gas market equilibrium solution; whereas the other two categories are determined as a part of the market equilibrium process in the NGTDM.

[21] For programming convenience natural gas produced with oil shales (OGSHALENG) is also added to this category.

[22] Structurally an LNG regasification terminal in the Bahamas would be represented as entering into Florida and be reported as pipeline imports, although modeled as LNG imports. No regasification terminals were considered for Alaska or Hawaii in *AEO2014*, even though there has been some discussion about potential imports in both states.

Figure 2-4. Oil and Gas Supply Module (OGSM) Regions

Figure 2-5. NGTDM/OGSM Regions



“Variable” dry natural gas production supply curve

The two “variable” (or price-responsive) natural gas supply categories represented in the model are domestic non-associated production and tight and other production (i.e., all but shale and coalbed) from the Western Canadian Sedimentary Basin (WCSB). Non-associated natural gas is largely defined as gas that is produced from gas wells, and is assumed to vary in response to a change in the natural gas price. Associated-dissolved gas is defined as gas that is produced from oil wells and can be classified as a byproduct in the oil production process. Each domestic supply curve is defined through its associated parameters as being net of lease and plant fuel consumption (i.e., the amount of dry gas available for market after any necessary processing and before being transported via pipeline). For both of these categories, the supply curve represents annual production levels. The methodology for translating this annual form into a seasonal representation is presented in Chapter 4.

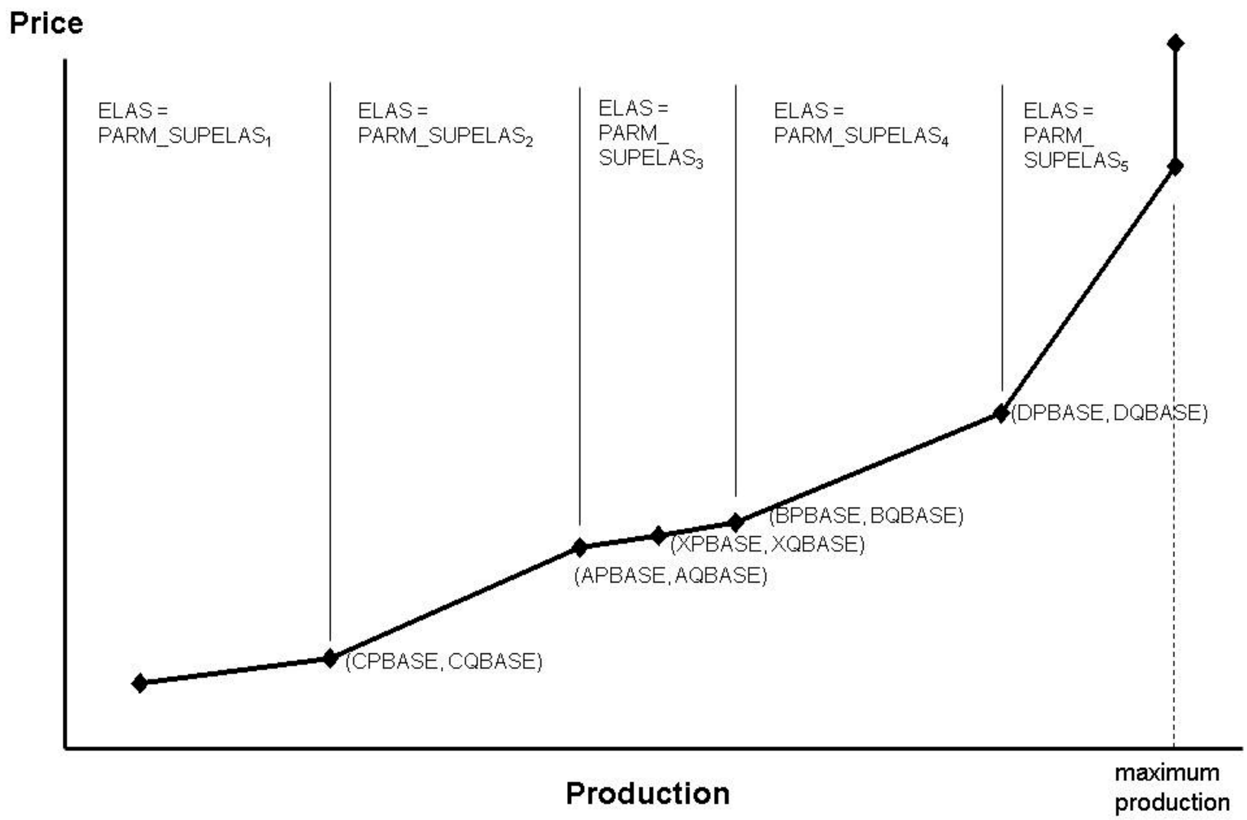
The supply curve for regional non-associated lower 48 natural gas production and for WCSB production is built from a price/quantity (P/Q) pair, where quantity is the “expected” production (XQBASE) or the base production level as defined by the product of reserves times the “expected” production-to-reserves ratio (as set in the OGSM) and price is the projected associated regional wellhead price (XPBASE, presented below) for the expected production.[23] The basic assumption behind the curve is that the realized market price will increase from the base price if the current year’s production levels exceed the expected production; and the opposite will occur if current production is less. In addition, it is assumed that the relative price response will likely be greater for a marginal increase in production above the expected production, compared to below. To represent these assumptions, five segments of the curve are defined from the base point. The middle segment is centered around the base point, extends plus or minus a percent (PARM_SUPCRV3, Appendix E) from the base quantity, and if activated, is generally set nearly horizontal (i.e., there is little price response to a quantity change). The next two segments, on either side of the middle, extend more vertically (with a positive slope), and reach plus or minus a percent (PARM_SUPCRV5, Appendix E) beyond the end of the middle segment. The remaining two segments extend the curve above and below even further for the case with relatively large annual production changes, and can be assigned the same or different slopes from their adjacent segments. The slope of the upper segment(s) is generally set greater than or equal to that of the lower segment(s). An illustrative presentation of the supply curve is provided in **Figure 2-6**. The general structure for all five segments of the supply curve, in terms of defining price (NGSUP_PR) as a function of the quantity or production level (QVAR), is:

$$NGSUP\_PR = PBASE * \left\{ \left[\left(\frac{1}{ELAS} \right) * \left(\frac{QVAR - QBASE}{QBASE} \right) \right] + 1 \right\} \tag{2}$$

Each of the five segments is assigned different values for the variables ELAS, PBASE, and QBASE, as follows:

[23] The values for HPBASE in the historical years and in the first forecast year are based on historical data for key regional spot prices. Historical wellhead prices are set to a representative historical regional spot price minus an assumed gathering charge (GATHER, Appendix E).

Figure 2-6. Generic supply curve



Lowest segment:

$$\text{PBASE} = \text{CPBASE} = \text{APBASE} * (1 - (\text{PARM\_SUPCRV5}/\text{PARM\_SUPELAS2}) \quad (3)$$

$$\text{QBASE} = \text{CQBASE} = \text{AQBASE} * (1 - \text{PARM\_SUPCRV5}) \quad (4)$$

$$\text{ELAS} = \text{PARM\_SUPELAS1} = 0.40 \quad (5)$$

Lower segment:

$$\text{PBASE} = \text{CPBASE} = \text{APBASE} * (1 - (\text{PARM\_SUPCRV3}/\text{PARM\_SUPELAS3}) \quad (6)$$

$$\text{QBASE} = \text{AQBASE} = \text{XQBASE} * (1 - \text{PARM\_SUPCRV3}) \quad (7)$$

$$\text{ELAS} = \text{PARM\_SUPELAS2} = 0.35 \quad (8)$$

Middle segment:

(in historical years)

$$PBASE = XPBASE = historical \quad wellhead \quad price \tag{9}$$

$$QBASE = AQBASE = XQBASE * (1 - PARM\_SUPCRV3) \tag{10}$$

(in forecast years)

$$PBASE = XPBASE = ZWPRLAG_s \tag{11}$$

$$QBASE = XQBASE = ZOGRESNG_s * ZOGPRRNG_s \tag{12}$$

$$ELAS = PARM\_SUPELAS3 = 0.30 \tag{13}$$

Upper segment:

$$PBASE = BPBASE = XPBASE * \\ (1 + (PARM\_SUPCRV3/PARM\_SUPELAS3)) \tag{14}$$

$$QBASE = BQBASE = XQBASE * (1 + PARM\_SUPCRV3) \tag{15}$$

$$ELAS = PARM\_SUPELAS4 = 0.25 \tag{16}$$

Uppermost segment:

$$PBASE = DPBASE = BPBASE * \\ (1 + (PARM\_SUPCRV5/PARM\_SUPELAS4)) \tag{17}$$

$$QBASE = DQBASE = BQBASE * (1 + PARM\_SUPCRV5) \tag{18}$$

$$ELAS = PARM\_SUPELAS5 = 0.20 \tag{19}$$

where,

NGSUP_PR	=	wellhead price (1987$/Mcf)
QVAR	=	production, including lease & plant (Bcf)
XPBASE	=	base wellhead price on the supply curve (1987$/Mcf)
XQBASE	=	base wellhead production on the supply curve (Bcf)
PBASE	=	base wellhead price on a supply curve segment (1987$/Mcf)
QBASE	=	base wellhead production on a supply curve segment (Bcf)
AQBASE, BQBASE, CQBASE, DQBASE	=	production levels defining the supply curve in **Figure 2-6** (Bcf)
APBASE, BPBASE, CPBASE, DPBASE	=	price levels defining the supply curve in **Figure 2-6** (Bcf)
ELAS	=	elasticity (percent change in quantity over percent change in price) (analyst judgment)

PARM_SUPCRV3 = (defined in preceding paragraph)
PARM_SUPCRV5 = (defined in preceding paragraph)
PARM_SUPELAS# = elasticity (percentage change in quantity over percentage change in price) on different segments (#) of supply curve
$ZWPRLAG_s$ = lagged (last year's) wellhead price for supply source s (1987$/Mcf)
$ZOGRESNG_s$ = natural gas proved reserves for supply source s at the beginning of the year (Bcf)
$ZOGPRRNG_s$ = natural gas production to reserves ratio for supply sources (fraction)
$PERCNT_n$ = percent lease and plant
s = supply source
n = region/node
t = year

The parameters above will be set depending on the location of QVAR relative to the base quantity (XQBASE) (i.e., on which segment of the curve QVAR falls). In the above equation, the QVAR variable includes lease and plant fuel consumption. Since the ITM domestic production quantity (VALUE) represents supply levels net of lease and plant, this value must be adjusted once it is sent to the supply curve function, and before it can be evaluated, to generate a corresponding supply price. The adjustment equation is:

$$QVAR = (VALUE - FIXSUP) / (1.0 - PERCNT_n)$$
$$[\text{where, } FIXSUP = ZOGCCAPPRD_s * (1.0 - PERCNT_n)]$$

where,

QVAR = production, including lease and plant consumption
VALUE = production, net of lease and plant consumption
$PERCNT_n$ = percent lease and plant consumption in region/node n (set to PCTLP, set to zero for Canada)
$ZOGCCAPPRD_s$ = coalbed gas production related to the Climate Change Action Plan[24]
FIXSUP = ZOGCCAPPRD net of lease and plant consumption
s = NGTDM/OGSM supply region
n = region/node

Associated-dissolved natural gas production

Associated-dissolved natural gas refers to the natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved). The production of associated-dissolved natural gas is tied directly with the production (and price) of crude oil. The OGSM projects the level of associated-dissolved natural gas production and the results are passed to the NGTDM for each iteration and forecast year of NEMS. Within the NGTDM, associated-dissolved natural gas production is considered "fixed" for a given forecast year and is split into peak and off-peak values based on average (1994-2012) historical shares of total (including non-associated) peak production in the year (PKSHR_PROD).

[24] This special production category is not included in the reserves and production-to-reserve ratios calculated in the OGSM, so it was necessary to account for it separately when relevant. It is no longer relevant and is set to zero in OGSM.

Supplemental gas sources

Existing sources for synthetically produced pipeline-quality natural gas and other supplemental supplies are assumed to continue to produce at historical levels. While the NGTDM has an algorithm (see Appendix H) to project potential new coal-to-gas plants and their gas production, the annual production of synthetic natural gas from coal at the existing plant is exogenously specified (Appendix E, SNGCOAL), independent of the price of natural gas in the current forecast year. The *AEO2014* forecast assumes that the sole existing plant (the Great Plains Coal Gasification Plant in North Dakota) will continue to operate at recent historical levels indefinitely. Regional forecast values for other supplemental supplies (SNGOTH) are set at historical averages (2003 to 2011) and held constant over the forecast period. Synthetic natural gas is no longer produced from liquid hydrocarbons in the continental United States, although small amounts were produced in Illinois in some historical years. This production level (SNGLIQ) is set to zero for the forecast. The small amount produced in Hawaii is accounted for in the output reports (set to the historical average from 1997 to 2011). If the option is set for the first two forecast years of the model to be calibrated to the *Short-Term Energy Outlook* (*STEO*) forecast, then these three categories of supplemental gas are similarly scaled so that their sum will equal the national annual forecast for total supplemental supplies published in the STEO (Appendix E, STOGPRSUP). To guarantee a smooth transition, the scaling factor in the last STEO year can be progressively phased out over the first STPHAS_YR (Appendix E) forecast years of the NGTDM. Regional peak and off-peak supply levels for the three supplemental gas supplies are generated by applying the same average (1990-2012) historical share (PKSHR_SUPLM) of national supplemental supplies in the peak period.

Natural gas imports and exports interface and representation

The NGTDM sets the parameters for projecting gas imported and exported through LNG facilities in the U.S. and Canada, the other parameters and forecast values associated with the Canada gas market, and the projected values for imports from and exports to Mexico.

Canada

A node for east and west Canada is included in the NGTDM equilibration network, as well as seven border crossings with the United States. The model includes a representation/accounting of the U.S. border-crossing pipeline capacity, east and west seasonal storage transfers, east and west consumption, east and west LNG imports (described in a later section), eastern production, tight sands/other production in the west, and coalbed/shale production. The ultimate determination of the import volumes into and most of the export volumes out of the United States occurs in the equilibration process of the NGTDM.

Base-level consumption of natural gas in eastern and western Canada (Appendix E, CN_DMD), including gas used in lease, plant, and pipeline operations, is set exogenously,[25] adjusted based on oil sands production and world oil prices, and ultimately split into seasonal periods using PKSHR_CDMD (Appendix E). The projected level of oil produced from oil sands is set exogenously to the NGTDM (based on the most recently available EIA projections) and varies depending on the world oil price case. Starting in a recent historical year (Appendix E, YDCL_GASREQ), the natural gas required to support the oil sands production is set at an assumed ratio (Appendix E, INIT_GASREQ) of the oil sands production.

[25] These consumption values were based on projections taken from the *Annual Energy Outlook 2013*.

Over the projection period this ratio is assumed to decline with technological improvements and as other fuel options become viable. The ratio in year t is set by multiplying the initially assumed rate by (t-YDCL_GASREQ+1)$^{DECL\_GASREQ}$, where DECL_GASREQ is assumed based on anecdotal information (Appendix E). The oil-sands-related gas consumption under reference case world oil prices is subtracted from the base-level total consumption and the remaining volumes are adjusted slightly based on differences in the world oil price in the model run versus the world oil price used in setting the base-level consumption, using an assumed elasticity (Appendix E, CONNOL_ELAS). Finally, total consumption is set to this adjusted value plus the calculated gas consumed for oil sands production under the world oil price case selected. Oil sands production is assumed to occur only in western Canada.

Currently, the NGTDM exogenously sets a forecast of the physical capacity of natural gas pipelines crossing at seven border points from Canada into the United States (excluding any expansion related to the building of an Alaska pipeline or an LNG facility in Oregon). This option can also be used within the model, if border-crossing capacity is set endogenously, to establish a minimum pipeline build level (Appendix E, ACTPCAP and PLANPCAP). The model allows for an endogenous setting of annual Canadian pipeline expansion at each Canada/U.S. border crossing point based on the annual growth rate of consumption in the U.S. market it predominantly serves. The resulting physical capacity limit is then multiplied by a set of exogenously specified maximum utilization rates for each seasonal period to establish maximum effective capacity limits for these pipelines (Appendix E, HPKUTZ and HOPUTZ). "Effective capacity" is defined as the maximum seasonal, physically sustainable, capacity of a pipeline times the assumed maximum utilization rate. It should be noted that some of the natural gas on these lines passes through the United States only temporarily before reentering Canada, and therefore is not classified as imports.[26]

If a decision is made to construct a pipeline from Alaska (or the Mackenzie Delta) to Alberta, the import pipeline capacity added from the time the decision is made until the pipeline is in service is tracked. This amount is subtracted from the size of the pipeline to Alberta to arrive at an approximation for the amount of additional import capacity that will be needed to bring the Alaska or Mackenzie[27] gas to the United States. This total volume is apportioned to the pipeline capacity at the western import border crossings according to their relative size at the time. Similarly, if a decision is made to build an LNG export facility in Washington or Oregon that would be supplied for the most part by gas from Canada, then the model makes sure that the capacity going into region from Canada is sufficient to accommodate the total additional volume.

Tight and other western Canada production

The vast majority of natural gas produced in Canada currently is from the WCSB. Therefore, a different approach was used in modeling supplies from this region. The model consists of a series of estimated

[26] A significant amount of natural gas flows into Minnesota from Canada on an annual basis only to be routed back to Canada through Michigan. The levels of gas in this category are specified exogenously (Appendix E, FLO_THRU_IN) and split into peak and off-peak levels based on average (1990-2012 historically based shares for general Canadian imports (PKSHR_ICAN).

[27] All of the gas from the Mackenzie Delta is not necessarily targeted for the U.S. market directly, although it is anticipated that the additional supply in the Canadian system will reduce prices and increase the demand for Canadian gas in the United States. The methodology for representing natural gas production in the Mackenzie Delta and the associated pipeline is described in the section titled "Alaskan Natural Gas Routine."

and reserves accounting equations for forecasting tight and other[28] wells drilled, reserves added, reserve levels, and expected production-to-reserve ratios in the WCSB. Drilling activity, measured as the number of successful natural gas wells drilled, is estimated directly as a function of various market drivers rather than as a function of expected profitability. No distinction is made between wells for exploration and development. Next, an econometrically specified finding rate is applied to the successful wells to determine reserve additions; a reserves accounting procedure yields reserve estimates (beginning of year reserves). Finally, an estimated extraction rate determines production potential [production-to-reserves ratio (PRR)].

Wells determination

The total number of successful tight and other natural gas wells drilled in western Canada each year is forecast econometrically as a function of the Canadian natural gas wellhead price, remaining undiscovered resources, last year's production-to-reserve ratio, and a proxy term for the drilling cost per well, as follows:

$$\begin{aligned} \mathrm{SUCWELL}_t = {} & \exp((1-0.324614)*-22.66103)*\mathrm{OGCNPPRD}_t^{0.678076}*\mathrm{URRCAN}_t^{3.012933} \\ & *\mathrm{CURPRRCAN}_t^{2.3322307}*SUCWELLAG^{0.324614}*OGCNPPRD_{t-1}^{0.678076*-0.324614} \\ & *URRLAG^{3.012933*-0.324614}*PRRATLAG^{2.322307*-0.322307} \end{aligned} \tag{20}$$

where,

$\mathrm{SUCWELL}_t$	=	total tight and other successful gas wells completed in western Canada in the current forecast year t
SUCWELLAG	=	total tight and other successful gas wells completed in western Canada in the previous forecast year (i.e., the lagged value of SUCWELL)
$\mathrm{OGCNPPRD}_t$	=	average western Canada wellhead price per Mcf (1987 U.S. dollars)
URRCAN_t	=	remaining tight and other marketable gas resources in the beginning of the current forecast year in western Canada in (Bcf), specified below
URRLAG	=	remaining tight and other marketable gas resources in the beginning of the previous forecast year in western Canada in (Bcf) (i.e., the lagged value of URRCAN)
$\mathrm{CURPRRCAN}_t$	=	expected production-to-reserve ratio from the previous forecast year, specified below
PRRATLAG	=	expected production-to-reserve ratio from the forecast year two years prior (i.e., the lagged value of CURPRRCAN)
t	=	forecast year

Parameter values and details about the estimation of this equation can be found in Table F9 of Appendix F. The number of wells is restricted to increase by no more than 30% annually.

[28] Since current data tend to combine statistics for drilling and production from other (i.e., traditionally "conventional") sources and that from tight gas formations, the model does not distinguish between the two at present. The baseline "other" resource estimate was increased by an assumed percent per year (RESTECH, Appendix E) as a rough estimate of the future contribution from resource appreciation and from tight formations until more reliable estimates can be generated.

Reserve additions

The reserve additions algorithm calculates units of gas added to Western Canadian Sedimentary Basin proved reserves. The methodology for conversion of gas resources into proved reserves is a critically important aspect of supply modeling. The actual process through which gas becomes proved reserves is a highly complex one. This section presents a methodology that is representative of the major phases that occur, although by necessity, it is a simplification from a highly complex reality.

Gas reserve additions are calculated using a finding rate equation. Typical finding rate (reserves added per well) equations relate reserves added to 1) wells or feet drilled, in such a way that reserve additions per well decline as more wells are drilled; and/or 2) remaining resources, in such a way that reserve additions per well decline as remaining resources deplete. The reason for this is that, given a choice, larger prospects would be typically be drilled first as they should be more profitable. Consequently, the finding rate would be expected to decline as a region matures all else being equal. The rate of decline and the functional form are a subject of considerable debate and all else is typically not equal. In addition, historically reserve additions are rather erratic from year to year, making them difficult to project. In previous versions of the model, the finding rate was econometrically estimated and did not always perform well, while the current version is assumption based (i.e., uses a simple decline rate) as follows:

$$\mathrm{FRCAN}_t = \mathrm{FRLAG} * 0.98 \tag{21}$$

where,

FRCAN_t	=	finding rate in current forecast year (Bcf per well)
FRLAG	=	finding rate in previous forecast year or lagged value of FRCAN (Bcf per well)[29]
0.98	=	assumed value of annual decline of finding rate, set to value in 2012
t	=	forecast year

Remaining tight and other gas marketable resources are initialized in 2011 and set each year thereafter as follows:

$$\mathrm{URRCAN}_t = \mathrm{RESBASE} * (1 + \mathrm{RESTECH})^T - \mathrm{CUMRCAN}_t \tag{22}$$

where,

URRCAN_t	=	remaining tight and other gas marketable resources in current forecast year in western Canada (Bcf)
RESBASE	=	initial other marketable resources in 2011 (set at 127,000 Bcf)[30]
RESTECH	=	assumed rate of increase, primarily due to the contribution from tight gas formations, but also attributable to technological improvement (3% or 0.03)[31]

[29] From 1996 through 2007, the finding rate averaged 0.55 (median 0.57), not exceeding 0.74, whereas from 2008 to 2012 the average was 1.3 (median 1.15). The 2012 value was used as the starting lag term at 1.08.

[30] Source: National Energy Board's "Canada's Energy Future: Energy supply and demand projections to 2035", Table A4.1, November 2011.

$CUMRCAN_t$ = cumulative reserves added since initial year of 2011 in Bcf
T = the forecast year (t) minus the base year of 2011.
t = forecast year

Total reserve additions in period t are given by:

$$RESADCAN_t = FRCAN_t * SUCWELL_t \quad (23)$$

where,

$RESADCAN_t$ = reserve additions in year t, in Bcf
$FRCAN_{t-1}$ = finding rate in the previous year, in Bcf per well
$SUCWELL_t$ = successful gas wells drilled in year t
t = forecast year

Total end-of-year proved reserves for each period equal proved reserves from the previous period plus new reserve additions less production.

$$RESBOYCAN_{t+1} = CURRESCAN_t + RESADCAN_t - OGPRDCAN_t \quad (24)$$

where,

$RESBOYCAN_{t+1}$ = beginning of year reserves for year t+1, in Bcf
$CURRESCAN_t$ = beginning of year reserves for year t, in Bcf
$RESADCAN_t$ = reserve additions in year t, in Bcf
$OGPRDCAN_t$ = production in year t, in Bcf
t = forecast year

Gas production

Production is commonly modeled using a production-to-reserves ratio. A major advantage to this approach is its transparency. Additionally, the performance of this function in the aggregate is consistent with its application on the micro level. The production-to-reserves ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves.

Tight/other gas production in the WCSB in year t is determined in the NGTDM through a market equilibrium mechanism using a supply curve based on an expected production level. The realized extraction is likely to be different. The expected or normal operating level of production is set as the product of the beginning-of-year reserves (RESBOYCAN) and an expected extraction rate under normal

[31] Set to fully add tight gas resources from National Energy Board's "Canada's Energy Future: Energy supply and demand projections to 2035", Table A4.1, November 2011 by 2040.

operating conditions. This expected production-to-reserve ratio in previous versions of the model was estimated, however, for AEO2014 the value was assumed to decline at recent historical levels as follows:

$$\text{PRRATCAN}_t = \text{PRRATCAN}_{t-1} * 0.99 \tag{25}$$

where,

PRRATCAN_t	=	expected production-to-reserve natural gas ratio in western Canada for tight and other gas in forecast year t
0.99	=	reflects assumed annual decline in production-to-reserve ratio consistent with recent history
t	=	forecast year

The resulting production-to-reserve ratio is limited, so as not to increase or decrease more than 5% from one year to the next and to stay within the range of 0.07 to 0.12.

The potential or expected production level is used within the NGTDM to build a supply curve for tight and other natural gas production in western Canada. The form of this supply curve is effectively the same as the one used to represent non-associated natural gas production in lower 48 regions. This curve is described later in this chapter, with the exceptions related to Canada noted. A primary difference is that the supply curve for the Lower 48 states represents non-associated natural gas production net of lease and plant fuel consumption; whereas the western Canada supply curve represents total tight and other natural gas production inclusive of lease and plant fuel consumption.

Canada shale and coalbed

Natural gas produced from coal beds and shale in western Canada (PRD2) is based on an assumed production profile, with the area under the curve equal to the assumed remaining economically recoverable resource (CUR_ULTRES). The production level is initially specified in terms of the forecast year and is set using one functional form before reaching its peak production level and a second functional form after reaching its peak production level. Before reaching peak production, the production levels are assumed to follow a quadratic form, where the level of production is zero in the first year (LSTYR0) and reaches its peak level (PKPRD) in the peak year (PKIYR). The area under the assumed production function equals the assumed economically recoverable resource level (CUR_ULTRES) times the assumed percentage (PERRES) produced before hitting the peak level. After peak production the production path is assumed to decline linearly to the last year (LSTYR) when production is again zero. The two curves meet in the peak year (PKIYR) when both have a value equal to the peak production level (PKPRD). The actual production volumes are adjusted to reflect assumed technological improvement and by a factor that depends on the difference between an assumed price trajectory and the actual price projected in the model. The specifics follow:

Before Peak Production

Assumptions:

production function

$$\text{PRD2} = \text{PARMA}*(\text{PRDIYR-PKIYR})^2 + \text{PARMB} \tag{27}$$

area under the production function

$$CUR\_ULTRES*PERRES = \int_{LSTYR0}^{PKIYR} [PARMA*(PRDIYR - PKIYR)^2 + PARMB]\, dPRDIYR \quad (28)$$

production in year LSTYR0:

$$0 = PARMA*(LSTYR0 - PKIYR)^2 + PARMB \quad (29)$$

production in peak year when PRDIYR = PKIYR

$$PKPRD = PARMA*(PKIYR-PKIYR)^2 + PARMB = PARMB \quad (30)$$

Derived from above:

$$PARMA = \frac{-3}{2} * \frac{CUR\_ULTRES*PERRES}{(PKIYR - LSTYRO)^3} \quad (31)$$

$$PARMB = -PARMA*(LSTYRO - PKIYR)^2 \quad (32)$$

After Peak Production

Assumptions:

production function

$$PRD2 = (PARMC*PRDIYR) + PARMD \quad (33)$$

area under the production function

$$CUR\_ULTRES*(1 - PERRES) = \int_{PKIYR}^{LSTYR} [(PARMC*PRDIYR) + PARMD]\, dPRDIYR \quad (34)$$

production in peak year when PRDIYR = PKIYR

$$PKPRD = PARMB = (PARMC*PKIYR) + PARMD \quad (35)$$

production in last year LSTYR

$$0 = (PARMC*LSTYR) + PARMD \quad (36)$$

Derived from above:

$$PARMC = \frac{-PARMB^2}{2*CUR\_ULTRES*(1 - PERRES)} \quad (37)$$

$$LSTYR = \frac{2*CUR\_ULTRES*(1 - PERRES)}{PARMB} + PKIYR \quad (38)$$

$$PARMD = -PARMC*LSTYR \quad (39)$$

given,

$$CUR\_ULTRES = ULTRES*(1+RESTECH)^{(MODYR-RESBASE)}*(1+RESADJ) \quad (40)$$

and,

PRD2	=	unadjusted Canada shale/coalbed gas production (Bcf)
PKPRD	=	peak production level in year PKIYR
CUR_ULTRES	=	estimate of ultimate recovery of natural gas from shale/coalbed Canada sources in the current forecast year (Bcf)
ULTRES	=	estimate of ultimate recovery of natural gas from shale/coalbed Canada sources in the year RESBASE (45,000 Bcf for coalbed in 2011 and 90,000 Bcf for shale in 2011, based on assumed resource levels from the National Energy Board, 2011)
RESBASE	=	year associated with CUR_ULTRES
RESTECH	=	technology factor to increase resource estimate over time (1.0)
MODYR	=	current forecast year
RESADJ	=	scenario-specific resource adjustment factor (default value of 0.0)
PERRES	=	percent of ultimate resource produced before the peak year of production (0.40, fraction)
PKIYR	=	assumed peak year of production (2050)
LSTYR0	=	last year of zero production (1999)
PRDIYR	=	implied year of production along cumulative production path after price adjustment

The actual production is set by taking the unadjusted shale/coalbed gas production (PRD2) and multiplying it by a price adjustment factor, as well as a technology factor. The price adjustment factor (PRCADJ) is based on the degree to which the actual price in the previous forecast year compares against a prespecified expected price path (exprc), represented by the functional form: exprc = (2.1 + [0.08*(MODYR-2010)]). The price adjustment factor is set to the price in the previous forecast year divided by the expected price, all raised to the 0.7 power. Technology is assumed to progressively increase production by 1% per year (TECHGRW) more than it would have been otherwise (e.g., in the fifth forecast year production is increased by 5% above what it would have been otherwise).[32] Once the production is established for a given forecast year, the value of PRDIYR is adjusted to reflect the actual production in the previous year and incremented by 1 for the next forecast year.

The remaining forecast elements used in representing the Canada gas market are set exogenously in the NGTDM, with the exception of exports to eastern Canada (described later). When required, such annual forecasts are split into peak and off-peak values using historically based or assumed peak shares that are held constant throughout the forecast. For example, the level of natural gas exports from the United States to western Canada (Appendix E, CANEXP) is currently set exogenously to NEMS, is distinguished by four Canada/U.S. border crossings, and is split between peak and off-peak periods by applying average (1992 to 2012, PKSHR_ECAN) historical shares to the assumed annual levels. While most

[32] If a rapid or slow technology case is being run, this value is increased or decreased accordingly.

Canadian import levels into the U.S. are set endogenously, the flow from eastern Canada into the East North Central region is secondary to the flow going in the opposite direction and is therefore set exogenously (Appendix E, Q23TO3). "Fixed" supply values for the entire eastern Canada region are set exogenously (Appendix E, CN_FIXSUP)[33] and split into peak and off-peak periods using PKSHR_PROD (Appendix E).

Mexico

The Mexico model is largely based on exogenously specified assumptions about consumption and production growth rates and LNG import levels. For the most part, natural gas imports from Mexico are set exogenously for each of the three border crossing points with the United States, with the exception of any gas that is imported into Baja, Mexico, in liquid form only to be exported to the United States. Exports to Mexico from the United States are established before the NGTDM equilibrates and represent the required level to balance the assumed consumption in (and exports from) Mexico against domestic production and LNG imports. The supply levels are also largely assumption-based, but are set to vary to a degree with changes in the expected average wellhead price in the United States. Peak and off-peak values for imports from and exports to Mexico are based on average historical shares (1994 or 1991 to 2012, PKSHR_IMEX and PKSHR_EMEX, respectively).

Mexican gas production and trade is a complex issue, as a range of non-economic factors will influence, if not determine, future flows of gas between the United States and Mexico. Despite the uncertainty and the significant influence of non-economic factors that influence Mexican gas production,[34] and therefore trade with the United States, a methodology to anticipate the path of future Mexican imports from, and exports to, the United States has been incorporated into the NGTDM. This outlook is generated using assumptions regarding regional supply from indigenous production and/or liquefied natural gas (LNG) and regional/sectoral demand growth for natural gas in Mexico.

Assumptions for the growth rate of consumption (Appendix E, PEMEX_GFAC, IND_GFAC, ELE_GFAC, RC_GFAC) were based on the projections from the *International Energy Outlook 2013*. Assumptions about base-level domestic production (PRD_GFAC) are based in part on the same source and analyst judgment. The production growth rate is adjusted using an additive factor based on the degree to which the average lower 48 wellhead price varies from a set base price, as follows:

$$\mathrm{PRC\_FAC}_t = MIN\left\{\left(\frac{\mathrm{OGWPRNG}_t}{2*1.031^{(t-2013)}}\right)^{0.05} -1,\quad 0.05\right\} \tag{41}$$

where,

PRC_FAC = factor to add to assumed base-level production growth rate (PRD_GFAC)

[33] Eastern Canada is expected to continue to provide only a small share of the total production in Canada and is almost exclusively offshore.

[34] Mexican gas production estimates reflect current laws at the time of the *AEO2014* analysis and therefore do not reflect the subsequent approval of a constitutional amendment to reopen its energy sector to private investment.

OGWPRNG	=	lower 48 average natural gas wellhead price in the current forecast year (1987$/Mcf)
$2*1.031^{(IYR-2013)}$	=	assumed base level price path associated with assumed production growth rate of PRD_GFAC, approximately equal to the average lower 48 natural gas wellhead price over the projection period in *AEO2013* reference case (1987$/Mcf)
0.05 (exponent)	=	an assumed parameter relating change in production to change in price
0.05	=	assumed minimum value of PRC_FAC
t	=	current forecast year

The volumes of LNG imported into Mexico for use in the country are initially set exogenously (Appendix E, MEXLNG). However, these values are scaled back if the projected total volumes available to North America (see below) are not sufficient to accommodate these levels. LNG imports into Baja destined for the United States are set endogenously with the LNG import volumes for the rest of North America, as discussed below. Finally, any excess supply in Mexico is assumed to be available for export to the United States, and any shortfall is assumed to be met by imports from the United States.[35]

Liquefied natural gas

LNG imports and exports are largely set endogenously in NGTDM. An assessment is made at the beginning of each forecast year as to the economic viability of adding a generic LNG export facility in the United States or Canada, with a limit placed on how much capacity can be added each year. Once added, a facility is assumed to be utilized throughout the rest of the forecast at a set level, unless the ratio of the variable cost to supply to the world market from the United States versus the comparable competitive world price exceeds an assumed level. LNG imports not associated with re-exports are set at the beginning of each NEMS iteration within the model by evaluating seasonal supply curves, based on outputs from INGM, at associated regasification tailgate prices set in the previous NEMS iteration. LNG re-export levels are set exogenously (REEXP, Appendix E) based on historical levels and added to the projected import levels, as well as to the exports of domestically sourced LNG. LNG exports to Japan from the existing facility in Kenai, Alaska are set exogenously (OGQNGEXP, Appendix E) and set to zero for the forecast period with the closing of the facility in 2012.[36]

Imports

LNG import levels are established/set for each region in North America (excluding Alaska), and period (peak and off-peak). The basic process is as follows for each NEMS iteration (except for the first step): 1) at the beginning of each forecast year set up LNG supply curves for eastern and western North America for each period (peak and off-peak), 2) using the supply curves and the quantity-weighted average regasification tailgate price from the previous NEMS iteration, determine the amount of LNG available for import into North America, 3) subtract the volumes that are exogenously set and dedicated to the Mexico market (unless they exceed the total), and 4) allocate the remaining amount to the associated LNG terminals using a share based on the regasification capacity, the volumes imported last year, and the relative prices.

[35] A minimum import level from Mexico is set exogenously (DEXP_FRMEX, Appendix E), as well as a maximum decline from historical levels for exports to Mexico (DFAC_TOMEX, Appendix E).
[36] The facility has since been authorized to reopen so this assumption will be modified in the future.

The LNG import supply curves are developed off a base price/quantity pair (Appendix E, LNGPPT, LNGQPT) from a reference case run of the INGM, using the same, or very similar, world oil price assumptions. The quantities equal the sum of the LNG imports into east or west North America in the associated period, and the prices equal the quantity-weighted average tailgate price at the regasification terminals. The mathematical specification of the curve is exactly like the ones used for domestic production described earlier in this chapter, except that the assumed elasticities are represented with different variables and have different values.[37] This representation represents a first cut at integrating the information from INGM in the domestic projections.[38]

Once the North American LNG import volumes are established, the exogenously specified LNG imports into Mexico are subtracted,[39] along with the sum of any assumed minimum level (Appendix E, LNGMIN) for each of the representative terminals in the U.S., Canada, and Baja, Mexico (as shown in **Table 2-1**). The remainder (TOTQ) is shared out to the terminals and then added to the terminal's assumed minimum import level to arrive at the final LNG import level by terminal and season. The shares are initially set as follows and then normalized to total to 1.0:

$$LSHR_{n,r} = \left\{ \frac{QLNGLAG_{n,r} - (LNGMIN_r * SH_{r,n})}{TOTQ_{n,c}} * PERQ + \frac{LNGCAP_r - LNGMIN_r}{TOTCAP_c} * (1 - PERQ) \right\} * \left\{ \frac{PLNG_{n,r}}{AVGPR_{n,c}} \right\}^{BETA} \quad (42)$$

where,

$LSHR_{n,r}$	=	initial share (before normalization) of LNG imports going to terminal r in period n from the east or west coast, fraction
$TOTQ_{n,c}$	=	the level of LNG imports in the east or west coast to be shared out for a period n to the associated U.S. regasification regions
$QLNGLAG_{n,r}$	=	LNG import level last year (Bcf)
$LNGMIN_r$	=	minimum annual LNG import level (Bcf) (Appendix E)
$SH_{r,n}$	=	fraction of LNG imported in period n last year
$LNGCAP_r$	=	beginning of year LNG sendout capacity[40] (Bcf) (Appendix E)
$TOTCAP_c$	=	total LNG sendout capacity on the east or west coast (Bcf)
PERQ	=	assumed parameter (0.5)
$PLNG_{n,r}$	=	regasification tailgate price (1987$/Mcf)
$AVGPR_{n,r}$	=	average regasification tailgate price by coast (1987$/Mcf)
BETA	=	assumed parameter (1.2)
r	=	regasification terminal number (See Table 2-1)
n	=	network or period (peak or off-peak)
c	=	east or west coast

[37] For LNG the variables are called PARM_LNGxx, instead of PARM_SUPxx, and are also traceable using Appendix E.

[38] The initial LNG import volumes were somewhat erratic, so a five-year moving average (2 years back, current year, 2 years in the future) was applied to the quantity inputs to smooth out the trajectory and more closely approximate a trend line.

[39] If the total available LNG import levels exceed the assumed LNG imports into Mexico, the volumes into Mexico are adjusted accordingly, not to be set below assumed minimums (Appendix E, MEXLNGMIN).

[40] Send-out capacity is the maximum annual volume of gas that can be delivered by a regasification facility into the pipeline.

Table 2-1. LNG regasification regions

Number	Regasification Terminal/Region	Number	Regasification Regions
1	Everett, MA	9	Alabama/Mississippi
2	Cove Point, MD	10	Louisiana/Texas
3	Elba Island, GA	11	California
4	Lake Charles, LA	12	Washington/Oregon
5	New England	13	Eastern Canada
6	Middle Atlantic	14	Western Canada
7	South Atlantic	15	Baja into the U.S.
8	Florida/Bahamas	--	--

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

Exports

LNG exports from domestically sourced natural gas are projected endogenously in the NGTDM. The basic approach is to evaluate the long-term economic viability of adding a generic LNG liquefaction facility consisting of two trains of prespecified sustained capacity (GEN_EVOL_INCR, Appendix E) independently in each of the coastal regions of the United States and Canada, selecting the most economically profitable for construction (if any and accounting for any assumed restrictions, like earliest start year), and building it over the next two years, one train a year at a time. The model limits the number of trains coming on line in Canada and the United States to three trains, reflecting practical limits on the necessary resources/manpower for such specialized construction. Once built, the liquefaction facility is assumed to operate at full sustained capacity (accounting for some operational down-time) throughout the rest of the forecast period unless on-board variable rate prices in the United States, plus shipping and regasification charges, start to become uncompetitive relative to other price alternatives.

In order to assess economic viability, the model projects a representative alternative price of natural gas in Europe and Asia where the LNG is assumed to be sold. These prices are largely based on projections taken from EIA's *International Energy Outlook 2013* (*IEO2013*), with updates to account for recent market events, and some additional nonpublished information and analysis based on INGM results. The world natural gas prices are assumed to start at their recent historical ratio to the world oil price and become less (or potentially more) tied to the world oil price as the ratio of flexibly priced LNG to a representative regional natural gas demand figure increases relative to its base year level over time. The concept is that the ratio reflects the tightness or looseness of the world LNG market pushing or pulling, respectively, world natural gas prices toward or away from the world oil price. The specific form of the price equation follows:

$$ALTPRC_{y,c} = \left(\frac{XBRENT\_PRICE_{t+y}}{5.8} \right)^{ALP_c} * RAT_c^{BET_c} \tag{43}$$

where for Europe,

$$RAT_1 = \frac{\dfrac{FLEXLNG_{t+y} + ((FLEXADD_{t+y} + EVOL\_INCR) * PERTOFLEX_1)}{QOECD\_EUR_{t+y}}}{\dfrac{FLEXLNG_{lhisyr} + ((FLEXADD_{lhisyr} + EVOL\_INCR) * PERTOFLEX_1)}{QOECD\_EUR_{lhisyr}}} \quad (44)$$

where for Asia,

$$RAT_2 = \frac{[FLEXLNG_{t+y} + ((FLEXADD_{t+y} + EVOL\_INCR) * PERTOFLEX_1)] / NETASIA_{t+y}}{[FLEXLNG_{lhisyr} + ((FLEXADD_{lhisyr} + EVOL\_INCR) * PERTOFLEX_1)] / NETASIA_{lhisyr}} \quad (45)$$

[Note: when evaluating RAT in years beyond the last forecast year a conservative extrapolation is used such that the value of RAT for post forecast years does not vary much from the value of RAT in the last forecast year.]

where,

$ALTPRC_{y,c}$	=	the expected competing natural gas price in continent Europe or Asia for LNG in y years from the current forecast year (1987$/MMBtu)
$XBRENT\_PRICE_{t+y}$	=	the Brent crude oil price in y years from the current forecast year t (1987$/bbl) [Note: the 5.8 converts the price into 1987$/MMBtu.]
ALP_c	=	an assumed coefficient representing the value necessary to align the oil price to the natural gas price in each continent in history when "RAT" has value of 1 [Appendix E]
BET_c	=	an assumed coefficient which drives the movement of the natural gas price away from (or to) the oil price as the market loosens (or tightens), as indicated by RAT [Appendix E]
$FLEXLNG_{t+y}$	=	exogenously set projected level of flexibly priced LNG on the world market, excluding any potential volumes from the United States (Bcf)
$FLEXADD_{t+y}$	=	LNG exports from the United States in the current forecast year from liquefaction facilities constructed as of the current forecast year (Bcf)
EVOL_INCR	=	LNG exports from the United States from liquefaction facility under consideration for construction (represents two generic trains GEN_EVOL_INCR or a planned facility size PLCAP, Appendix E) (Bcf)
$QOECD\_EUR_{t+y}$	=	exogenously set projected natural gas consumption for Organization for Economic Cooperation and Development (OECD) Europe [Appendix E] (Bcf)
$NETASIA_{t+y}$	=	exogenously set projected representative net natural gas consumption for Asia equal to consumption in Japan, South Korea, and China, minus production in China [QJAP + QSKOR + QCHINA – PCHINA, Appendix E] (Bcf)
$PERTOFLEX_c$	=	the fraction of the LNG exports from the United States that are assumed to be flexibly priced [Appendix E]
c	=	continent (1-Europe, 2-Asia)
t	=	forecast year
lhisyr	=	last year of historical year data
y	=	number of years after the current forecast year

Once prices are established for Europe and Asia for the next 20 years (the assumed planning life of a liquefaction plant), a comparison is made between expected future prices for natural gas in the United States plus assumed costs for liquefaction (including pipeline costs)[41] [CST_LIQ, Appendix E], shipping [CST_SHP, Appendix E], and regasification [CST_RGAS, Appendix E].[42] The differences in these two prices represents the added value to the consumer (or to whomever is able to capture the economic return) of purchasing LNG from the United States over potential other supply options. These price differences are accumulated over the 20-year time horizon and set in present forecast year terms using an assumed discount rate [DCF_RATE, Appendix E]. The region with the resulting highest present economic value is assumed to be the location of the next liquefaction build[43] with completion date three years from the current forecast year, presuming other assumed limiting factors are not binding (i.e., earliest potential start year [FYREXP, Appendix E], maximum allowed export volume [MAXEXP, Appendix E]). If a liquefaction facility is already under construction it is assumed to come on line at specified volumes and times.

In general and under normal circumstances, once it has been determined in the model that a liquefaction facility is economic to be built, it will operate at full capacity, accounting for some operational down time. However, the capacity utilization (and therefore the export level) is lowered in the model if the economics warrant. In each forecast year, the alternative price in Asia and Europe is calculated for the given year using the same basic equations provided above, with the value of EVOL_INCR set to zero. These prices are compared against the estimated variable price of U.S. exports into Europe and Asia, calculated as the regional wellhead price, plus fuel costs for liquefaction, plus costs for transporting, liquefying, and regasifying, minus assumed sunk costs (i.e., upfront costs paid to reserve liquefaction capacity regardless if it is used). If the variable U.S. price into Europe or Asia is lower than the alternative price then export levels are set assuming full utilization. Otherwise export levels are set as follows:

$$NALNGEXP_{r,y} = LNGEXPCAP_{r,y} * \frac{RATIO - LRATIO}{HRATIO - LRATIO} \tag{46}$$

where,

$NALNGEXP_{r,y}$	=	LNG exports out of NGTDM region r (Bcf)
$LNGEXPCAP_{r,y}$	=	annual export volumes out of NGTDM region r if running at a normal full capacity (Bcf)
RATIO	=	alternative price in Europe (or Asia) divided by variable U.S. price in Europe (or Asia), whichever is greater

[41] The pipeline costs from wellhead to liquefaction terminal are of particular significance for a liquefaction facility in Alaska, bringing North Slope gas to market. If two trains have already been built in a region, a potential third and fourth train are assumed to be able to charge a lower rate [BONUS, Appendix E] to reflect lower marginal costs.

[42] A risk factor to account for any externalities (positive or negative) beyond price is included in the model but set to 0 for *AEO2014*.

[43] The code was changed for *AEO2014* side cases to have facilities that have been approved with signed contracts come on line based on their planned schedules, if generally deemed economic, rather than selecting the most economic. When tested, this modification did not cause a change in the reference case results.

HRATIO = Assumed minimum RATIO to run at full capacity [Appendix E, for *AEO2014* set at 1.0 or when U.S. and alternative world prices are equal]
LRATIO = Assumed minimum RATIO before facility would be shut-down [Appendix E]
r = NGTDM region, including a region representing Alaska
y = forecast year

Alaska natural gas routine

The NEMS demand modules provide a forecast of natural gas consumption for the total Pacific Census Division, which includes Alaska. Currently natural gas that is produced in Alaska cannot be transported to the Lower 48 states via pipeline. Therefore, the production and consumption of natural gas in Alaska is handled separately within the NGTDM from the contiguous states. Annual estimates of contiguous Pacific Division consumption levels are derived within the NGTDM by first estimating Alaska natural gas consumption for all sectors, and then subtracting these from the core market consumption levels in the Pacific Division provided by the NEMS demand modules. The use of natural gas in compressed natural gas vehicles in Alaska is assumed to be negligible or nonexistent. The Electricity Market Module provides a value for natural gas consumption in Alaska by electric generators. The series of equations for specifying the consumption of gas by Alaska residential and commercial customers follows:

$$\begin{aligned} AK\_RN_t = & -4.69 + (1.46 * AK\_RN_{t-1}) + (-0.499 * AK\_RN_{t-2}) \\ & + (0.0172 * AK\_POP_t) + (-0.31 * oMC\_RUC_t) \end{aligned} \tag{47}$$

$$\begin{aligned} AK\_CN_y = & \ 4.05 - 0.625 + (0.17 * AK\_POP_t) + (-0.158 * oMC\_RUC_t) \\ & + (-0.182 * oMC\_RUC_{t-1}) \end{aligned} \tag{48}$$

$$(res):\ AKQTY\_F_{s=1,t} = \{4129.965 + (133.66 * AK\_RN_t\} / 1000. \tag{49}$$

$$\begin{aligned} (com):\ AKQTY\_F_{s=2,t} = & \{17251.45 + (124.55 * AK\_CM_t) \\ & - (125.132 * oMC\_RUC_t)\} / 1000. \end{aligned} \tag{50}$$

where,

$AKQTY\_F_{s=1,t}$ = consumption of natural gas by residential (s=1) customers in Alaska (MMcf, converted to Bcf, Table F1, Appendix F)
$AKQTY\_F_{s=2,t}$ = consumption of natural gas by commercial (s=2) customers in Alaska (MMcf, converted to Bcf, Table F1, Appendix F)
AK_RN_t = number of residential customers (thousands, Table F2, Appendix F)
AK_CN_t = number of commercial customers (thousands, Table F2, Appendix F)
AK_POP_t = exogenously specified projection of the population in Alaska (thousands, Appendix E)
oMC_RUC_t = U.S. unemployment rate (percent) from NEMS Macroeconomic Activity Module
t = year

Gas consumption by Alaska industrial customers is set as follows:

$$(ind): AKQTY\_F_{s=3,t} = AK\_QIND\_S_t + (oNALNGEXP_{r,t} * PERLIQFUEL) \tag{51}$$

where,

$AKQTY\_F_{s=3,t}$	=	consumption of natural gas by industrial customers (s=3), (Bcf)
AK_QIND_S	=	exogenous component reflecting historical consumption of natural gas by industrial customers in southern Alaska (Bcf), equal to the sum of consumption at the Agrium fertilizer plant (assumed to close in 2007, Appendix E) and at the Kenai LNG liquefaction facility (assumed to close in 2012, Appendix E), as well as a nominal small volume thereafter of around 6 Bcf.
oNALNGEXP	=	North American LNG export volume out of region r (Bcf)
PERLIQFUEL	=	natural gas consumed in liquefying natural gas for export as a fraction of the exported volumes (Appendix E).
s	=	sector
r	=	LNG export region representing Alaska
t	=	year

While the above equations are meant to reflect total gas consumption in the state, if a pipeline is built to bring North Slope gas to the South, it is possible that the projected volumes could be higher, particularly for the industrial sector, since consumption growth is currently hindered by declining supplies in South Alaska. The current modeling approach does not sufficiently capture such potential.

The production of gas in Alaska is basically set equal to the sum of the volumes consumed in and transported out of Alaska. Therefore production depends on whether a pipeline is constructed from Alaska to Alberta or whether a new LNG export facility is built in Alaska,[44] as well as any exports from the existing facility in Alaska[45] and any gas consumed in the state. The production of gas related to an Alaska pipeline to Alberta or one to a new LNG export facility in the South equals the volumes delivered to Alberta or exported, respectively, plus what is consumed for related lease, plant, and pipeline operations (calculated as the delivered or exported volume divided by 1 minus the percent used for lease, plant, and pipeline operations). The production volumes related to both projects are summed together (N.AK2 below), although the model restricts construction to one or the other. Other production in North Alaska that is not related to either pipeline project is largely lease and plant fuel associated with the crude oil extraction processes, whereas gas is produced in the south largely to satisfy state consumption requirements. The quantity of lease and plant fuel not related to either pipeline in Alaska (N.AK1 below) is assigned separately, includes lease and plant fuel used in the north and south, and is added to the other production (N.AK2 below) to arrive at total North Alaska production. The details follow:

[44] The process for deciding to build a pipeline to Alberta is discussed later, whereas the LNG export facility decision was discussed in the previous section.

[45] Although there has been some discussion about the potential need to import LNG into Alaska to satisfy consumption requirements, this potential is not being modeled in the current version of the NGTDM. The inherent assumption is that sufficient production will be found in South Alaska or transported to South Alaska from the north.

$$(S.AK):\ AK\_PROD_{r=1} = AK\_CONS\_S + EXPJAP + QALK\_LAP\_S + QALK\_PIP\_S - AK\_DISCR \tag{52}$$

$$(N.AK_1):\ AK\_PROD_{r=2} = QALK\_LAP\_N = (0.0943884 * QALK\_LAP\_NLAG) + (0.038873 * \sum_{s=1}^{3} oOGPRCOAK_{s,t}) \tag{53}$$

$$(N.AK_2):\ AK\_PROD_{r=3} = \frac{QAK\_ALB_t + oNALNGEXP_{e,t}}{1. - AK\_PCTLSE_{r=3} - AK\_PCTPLT_{r=3} - AK\_PCTPIP_{r=3}} \tag{54}$$

where,

$$AK\_CONS\_S = \sum_{s=1}^{4} (AKQTY\_F_s + AKQTY\_I_s) \tag{55}$$

$$QALK\_LAP\_S = 0.0 \qquad (\textit{total is assigned to the North}) \tag{56}$$

$$QALK\_PIP\_S = (AK\_CONS\_S + EXPJAP) * AK\_PCTPIP_2 \tag{57}$$

where,

AK_PROD_r	=	dry gas production in Alaska (Bcf)
AK_CONS_S	=	total gas delivered to customers in South Alaska (Bcf)
$AKQTY\_F_s$	=	total gas delivered to core customers in Alaska in sector s (Bcf)
$AKQTY\_I_s$	=	total gas delivered to non-core customers in Alaska in sector s (Bcf)
EXPJAP	=	quantity of gas liquefied and exported from existing Kenai facility (Bcf)
QALK_LAP_N	=	quantity of gas consumed in Alaska for lease and plant operations, excluding that related to either Alaska pipeline from the North Slope (Bcf)
QALK_LAP_NLAG	=	quantity of gas consumed for lease and plant operations in the previous year, excluding that related to either pipeline (Bcf)
$oOGPRCOAK_{s,y}$	=	crude oil production in Alaska by sector
$QALK\_PIP_r$	=	quantity of gas consumed as pipeline fuel (Bcf)
AK_DISCR	=	discrepancy, the average (2006-2011) historically based difference in reported supply levels and consumption levels in Alaska (Bcf)
QAK_ALB_t	=	gas produced on North Slope entering Alberta via pipeline (Bcf)
oNALNGEXP	=	quantity of LNG exported out of a new Alaskan LNG export facility (Bcf)
AK_PCTLSE_r	=	(for r=1) not used, (for r=2) lease and plant consumption as a percent of gas consumption, (for r=3) lease consumption as a percent of gas production (fraction, Appendix E)
AK_PCTPLT_r	=	(for r=1 and r=2) not used, (for r=3) plant fuel as a percent of gas production (fraction, Appendix E)
AK_PCTPIP_r	=	(for r=1) not used, (for r=2) pipeline fuel as a percent of gas consumption, (for r=3) pipeline fuel as a percent of gas production fraction, Appendix E)
s	=	sectors (1=residential, 2=commercial, 3=industrial, 4=transportation, 5=electric generators)

r = region (1 = south, 2 = north not associated with a pipeline to Alberta or a new export facility, 3 = north associated with a pipeline to Alberta or a new export facility

Lease, plant, and pipeline fuel consumption are calculated as follows. For south Alaska, the calculation of pipeline fuel (QALK_PIP_S) and lease and plant fuel (QALK_LAP_S) are shown above. For either Alaska pipeline, all three components are set to the associated production times the percentage of lease (AK_PCTLSE_3), plant (AK_PCTPLT_3), or pipeline fuel (AK_PCTPIP_3). For the rest of north Alaska, pipeline fuel consumption is assumed to be negligible, while lease and plant fuel not associated with either pipeline (QALK_LAP_N) is set based on an estimated equation shown previously (Table F8, Appendix F).

Estimates for natural gas wellhead and delivered prices in Alaska are estimated in the NGTDM for proper accounting, but have a very limited impact on the NEMS system. The average Alaska wellhead price (AK_WPRC) over the North and South regions (not accounting for the impact if a pipeline ultimately is connected to Alberta) is set using the following estimated equation:

$$AK\_WPRC_1 = WPRLAG^{0.934077} * oIT\_WOP_{y,1}^{(0.280960*(1-0.934077))} \tag{58}$$

where,

AK_WPRC_1 = natural gas wellhead price in Alaska, presuming no pipeline to Alberta (1987$/Mcf) (Table F1, Appendix F)
WPRLAG = AK_WPRC in the previous forecast year ($/Mcf)
$oIT\_WOP_{y,1}$ = world oil price (1987$ per barrel)

The wellhead price for natural gas associated with a pipeline to Alberta or to a new LNG export facility is exogenously specified ($FR\_PMINWPR_1$, Appendix E) and does not vary by forecast year. The average wellhead price for the state is calculated as the quantity-weighted average of AK_WPRC and $FR\_PMINWPR_1$. Delivered prices in Alaska are set equal to the wellhead price (AK_WPRC) resulting from the equation above plus a fixed, exogenously specified markup (Appendix E -- AK_RM, AK_CM, AK_IN, AK_EM).

Within the model, the commencement of construction of the Alaska-to-Alberta pipeline is restricted to the years beyond an earliest start date (FR_PMINYR, Appendix E) and can only occur if a pipeline from the Mackenzie Delta to Alberta is not under construction and the decision to build a new LNG export terminal has not already been made. The same is true for the Mackenzie Delta pipeline relative to construction of the Alaska pipeline. Otherwise, the structural representation of the Mackenzie Delta pipeline is nearly identical to that of the Alaska pipeline, with different numerical values for model parameters. Therefore, the following description applies to both pipelines. Within the model the same variable names are used to specify the supporting data for the two pipelines, with an index of 1 for Alaska and an index of 2 for the Mackenzie Delta pipeline.

The decision to build a pipeline is triggered if the estimated cost to supply the gas to the Lower 48 states is lower than an average of the lower 48 average wellhead price over the planning period of FR_PPLNYR

(Appendix E) years.[46] Construction is assumed to take FR_PCNSYR (Appendix E) years. Initial pipeline capacity is assumed to accommodate a throughput delivered to Alberta of FR_PVOL (Appendix E). The first year of operation, the volume is assumed to be half of its ultimate throughput. If the trigger price exceeds the minimum price by FR_PADDTAR (Appendix E) after the initial pipeline is built, then the capacity will be expanded the following year by a fraction (FR_PEXPFAC, Appendix E) of the original capacity.

The expected cost to move the gas to the lower 48 is set as the sum of the wellhead price, the charge for treating the gas, and the fuel costs (FR_PMINWPR, Appendix E), plus the pipeline tariff for moving the gas to Alberta and an assumed differential between the price in Alberta and the average lower 48 wellhead price (ALB_TO_L48, Appendix E). A risk premium is also included to largely reflect the expected initial price drop as a result of the introduction of the pipeline, as well as some of the uncertainties in the necessary capital outlays and in the ultimate selling price (FR_PRISK, Appendix E).[47] The cost-of-service based calculation for the pipeline tariff (NGFRPIPE_TAR) to move gas from each production source to Alberta is presented at the end of Chapter 6.

[46] The prices are weighted, with a greater emphasis on the prices in the recent past. An additional check is made that the estimated cost is lower than the lower 48 price in the last two years of the planning period and lower than a weighted average of the expected prices in the three years after the planning period, during the construction period.
[47] If there is an annual decline in the average lower 48 wellhead price over the planning period for the Alaska pipeline, an additional adjustment is made to the expected cost (although it is not a cost item), equivalent to half of the drop in price averaged over the planning period, to account for the additional concern created by declining prices.

3. Overview of Solution Methodology

The previous chapter described the function of the NGTDM within NEMS and the transformation and representation of supply and demand elements within the NGTDM. This chapter will present an overview of the NGTDM model structure and of the methodologies used to represent the natural gas transmission and distribution industries. First, a detailed description of the network used in the NGTDM to represent the U.S. natural gas pipeline system is presented. Next, a general description of the interrelationships between the submodules within the NGTDM is presented, along with an overview of the solution methodology used by each submodule.

NGTDM regions and the pipeline flow network

General description of the NGTDM network

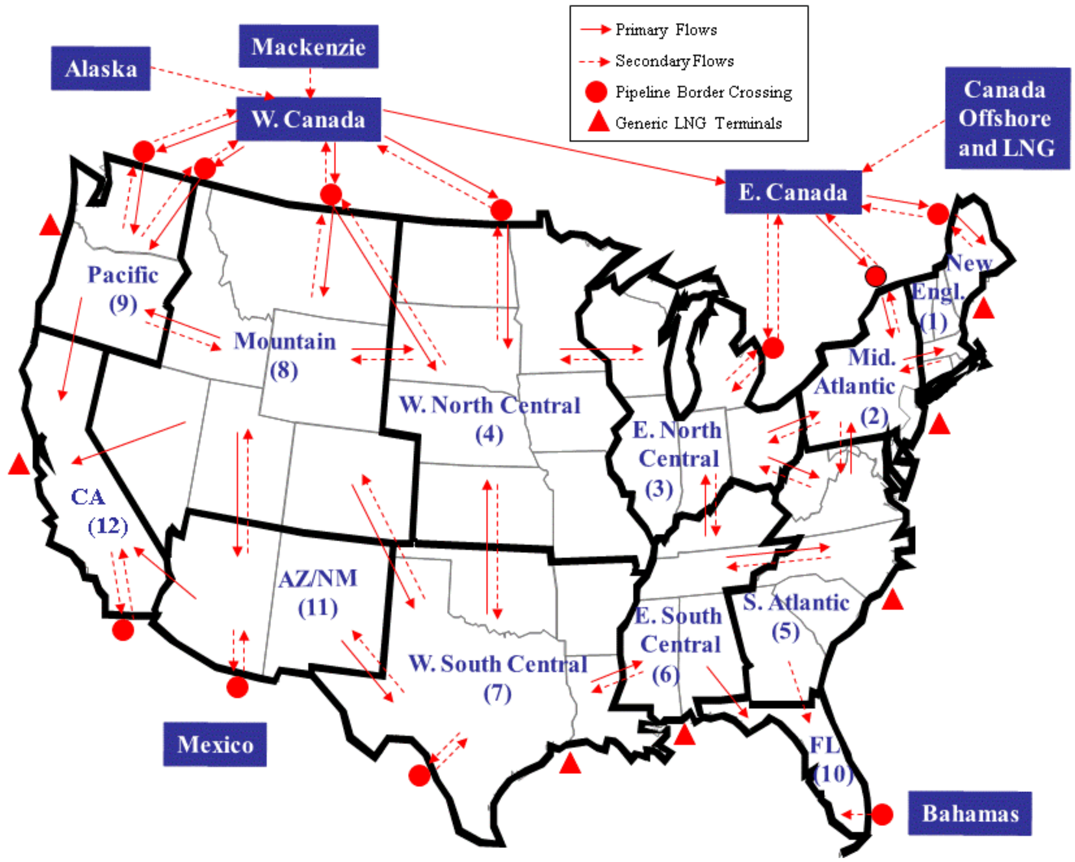
In the NGTDM, a transmission and distribution network (**Figure 3-1**) simulates the interregional flow of gas in the contiguous United States and Canada in either the peak (December through March) or off-peak (April through November) period. This network is a simplified representation of the physical natural gas pipeline system and establishes the possible interregional transfers to move gas from supply sources to end-users. Each NGTDM region contains one transshipment node, a junction point representing flows coming into and out of the region. Nodes have also been defined at the Canadian and Mexican borders, as well as in eastern and western Canada. Arcs connecting the transshipment nodes are defined to represent flows between these nodes, and thus to represent interregional flows. Each of these interregional arcs represents an aggregation of pipelines that are capable of moving gas from one region into another region.

Bidirectional flows are allowed in cases where the aggregation includes some pipelines flowing in one direction and other pipelines flowing in the opposite direction.[48] Bidirectional flows can also be the result of directional flow shifts within a single pipeline system due to seasonal variations in flows. Arcs leading from or to international borders generally[49] represent imports or exports. The arcs which are designated as “secondary” in **Figure 3-1** historically represented relatively low flow volumes and are therefore handled somewhat differently and separately from those designated as “primary.” However, with the recent and expected future increases in production in northeastern states, particularly in the Marcellus play, the historical flow patterns have started to shift and are expected to continue to shift. Therefore for *AEO2014* a new algorithm (described later) was implemented to endogenously set flows on arcs labeled as secondary but that are expected to experience significant growth.

[48] Historically, one out of each pair of bidirectional arcs in Figure 3-1 represents a relatively small amount of gas flow during the year. These arcs are referred to as “the bidirectional arcs” and are identified as the secondary arcs in Figure 3-1, excluding 3 to E. Canada, 5 to 10, 15 to E. Canada, Mexico to 7, 11, and 12, and Alaska to W. Canada. The flows along these arcs are initially set at the last historical level and for most are only increased (proportionately) when a known (or likely) planned capacity expansion occurs. Flows on the following secondary arcs are allowed to exceed their historical level endogenously based on relative price: 2 to 3, 2 to 5, 2 to E. Canada, and 3 to E. Canada.

[49] Some natural gas flows across the Canadian border into the United States, only to flow back across the border without changing ownership or truly being imported. In addition, any natural gas that might flow from Alaska to the Lower 48 states would cross the Canadian/U.S. border, but not be considered as an import.

Figure 3-1. Natural gas transmission and distribution module network



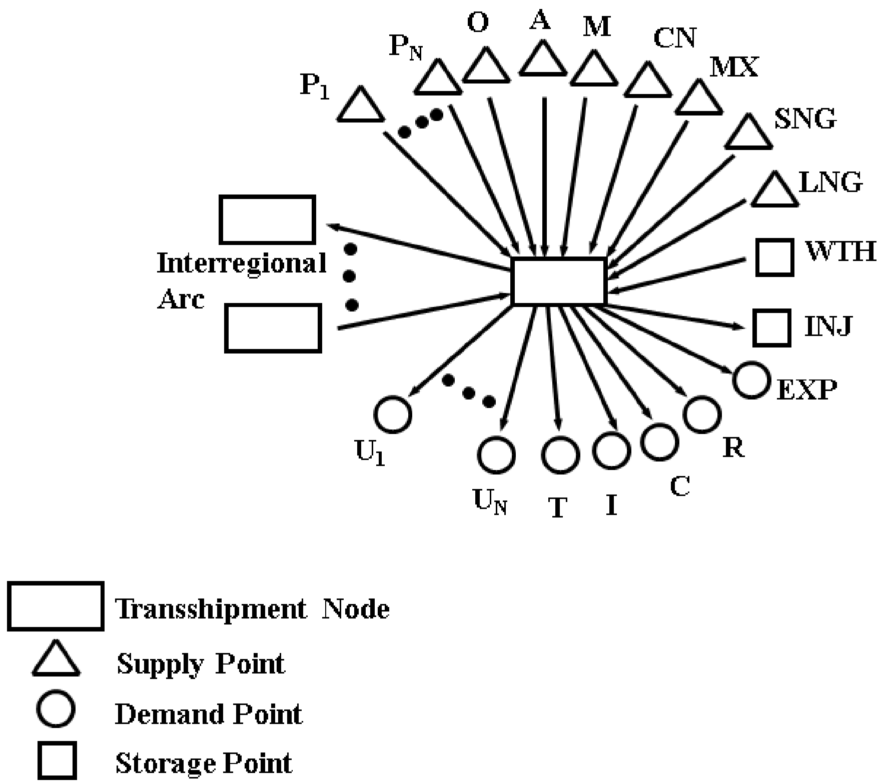
Flows are further represented by establishing arcs from the transshipment node to each demand sector/subregion represented in the NGTDM region. Demand in a particular NGTDM region can only be satisfied by gas flowing from that same region's transshipment node. Similarly, arcs are also established from supply points into transshipment nodes. The supply from each NGTDM/OGSM region is directly available to only one transshipment node, through which it must first pass if it is to be made available to the interstate market (at an adjoining transshipment node). During a peak period, one of the supply sources feeding into each transshipment node represents net storage withdrawals in the region during the peak period. Conversely during the off-peak period, one of the demand nodes represents net storage injections in the region during the off-peak period.

Figure 3-2 shows an illustration of all possible flows into and out of a transshipment node. Each transshipment node has one or more arcs to represent flows from or to other transshipment nodes. The transshipment node also has an arc representing flow to each end-use sector in the region (residential, commercial, industrial, electric generators, and transportation), including separate arcs to each electric generator subregion.[50] Exports and (in the off-peak period) net storage injections are also

[50] Conceptually within the model, the flow of gas to each end-use sector, excluding electric generators, passes through a common city gate point before reaching the end-user.

represented as flow out of a transshipment node. Each transshipment node can have one or more arcs flowing in from each supply source represented within the region. These supply points represent U.S. or Canadian onshore or U.S. offshore production, liquefied natural gas imports, gas produced in Alaska and transported via pipeline, Mexican imports, (in the peak period) net storage withdrawals in the region, or supplemental gas supplies.

Figure 3- 2. Transshipment node



P_i - Production in NGTDM/OGSM Region i
O - Offshore Supplies
A - Alaskan Supplies via pipeline to Alberta
M - Mackenzie Delta Gas via pipeline to Alberta
CN - Canadian Supplies
MX - Mexican Imports
SNG - Supplemental Supplies
LNG - Liquefied Natural Gas Imports
WTH - Storage Withdrawals (peak only)
INJ - Storage Injections (offpeak only)
EXP - Exports to either Canada or Mexico or as LNG
R - Residential Demand
C - Commercial Demand
I - Industrial Demand
T - Transportation Demand
U_i - Electric Generator Demand in NGTDM/EMM Region i

Two items accounted for but not presented in **Figure 3-2** are discrepancies or balancing items (i.e., average historically observed differences between independently reported natural gas supply and disposition levels (DISCR for the United States, CN_DISCR for Canada) and backstop supplies.[51]

Many of the types of supply listed above are relatively low in volume and are set independently of current prices and before the NGTDM determines a market equilibrium solution. As a result, these sources of supply are handled differently within the model. Structurally within the model only the price-responsive sources of supply (i.e., onshore and offshore lower 48 U.S. production, Western Canadian Sedimentary Basin (WCSB) production, and storage withdrawals) are explicitly represented with supply nodes and connecting arcs to the transshipment nodes when the NGTDM is determining a market equilibrium solution. However, other sources of supply or demand requirements can effectively be represented as price-responsive if their volumes are adjusted in response to price outside of the Interstate Transmission Submodule (ITS) equilibrium solution process.

Once the types of end-use destinations and supply sources into and out of each transshipment node are defined, a general network structure is created. Each transshipment node does not necessarily have all supply source types flowing in, or all demand source types flowing out. For instance, some transshipment nodes will have liquefied natural gas available while others will not. The specific end-use sectors and supply types specified for each transshipment node in the network are listed in **Table 3-1.** This table also provides the mapping of Electricity Market Module regions and Oil and Gas Supply Module regions to NGTDM regions (**Figure 2-3** and **Figure 2-5** in Chapter 2). The transshipment node numbers in the U.S. align with the NGTDM regions in **Figure 3-1**. Transshipment nodes 13 through 19 are pass-through nodes for the border crossings on the Canada/U.S. border, going from east to west.

As described earlier, the NGTDM determines the flow and price of natural gas in both a peak and off-peak period. The basic network structure separately represents the flow of gas during the two periods within the ITS. Conceptually this can be thought of as two parallel networks, with three areas of overlap. First, pipeline expansion is determined only in the peak-period network (with the exception of pipelines going into Florida from the East South Central Division). These levels are then used as constraints for pipeline flow in the off-peak period. Second, net withdrawals from storage in the peak period establish the net amount of natural gas that will be injected in the off-peak period, within a given forecast year. Similarly, the price of gas withdrawn in the peak period is the sum of the price of the gas when it was injected in the off-peak, plus an established storage tariff. Third, the supply curves provided by the Oil and Gas Supply Module are specified on an annual basis. Although these curves are used to approximate peak and off-peak supply curves, the model is constrained to solve on the annual supply curve (i.e., when the annual curve is evaluated at the quantity-weighted average annual wellhead price, the resulting quantity should equal the sum of the production in the peak and off-peak periods). The details of how this is accomplished are provided in Chapter 4.

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[51] Backstop supplies are allowed when the flow out of a transshipment node exceeds the maximum flow into a transshipment node. A high price is assigned to this supply source and it is generally expected not to be required (or desired). Chapter 4 provides a more detailed description of the setting and use of backstop supplies in the NGTDM.

Table 3-1. Demand and supply types at each transshipment node in the network

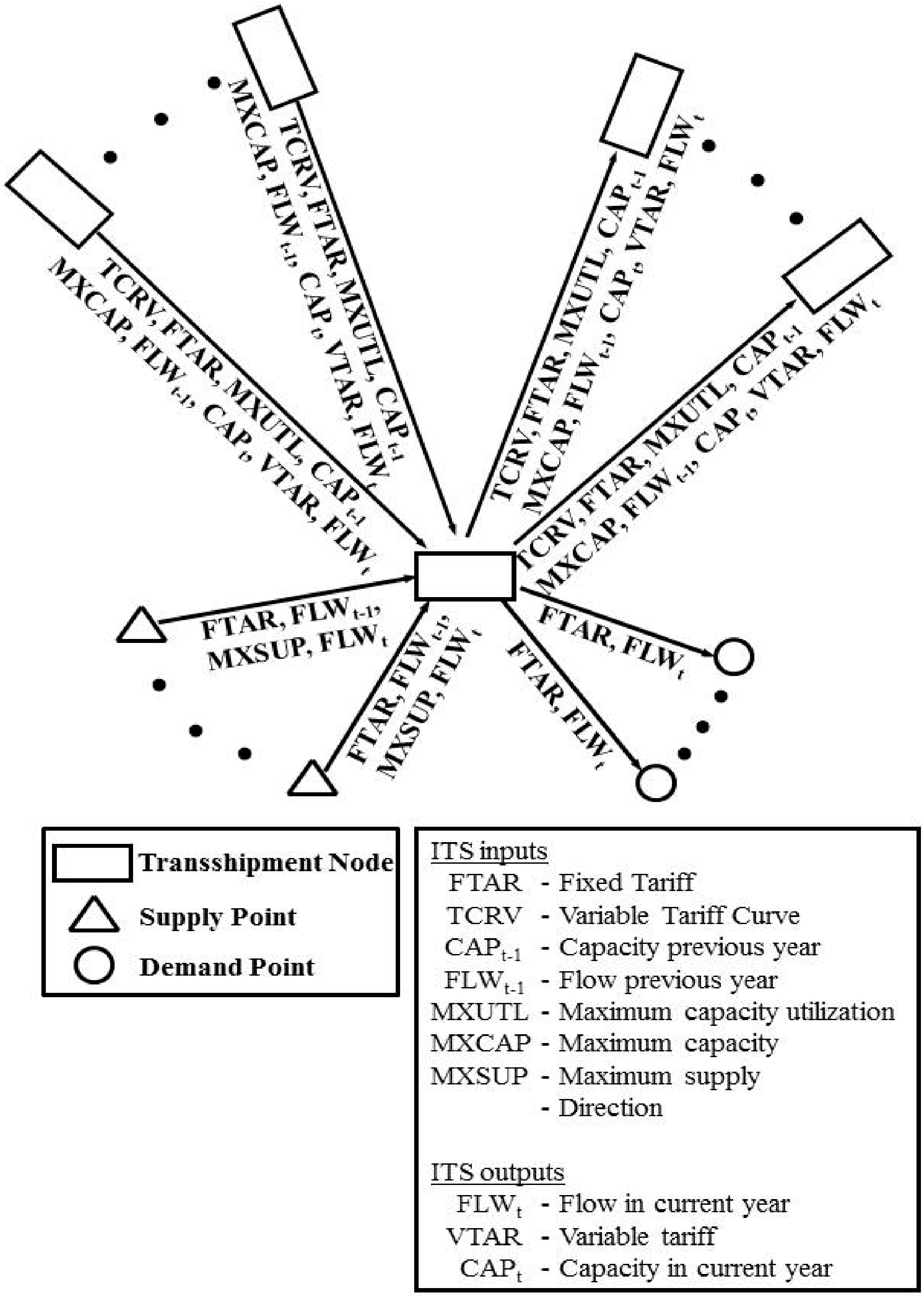
Transshipment Node	Demand Types	Supply Types
1	R, C, I, T, U(1), EXP	P(1/1), LNG, SNG
2	R, C, I, T, U(2), INJ, EXP	P(2/1), WTH, LNG, SNG
3	R, C, I, T, U(3), U(4), INJ	P(3/1), WTH, SNG
4	R, C, I, T, U(5), INJ	P(4/3), P(4/5), WTH, SNG
5	R, C, I, T, U(6), U(7), INJ, EXP	P(5/1), Atlantic Offshore, WTH, LNG, SNG
6	R, C, I, T, U(9), U(10), INJ, EXP	P(6/1), P(6/2), WTH, LNG, SNG
7	R, C, I, T, U(11), INJ, EXP	P(7/2), P(7/3), P(7/4), Gulf of Mexico, WTH, LNG, SNG
8	R, C, I, T, U(12), U(13), INJ	P(8/5), WTH, SNG
9	R, C, I, T, U(15), INJ, EXP	P(9/6), WTH, LNG, SNG
10	R, C, I, T, U(6), U(8), INJ	P(10/2), WTH, LNG, SNG
11	R, C, I, T, U(14), INJ	P(11/4), P(11/5), WTH, SNG
12	R, C, I, T, U(16), INJ, EXP	P(12/6), Pacific Offshore, WTH, LNG, SNG
13 – 19	--	--
20	Exports to Mexico (TX)	Mexican Imports (TX)
21	Exports to Mexico (AZ/NM)	Mexican Imports (AZ/NM)
22	Exports to Mexico (CA)	Mexican Imports (CA)
23	East Canada consumption, INJ, EXP	East Canada production, WTH, LNG
24	West Canada consumption, INJ, EXP	West Canada production, WTH, LNG, Alaska and Mackenzie Valley gas via a pipeline

Abreviations as defined in Figure 3-2. P(x/y) – production in region defined in Figure 2-5 for NGTDM region x and OGSM region y. U(z) – electric generator consumption in region z, defined in Figure 2-3

Specifications of a network arc

Each arc of the network has associated variable inputs and outputs. The variables that define an interregional arc in the ITS are the pipeline direction, available capacity from the previous forecast year, the "fixed" tariffs and/or tariff curve, the flow on the arc from the previous year, the maximum capacity level, and the maximum utilization of the capacity (**Figure 3-3**). While a model solution is determined (i.e., the quantity of the natural gas flow along each interregional arc is determined), the "variable" or quantity-dependent tariff and the required capacity to support the flow are also determined in the process.

Figure 3-3. Variables defined and determined for network arc



For the peak period, the maximum capacity build levels are set to a factor above the 1990 levels. The factor is set high enough so that this constraint is rarely, if ever, binding. However, the structure could be used to limit growth along a particular path. In the off-peak period the maximum capacity levels are set to the capacity level determined in the peak period. The maximum utilization rate along each arc is used to capture the impact that varying demand loads over a season have on the utilization along an arc.

For the peak period, the maximum utilization rate is calculated based on an estimate of the ratio of January-to-peak-period consumption requirements. For the off-peak the maximum utilization rates are set exogenously (HOPUTZ, Appendix E). Capacity and flow levels from the previous forecast year are used as input to the solution algorithm for the current forecast year. In some cases, capacity that is newly available in the current forecast year will be exogenously set (PLANPCAP, Appendix E) as "planned" (i.e., highly probable that it will be built by the given forecast year based on project announcements). Any additional capacity beyond the planned level is determined during the ITS equilibrium solution process and is checked against maximum capacity levels and adjusted accordingly.

Each of the interregional arcs has an associated "fixed" and "variable" tariff, to represent usage and reservation fees, respectively. The model uses the fixed rate (i.e., the usage fee) when setting flows within the system and then adds the variable rate when ultimately setting the final delivered prices. The fixed rates are set based on historical basis differentials of spot prices (averaged from 2005 to 2012) and do not vary across the forecast period.[52] The variable tariffs are established by applying the flow level along the arc to the associated tariff supply curve, established by the Pipeline Tariff Submodule (PTS). During the equilibrium solution process in the ITS, the resulting tariff (either variable or fixed plus variable) in the peak or off-peak period is added to the price at the source node to arrive at a price for the gas along the interregional arc right before it reaches its destination node. Through an iterative process, the relative values of these prices for all of the arcs entering a node are used as the basis for reevaluating the flow along each of these arcs when using fixed tariffs and for setting delivered prices when using total tariffs.

For the arcs from the transshipment nodes to the final delivery points, the variables defined are tariffs and flows (or consumption). The tariffs here represent the sum of several charges or adjustments, including interstate pipeline tariffs in the region, intrastate pipeline tariffs, and distributor markups. Associated with each of these arcs is the flow along the arc, which is equal to the amount of natural gas consumed by the represented sector. For arcs from supply points to transshipment nodes, the input variables are the production levels from the previous forecast year, a tariff, and the maximum limit on supplies or production. In this case the tariffs represent a gathering charge, an assumed fix price of $0.15 1987$/Mcf to move gas from the wellhead to the representative regional hub. Maximum supply levels are set at a percentage above a baseline or "expected" production level (described in Chapter 4). Although capacity limits can be set for the arcs to and from end-use sectors and supply points, respectively, the current version of the module does not impose such limits on the flows along these arcs.

[52] Before *AEO2014*, the fixed tariffs were based on regulated rates. An unsuccessful attempt was made to develop an algorithm consistent with history relating the basis differential to pipeline utilization and thus to allow the rate to increase with utilization. This will be revisited in the future.

Note that any of the above variables may have a value of zero, if appropriate. For instance, some pipeline arcs may be defined in the network that currently have zero capacity, yet where new capacity is expected in the future. On the other hand, some arcs such as those to end-use sectors are defined with infinite pipeline capacity because the model does not forecast limits on the flow of gas from transshipment nodes to end users.

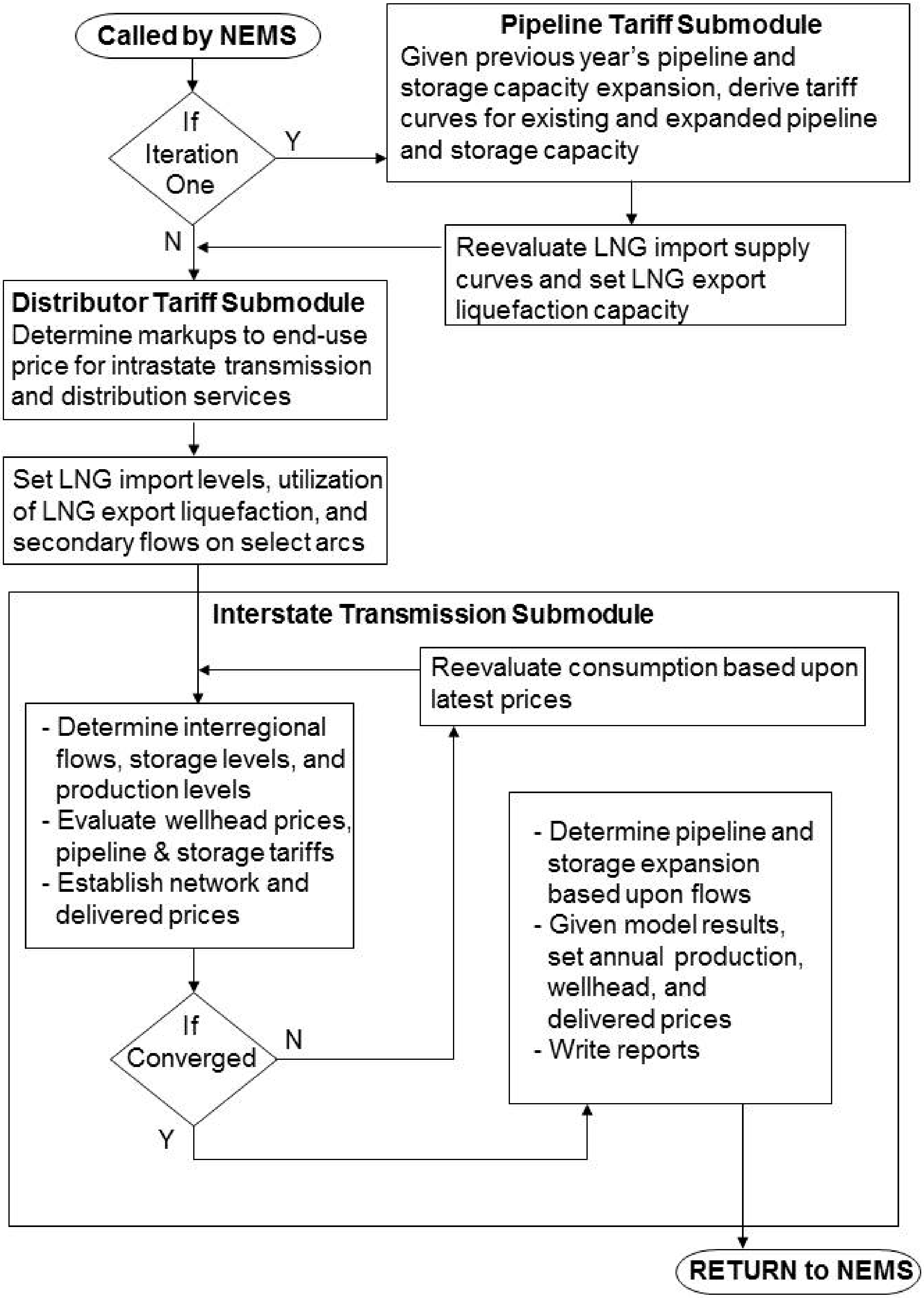
Overview of the NGTDM submodules and their interrelationships

NEMS generates an annual forecast of the outlook for U.S. energy markets for the years 1990 through 2040. For the historical years, many of the modules in NEMS do not execute, but simply assign historically published values to the model's output variables. The NGTDM similarly assigns historical values to most of the known module outputs for these years. However, some of the required outputs from the module are not known (e.g., the flow of natural gas between regions on a seasonal basis). Therefore, the model is run in a modified form to fill in such unknown, but required values. Through this process, historical values are generated for the unknown parameters that are consistent with the known historically based values (e.g., the unknown seasonal interregional flows sum to the known annual totals).

Although the NGTDM is executed for each iteration of each forecast year solved by NEMS, it is not necessary that all of the individual components of the module be executed for all iterations. Of the NGTDM's three components or submodules, the PTS is executed only once per forecast year since the submodule's input values do not change from one iteration of NEMS to the next. However, the ITS and the Distributor Tariff Submodule (DTS) are executed during every iteration for each forecast year because their input values can change by iteration. Within the ITS an iterative process is used. The basic solution algorithm is repeated multiple times until the resulting wellhead prices and production levels from one iteration are within a user-specified tolerance of the resulting values from the previous iteration, and equilibrium is reached. A process diagram of the NGTDM is provided in **Figure 3-4**, with the general calling sequence.

The ITS is the primary submodule of the NGTDM. One of its functions is to forecast interregional pipeline and underground storage expansions and produce annual pipeline load profiles based on seasonal loads. Using this information from the previous forecast year and other data, the PTS uses an accounting process to derive revenue requirements for the current forecast year. This submodule builds pipeline and storage tariff curves based on these revenue requirements for use in the ITS. These curves extend beyond the level of the current year's capacity and provide a means for assessing whether the demand for additional capacity, based on a higher tariff, is sufficient to warrant expansion of the capacity. The DTS provides distributor tariffs for use in the ITS. The DTS must be called in each iteration because some of the distributor tariffs are based on consumption levels that may change from iteration to iteration. Finally, using the information provided by these other NGTDM submodules and other NEMS modules, the ITS solves for natural gas prices and quantities that reflect a market equilibrium for the current forecast year. A few things (LNG imports and exports and secondary flows on selected arcs) are set each NEMS iteration, which ideally would be set within the ITS balancing process but are not because of model limitations. A brief summary of each of the NGTDM submodules follows.

Figure 3-4. NGTDM process diagram



Interstate Transmission Submodule

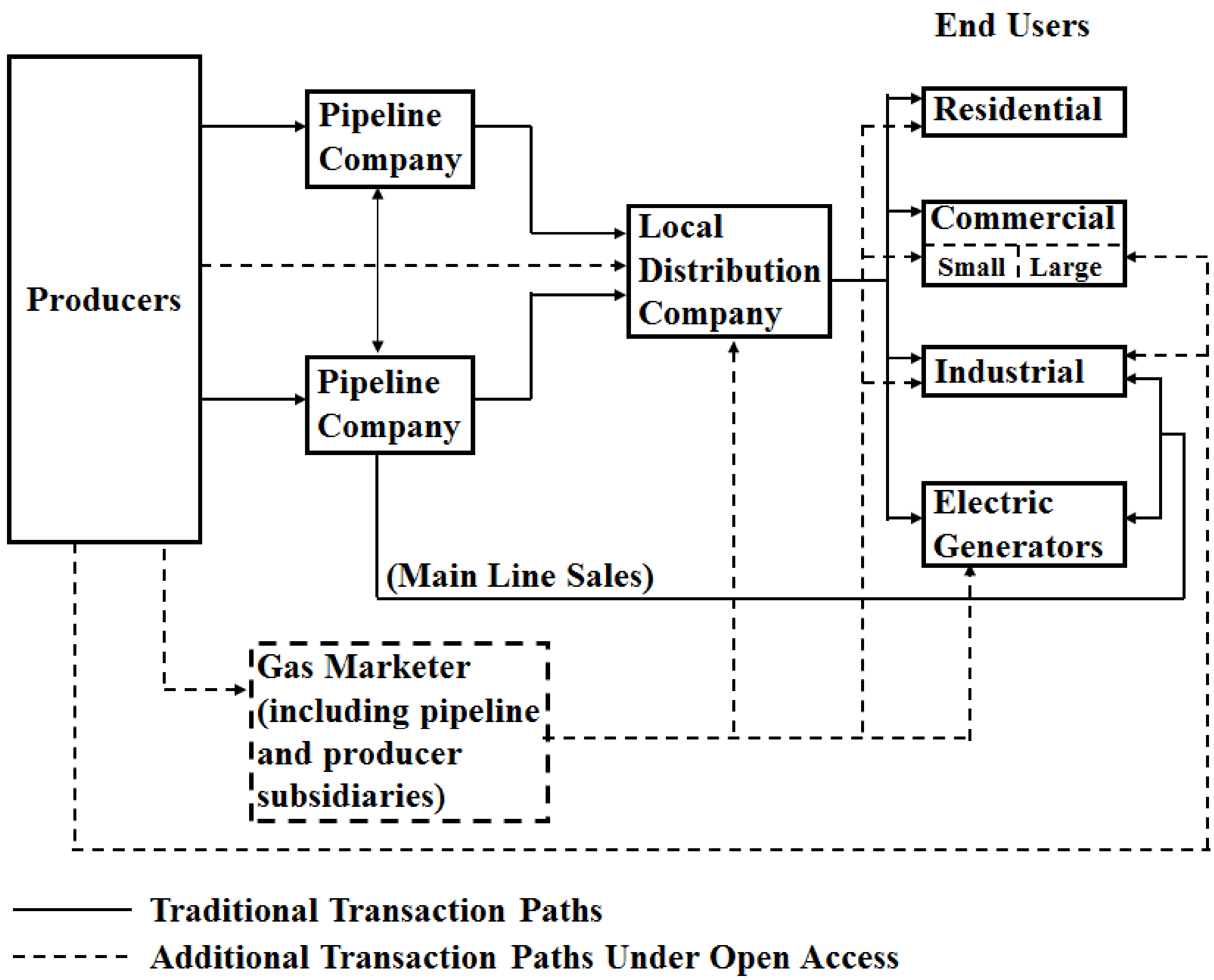
The ITS is the main integrating module of the NGTDM. One of its major functions is to simulate the natural gas price determination process. The ITS brings together the major economic factors that influence regional natural gas trade on a seasonal basis in the United States, the balancing of the demand for and the domestic supply of natural gas, including competition from imported natural gas. These are examined in combination with the relative prices associated with moving the gas from the producer to the end-user, or to the border for exporting, where and when (peak versus off-peak) it is needed. In the process, the ITS models the decision-making process for expanding pipeline and/or seasonal storage capacity in the U.S. gas market, determining the amount of pipeline and storage capacity to be added between or within regions in the NGTDM. Storage serves as the primary link between the two seasonal periods represented.

The ITS employs an iterative heuristic algorithm to establish a market equilibrium solution. Given the consumption levels from other NEMS modules and the established export volumes, the basic process followed by the ITS involves first establishing the backward flow of natural gas in each period from the consumers, through the network, to the producers, based primarily on the relative prices offered for the gas (from the previous ITS iteration). This process is performed for the peak period first since the net withdrawals from storage during the peak period will establish the net injections during the off-peak period. Second, using the model's supply curves, wellhead prices are set corresponding to the desired production volumes. Also, using the pipeline and storage tariff curves from the PTS, pipeline and storage tariffs are set corresponding to the associated flow of gas, as determined in the first step. These prices are then translated from the producers, back through the network, to the city gate and the end-users, by adding the appropriate tariffs along the way. A regional storage tariff is added to the price of gas injected into storage in the off-peak to arrive at the price of the gas when withdrawn in the peak period. Delivered prices are derived for residential, commercial, electric generation, and transportation customers, as well as for both the core and non-core industrial sectors, using the distributor tariffs provided by the DTS. At this point consumption and/or export levels can be reevaluated given the resulting set of delivered and export prices. Either way, the process is repeated until the solution has converged.

In the end, the ITS derives average seasonal (and ultimately annual) natural gas prices (wellhead, hub or spot, city gate, delivered, imported, and exported), and the associated production and flows, that reflect an interregional market equilibrium among the competing participants in the market. In the process of determining interregional flows and storage injections/withdrawals, the ITS also forecasts pipeline and storage capacity additions. In the calculations for the next forecast year, the PTS will adjust the requirements to account for the associated expansion costs. Other primary outputs of the module include lease, plant, and pipeline fuel use, Canadian import levels, and net storage withdrawals in the peak period.

The historical evolution of the price determination process simulated by the ITS is depicted schematically in **Figure 3-5**. At one point, the marketing chain was very straightforward, with end-users and local distribution companies contracting with pipeline companies, and the pipeline companies in turn contracting with producers. Prices typically reflected average costs of providing service plus some regulator-specified rate of return. Although this approach is still used as a basis for setting reservation fees for pipeline tariffs, more pricing flexibility has been introduced, particularly in the interstate pipeline industry and more recently by some local distributors. Pipeline companies are also offering a range of services under competitive and market-based pricing arrangements.

Figure 3 5. Principal buyer/seller transaction paths for natural gas marketing



The level of competition for pipeline services (generally a function of the number of pipelines having access to a customer and the amount of capacity available) drives the prices for interruptible transmission service and is having an effect on firm service prices. Currently, there are significant differences across regions in pipeline capacity utilization.[53] These regional differences are evolving as new pipeline capacity has been and is being constructed to relieve capacity constraints in the Northeast, to expand markets in the Midwest and the Southeast, and to move more gas out of the Middle Atlantic region and other shale-rich areas. As capacity changes take place, prices of services should adjust accordingly to reflect new market conditions. Mechanisms used to make the transmission sector more competitive include the widespread capacity release programs, market-based rates, and the market

[53] Further information can be found on the U.S. Energy Information Administration web page under "Pipeline Capacity and Usage," www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html .

centers with deregulated upstream pipeline services. The ITS is not designed to model any specific type of program, but to simulate the pricing of market-based transmission services.

Pipeline Tariff Submodule

The primary purpose of the PTS is to provide tariffs or volume-dependent curves for computing tariffs for interstate transportation and storage services within the ITS. These curves extend beyond current capacity levels and relate incremental pipeline or storage capacity expansion to corresponding estimated rates. The underlying basis for each tariff curve in the model is a forecast of the associated regulated revenue requirement. An accounting system is used to track costs and compute revenue requirements associated with both reservation and usage fees under a current typical regulated rate design. [54] Other than an assortment of macroeconomic indicators, the primary input to the PTS from other modules/submodules in NEMS is the level of pipeline and storage capacity expansions in the previous forecast year. Once an expansion is projected to occur, the submodule calculates the resulting impact on the revenue requirement. The PTS currently assumes rolled-in (or average), not incremental, rates for new capacity (i.e., the cost of any additional capacity is lumped in with the remaining costs of existing capacity when deriving a single tariff for all the customers along a pipeline segment).

Transportation revenue requirements (and associated tariff curves) are established for interregional arcs defined by the NGTDM network. These network tariff curves reflect an aggregation of the revenue requirements for individual pipeline companies represented by the network arc. Storage tariff curves are defined at regional NGTDM network nodes, and similarly reflect an aggregation of individual company storage revenue requirements. Note that these services are unbundled and do not include the price of gas, except for the cushion gas used to maintain minimum gas pressure. Furthermore, the submodule cannot address competition for pipeline or storage services along an aggregate arc or within an aggregate region, respectively. It should also be noted that the PTS deals only with the interstate market, and thus does not capture the impacts of state-specific regulations for intrastate pipelines. Intrastate transportation charges are indirectly accounted for within the DTS.

Pipeline tariffs for transportation and storage services represent a more significant portion of the price of gas to industrial and electric generator end-users than to other sectors. Consumers of natural gas are grouped generally into two categories: (1) those that need firm or guaranteed service because gas is their only fuel option or because they are willing to pay for security of supply, and (2) those that do not need guaranteed service because they can either periodically terminate operations or use fuels other than natural gas. The first group of customers (core customers) is assumed to purchase firm transportation services, while the latter group (non-core customers) is assumed to purchase non-firm service (e.g., interruptible service, released capacity). Pipeline companies guarantee to their core customers that they will provide peak day service up to the maximum capacity specified under their contracts even though these customers may not actually request transport of gas on any given day. In return for this service guarantee, these customers pay monthly reservation fees (or demand charges). These reservation fees are paid in addition to charges for transportation service based on the quantity

[54] For *AEO2014*, the reservation fee and associated per unit tariff are set based on the calculated revenue requirements. For storage tariffs, the usage fee is also based on a revenue requirements calculation. However, for interstate pipelines, the usage fee is set to the average basis differential between primary regional spot prices, as seen historically.

of gas actually transported (usage fees or commodity charges). The pipeline tariff curves generated by the PTS are used within the ITS when determining the relative cost of purchasing and moving gas from one source versus another in the peak and off-peak seasons. They are also used when setting the price of gas along the NGTDM network and ultimately to the end-users.

The actual rates or tariffs that pipelines are allowed to charge are largely regulated by the Federal Energy Regulatory Commission (FERC). FERC's ratemaking traditionally allows (but does not necessarily guarantee) a pipeline company to recover its costs, including what the regulators consider a fair rate of return on capital. Furthermore, FERC not only has jurisdiction over how cost components are allocated to reservation and usage categories, but also how reservation and usage costs are allocated across the various classes of transmission (or storage) services offered (e.g., firm versus non-firm service). Previous versions of the NGTDM (and therefore the PTS) included representations of natural gas moved (or stored) using firm and non-firm service. However, in an effort to simplify the module, this distinction has been removed in favor of moving from an annual to a seasonal model. The impact of the distinction of firm versus non-firm service on core and non-core delivered prices is indirectly captured in the markup established in the DTS. More recent initiatives by FERC have allowed for more flexible processes for setting rates when a service provider can adequately demonstrate that it does not possess significant market power. The use of volume-dependent tariff curves partially serves to capture the impact of alternate rate-setting mechanisms. Additionally, various rate-making policy options discussed by FERC would allow peak-season rates to rise substantially above the 100% load factor rate (also known as the full cost-of-service rate). In capacity-constrained markets, the basis differential between markets connected via the constrained pipeline route will generally be above the full cost of service pipeline rates. The NGTDM's ultimate purpose is to project market prices; it uses cost-of-service rates as a means in the process of establishing market prices.

Distributor Tariff Submodule

The primary purpose of the DTS is to determine the price markup from the regional market hub to the final purchaser. For most customers, this consists of (1) distributor markups charged by local distribution companies for the distribution of natural gas from the city gate to the end-user, (2) an intraregional interstate pipeline tariff charge (set in the PT S), and (3) markups charged by intrastate pipeline companies for intrastate transportation services. Intrastate pipeline tariffs are specified exogenously to the model and are currently set to zero (INTRAST_TAR, Appendix E). However, these tariffs are accounted for in the module indirectly. For electric generators, which generally do not purchase gas through a location distribution company, the "distributor tariff" represents the difference between the delivered price and the regional hub or spot price. In the case of industrial customers which also purchase gas independently of the local distribution company, the "distributor tariff" represents the difference between the average price paid by local distribution companies at the city gate and the price paid by the average industrial customer. Distributor tariffs are distinguished within the DTS by sector (residential, commercial, industrial, transportation, and electric generator), region (NGTDM/EMM regions for electric generators and NGTDM regions for the rest), seasons (peak or off-peak), and as appropriate by service type or class (core or non-core).

Distribution markups represent a significant portion of the price of gas to residential, commercial, and transportation customers, and less so to the industrial and electric generation sectors. Each sector has different distribution service requirements, and frequently different transportation needs. For example, the core customers in the model (residential, transportation, commercial and some industrial and electric generator customers) are assumed to require guaranteed on-demand (firm) service because natural gas is largely their only fuel option. In contrast, large portions of the industrial and electric generator sectors may not rely solely on guaranteed service because they can either periodically terminate operations or switch to other fuels. These customers are referred to as non-core. They can elect to receive some gas supplies through a lower-priority (and lower-cost) interruptible transportation service. While not specifically represented in the model, during periods of peak demand, services to these sectors can be interrupted in order to meet the natural gas requirements of core customers. In addition, these customers frequently select to bypass the local distribution company pipelines and hook up directly to interstate or intrastate pipelines.

The rates that local distribution companies and intrastate carriers are allowed to charge are regulated by State authorities. State ratemaking traditionally allows (but does not necessarily guarantee) local distribution companies and intrastate carriers to recover their costs, including what the regulators consider a fair return on capital. These rates are derived from the cost of providing service to the end-use customer. The State authority determines which expenses can be passed through to customers and establishes an allowed rate of return. These measures provide the basis for distinguishing rate differences among customer classes and type of service by allocating costs to these classes and services based on a rate design. The DTS does not project distributor tariffs through a rate base calculation as is done in the PTS, partially due to limits on data availability.[55] In most cases, projected distributor tariffs in the model depend initially on base year values, which are established by subtracting historical city gate prices from historical delivered prices, and generally fall within the range of recent historical values. The price to electric generators is based on the regional hub or spot price rather than the regional city gate price.

Distributor tariffs for all but the electric and transportation sector are set using econometrically estimated equations.[56] Transportation sector markups, representing gas sales for use in compressed natural gas and liquefied natural gas vehicles, trains, and ships, are set separately for fleet and personal vehicles and account for distribution to delivery stations, retail markups, and federal and state motor fuels taxes, as appropriate. Electric sector markups are initially set at an historical average and adjusted over the forecast in response to changes in consumption by electric generators.

[55] In theory these cost components could be compiled from rate filings to state Public Utility Commissions; however, such an extensive data collection effort is beyond the available resources.

[56] An econometric approach was used largely as a result of data limitations. EIA data surveys do not collect the cost components required to derive revenue requirements and cost-of-service for local distribution companies and intrastate carriers. These cost components can be compiled from rate filings to Public Utility Commissions; however, an extensive data collection effort is beyond the scope of NEMS at this time.

4. Interstate Transmission Submodule Solution Methodology

As a key component of the NGTDM, the Interstate Transmission Submodule (ITS) determines the market equilibrium between supply and demand of natural gas within the North American pipeline system. This translates into finding the price such that the quantity of gas that consumers would desire to purchase equals the quantity that producers would be willing to sell, accounting for the transmission and distribution costs, pipeline fuel use, capacity expansion costs and limitations, and mass balances. To accomplish this, two seasonal periods were represented within the module: a peak and an off-peak period. The network structures within each period consist of an identical system of pipelines, and are connected through common supply sources and storage nodes. Thus, two interconnected networks (peak and off-peak) serve as the framework for processing key inputs and balancing the market to generate the desired outputs. A heuristic approach is used to systematically move through the two networks solving for production levels, network flows, pipeline and storage capacity requirements,[57] supply and citygate prices, and ultimately delivered prices, until mass balance and convergence are achieved. (The methodology used for calculating distributor tariffs is presented in Chapter 5.) Primary input requirements include seasonal consumption levels, capacity expansion cost curves, annual natural gas supply levels and/or curves, a representation of pipeline and storage tariffs, as well as values for pipeline and storage starting capacities, and network flows and prices from the previous year. Some of the inputs are provided by other NEMS modules, some are exogenously defined and provided in input files, and others are generated by the module in previous years or iterations and used as starting values. Wellhead,[58] spot, import, and delivered prices, supply quantities, and resulting flow patterns are obtained as output from the ITS and sent to other NGTDM submodules or other NEMS modules after some processing. Network characteristics, input requirements, and the ITS equilibrium solution process are presented more fully below.

Network characteristics in the ITS

As described in an earlier chapter, the NGTDM network consists of 12 NGTDM regions (or transshipment nodes) in the Lower 48 states, three Mexican border crossing nodes, seven Canadian border crossing nodes, and two Canadian supply/demand regions. LNG imports and exports are represented as a supply or demand, respectively, within each coastal region. Interregional arcs connecting the nodes represent an aggregation of pipelines that are capable of moving gas from one region (or transshipment node) into another. These arcs have been classified as either primary flow arcs or secondary flow arcs. The primary flow arcs (see **Figure 3-1**) represent major flow corridors for the transmission of natural gas. Secondary arcs represent either flow in the opposite direction from the primary flow (in 2011, about 7% of the interregional flow in the Lower 48 states)[59] or relatively low flow volumes that are set exogenously or outside the ITS equilibration routine (e.g. Mexican and LNG imports and exports). In the

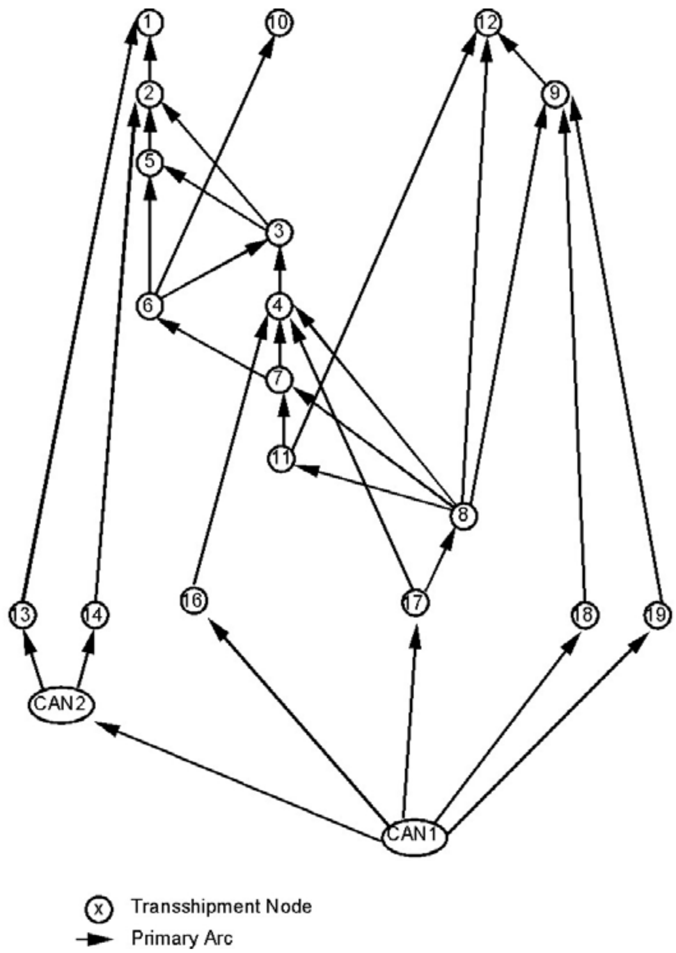
[57] In reality, capacity expansion decisions are made based on expectations of future demand requirements, allowing for regulatory approvals and construction lead times. In the model, additional capacity is available immediately, once it is determined that it is needed. The implicit assumption is that decision makers exercised perfect foresight and that planning and construction for the pipeline actually started before the pipeline came online.

[58] Historically wellhead prices are set to the regional spot price minus an assumed gathering charge (GATHER, Appendix E).

[59] However, with recent increased production potential in the Northeast and proposals to reverse flow on major interstate pipelines, these flow patterns are expected to change. Therefore volumes on selected secondary arcs in the model are now being set endogenously each NEMS iteration, allowing for a reversal of net flow volumes as prices warrant.

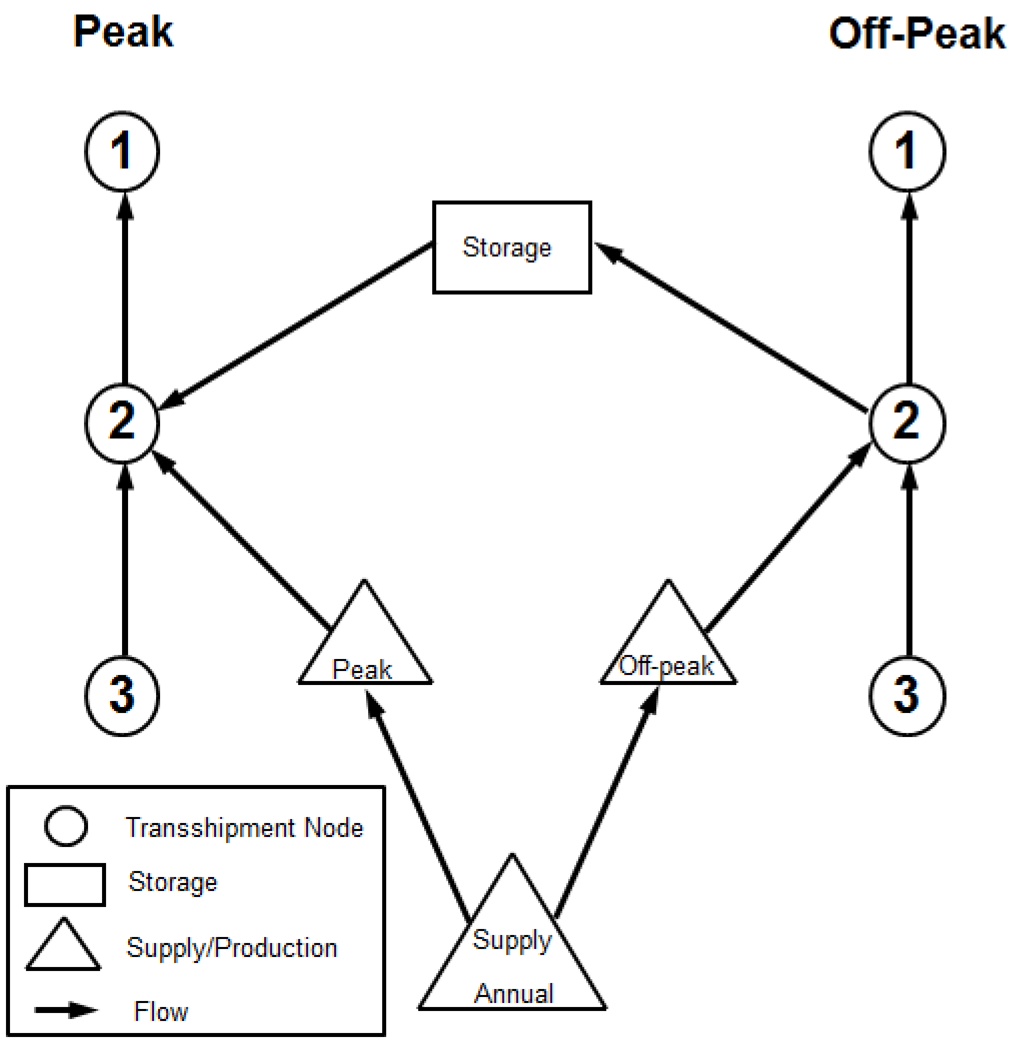
ITS, this North American natural gas pipeline flow network has been restructured into a hierarchical, acyclic network representing just the primary flow of natural gas (**Figure 4-1**). The representation of flows along secondary arcs is described in the ITS Equilibrium Solution Process section below. A hierarchical, acyclic network structure allows for the systematic representation of the flow of natural gas (and its associated prices) from the supply sources, represented towards the bottom of the network, up through the network to the end-use consumer at the upper end of the network.

Figure 4-1. Network "tree" of hierarchical, acyclic network of primary arcs



In the ITS, two interconnected acyclic networks are used to represent natural gas flow to end-use markets during the peak period (PK) and flow to end-use markets during the off-peak period (OP). These networks are connected regionally through common supply sources and storage nodes (**Figure 4-2**). Storage within the module only represents the transfer of natural gas produced in the off-peak period to meet the higher demands in the peak period. Therefore, net storage injections are included only in the off-peak period, while net storage withdrawals occur only in the peak period. Within a given forecast year, the withdrawal level from storage in the peak period establishes the level of gas injected in the off-peak period. Annual supply sources provide natural gas to both networks based on the combined network production requirements and corresponding annual supply availability in each region.

Figure 4-2. Simplified example of supply and storage links across networks



Input requirements of the ITS

The following is a list of the key inputs required during ITS processing for a given year or iteration:[60]

- Seasonal end-use consumption or demand curves for each NGTDM region and Canada
- Seasonal imports (except Canada) and exports by border crossing
- Canadian import capacities by border crossing
- Total natural gas production in eastern Canada and shale/coalbed production in western Canada, by season
- Natural gas flow by pipeline from Alaska to Alberta

[60] Forecast values that are set exogenously to the ITS equilibration process are either set exogenously to NEMS, allowed to change each NEMS iteration (usually in response to prices from the previous iteration), or allowed to change each ITS iteration (usually in response to prices from the previous ITS iteration). In some cases, the latter options were used when the model was modified after its original development to allow for a dynamic response that was not easily incorporated directly into the existing hierarchical structure.

- Natural gas flow by pipeline from the Mackenzie Delta to Alberta
- Regional supply curve parameters for U.S. nonassociated and western Canadian tight/other natural gas supply[61]
- Seasonal supply quantities for U.S. associated-dissolved gas, synthetic gas, and other supplemental supplies by NGTDM region
- Seasonal network flow patterns from the previous year, by arc (including flows from storage, variable supply sources, and pipeline arcs)
- Seasonal network prices from the previous year, by arc (including flows from storage, variable supply sources, and pipeline arcs)
- Pipeline capacities, by arc
- Seasonal maximum pipeline utilizations, by arc
- Seasonal pipeline (and storage) tariffs representing variable costs or usage fees, by arc (and region)
- Pipeline capacity expansion/tariff curves for the peak network, by arc
- Storage capacity expansion/tariff curves for the peak network, by region
- Seasonal distributor tariffs by sector and region

Many of the inputs are provided by other NEMS submodules, some are defined from data within the ITS, and others are ITS model results from operation in the previous year. For example, supply curve parameters for lower 48 nonassociated onshore and offshore natural gas production and lower 48 associated-dissolved gas production are provided by the Oil and Gas Supply Module (OGSM). In contrast, Canadian data are set within the NGTDM as direct input to the ITS. U.S. end-use consumption levels are provided by NEMS demand modules; pipeline and storage capacity expansion/tariff curve parameters are provided by the Pipeline Tariff Submodule (PTS, see chapter 6); and seasonal distributor tariffs are defined by the Distributor Tariff Submodule (DTS, see Chapter 5). Seasonal network flow patterns and prices are determined within the ITS. They are initially set based on historical data, and then from model results in the previous model year.

Because the ITS is a seasonal model, most of the input requirements are on a seasonal level. In most cases, however, the information provided is not represented in the form defined above and needs to be processed into the required form. For example, regional end-use consumption levels are initially defined by sector on an annual basis. The ITS disaggregates each of these sector-specific quantities into a seasonal peak and off-peak representation, and then aggregates across sectors within each season to set a total consumption level. Also, regional fixed supplies and some of the import/export levels represent annual values. A simple methodology has been developed to disaggregate the annual information into peak and off-peak quantities using item-specific peak-sharing factors (e.g., PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, PKSHR_SUPLM, PKSHR_ILNG, PKSHR_ELNG, and PKSHR_YR). For more detail on these inputs see Chapter 2. A similar method is used to approximate the consumption and supply in the peak month of each period. This information is used to

[61] These supply sources are referred to as the "variable" supplies because they are allowed to change in response to price changes during the ITS equilibrium solution process. A few of the "fixed" supplies are adjusted each NEMS iteration, generally in response to price, but are held constant within the ITS equilibrium solution process.

verify that sufficient sustained[62] capacity is available for the peak day in each period; if not, it is used as a basis for adding additional capacity. The assumption reflected in the model is that, if there is sufficient sustained capacity to handle the peak month, line packing[63] and propane injection can be used to accommodate a peak day in this month.

ITS equilibrium solution process

The basic process used to determine supply and delivered prices in the ITS involves starting from the top of the hierarchical, acyclic network or "tree" (as shown in **Figure 4-1**) with end-use consumption levels, systematically moving down each network (in the opposite direction from the primary flow of gas) to define seasonal flows along network arcs that will satisfy the consumption, evaluating wellhead prices for the desired production levels, and then moving up each network (in the direction of the primary flow of gas) to define transmission, node, storage, and delivered prices.

While progressively moving down the peak or off-peak network, net regional demands are assigned for each node on each network. Net regional demands are defined as the sum of consumption in the region plus the gas that is exiting the region to satisfy consumption elsewhere, net of fixed[64] supplies in the region. The consumption categories represented in net regional demands include end-use consumption in the region, exports, pipeline fuel consumption, secondary and primary flows out of the region, and for the off-peak period, net injections into regional storage facilities. Regional fixed supplies include imports (except tight/other gas from western Canada), secondary flows into the region, and the region's associated-dissolved production, supplemental supplies, and other fixed supplies. The net regional demands at a node will be satisfied by the gas flowing along the primary arcs into the node, the local "variable" supply flowing into the node, and for the peak period, the gas withdrawn from the regional storage facilities on a net basis.

Starting with the node(s) at the top of the network tree (i.e., nodes 1, 10, and 12 in **Figure 4-1**), the model uses a sharing algorithm to determine the percentage of the represented region's net demand that is satisfied by each arc going into the node. The resulting shares are used to define flows along each arc (supply, storage, and interregional pipeline) into the region (or node). The interregional flows then become additional consumption requirements (i.e., primary flows out of a region) at the corresponding source node (region). If the arc going into the original node is from a supply or storage[65] source, then the flow represents the production or storage withdrawal level, respectively. The sharing algorithm is systematically applied (going down the network tree) to each regional node until flows have been defined for all arcs along a network, such that consumption in each region is satisfied.

Once flows are established for each network (and pipeline tariffs are set by applying the flow levels to the pipeline tariff curves), resulting production levels for the variable supplies are used to determine regional wellhead prices and, ultimately, storage, node, and delivered prices. By systematically moving

[62] "Sustained" capacity refers to levels that can operationally be sustained throughout the year, as opposed to "peak" capacity which can be realized at high pressures and would not generally be maintained other than at peak demand periods.
[63] Line packing is a means of storing gas within a pipeline for a short period of time by compressing the gas.
[64] Fixed supplies are those supply sources that are not allowed to vary in response to changes in the natural gas price during the ITS equilibrium solution process.
[65] For the peak period networks only.

up each network tree, regional wellhead prices plus gathering charges are used with pipeline tariffs, while adjusting for price impacts from pipeline fuel consumption, to calculate regional node prices for each season. Two separate node prices are set, one that is based on only the variable pipeline charges and the other based on variable charges plus a reservation fee. The first is used when establishing flows and setting regional spot prices and the second is used when setting city gate and end-use prices. Next, intraregional and intrastate markups are added to the regional/seasonal node prices, followed by the addition of corresponding seasonal, sectoral distributor tariffs as appropriate, to generate delivered prices. Seasonal prices are then converted to annual delivered prices using quantity-weighted averaging. To speed overall NEMS convergence,[66] the delivered prices can be applied to representative demand curves to approximate the demand response to a change in the price and to generate a new set of consumption levels. This process of going up and down the network tree is repeated until convergence is reached.

The order in which the networks are solved differs depending on whether movement is down or up the network tree. When proceeding down the network trees, the peak network flows are established first, followed by the off-peak network flows. This order has been established for two reasons. First, capacity expansion is decided based on peak flow requirements.[67] This in turn is used to define the upper limits on flows along arcs in the off-peak network. Second, net storage injections (represented as consumption) in the off-peak season cannot be defined until net storage withdrawals (represented as supplies) in the peak season are established. When going up the network trees, prices are determined for the off-peak network first, followed by the peak network. This order has been established mainly because the price of fuel withdrawn from storage in the peak season is based on the cost of fuel injected into storage in the off-peak season plus a storage tariff.

If net demands exceed available supplies on a network in a region, then a backstop supply is made available at a higher price than other local supply. The higher price is passed up the network tree to discourage (or decrease) demands from being met via this supply route. Thus, network flows respond by shifting away from the backstop region until backstop supply is no longer needed.

Movement down and up each network tree (defined as a cycle) continues within a NEMS iteration until the ITS converges. Convergence is achieved when the regional seasonal supply prices determined during the current cycle down the network tree are within a designated minimum percentage tolerance from the supply prices established the previous cycle down the network tree. In addition, the absolute change in production between cycles within supply regions with relatively small production levels are checked in establishing convergence. In addition, the presence of backstop will prevent convergence from being declared. Once convergence is achieved, only one last movement up each network tree is required to define final regional/seasonal node and delivered prices. If convergence is not achieved, then a set of “relaxed” supply prices is determined by weighting regional production results from both the current and the previous cycle down the network tree, and obtaining corresponding new annual and

[66] At various times, NEMS has not readily converged and various approaches have been taken to improve the process. If the NGTDM can anticipate the potential demand response to a price change from one iteration to the next, and accordingly moderate the price change, NEMS will theoretically converge to an equilibrium solution in fewer iterations.
[67] Pipeline capacity into region 10 (Florida) is allowed to expand in either the peak or off-peak period because the region experiences its peak usage of natural gas in what is generally the off-peak period for consumption in the rest of the country.

seasonal supply prices from the supply curves in each region based on these "relaxed" production levels. The concept of "relaxation" is a means of speeding convergence by solving for quantities (or prices) in the current iteration based on a weighted average of the prices (or quantities) from the previous two iterations, rather than just using the previous iteration's values.[68]

The following subsections describe many of these procedures in greater detail, including: net node demands, pipeline fuel consumption, sharing algorithm, secondary flows, spot/wellhead prices, tariffs, arc, node, and storage prices, backstop, convergence, and delivered and import prices. A simple flow diagram of the overall process is presented in **Figure 4-3**.

Net node demands

Seasonal net demands at a node are defined as total seasonal demands in the region, net of seasonal fixed supplies entering the region. Regional demands consist of primary flows exiting the region (including net storage injections in the off-peak), pipeline fuel consumption, end-use consumption, discrepancies (or historical balancing item), Canadian consumption, exports, and other secondary flows exiting the region. Fixed supplies include associated-dissolved gas, Alaskan gas supplies to Alberta, synthetic natural gas, other supplemental supplies, LNG imports, fixed Canadian supplies (including Mackenzie Delta gas), and other secondary flows entering the region. Seasonal net node demands are represented by the following equations:

Peak:

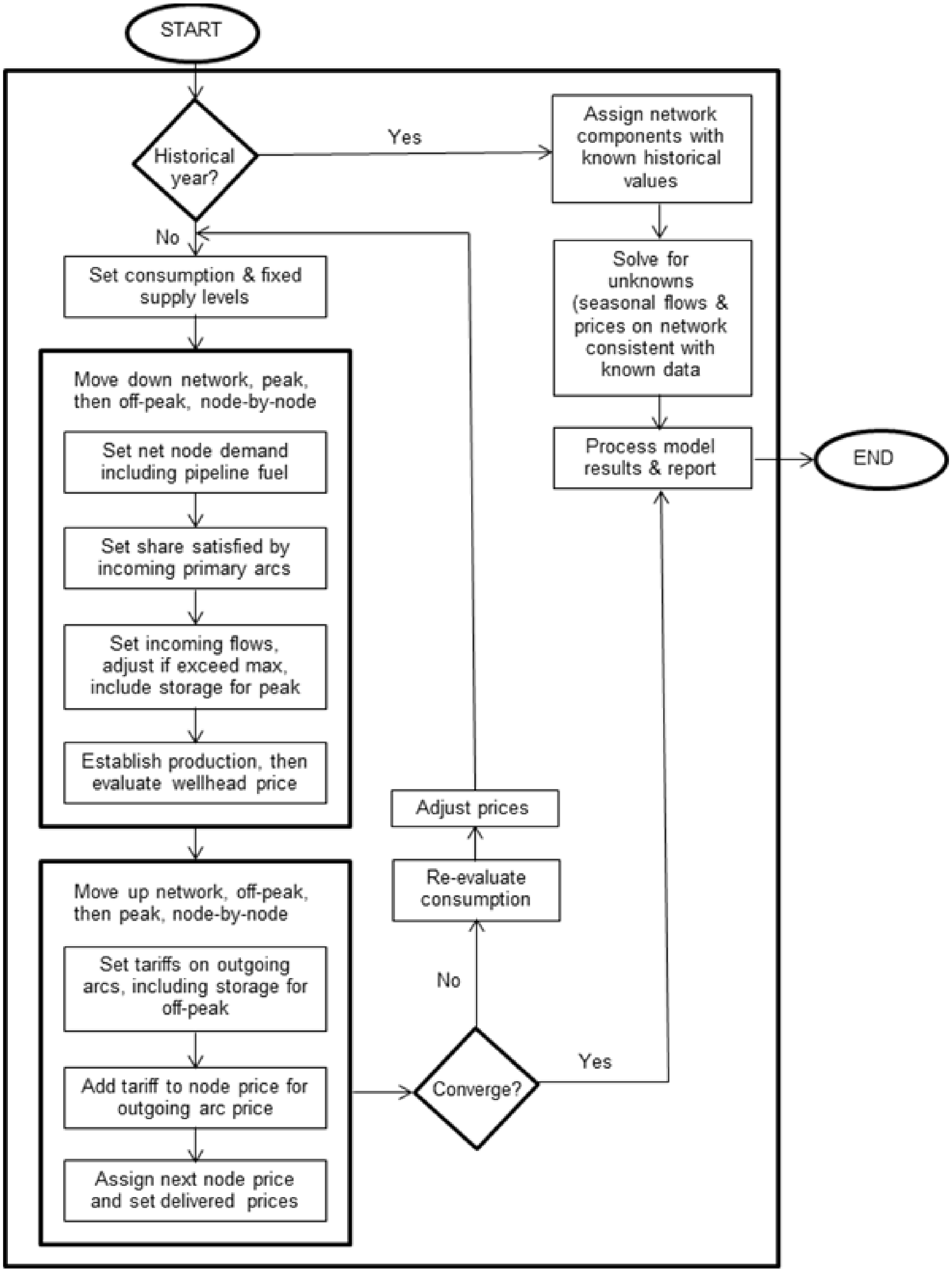
$$\begin{aligned} NODE\_DMD_{PK,r} = {} & PFUEL_{PK,r} + FLOW_{PK,a} + NODE\_CDMD_{PK,r} \\ & \sum_{nonu} (PKSHR\_DMD_{nonu,r} * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \\ & \sum_{jutil \subset r} (PKSHR\_UDMD_{jutil} * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil}) \end{aligned} \tag{59}$$

$$\begin{aligned} NODE\_CDMD_{PK,r} = {} & YEAR\_CDMD_{PK,r} - (PKSHR\_PROD_s * ZFIXSUP_s) - \\ & (PKSHR\_ILNG * OGQNGIMP_{L,t}) + (PKSHR\_YR * \\ & (OGQNGEXP_{L,t} - REEXP_{if\,r=7)}) * (1 + PERLIQFUEL)) \end{aligned} \tag{60}$$

$$\begin{aligned} YEAR\_CDMD_{PK,r} = {} & DISCR_{PK,r,t} + CN\_DISCR_{PK,cn} \\ & ((PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\ & (PK1 * SAFLOW_{a,t}) - (PK2 * SAFLOW_{a',t}) - \\ & (PKSHR\_YR * QAK\_ALB_t) - (PKSHR\_SUPLM * ZTOTSUP_r) - \\ & (PKSHR\_PROD_s * CN\_FIXSUP_{cn,t}) - \\ & (PKSHR\_ILNG * CNLNG\_FLOW) \end{aligned} \tag{61}$$

[68] The model typically solves within 3 to 6 cycles.

Figure 4-3. Interstate Transmission Submodule System



Off-Peak:

$$\begin{aligned}NODE\_DMD_{OP,r} = {} & PFUEL_{OP,r} + FLOW_{OP,a} + FLOW_{PK,st} + NODE\_CDMD_{OP,r} + \\ & \sum_{nonu} ((1 - PKSHR\_DMD_{nonu,r}) * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \\ & \sum_{jutil \in r} ((1 - PKSHR\_UDMD_{jutil}) * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil})) +\end{aligned} \tag{62}$$

$$\begin{aligned}NODE\_CDMD_{OP,r} = {} & YEAR\_CDMD_{OP,r} - ((1 - PKSHR\_PROD_s) * ZFIXSUP_s) - \\ & ((1 - PKSHR\_ILNG) * OGQNGIMP_{L,t}) - \\ & ((1 - PKSHR\_YR * (OGQNGEXP_{L,t} - REEXP_{if\ r=7})) * (1 + PERLIQFUEL))\end{aligned} \tag{63}$$

$$\begin{aligned}YEAR\_CDMD_{OP,r} = {} & DISCR_{OP,r,t} + CN\_DISCR_{OP,cn} + \\ & ((1 - PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\ & ((1 - PK1) * SAFLOW_{a,t}) - ((1 - PK2) * SAFLOW_{a',t}) - \\ & ((1 - PKSHR\_YR) * QAK\_ALB_t) - \\ & ((1 - PKSHR\_SUPLM) * ZTOTSUP_r) - \\ & ((1 - PKSHR\_PROD_s) * CN\_FIXSUP_{cn,t}) + \\ & (1 - PKSYR\_ILNG * CNLNG\_FLOW)\end{aligned} \tag{64}$$

where,

$NODE\_DMD_{n,r}$	=	net node demands in region r, for network n (Bcf)
$NODE\_CDMD_{n,r}$	=	net node demands remaining constant each NEMS iteration in region r, for network n (Bcf)
$YEAR\_CDMD_{n,r}$	=	net node demands remaining constant within a forecast year in region r, for network n (Bcf)
$PFUEL_{n,r}$	=	pipeline fuel consumption in region r, for network n (Bcf)
$FLOW_{n,a}$	=	seasonal flow on network n, along arc a [out of region r] (Bcf)
$ZNGQTY\_F_{nonu,r}$	=	core demands in region r, by non-electric sectors nonu (Bcf)
$ZNGQTY\_I_{nonu,r}$	=	noncore demands in region r, by non-electric sectors nonu(Bcf)
$ZNGUQTY\_F_{jutil}$	=	core utility demands in NGTDM/EMM subregion jutil [subset of region r] (Bcf)
$ZNGUQTY\_I_{jutil}$	=	noncore utility demands in NGTDM/EMM subregion jutil [subset of region r] (Bcf)
$ZFIXSUP_s$	=	fixed supply values (i.e., values that do not change during market balance routine, in supply subregion s (Bcf)
$DISCR_{n,r,t}$	=	lower 48 discrepancy in region r, for network n, in forecast year t (Bcf)[69]
$CN\_DISCR_{n,cn}$	=	Canada discrepancy in Canadian region cn, for network n (Bcf)
$CN\_DMD_{cn,t}$	=	Canada demand in Canadian region cn, in forecast year t (Bcf, Appendix E)

[69] Projected lower 48 discrepancies are primarily based on the average historical level from 1999 to 2011. Discrepancies are adjusted in the STEO years to account for STEO discrepancy (Appendix E, STDISCR) and annual net storage withdrawals (Appendix E, NNETWITH) forecasts, and differences between NEMS and STEO total consumption levels Appendix E, STENDCON). These adjustments are phased out over a user-specified number of years (Appendix E, STPHAS_YR).

$SAFLOW_{a,t}$	=	secondary flows out of region r, along arc a [includes Canadian and Mexican exports, Canadian gas that flows through the U.S., and lower 48 bidirectional flows] (Bcf)
$SAFLOW_{a',t}$	=	secondary flows into region r, along arc a' [includes Mexican imports, Canadian imports into the East North Central Census Division, Canadian gas that flows through the U.S., and lower 48 bidirectional flows] (Bcf)
QAK_ALB_t	=	natural gas flow from Alaska into Alberta via pipeline (Bcf)
$ZTOTSUP_r$	=	Total supply from SNG liquids, SNG coal, and other supplemental in forecast year t (Bcf)
$OGQNGIMP_{L,t}$	=	LNG imports from LNG region L, in forecast year t (Bcf)
$CN\_FIXSUP_{cn,t}$	=	fixed supply from Canadian region cn, in forecast year t (Bcf, Appendix E)
$OGQNGEXP_{L,t}$	=	LNG export levels (Bcf)
PERLIQFUEL	=	fraction of fuel to liquefaction facilities used in facility (fraction)
REEXP	=	level of re-exports, all assumed out of the East South Central Census division (Bcf) (REEXP, Appendix E)
PK1, PK2	=	fraction of either in-flow or out-flow volumes corresponding to peak season (composed of PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, or PKSHR_YR)
$PKSHR\_DMD_{nonu,r}$	=	average (2001-2011) fraction of annual consumption in each non-electric sector in region r corresponding to the peak season
$PKSHR\_UDMD_{jutil}$	=	average (1994-2011, except New England 1997-2011) fraction of annual consumption in the electric generator sector in region r corresponding to the peak season
PKSHR_PRODs	=	average (1994-2011) fraction of annual production in supply region s corresponding to the peak season (fraction, Appendix E)
PKSHR_CDMD	=	fraction of annual Canadian demand corresponding to the peak season (fraction, Appendix E)
PKSHR_YR	=	fraction of the year represented by the peak season
PKSHR_SUPLM	=	average (1990-2011) fraction of supplemental supply corresponding to the peak season
PKSHR_ILNG	=	fraction of LNG imports corresponding to the peak season
PKSHR_ECAN	=	fraction of Canadian exports transferred in peak season
PKSHR_ICAN	=	fraction of Canadian imports transferred in peak season
PKSHR_EMEX	=	fraction of Mexican exports transferred in peak season
PKSHR_IMEX	=	fraction of Mexican imports transferred in peak season
r	=	region/node
n	=	network (peak or off-peak)
PK,OP	=	peak and off-peak network, respectively
nonu	=	non-electric sector ID: residential, commercial, industrial, transportation
jutil	=	utility sector subregion ID in region r
a,a’	=	arc ID for arc entering (a’) or exiting (a) in region 4
s	=	supply subregion ID into region r (1-21)
cn	=	Canadian supply subregion ID in region r (1-2)
L	=	LNG import/export region ID into region r (1-12)
st	=	arc ID corresponding to storage supply into region r
t	=	current forecast year

Pipeline fuel use and intraregional flows

Pipeline fuel consumption represents the natural gas consumed by compressors to transmit gas along pipelines within a region. In the ITS, pipeline fuel consumption is modeled as a regional demand component. It is estimated for each region on each network using a historically based factor, corresponding net demands, and a multiplicative scaling factor. The scaling factor is used to calibrate the results to equal the most recent national *Short-Term Energy Outlook (STEO)* forecast[70] for pipeline fuel consumption (Appendix E, STQGPTR), net of pipeline fuel consumption in Alaska (QALK_PIP), and is phased out by a user-specified year (Appendix E, STPHAS_YR). The following equation applies:

$$PFUEL_{n,r} = PFUEL\_FAC_{n,r} * NODE\_DMD_{n,r} * SCALE\_PF \tag{65}$$

where,

$PFUEL_{n,r}$	=	pipeline fuel consumption in region r, for network n (Bcf)
$PFUEL\_FAC_{n,r}$	=	average (2007-2012) historical pipeline fuel factor in region r, for network n (calculated historically for each region as equal PFUEL/NODE_DMD)
$NODE\_DMD_{n,r}$	=	net demands (excluding pipeline fuel) in region r, for network n (Bcf)
SCALE_PF	=	STEO benchmark factor for pipeline fuel consumption
n	=	network (peak and off-peak)
r	=	region/node

After pipeline fuel consumption is calculated for each node on the network, the regional/seasonal value is added to net demand at the respective node. Flows into a node ($FLOW_{n,a}$) are then defined using net demands and a sharing algorithm (described below). The regional pipeline fuel quantity (net of intraregional pipeline fuel consumption)[71] is distributed over the pipeline arcs entering the region. This is accomplished by sharing the net pipeline fuel quantity over all of the interregional pipeline arcs entering the region, based on their relative levels of natural gas flow:

$$ARC\_PFUEL_{n,a} = (PFUEL_{n,r} - INTRA\_PFUEL_{n,r}) * \frac{FLOW_{n,a}}{TFLOW} \tag{66}$$

where,

$ARC\_PFUEL_{n,a}$	=	pipeline fuel consumption along arc a (into region r), for network n (Bcf)
$PFUEL_{n,r}$	=	pipeline fuel consumption in region r, for network n (Bcf)
$INTRA\_PFUEL_{n,r}$	=	intraregional pipeline fuel consumption in region r, for network n (Bcf)
$FLOW_{n,a}$	=	interregional pipeline flow along arc a (into region r), for network n (Bcf)
TFLOW	=	total interregional pipeline flow [into region r] (Bcf)

[70] EIA produces a separate quarterly forecast for primary national energy statistics over the next several years. For certain forecast items, NEMS is calibrated to produce an equivalent (within 2% to 5%) result for these years. For *AEO2014*, the years calibrated to *STEO* results were 2013 and 2014.

[71] Currently, intraregional pipeline fuel consumption (INTRA_PFUEL) is set equal to the regional pipeline fuel consumption level (PFUEL); therefore, pipeline fuel consumption along an arc (ARC_PFUEL) is set to zero. The original design was to allocate pipeline fuel according to flow levels on arcs and within a region. It was later determined that assigning all of the pipeline fuel to a region would simplify benchmarking the results to the STEO and would not change the later calculation of the price impacts of pipeline fuel use.

n = network (peak and off-peak)
r = region/node
a = arc

Pipeline fuel consumption along an interregional arc and within a region on an intrastate pipeline will have an impact on pipeline tariffs and node prices. This will be discussed later in the Arc, Node, and Storage Prices subsection.

The flows of natural gas on the interstate pipeline system within each NGTDM region (as opposed to between two NGTDM regions) are established for the purpose of setting the associated revenue requirements and tariffs. The charge for moving gas within a region (INTRAREG_TAR), but on the interstate pipeline system, is taken into account when setting city gate prices, described below. The algorithm for setting intraregional flows is similar to the method used for setting pipeline fuel consumption. For each region in the historical years, a factor is calculated reflective of the relationship between the net node demand and the intraregional flow. This factor is applied to the net node demand in each forecast year to approximate the associated intraregional flow. Pipeline fuel consumption is excluded from the net node demand for this calculation, as follows:

Calculation of intraregional flow factor based on data for an historical year:

$$FLO\_FAC_{n,r} = INTRA\_FLO_{n,r} \;/\; (NODE\_DMD_{n,r} - PFUEL_{n,r}) \qquad (67)$$

Forecast of intraregional flow:

$$INTRA\_FLO_{n,r} = FLO\_FAC_{n,r} * (NODE\_DMD_{n,r} - PFUEL_{n,r}) \qquad (68)$$

where,

$INTRA\_FLO_{n,a}$ = intraregional, interstate pipeline flow within region r, for network n (Bcf)
$PFUEL_{n,r}$ = pipeline fuel consumption in region r, for network n (Bcf)
$NODE\_DMD_{n,r}$ = net demands (with pipeline fuel) in region r, for network n (Bcf)
$FLO\_FAC_{n,r}$ = average (1990 - 2012) historical relationship between net node demand and intraregional flow
n = network (peak and off-peak)
r = region/node

Historical annual intraregional flows are set for the peak and off-peak periods based on the peak and off-peak share of net node demand in each region.

Sharing algorithm, flows, and capacity expansion

Moving systematically downward from node to node through the acyclic network, the sharing algorithm allocates net demands ($NODE\_DMD_{n,r}$) across all arcs feeding into the node. These “inflow” arcs carry flows from local supply sources, storage (net withdrawals during peak period only), or other regions (interregional arcs). If any of the resulting flows exceed their corresponding maximum levels,[72] then the

[72] Maximum flows include potential pipeline or storage capacity additions, and maximum production levels.

excess flows are reallocated to the unconstrained arcs, and new shares are calculated accordingly. At each node within a network, the sharing algorithm determines the percent of net demand ($SHR_{n,a,t}$) that is satisfied by each of the arcs entering the region.

The sharing algorithm (shown below) dictates that the share ($SHR_{n,a,t}$) of demand for one arc into a node is a function of the share defined in the previous model year[73] and the ratio of the price on the one arc relative to the average of the prices on all of the arcs into the node, as defined the previous cycle up the network tree. These prices ($ARC\_SHRPR_{n,a}$) represent the unit cost associated with an arc going into a node, and are defined as the sum of the unit cost at the source node ($NODE\_SHRPR_{n,r}$) and the tariff charge along the arc ($ARC\_SHRFEE_{n,a}$). (A description of how these components are developed is presented later.) The variable γ is an assumed parameter that is always positive. This parameter can be used to prevent (or control) broad shifts in flow patterns from one forecast year to the next. Larger values of γ increase the sensitivity of $SHR_{n,a,t}$ to relative prices; a very large value of γ would result in behavior equivalent to cost minimization. The algorithm is presented below:

$$SHR_{n,a,t} = \frac{ARC\_SHRPR_{n,a}^{-\gamma}}{\frac{\sum_{b} ARC\_SHRPR_{n,b}^{-\gamma}}{N}} * SHR_{n,a,t-1} \qquad (69)$$

where,

SHRn,a,t, $SHR_{n,a,t-1}$	=	the fraction of demand represented along inflow arc a on network n, in year t (or year t-1) [Note: The value for year t-1 has a lower limit set to 0.01]
$ARC\_SHRPR_{n,a \text{ or } b}$	=	the last price calculated for natural gas from inflow arc a (or b) on network n [i.e., from the previous cycle while moving up the network] (1987$/Mcf)
N	=	total number of arcs into a node
γ	=	coefficient defining degree of influence of relative prices (represented as GAMMAFAC, Appendix E)
t	=	forecast year
n	=	network (peak or off-peak)
a	=	arc into a region
r	=	region/node
b	=	set of arcs into a region

[Note: The resulting shares ($SHR_{n,a,t}$) along arcs going into a node are then normalized to ensure that they add to one.]

Seasonal flows are generated for each arc using the resulting shares and net node demands, as follows:

[73] When planned pipeline capacity is added at the beginning of a forecast year, the value of SHRt-1 is adjusted to reflect a percent usage (PCTADJSHR, Appendix E) of the new capacity. This adjustment is based on the assumption that last year's share would have been higher if not constrained by the existing capacity levels. A similar adjustment is made if expected production increases or decreases by more than 20% from one year to the next or if it goes from zero to a positive value.

$$FLOW_{n,a} = SHR_{n,a,t} * NODE\_DMD_{n,r} \tag{70}$$

where,

$FLOW_{n,a}$	=	interregional flow (into region r) along arc a, for network n (Bcf)
$SHR_{n,a,t}$	=	the fraction of demand represented along inflow arc a on network n, in year t
$NODE\_DMD_{n,r}$	=	net node demands in region r, for network n (Bcf)
n	=	network (peak or off-peak)
a	=	arc into a region
r	=	region/node

These flows must not exceed the maximum flow limits ($MAXFLO_{n,a}$) defined for each arc on each network. The algorithm used to define maximum flows may differ depending on the type of arc (storage, pipeline, supply, Canadian imports) and the network being referenced. For example, maximum flows for all peak network arcs are a function of the maximum permissible annual capacity levels ($MAXPCAP_{PK,a}$) and peak utilization factors. However, maximum *pipeline* flows along the *off-peak* network arcs are a function of the annual capacity defined by peak flows and off-peak utilization factors. Thus, maximum flows along the off-peak network depend on whether or not capacity was added during the peak period. Also, maximum flows from *supply* sources in the off-peak network are limited by maximum annual capacity levels and off-peak utilization. (Note: *storage* arcs do not enter nodes on the off-peak network; therefore, maximum flows are not defined there.) The following equations define maximum flow limits and maximum annual capacity limits:

Maximum peak flows (note: for storage arcs, PKSHR_YR=1):

$$MAXFLO_{PK,a} = MAXPCAP_{PK,a} * (PKSHR\_YR * PKUTZ_a) \tag{71}$$

with $MAXPCAP_{PK,a}$ defined by type as follows:

for *Supply*[74] :

$$\begin{aligned} MAXPCAP_{PK,a} = {} & ZOGRESNG_s * ZOGPRRNG_s * MAXPRRFAC * \\ & (1 - (PCTLP_r * SCALE\_LP_t)) \end{aligned} \tag{72}$$

for *Pipeline*:

$$MAXPCAP_{PK,a} = PTMAXPCAP_{i,j} \tag{73}$$

for *Storage*:

$$MAXPCAP_{PK,a} = PTMAXPSTR_{st} \tag{74}$$

[74] In historical years, historical production values are used in place of the product of ZOGRESNG and ZOGPRRNG.

for *Canadian imports*:

$$MAXPCAP_{PK,a} = CURPCAP_{a,t} \tag{75}$$

Maximum off-peak pipeline flows:

$$MAXFLO_{OP,a} = MAXPCAP_{OP,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \tag{76}$$

with $MAXPCAP_{OP,a}$ is defined as follows for

either *current capacity*:

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} \tag{77}$$

or *current* capacity plus *capacity additions*,

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} + ((1 + XBLD) * \left(\frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} - CURPCAP_{a,t}\right)) \tag{78}$$

or, *for pipeline arc entering region 10 (Florida), peak maximum capacity*,

$$MAXPCAP_{OP,a} = MAXPCAP_{PK,a} \tag{79}$$

Maximum off-peak flows from supply sources:

$$MAXFLO_{OP,a} = MAXPCAP_{PK,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \tag{80}$$

where,

$MAXFLO_{n,a}$	=	maximum flow on arc a, in network n [PK-peak or OP-off-peak] (Bcf)
$MAXPCAP_{n,a}$	=	maximum annual physical capacity along arc a for network n (Bcf)
$CURPCAP_{a,t}$	=	current annual physical capacity along arc a in year t (Bcf)
$ZOGRESNG_s$	=	natural gas reserve levels for supply source s [defined by OGSM] (Bcf)
$ZOGPRRNG_s$	=	expected natural gas production-to-reserves ratio for supply source s [defined by OGSM] (fraction)
MAXPRRFAC	=	factor to set maximum production-to-reserves ratio [MAXPRRCAN for Canada] (Appendix E)
$PCTLP_t$	=	average (2008-2012) fraction of production consumed as lease and plant fuel in forecast year t
$SCALE\_LP_t$	=	scale factor for STEO year percent lease and plant consumption for forecast year t to force regional lease and plant consumption forecast to total to STEO forecast.
$PTMAXPCAP_{i,j}$	=	maximum pipeline capacity along arc defined by source node i and destination node j [defined by PTS] (Bcf)
$PTMAXPSTR_{st}$	=	maximum storage capacity for storage source st [defined by PTS] (Bcf)
$FLOWPK,_a$	=	flow along arc a for the peak network (Bcf)
PKSHR_YR	=	fraction of the year represented by peak season

$PKUTZ_a$	=	pipeline utilization along arc a for the peak season (fraction, HPKUTZ Appendix E)
$OPUTZ_a$	=	pipeline utilization along arc a for the off-peak season (fraction, OPKUTZ, Appendix E)
XBLD	=	percent increase over capacity builds to account for weather (fraction, Appendix E)
a	=	arc
t	=	forecast year
n	=	network (peak or off-peak)
PK, OP	=	peak and off-peak network, respectively
s,st	=	supply or storage source
i,j	=	regional source (i) and destination (j) link on arc a

If the model has been restricted from building capacity through a specified forecast year (Appendix E, NOBLDYR), then the maximum pipeline and storage flow for either network will be based only on current capacity and utilization for that year.

If the flows defined by the sharing algorithm above exceed these maximum levels, then the excess flow is reallocated along adjacent arcs that have excess capacity. This is achieved by determining the flow distribution of the qualifying adjacent arcs, and distributing the excess flow according to this distribution. These adjacent arcs are checked again for excess flow; if excess flow is found, the reallocation process is performed again on all arcs with space remaining. This applies to supply and pipeline arcs on all networks, as well as storage withdrawal arcs on the peak network. To handle the event where insufficient space or supply is available on all inflowing arcs to meet demand, a backstop supply ($BKSTOP_{n,r}$) is available at an incremental price ($RBKSTOP\_PADJ_{n,r}$). The intent is to dissuade use of the particular route, or to potentially lower demands. Backstop pricing will be defined in another section below.

With the exception of import and export arcs,[75] the resulting interregional flows defined by the sharing algorithm for the peak network are used to determine if *pipeline* capacity expansion should occur. Similarly, the resulting storage withdrawal quantities in the peak season define the *storage* capacity expansion levels. Thus, initially capacity expansion is represented by the difference between new capacity levels ($ACTPCAP_a$) and current capacity ($CURPCAP_{a,t}$, previous model year capacity plus planned additions). In the module, these initial new capacity levels are defined as follows:

Storage:

$$ACTPCAP_a = \frac{FLOW_{PK,a}}{PKUTZ_a} \tag{81}$$

Pipeline:

$$ACTPCAP_a = MAXPCAP_{OP,a} \tag{82}$$

[75] For *AEO2014* capacity expansions on Canadian import arcs were set exogenously (PLANPCAP, Appendix E).

Pipeline arc entering region 10 (Florida):

$$ACTPCAP_a = \text{MAX between } \frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} \text{ and } \frac{FLOW_{OP,a}}{(1 - PKSHR\_YR) * OPUTZ_a} \quad (83)$$

where,

$ACTPCAP_a$	=	annual physical capacity along an arc a (Bcf)
$MAXPCAP_{OP,a}$	=	maximum annual physical capacity along pipeline arc a for network n [see equation above] (Bcf)
$FLOW_{n,a}$	=	flow along arc a on network n (Bcf)
$PKUTZ_a$	=	maximum peak utilization of capacity along arc a (fraction, Appendix E)
$OPUTZ_a$	=	maximum off-peak utilization of capacity along arc a (fraction, Appendix E)
PKSHR_YR	=	fraction of the year represented by the peak season
a	=	pipeline and storage arc
n	=	network (peak or off-peak)
PK	=	peak season
OP	=	off-peak season

A second check and potential adjustment are made to these capacity levels to insure that capacity is sufficient to handle estimated flow in the peak month of each period.[76] Since capacity is defined as sustained capacity, it is assumed that the peak month flows should be in accordance with the maximum capacity requirements of the system, short of line packing, propane injections, and planning for the potential of above-average temperature months.[77] Peak month consumption and supply levels are set at an assumed fraction of the corresponding period levels. Based on historical relationships, an initial guess is made at the fraction of each period's net storage withdrawals removed during the peak month. With this information, peak month flows are set at the same time flows are set for each period, while coming down the network tree, and following a similar process. At each node a net monthly demand is set equal to the sum of the monthly flows going out of the node, plus the monthly consumption at the node, minus the monthly supply and net storage withdrawals. The period shares are then used to set initial monthly flows, as follows:

$$MTHFLW_{n,a} = MTH\_NETNOD_{n,r} * \frac{SHR_{n,a,t}}{\sum_c SHR_{n,c,t}} \quad (84)$$

where,

[76] Currently this is only done in the model for the peak period of the year.

[77] To represent that the pipeline system is built to accommodate consumption levels outside the normal range due to colder than normal temperatures, the net monthly demand levels are increased by an assumed percentage (XBLD, Appendix E).

$MTHFLW_{n,a}$ = monthly flow along pipeline arc a (Bcf)
$MTH\_NETNOD_{n,r}$ = monthly net demand at node r (Bcf)
$SHR_{n,a,t}$ = fraction of demand represented along inflow arc a
c = set of arcs into a region representing pipeline arcs
n = network (peak or off-peak)
a = arc into a region
r = region/node
t = forecast year

These monthly flows are then compared against a monthly capacity estimate for each pipeline arc and reallocated to the other available arcs if capacity is exceeded, using a method similar to what is done when flows for a period exceed maximum capacity. These adjusted monthly flows are used later in defining the net node demand for nodes lower in the network tree. Monthly capacity is estimated by starting with the previously set ACTPCAP for the pipeline arc divided by the number of months in the year, to arrive at an initial monthly capacity estimate (MTH_CAP). This number is increased if the total of the monthly capacity entering a node exceeds the monthly net node demand, as follows:

$$MTH\_CAPADD_{n,a} = MTH\_TCAPADD_{n} * \frac{INIT\_CAPADD_{n,a}}{\sum_{c} INIT\_CAPADD_{n,c}} \tag{85}$$

where,

$MTH\_CAPADD_{n,a}$ = additional added monthly capacity to accommodate monthly flow estimates (Bcf)
$MTH\_TCAPADD_{n}$ = total initial monthly capacity entering a node minus monthly net node demand (Bcf), if value is negative then it is set to zero
$INIT\_CAPADD_{n,a}$ = MTHFLWa - MTH_CAPa, if value is negative then it is set to zero (Bcf)
n = network (peak or off-peak)
a = arc into a region
c = set of arcs into a region representing pipeline arcs

The additional added monthly capacity is multiplied by the number of months in the year and added to the originally estimated pipeline capacity levels for each arc (ACTPCAP). Finally, if the net node demand is not close to zero at the lowest node on the network tree (node number 24 in western Canada), then monthly storage levels are adjusted proportionally throughout the network to balance the system for the next time quantities are brought down the network tree.

Secondary flows

Before *AEO2014*, secondary flows were set at historical levels and held constant through the forecast period. When the NGTDM was developed secondary flows represented about 3% of total flows and were basically included for proper accounting. Recently, it has become clear that some of the primary flows, largely related to moving natural gas out of the Northeast, will be reversing direction and eventually result in the “secondary” flow volumes on these arcs being greater than the associated “primary” flow. To allow for this reversal within the current model structure, the secondary flows on selected arcs were endogenously set each NEMS iteration based on the relative node prices from the previous iteration.

The secondary arcs selected for *AEO2014* include gas flowing from the Middle Atlantic to East Canada, to the South Atlantic, and to East North Central and from there on to East Canada. The same sharing algorithm described above was used in isolation (i.e., not involving going up and down the hierarchical tree) for each of the selected destination points (East Canada, South Atlantic, and East North Central) with the inclusion of the selected secondary arc(s). Based on relative node/arc prices established in the previous NEMS iteration, the shares along each of the arcs going into the destination node are set and normalized to total to one. This share for the secondary arc is applied to the total flow into the destination node the last NEMS iteration to arrive at a projected flow level for the secondary flow to be used in solving the NGTDM for the current NEMS iteration.

Wellhead, Spot, and Henry Hub prices

Ultimately, all of the network-specific consumption levels are transferred down the network trees and into supply nodes, where corresponding supply prices are calculated. The Oil and Gas Supply Module (OGSM) provides only annual price/quantity supply curve parameters for each supply subregion. Because this alone will not provide a price differential between seasons, a special methodology has been developed to approximate seasonal prices that are consistent with the annual supply curve. First, in effect the quantity axis of the annual supply curve is scaled to correspond to seasonal volumes (based on the period’s share of the year); and the resulting curves are used to approximate seasonal prices. (Operationally within the model this is done by converting seasonal production values to annual equivalents and applying these volumes to the annual supply curve to arrive at seasonal prices.) Finally, the resulting seasonal prices are scaled to ensure that the quantity-weighted average annual supply price equals the price obtained from the annual supply curve when evaluated using total annual production. To obtain seasonal supply prices, the following methodology is used. Taking one supply region at a time, the model estimates equivalent annual production levels (ANNSUP) for each season.

Peak:

$$ANNSUP = \frac{NODE\_QSUP_{PK,s}}{PKSHR\_YR} \tag{86}$$

Off-peak:

$$ANNSUP = \frac{NODE\_QSUP_{OP,s}}{(1 - PKSHR\_YR)} \tag{87}$$

where,

ANNSUP	=	equivalent annual production level (Bcf)
$NODE\_QSUP_{n,s}$	=	seasonal (n=PK or OP) production level for supply region s (Bcf)
PKSHR_YR	=	fraction of year represented by peak season
PK	=	peak season
OP	=	off-peak season
s	=	supply region

Next, estimated seasonal prices ($SPSUP_n$) are obtained using these equivalent annual production levels and the annual supply curve function. These initial seasonal prices are then averaged, using quantity weights, to generate an equivalent *average* annual supply price (SPAVG*s*). An *actual* annual price (PSUP*s*) is also generated, by evaluating the price on the annual supply function for a quantity equal to the sum of the seasonal production levels. The average annual supply price is then compared to the *actual* price. The corresponding ratio (FSF) is used to adjust the estimated seasonal prices to generate final seasonal supply prices ($NODE\_PSUP_{n,s}$) for a region.

For a *supply source* s,

$$FSF = \frac{PSUP_s}{SPAVG_s} \tag{88}$$

and,

$$NODE\_PSUP_{n,s} = SPSUP_n * FSF \tag{89}$$

where,

FSF	=	scaling factor for seasonal prices
$PSUP_s$	=	annual supply price from the annual supply curve for supply region s (1987$/Mcf)
$SPAVG_s$	=	quantity-weighted average annual supply price using peak and off-peak prices and production levels for supply region s (1987$/Mcf)
$NODE\_PSUP_{n,s}$	=	adjusted seasonal supply prices for supply region s (1987$/Mcf)
SPSUPn	=	estimated seasonal supply prices for supply region s (1987$/Mcf)
n	=	network (peak or off-peak)
s	=	supply source

The regional hub prices established when the model is setting regional flows (i.e., when pipeline tariffs or differentials between nodes reflect usage fees alone and exclude reservation fees) are in effect regional spot prices. In fact, the model is calibrated by benchmarking these prices to representative historical spot prices. This is done by applying a benchmark factor (BSPOT) to the projected hub price. The benchmark factor is set equal to the average difference between the historical spot price and the price set by the model in the historical years for the hub price, averaged from 2005 (FSPOTYR) to 2012. Given that the differentials between the hubs are based on historical basis differentials, the hub prices should already align reasonably well with historical data.

Previous to *AEO2013*, the prices seen by producers in the NEMS model were based initially on historical wellhead prices. Going forward, since EIA will no longer be collecting wellhead price data it was necessary to establish another basis for setting the supply price. After reviewing historical values for wellhead and regional spot prices, it was observed that the two series track each other reasonably well on a regional basis, particularly in more recent years. Therefore historical wellhead prices are set in the model as the regional spot price net of an assumed gathering charge (GATHER, Appendix E).

In order to set a spot price for the Henry Hub specifically, the projected wellhead price in the NGTDM/OGSM subregion containing the Henry Hub is used, as follows:

$$oOGHHPRNG_t = (PSUP_9 + GATHER) / CFNGC_t \quad (90)$$

where,

$oOGHHPRNG_t$	=	natural gas price at the Henry Hub (1987$/MMBtu)
$PSUP_9$	=	spot price in region 9 in current forecast year (1987$/Mcf)
CFNGC	=	factor to convert units from Mcf to MMBtu
GATHER	=	assumed gathering charge (1987$/Mcf, Appendix E)
9	=	NGTDM/OGSM supply region containing Henry Hub
t	=	forecast year

Supply prices in the NGTDM are benchmarked to prices generated in the STEO based on how well the resulting Henry Hub price projection matches the STEO's projection for the Henry Hub. During the STEO years (2013 and 2014 for AEO2014) a benchmark factor (SCALE_WPR) is generated that equals STEO's Henry Hub price divided by the NGTDM's projected Henry Hub price. This factor is used to adjust the regional (annual and seasonal) Lower 48 wellhead prices to align with STEO results. This benchmark factor is only applied for the STEO years. The benchmark factor is applied as follows:

Annual:

$$PSUP_s = PSUP_s * SCALE\_WPR_t \quad (91)$$

Seasonal:

$$NODE\_PSUP_{n,s} = NODE\_PSUP_{n,s} * SCALE\_WPR_t \quad (92)$$

where,

PSUPs	=	annual supply price from the annual supply curve for supply region s (1987$/Mcf)
$NODE\_PSUP_{n,s}$	=	adjusted seasonal supply prices for supply region s (1987$/Mcf)
$SCALE\_WPR_t$	=	STEO benchmark factor for spot price in year t, equal to the STEO Henry Hub Price divided by the NGTDM Henry Hub price
n	=	network (peak or off-peak)
s	=	supply source
t	=	forecast year

A similar adjustment is made for the Canadian supply price, with an additional multiplicative factor applied (STSCAL_CAN, Appendix E) which is set to align Canadian import levels with STEO results.

Arc fees (tariffs)

Fees (or tariffs) along arcs are used in conjunction with supply, storage, and node prices to determine competing arc prices that, in turn, are used to determine network flows, transshipment node prices, and delivered prices. Arc fees exist in the form of pipeline tariffs, storage fees, and gathering charges.

Pipeline tariffs are transportation rates along interregional arcs, reflect the average rate charged over all of the pipelines represented along an arc, and represent either just the usage fee or the reservation and usage fee combined. Storage fees represent the charges applied for storing, injecting, and withdrawing natural gas that is injected in the off-peak period for use in the peak period, and are applied along arcs connecting the storage sites to the peak network. Gathering charges are applied to the arcs going from the supply points to the transshipment nodes.

Pipeline and storage tariffs consist of both a fixed (volume-independent) term and a variable (volume-dependent) term. For pipelines, the fixed term ($ARC\_FIXTAR_{n,a,t}$) is set in the PTS at the beginning of each forecast year to represent pipeline usage fees and does not vary in response to changes in flow in the current year. For *AEO2014* these tariffs were based on the historical basis differentials between representative regional spot prices. For storage, the fixed term establishes a minimum and is set to $0.001 per Mcf. The variable term is obtained from tariff/capacity curves provided by two PTS functions and represents reservation fees for pipelines and all charges for storage. These two functions are NGPIPE_VARTAR and X1NGSTR_VARTAR. When determining network flows and a different set of tariffs ($ARC_SHRFEE_{n,a}$) are used than are used when setting city-gate prices ($ARC_ENDFEE_{n,a}$).[78] The following arc tariff equations apply:

Pipeline:

$$\begin{aligned} &ARC\_ENDFEE_{n,a} = ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n,a,i,j,FLOW_{n,a}) \\ &ARC\_SHRFEE_{n,a} = ARC\_FIXTAR_{n,a,t} \end{aligned} \tag{93}$$

Storage:

$$\begin{aligned} &ARC\_SHRFEE_{n,a} = ARC\_FIXTAR_{n,a,t} + X1NGSTR\_VARTAR(st,FLOW_{n,a}) \\ &ARC\_ENDFEE_{n,a} = ARC\_FIXTAR_{n,a,t} + X1NGSTR\_VARTAR(st,FLOW_{n,a}) \end{aligned} \tag{94}$$

where,

$ARC\_SHRFEE_{n,a}$	=	total arc fees along arc a for network n [used with sharing algorithm] (1987$/Mcf)
$ARC\_ENDFEE_{n,a}$	=	total arc fees along arc a for network n [used with delivered pricing] (1987$/Mcf)
$ARC\_FIXTAR_{n,a,t}$	=	fixed (or usage) fees along an arc a for a network n in time t (1987$/Mcf)
NGPIPE_VARTAR	=	PTS function to define pipeline tariffs representing reservation fees for specified arc at given flow level

[78] Reservation fees are frequently considered "sunk" costs and are not expected to influence short-term purchasing decisions as much, but still must ultimately be paid by the end-user. Therefore within the ITS, the arc prices used in determining flows can have tariff components defined differently than their counterparts (arc and node prices) ultimately used to establish delivered prices.

X1NGSTR_VARTAR	=	PTS function to define storage fees at specified storage region for given storage level
$FLOW_{n,a}$	=	flow of natural gas on the arc in the given period
n	=	network (peak or off-peak)
a	=	arc
i, j	=	from transshipment node i to transshipment node j

The supply arc indices in the variable $ARC\_FIXTAR_{n,a}$ are gathering charges and are all set to an assumed value (GATHER).

Arc, node, and storage prices

Prices at the transshipment nodes (or node prices) represent intermediate prices that are used to determine regional delivered prices. Node prices (along with tariffs) are also used to help make model decisions, primarily within the flow-sharing algorithm. In both cases it is not required (as described above) to set delivered or arc prices using the same price components or methods used to define prices needed to establish flows along the networks (e.g., in setting $ARC\_SHRPR_{n,a}$ in the share equation). Thus, *process-specific* node prices ($NODE\_ENDPR_{n,r}$ and $NODE\_SHRPR_{n,r}$) are generated using *process-specific* arc prices ($ARC\_ENDPR_{n,a}$ and $ARC\_SHRPR_{n,a}$) which, in turn, are generated using *process-specific* arc fees/tariffs ($ARC\_ENDFEE_{n,a}$ and $ARC\_SHRFEE_{n,a}$).

The following equations define the methodology used to calculate arc prices. Arc prices are first defined as the average node price at the source node plus the arc fee (pipeline tariff, storage fee, or gathering charge). Next, the arc prices along pipeline arcs are adjusted to account for the cost of pipeline fuel consumption. These equations are as follows:

$$\begin{aligned} ARC\_SHRPR_{n,a} &= NODE\_SHRPR_{n,rs} + ARC\_SHRFEE_{n,a} \\ ARC\_ENDPR_{n,a} &= NODE\_ENDPR_{n,rs} + ARC\_ENDFEE_{n,a} \end{aligned} \tag{95}$$

with the adjustment accomplished through the assignment statements:

$$\begin{aligned} ARC\_SHRPR_{n,a} &= \frac{(ARC\_SHRPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})} \\ ARC\_ENDPR_{n,a} &= \frac{(ARC\_ENDPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})} \end{aligned} \tag{96}$$

where,

$ARC\_SHRPR_{n,a}$	=	price calculated for natural gas along inflow arc a for network n [used with sharing algorithm and to set spot prices] (1987$/Mcf)
$ARC\_ENDPR_{n,a}$	=	price calculated for natural gas along inflow arc a for network n [used to set city gate prices] (1987$/Mcf)
$NODE\_SHRPR_{n,r}$	=	node price for region i on network n [used with sharing algorithm and to set spot prices] (1987$/Mcf)

$NODE\_ENDPR_{n,r}$	=	node price for region i on network n [used to set city gate prices] 1987$/Mcf
$ARC\_SHRFEE_{n,a}$	=	tariff along inflow arc a for network n [used with sharing algorithm and to set spot prices] (1987$/Mcf)
$ARC\_ENDFEE_{n,a}$	=	tariff along inflow arc a for network n [used to set city gate prices] (1987$/Mcf)
$ARC\_PFUEL_{n,a}$	=	pipeline fuel consumption along arc a, for network n (Bcf)
$FLOW_{n,a}$	=	network n flow along arc a (Bcf)
n	=	network (peak or off-peak)
a	=	arc
rs	=	region corresponding to source link on arc a

Although each type of node price may be calculated differently (e.g., average prices for city gate price calculation, marginal prices for flow sharing calculation, or some combination of these for each), the current model uses the quantity-weighted averaging approach to establish node prices for both the end-use pricing and flow sharing algorithm pricing. Prices from all arcs entering a node are included in the average. Node prices then are adjusted to account for intraregional pipeline fuel consumption. The following equations apply:

$$NODE\_SHRPR_{n,rd} = \frac{\Sigma_a (ARC\_SHRPR_{n,a} * FLOW_{n,a})}{\Sigma_a (FLOW_{n,a} - ARC\_PFUEL_{n,a})}$$

$$NODE\_ENDPR_{n,rd} = \frac{\Sigma_a (ARC\_ENDPR_{n,a} * FLOW_{n,a})}{\Sigma_a (FLOW_{n,a} - ARC\_PFUEL_{n,a})} \tag{97}$$

and,

$$NODE\_SHRPR_{n,rd} = \frac{(NODE\_SHRPR_{n,rd} * NODE\_DMD_{n,rd})}{(NODE\_DMD_{n,rd} - INTRA\_PFUEL_{n,rd})}$$

$$NODE\_ENDPR_{n,rd} = \frac{(NODE\_ENDPR_{n,rd} * NODE\_DMD_{n,rd})}{(NODE\_DMD_{n,rd} - INTRA\_PFUEL_{n,rd})} \tag{98}$$

where,

$NODE\_SHRPR_{n,r}$	=	node price for region r on network n [used with flow sharing algorithm and to set spot prices] (1987$/Mcf)
$NODE\_ENDPR_{n,r}$	=	node price for region r on network n [used to set city gate prices] (1987$/Mcf)
$ARC\_SHRPR_{n,a}$	=	price calculated for natural gas along inflow arc a for network n [used with flow sharing algorithm and to set spot prices] (1987$/Mcf)
$ARC\_ENDPR_{n,a}$	=	price calculated for natural gas along inflow arc a for network n [used to set city gate prices] (1987$/Mcf)
$FLOW_{n,a}$	=	network n flow along arc a (Bcf)
$ARC\_PFUEL_{n,a}$	=	pipeline fuel consumed along the pipeline arc a, network n (Bcf)

$INTRA\_PFUEL_{n,r}$ = intraregional pipeline fuel consumption in region r, network n (Bcf)
$NODE\_DMD_{n,r}$ = net node demands (w/ pipeline fuel) in region r, network n (Bcf)
n = network (peak or off-peak)
a = arc
rd = region r destination link along arc a

Once node prices are established for the off-peak network, the cost of the gas injected into storage can be modeled. Thus, for every region where storage is available, the storage node price is set equal to the off-peak regional node price. This applies for both the end-use pricing and the flow sharing algorithm pricing:

$$NODE\_SHRPR_{PK,i} = NODE\_SHRPR_{OP,r}$$

$$NODE\_ENDPR_{PK,i} = NODE\_ENDPR_{OP,r} \tag{99}$$

where,

$NODE\_SHRPR_{PK,i}$ = price at node i [used with flow sharing algorithm and to set spot prices] (1987$/Mcf)
$NODE\_SHRPR_{OP,r}$ = price at node r in off-peak network [used with flow sharing algorithm and to set spot prices] (1987$/Mcf)
$NODE\_ENDPR_{PK,ii}$ = price at node i [used to set city gate prices] (1987$/Mcf)
$NODE\_ENDPR_{OP,r}$ = price at node r in off-peak network [used to set city gate prices] (1987$/Mcf)
PK, OP = peak and off-peak network, respectively
i = node ID for storage
r = region ID where storage exists

Backstop price adjustment

Backstop supply[79] is activated when seasonal net demand within a region exceeds total available supply for that region. When backstop occurs, the corresponding *share* node price ($NODE\_SHRPR_{n,r}$) is adjusted upward in an effort to reduce the demand for gas from this source. If this initial price adjustment ($BKSTOP\_PADJ_{n,r}$) is not sufficient to eliminate backstop, on the next cycle down the network tree, an additional adjustment ($RBKSTOP\_PADJ_{n,r}$) is added to the original adjustment, creating a cumulative price adjustment. This process continues until the backstop quantity is reduced to zero, or until the maximum number of ITS cycles has been completed. If backstop is eliminated, then the cumulative price adjustment level is maintained, as long as backstop does not resurface, and until ITS convergence is achieved. Maintaining a backstop adjustment is necessary because complete removal of this high-price signal would cause demand for this source to increase again, and backstop would return. However, if the need for backstop supply recurs following a cycle which did not need backstop supply, then the price adjustment ($BKSTOP\_PADJ_{n,r}$) factor is reduced by one-half and added to the cumulative

[79] Backstop supply can be thought of as a high-priced alternative supply when no other options are available. Within the model, it also plays an operational role in sending a price signal when equilibrating the network that additional supplies are unavailable along a particular path in the network.

adjustment variable, with the process continuing as described above. The objective is to eliminate the need for backstop supply at the lowest associated price. The node prices are adjusted as follows:

$$NODE\_SHRPR_{n,r} = NODE\_SHRPR_{n,r} + RBKSTOP\_PADJ_{n,r} \tag{100}$$

$$RBKSTOP\_PADJ_{n,r} = RBKSTOP\_PADJ_{n,r} + BKSTOP\_PADJ_{n,r} \tag{101}$$

where,

$NODE\_SHRPR_{n,r}$	=	node price for region r on network n [used with flow sharing algorithm] (1987$/Mcf)
$RBKSTOP\_PADJ_{n,r}$	=	cumulative price adjustment due to backstop (1987$/Mcf)
$BKSTOP\_PADJ_{n,r}$	=	incremental backstop price adjustment (1987$/Mcf)
n	=	network (peak or off-peak)
r	=	region

Currently, this cumulative backstop adjustment ($RBKSTOP\_PADJ_{n,r}$) is maintained for each NEMS iteration and set to zero only on the first NEMS iteration of each model year. Also, it is not used to adjust the NODE_ENDPR because it is an adjustment for making flow allocation decisions, not for pricing gas for the end-user.

ITS convergence

The ITS is considered to have converged when the regional/seasonal spot/wellhead prices are within a defined percentage tolerance (PSUP_DELTA) of the prices set during the last ITS cycle and, for those supply regions with relatively small production levels (QSUP_SMALL), production is within a defined tolerance (QSUP_DELTA) of the production set during the last ITS cycle. If convergence does not occur, then a new spot/wellhead price is determined based on a user-specified weighting of the seasonal production levels determined during the current cycle and during the previous cycle down the network. The new production levels are defined as follows:

$$\begin{aligned} NODE\_QSUP_{n,s} = {} & (QSUP\_WT * NODE\_QSUP_{n,s}) + \\ & ((1 - QSUP\_WT) * NODE\_QSUPPREV_{n,s}) \end{aligned} \tag{102}$$

where,

$NODE\_QSUP_{n,s}$	=	production level at supply source s on network n for current ITS cycle (Bcf)
$NODE\_QSUPPREV_{n,s}$	=	production level at supply source s on network n for previous ITS cycle (Bcf)
QSUP_WT	=	weighting applied to production level for current ITS cycle (Appendix E)
n	=	network (peak or off-peak)
s	=	supply source

Seasonal prices (NODE_PSUPn,s) for these quantities are then determined using the same methodology defined above for obtaining spot/wellhead prices.

End-use sector prices

The NGTDM provides regional end-use or delivered prices for the Electricity Market Module (electric generation sector) and the other NEMS demand modules (non-electric sectors). For the non-electric sectors (residential, commercial, industrial, and transportation), prices are established at the NGTDM region, based on regional city-gate prices, and then averaged (when necessary) using quantity weights to obtain prices at the Census Division level. For the electric generation sector, prices are provided on a seasonal basis, based on regional spot prices, and are set for core and noncore services at two different regional levels: the Census Division level and the NGTDM/EMM level (Chapter 2, **Figure 2-3**).

The first step toward generating these delivered prices is to translate regional, seasonal node prices into corresponding city gate prices ($CGPR_{n,r}$). To accomplish this, seasonal intraregional and intrastate tariffs are added to corresponding regional end-use node prices (NODE_ENDPR). This sum is then adjusted using a city gate benchmark factor ($CGBENCH_{n,r}$) which represents the average difference between historical city gate prices and model results for the historical years of the model. These equations are defined below:

$$\begin{aligned} CGPR_{n,r} = {} & NODE\_ENDPR_{n,r} + INTRAREG\_TAR_{n,r} + \\ & INTRAST\_TAR_{r} + CGBENCH_{n,r} \end{aligned} \tag{103}$$

such that:

$$CGBENCH_{n,r} = avg(HCG\_BENCH_{n,r,HISYR}) = avg(HCGPR_{n,r,HISYR} - CGPR_{n,r}) \tag{104}$$

where,

$CGPR_{n,r}$	=	city gate price in region r on network n in each HISYR (1987$/Mcf)
$NODE\_ENDPR_{n,r}$	=	node price for region r on network n (1987$/Mcf)
$INTRAREG\_TAR_{n,r}$	=	intraregional tariff for region r on network n (1987$/Mcf)
$INTRAST\_TAR_{r}$	=	intrastate tariff in region r (1987$/Mcf)
$CGBENCH_{n,r}$	=	city gate benchmark factor for region r on network n (1987$/Mcf)
$HCG\_BENCH_{n,r,HISYR}$	=	city gate benchmark factors for region r on network n in historical years HISYR (1987$/Mcf)
$HCGPR_{n,r,HISYR}$	=	historical city gate price in region r on network n in historical year HISYR (1987$/Mcf)
n	=	network (peak and off-peak)
r	=	region (lower 48 only)
HISYR	=	historical year, over which average is taken (2004-2011, excluding the outlier year of 2009)
avg	=	straight average of indicated value over indicated historical years of the model.

The intraregional tariffs are the sum of a usage fee (INTRAREG_FIXTAR), provided by the Pipeline Tariff Submodule, and a reservation fee that is set using the same function NGPIPE_VARTAR that is used in setting interregional tariffs and was described previously. The benchmark factor represents an adjustment to calibrate city gate prices to historical values.

Seasonal distributor tariffs are then added to the city gate prices to get seasonal, sectoral delivered prices by the NGTDM regions for non-electric sectors and added to the market hub or spot prices to get delivered prices by the NGTDM/EMM subregions for the electric generation sector. The prices for residential, commercial, and electric generation sectors (core and noncore) are then adjusted using STEO benchmark factors ($SCALE\_FPR_{sec,t}$, $SCALE\_IPR_{sec,t}$)[80] to calibrate the results to equal the corresponding national STEO delivered prices. Each seasonal sector price is then averaged to get an annual, sectoral delivered price for each representative region. The following equations apply.

Non-electric sectors (except transportation):

$$\begin{aligned} NGPR\_SF_{n,sec,r} &= CGPR_{n,r} + DTAR\_SF_{n,sec,r} + SCALE\_FPR_{sec,t} \\ NGPR\_SI_{n,sec,r} &= CGPR_{n,r} + DTAR\_SI_{n,sec,r} + SCALE\_IPR_{sec,t} \end{aligned} \tag{105}$$

$$\begin{aligned} NGPR\_F_{sec,r} &= NGPR\_SF_{PK,sec,r} * PKSHR\_DMD_{sec,r} + \\ &\quad NGPR\_SF_{OP,sec,r} * (1.-PKSHR\_DMD_{sec,r}) \\ NGPR\_I_{sec,r} &= NGPR\_SI_{PK,sec,r} * PKSHR\_DMD_{sec,r} + \\ &\quad NGPR\_SI_{OP,sec,r} * (1.-PKSHR\_DMD_{sec,r}) \end{aligned} \tag{106}$$

where,

$NGPR\_SF_{n,sec,r}$	=	seasonal (n) core non-electric sector (sec) price in region r (1987$/Mcf)
$NGPR\_SI_{n,sec,r}$	=	seasonal (n) noncore non-electric sector (sec) price in region r (1987$/Mcf)
$NGPR\_F_{sec,r}$	=	annual core non-electric sector (sec) price in region r (1987$/Mcf)
$NGPR\_I_{sec,r}$	=	annual noncore non-electric sector (sec) price in region r (1987$/Mcf)
$CGPR_{n,r}$	=	city gate price in region r on network n (1987$/Mcf)
$DTAR\_SF_{n.sec,r}$	=	seasonal (n) distributor tariff to core non-electric sector (sec) in region r (1987$/Mcf)
$DTAR\_SI_{n.\ sec,r}$	=	seasonal (n) distributor tariff to noncore non-electric sector (sec) in region r (1987$/Mcf)
$PKSHR\_DMD_{sec,r}$	=	average (2001-2011) fraction of annual consumption for non-electric sector in peak season for region r
$SCALE\_FPR_{sec,t}$	=	STEO benchmark factor for core delivered prices for sector sec, in year t (1987$/Mcf)
$SCALE\_IPR_{sec,t}$	=	STEO benchmark factor for noncore delivered prices for sector sec, in year t (1987$/Mcf)
n	=	network (peak or off-peak)
sec	=	non-electric sector
r	=	region (lower 48 only)

[80] The STEO scale factors are linearly phased out over a user-specified number of years (Appendix E, STPHAS_YR) after the last STEO year. STEO benchmarking is not done for the transportation sector since the STEO does not include a comparable value.

[Note: For the residential and commercial sectors, NGPR_SI equals NGPR_SF, but it is irrelevant since the consumption volumes related to NGPR_SI are zero.]

Electric Generation Sector:

$$NGUPR\_SF_{n,j} = NODE\_SHRPR_{n,r} + UDTAR\_SF_{n,j} + SCALE\_FPR_{sec,t}$$

$$NGUPR\_SI_{n,j} = NODE\_SHRPR_{n,r} + UDTAR\_SI_{n,j} + SCALE\_IPR_{sec,t} \qquad (107)$$

$$NGUPR\_F_{j} = NGUPR\_SF_{PK,j} * PKSHR\_UDMD_{j} + NGUPR\_SF_{OP,j} * (1. - PKSHR\_UDMD_{j})$$

$$NGUPR\_I_{j} = NGUPR\_SI_{PK,j} * PKSHR\_UDMD_{j} + NGUPR\_SI_{OP,j} * (1. - PKSHR\_UDMD_{j}) \qquad (108)$$

where,

$NGUPR\_SF_{n,j}$	=	seasonal (n) core utility sector price in region j (1987$/Mcf)
$NGUPR\_SI_{n,j}$	=	seasonal (n) noncore utility sector price in region j (1987$/Mcf)
$NGUPR\_F_{j}$	=	annual core utility sector price in region j (1987$/Mcf)
$NGUPR\_I_{j}$	=	annual noncore utility sector price in region j (1987$/Mcf)
$NODE\_SHRPR_{n,r}$	=	hub or spot price in region r on network n (1987$/Mcf)
$UDTAR\_SF_{n,j}$	=	seasonal (n) distributor tariff to core utility sector in region j (1987$/Mcf)
$UDTAR\_SI_{n,j}$	=	seasonal (n) distributor tariff to noncore utility sector in region j (1987$/Mcf)
$PKSHR\_UDMD_{j}$	=	average (1994-2011, except for New England 1997-2011) fraction of annual consumption for the electric generator sector in peak season, for region j
$SCALE\_FPR_{sec,t}$	=	STEO benchmark factor for core delivered prices for sector sec, in year t (1987$/Mcf)
$SCALE\_IPR_{sec,t}$	=	STEO benchmark factor for noncore delivered prices for sector sec, in year t (1987$/Mcf)
n	=	network (peak PK or off-peak OP)
sec	=	utility sector (electric generation only)
r	=	NGTDM region (lower 48 only)
j	=	NGTDM/EMM subregion

For *AEO2014*, the natural gas price that was finally sent to the Electricity Market Module for both core and noncore customers was the quantity-weighted average of the core and noncore prices derived from the above equations. This was done to alleviate some difficulties within the Electricity Market Module as selections were being made between different types of natural gas generation equipment.

Transportation sector:

A somewhat different methodology is used to determine natural gas delivered prices for the transportation sector. The transportation sector is represented for two fuel types: compressed natural gas (CNG) and liquefied natural gas (LNG). The model represents and prices each fuel as it is used in vehicles (further distinguished by personal vehicle and fleet vehicle), rail (for freight, intercity, transit, and commuter categories), and ships (for domestic, international, and recreational boat categories). Like the other non-electric sectors, seasonal distributor tariffs are added to the regional city gate prices to determine seasonal delivered prices for both components. Annual core prices are then established for each component in a region by averaging the corresponding seasonal prices. The following shows the equations used for CNG use in vehicles:

$$NGPR\_TRPV\_SF_{n,r} = CGPR_{n,r} + DTAR\_TRPV\_SF_{n,r} + SCALE\_FPR_{sec,t}$$

$$NGPR\_TRFV\_SF_{n,r} = CGPR_{n,r} + DTAR\_TRFV\_SF_{n,r} + SCALE\_FPR_{sec,t} \tag{109}$$

$$NGPR\_TRPV\_F_{r} = NGPR\_TRPV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + NGPR\_TRPV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r})$$

$$NGPR\_TRFV\_F_{r} = NGPR\_TRFV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + NGPR\_TRFV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r}) \tag{110}$$

where,

$NGPR\_TRPV\_SF_{n,r}$	=	seasonal (n) price of CNG used by personal vehicles in region r (1987$/Mcf)
$NGPR\_TRFV\_SF_{n,r}$	=	seasonal (n) price of CNG used by fleet vehicles in region r (1987$/Mcf)
$DTAR\_TRPV\_SF_{n,r}$	=	seasonal (n) distributor tariff for CNG in personal vehicles in region r (1987$/Mcf)
$DTAR\_TRFV\_SF_{n,r}$	=	seasonal (n) distributor tariff to CNG in fleet vehicles in region r (1987$/Mcf)
$CGPR_{n,r}$	=	city gate price in region r on network n (1987$/Mcf)
$NGPR\_TRPV\_F_{r}$	=	annual price of CNG used by personal vehicles in region r (1987$/Mcf)
$NGPR\_TRFV\_F_{r}$	=	annual price of CNG used by fleet vehicles in region r (1987$/Mcf)
$PKSHR\_DMD_{sec,r}$	=	fraction of annual consumption for the transportation sector (sec=4) in the peak season for region r (set to PKSHR_YR)
$SCALE\_FPR_{sec,t}$	=	STEO benchmark factor for core delivered prices for sector sec, in year t (set to 0 for transportation sector), (1987$/Mcf)
n	=	network (peak PK or off-peak OP)
sec	=	transportation sector =4
r	=	NGTDM region (lower 48 only)

The equations for LNG used in vehicles are structured exactly the same as those shown above for CNG, with the only difference being that the variable related to LNG ends with an “L” instead of an “F.”

Prices for CNG and LNG in ships and trains are set to the same value for each of their subcategories and are assigned as follows:

$$\begin{aligned} NGPR\_TRLN\_SR_{n,r} &= NGPR\_TRFV\_SL_{n,r} - TRAIN\_DISC - \\ &\quad (STAXL_n + FTAXL) / (oMC\_PCWGDP_t / oMC\_PCWGDP_{1987}) \\ NGPR\_TRCN\_SR_{n,r} &= NGPR\_TRFV\_SF_{n,r} - \\ &\quad (STAXL_n + FTAXL) / (oMC\_PCWGDP_t / oMC\_PCWGDP_{1987}) \end{aligned} \tag{111}$$

$$\begin{aligned} NGPR\_TRLN\_SS_{n,r} &= NGPR\_TRFV\_SL_{n,r} - \\ &\quad STAXL_n / (oMC\_PCWGDP_t / oMC\_PCWGDP_{1987}) \\ NGPR\_TRCN\_SS_{n,r} &= NGPR\_TRFV\_SF_{n,r} - \\ &\quad STAXL_n / (oMC\_PCWGDP_t / oMC\_PCWGDP_{1987}) \end{aligned} \tag{112}$$

where,

$NGPR\_TRLN\_SR_{n,r}$	=	seasonal (n) price of LNG used by trains in region r (1987$/Mcf)
$NGPR\_TRCN\_SR_{n,r}$	=	seasonal (n) price of CNG used by trains in region r (1987$/Mcf)
$NGPR\_TRLN\_SS_{n,r}$	=	seasonal (n) price of LNG used by ships in region r (1987$/Mcf)
$NGPR\_TRCN\_SS_{n,r}$	=	seasonal (n) price of CNG used by ships in region r (1987$/Mcf)
$NGPR\_TRFV\_SL_{n,r}$	=	seasonal (n) price of LNG used by fleet vehicles in region r (1987$/Mcf)
$NGPR\_TRFV\_SF_{n,r}$	=	seasonal (n) price of CNG used by fleetl vehicles in region r (1987$/Mcf)
TRAIN_DISC	=	assumed difference between price of LNG used by trains and LNG used by fleet vehicles, excluding tax differences
$STAXL_n$	=	state motor fuels taxes in region r (nominal dollars)
FTAXL	=	federal motor fuels tax (TFDL, Appendix E) (nominal dollars)
oMC_PCWGDP_t	=	GDP deflator for year t
n	=	network (peak PK or off-peak OP)
r	=	NGTDM region (lower 48 only)

Once a price is set for each fuel and transportation mode, a quantity-weighted average seasonal price is set averaging across CNG and LNG and across all modes ($NGPR\_SF_{n,sec=4,r}$), followed by a quantity-weighted average annual price ($NGPR\_F_{sec=4,r}$). Currently the variable NGPR_SI for the transportation sector serves no purpose since all transportation volumes are assumed to be core.

Finally, regional delivered prices can be used within the ITS cycle to approximate a demand response. The submodule can then be resolved with adjusted consumption levels in an effort to speed NEMS convergence. Finally, once the ITS has converged, regional prices are averaged using quantity weights to compute Census Division prices, which are sent to the corresponding NEMS modules.

Import prices

The price associated with Canadian imports at each of the module's border crossing points is established during the ITS convergence process. Each of these border-crossing points is represented by a node in the network. The import price for a given season and border crossing is therefore equal to the price at the associated node. For reporting purposes, these node prices are averaged using quantity weights to derive an average annual Canadian import price. The prices for imports at the three Mexican border crossings are set to the average spot price in the nearest NGTDM region plus a markup (or markdown) that is based on the difference between similar import and spot prices historically. The structure for setting LNG import prices is similar to setting Mexican import prices, although regional city gate prices are used instead of spot prices. For the facilities for which historical prices are not available (i.e., generic new facilities), an assumption was made about the difference between the regional city gate price and the LNG import price (LNGDIFF, Appendix E).

5. Distributor Tariff Submodule Solution Methodology

This chapter discusses the solution methodology for the Distributor Tariff Submodule (DTS) of the Natural Gas Transmission and Distribution Module (NGTDM). For each end-use sector within each region, the DTS develops seasonal, market-specific distributor tariffs (or city-gate-to-end-use markups) that are applied to projected seasonal city gate prices to derive end-use or delivered prices. Since most electric generators do not purchase their gas through local distribution companies, the DTS sets a markup to electric generators off of the regional spot price. Even though many industrial customers also bypass local distribution companies, their prices are still set off of the city gate price. In such cases, the markup effectively represents the difference between the average price paid by local distribution companies at the city gate and the average price paid by the industrial customer.[81] Distributor tariffs are defined for both core and noncore markets within the industrial and electric generator sectors, while residential, commercial, and transportation sectors have distributor tariffs defined only for the core market, since noncore customer consumption in these sectors is assumed to be insignificant and set to zero. The transportation sector is distinguished by compressed natural gas (CNG) or liquefied natural gas (LNG) sold for vehicles (at retail or other), for trains, and for ships, with separate distributor tariffs for each. While the volumes consumed for both trains and ships are further subdivided, the prices do not vary.

For the residential, commercial, industrial, and electric generation sectors, distributor tariffs are based on econometrically estimated equations or historical relationships and are driven in part by sectoral consumption levels.[82] This general approach was taken since data are not reasonably obtainable to develop a detailed cost-based accounting methodology similar to the approach used for interstate pipeline tariffs in the Pipeline Tariff Submodule. Representative distribution markups for CNG in vehicles are set to the sum of historical tariffs for delivering natural gas to refueling stations, federal and state motor fuels taxes and credits, and estimates of dispensing charges. For LNG in vehicles, trains, and ships, representative distribution markups are the sum of tariffs for delivering natural gas to a liquefaction facility, liquefaction and delivery costs to the dispensing facility, retail markup, and federal and state motor fuels taxes and credits as appropriate. The specific methodologies used to calculate each sector's distributor tariffs are discussed in the remainder of this chapter.

Residential and commercial sectors

Residential and commercial distributor tariffs are projected using econometrically estimated equations. The primary explanatory variables are floorspace and commercial natural gas consumption per floorspace for the commercial tariff, and number of households and natural gas consumption per household for the residential sector tariff. For the commercial sector, the distributor tariffs are estimated separately for the peak and off-peak periods, whereas the combined equation was used for residential, as follows:

[81] These "markups" can be negative.

[82] Historical distributor tariffs for a sector in a particular region/season can be estimated by taking the difference between the average sectoral delivered price and the average city gate price or representative spot price in the region/season (Appendix E, HCGPR).

Residential peak

$$
\begin{aligned}
\mathrm{DTAR\_SF}_{s=1,r,n=1} = {} & e^{(\mathrm{PRSREG23}_r + \mathrm{PRSREGPK23}_{r,n=1})} * \mathrm{NUMRS}_{r,t}^{0.200862} * \\
& \left(\frac{\mathrm{BASQTY\_SF}_{s=1,r,n=1} + \mathrm{BASQTY\_SI}_{s=1,r,n=1}}{\mathrm{NUMRS}_{r,t}} \right)^{-0.524533} * \\
& \mathrm{DTAR\_SFPREV}_{s=1,r,n=1}^{0.234747} * \\
& e^{(-0.234747*(\mathrm{PRSREG23}_r + \mathrm{PRSREGPK23}_{r,n=1})} * \mathrm{NUMRS}_{r,t-1}^{-0.234747*0.200862} * \\
& \left(\frac{\mathrm{BASQTY\_SFPREV}_{s=1,r,n=1} + \mathrm{BASQTY\_SIPREV}_{s=1,r,n=1}}{\mathrm{NUMRS}_{r,t-1}} \right)^{(-0.234747*-0.524533)}
\end{aligned}
\quad (113)
$$

Residential off-peak

$$
\begin{aligned}
\mathrm{DTAR\_SF}_{s=1,r,n=2} = {} & e^{(\mathrm{PRSREG23}_r + \mathrm{PRSREGPK23}_{r,n=2})} * \mathrm{NUMRS}_{r,t}^{0.243360} * \\
& \left(\frac{\mathrm{BASQTY\_SF}_{s=1,r,n=2} + \mathrm{BASQTY\_SI}_{s=1,r,n=2}}{\mathrm{NUMRS}_{r,t}} \right)^{-0.861027} * \\
& \mathrm{DTAR\_SFPREV}_{s=1,r,n=2}^{0.268308} * \\
& e^{(-0.268308*(\mathrm{PRSREG23}_r + \mathrm{PRSREGPK23}_{r,n=2})} * \mathrm{NUMRS}_{r,t-1}^{-0.268308*0.243360} * \\
& \left(\frac{\mathrm{BASQTY\_SFPREV}_{s=1,r,n=2} + \mathrm{BASQTY\_SIPREV}_{s=1,r,n=2}}{\mathrm{NUMRS}_{r,t-1}} \right)^{(-0.268308*-0.861027)}
\end{aligned}
\quad (114)
$$

Commercial peak

$$
\begin{aligned}
\mathrm{DTAR\_SF}_{s=2,r,n=1} = {} & e^{(\mathrm{PCMREG17}_r + P\mathrm{CMREGPK17}_{r,n=1})} * \mathrm{FLRSPC12}_{r,t}^{0.233430} * \\
& \left(\left(\frac{\mathrm{BASQTY\_SF}_{s=2,r,n=1} + \mathrm{BASQTY\_SI}_{s=2,r,n=1}}{\mathrm{FLRSPC12}_{r,t}} \right) \right)^{-0.199769} * \\
& \mathrm{DTAR\_SFPREV}_{s=2,r,n=1}^{0.286179} * e^{(-0.286179*(\mathrm{PCMREG17}_r + \mathrm{PCMREGPK17}_{r,n=1}))} * \mathrm{FLRSPC12}_{r,t-1}^{-0.28} \\
& \left(\left(\frac{\mathrm{BASQTY\_SFPREV}_{s=2,r,n=1} + \mathrm{BASQTY\_SIPREV}_{s=2,r,n=1}}{\mathrm{FLRSPC12}_{r,t-1}} \right) \right)^{(-0.286179*-0.199769)}
\end{aligned}
\quad (115)
$$

Commercial off-peak

$$\mathrm{DTAR\_SF}_{s=2,r,n=2} = e^{(\mathrm{PCMREG17}_r + \mathrm{PCMREGPK15}_{r,n=2})} * \mathrm{FLRSPC12}_{r,t}^{0.502852} * \left(\left(\frac{\mathrm{BASQTY\_SF}_{s=2,r,n=2} + \mathrm{BASQTY\_SI}_{s=2,r,n=2}}{\mathrm{FLRSPC12}_{r,t}} \right) \right)^{-0.565362}$$

$$\mathrm{DTAR\_SFPREV}_{s=2,r,n=2}^{0.181133} * e^{(-0.181133*(\mathrm{PCMREG15}_r + \mathrm{PCMREGPK15}_{r,n=2}))} * \mathrm{FLRSPC12}_{r,t-1}^{-0.18} \left(\frac{\mathrm{BASQTY\_SFPREV}_{s=2,r,n=2} + \mathrm{BASQTY\_SIPREV}_{s=2,r,n=2}}{\mathrm{FLRSPC12}_{r,t-1}} \right)^{(-0.181133*-0.565362)} \quad (116)$$

where,

$$\mathrm{NUMRS}_{r,t} = \mathrm{oRSGASCUST}_{cd,t} * \mathrm{RECS\_ALIGN}_r * \mathrm{NUM\_REGSHR}_r \quad (117)$$

and,

$$\mathrm{FLRSPC12}_{r,t} = (\mathrm{MC\_COMMFLSP}_{1,cd,t} - \mathrm{MC\_COMMFLSP}_{8,cd,t}) * \mathrm{SHARE}_r \quad (118)$$

where,

$\mathrm{DTAR\_SF}_{s,r,n}$	=	core distributor tariff in current forecast year for sector s, region r, and network n (1987$/Mcf)
$\mathrm{DTAR\_SFPREV}_{s,r,n}$	=	core distributor tariff in previous forecast year (1987$/Mcf). [For first forecast year set at the 2011 historical value.]
$\mathrm{BASQTY\_SF}_{s,r,n}$	=	sector (s) level firm gas consumption for region r, and network n (Bcf)
$\mathrm{BASQTY\_SI}_{s,r,n}$	=	sector (s) level nonfirm gas consumption for region r, and network n (Bcf) (assumed at 0 for residential and commercial)
$\mathrm{BASQTY\_SFPREV}_{s,r,n}$	=	sector (s) level gas consumption for region r, and network n in previous year (Bcf) (assumed at 0 for residential and commercial)
$\mathrm{BASQTY\_SIPREV}_{s,r,n}$	=	sector (s) level nonfirm gas consumption for region r, and network n in previous year (Bcf)
NUMRS	=	number of residential customers in year t
$\mathrm{PRSREG23}_{r,n}$	=	residential, regional constant term, set to zero since not used in estimation
$\mathrm{PCMREG17}_{r,n}$	=	commercial, regional constant term , set to zero since not used in estimation
$\mathrm{PRSREGPK23}_{r,n}$	=	residential, regional, period specific, constant term (Table F6, Appendix F)
$\mathrm{PCMREGPK17}_{r,n}$	=	commercial, regional, peak specific, constant term (Table F7, Appendix F)
$\mathrm{oRSGASCUST}_{cd,t-1}$	=	number of residential gas customers by census division in the previous forecast year (from NEMS residential demand module)

$RECS\_ALIGN_r$	=	factor to align residential customer count data from EIA's 2009 Residential Consumption Survey (RECS), the data on which oRSGASCUST is based, with similar data from EIA's Natural Gas Annual, the data on which the DTAR_SF estimation is based.
NUM_REGSHR_r	=	assumed share of residential customers in NGTDM region r relative to the number in the larger or equal-sized associated Census Division (fraction, Appendix E)
FLRSPC12.	=	commercial floorspace by NGTDM region (total net of for manufacturing) (billion square feet)
$MC\_COMMFLSP_{1,cd,t}$	=	commercial floorspace by Census Division (total, including manufacturing)
$MC\_COMMFLSP_{8,cd,t}$	=	commercial floorspace by Census Division (manufacturing)
$SHARE_r$	=	assumed fraction of the associated census division's commercial floorspace within each of the 12 NGTDM regions based on population data (1.0, 1.0, 1.0, 1.0, 0.66, 1.0, 1.0, 0.59, 0.24, 0.34, 0.41, 0.75)
s	=	sector (=1 for residential, =2 for commercial)
cd	=	census division
r	=	region (12 NGTDM regions)
n	=	network (=1 for peak, =2 for off-peak)
t	=	forecast year (e.g., 2020)

Parameter values and details about the estimation of these equations can be found in Tables F6 and F7 of Appendix F.

Industrial sector

The industrial sector is distinguished by a price and distributor tariff for two market segments representing non-energy-intensive and energy-intensive industries and labeled respectively as core and noncore. An examination by industry of the natural gas price data from the quadrennial Manufacturing Energy Consumption Survey (MECS) revealed that the more energy-intensive industries have historically paid a lower band of prices compared to the less-energy-intensive energies. These historical prices by the four Census Divisions were used as a basis for generating estimates for historical industrial prices for the core and noncore categories for the 12 NGTDM regions in all historical years. For the regions and years available from MECS, econometrically derived equations were developed for core and noncore prices as a function of the average regional supply price and the average industrial price as purchased through local distribution companies. These equations are used to estimate industrial prices for all historical years for both the core and noncore categories, as follows:

$$PIN\_FNG_{r,t} = 0.657744 + (0.398046 * PW\_NRG_{r,t}) + (0.530439 * HPIN_{r,t}) \quad (119)$$

$$PIN\_ING_{r,t} = 0.220117 + (0.602180 * PW\_NRG_{r,t}) + (0.421469 * HPIN_{r,t}) \quad (120)$$

where,

$PIN\_FNG_{r,t}$	=	estimated natural gas historical price to core (non-energy-intensive) industrial consumers in NGTDM region r (1987$/Mcf)
$PIN\_ING_{r,t}$	=	estimated natural gas historical price to noncore (energy-intensive) industrial consumers in NGTDM region r (1987$/Mcf)

$PW\_NRG_{r,t}$ = average historical supply price (production and import price weighted together) in NGTDM region r (1987$/Mcf)

$HPIN_{r,t}$ = average NGTDM regional historical price to industrial customers that purchase gas from a local distribution company as published by EIA (1987$/Mcf) (from SPIN, Appendix E)

r = NGTDM region

t = year

Parameter values and details about the estimation of these two equations can be found in Table F5, Appendix F.

The industrial distributor tariffs are projected for the core and noncore categories using separately derived econometric equations based in part on data derived from the estimated historical prices described above. The equations are specified by NGTDM region and season. The noncore distributor tariffs are estimated as a function of the industrial noncore (i.e., energy-intensive industries) natural gas consumption levels, while the core tariffs are estimated as a function of the noncore distributor tariffs, as follows:

$$\begin{aligned} DTAR\_SI_{n,s,r} = {} & PINREG19I_r + PIN\_REGPK19I_{r,n} + \\ & (-0.000651 * BASQTY\_SI_{n,s,r}) + (0.434485 * DTAR\_SFPREV_{n,s,r}) \\ & - 0.4334485 * [PIN\_REG19I_r + PIN\_REGPK19I_{r,n} + \\ & (-0.000651 * BASQTY\_SIPREV_{n,s,r})] \end{aligned} \tag{121}$$

$$\begin{aligned} DTAR\_SF_{n,s,r} = {} & PINREG19F_r + PIN\_REGPK19F_{r,n} + \\ & (1.017384 * DTAR\_SI_{n,s,r}) + (0.533751 * DTAR\_SFPREV_{n,s,r}) \\ & - 0.533751 * [PIN\_REG19F_r + PIN\_REGPK19F_{r,n} + \\ & (1.017384 * DTAR\_SIPREV_{n,s,r})] \end{aligned} \tag{122}$$

where,

$DTAR\_SF_{n,s,r}$ = seasonal distributor tariff for the core industrial sector (s=3) in region r (1987$/Mcf)

$DTAR\_SI_{n,s,r}$ = seasonal distributor tariff for the noncore industrial sector (s=3) in region r (1987$/Mcf)

PIN_REG19F_r, PIN_REG19I_r = estimated constant terms for core and noncore equations (Table F4, Appendix F)

$PIN\_REGPK19F_{r,n}$, $PIN\_REGPK19I_{r,n}$ = estimated coefficients for core and noncore equations, set to zero for the off-peak period and for any region where the coefficient is not statistically significant (Table F4, Appendix F)

$DTAR\_SFPREV_{n,s,r}$ = seasonal distributor tariff for the core industrial sector (s=3) in region r (1987$/Mcf) in the previous forecast year [In the first forecast year set to the value for the last historical year, 2012]

$DTAR\_SIPREV_{n,s,r}$ = seasonal distributor tariff for the noncore industrial sector (s=3) in region r (1987$/Mcf) in the previous forecast year [In the first forecast year set to the value for the last historical year, 2012]

$BASQTY\_SI_{n,s=3,r}$ = seasonal noncore natural gas consumption for industrial sector (s=3) in the current forecast year (Bcf)

$BASQTY\_SIPREV_{n,s=3,r}$ = seasonal noncore natural gas consumption for industrial sector (s=3) in the previous forecast year (Bcf)

s = end-use sector index (s=3 for industrial sector)

n = network (peak or off-peak)

r = NGTDM region

Parameter values and details about the estimation of these two equations can be found in Table F4 and F5, Appendix F.

Electric generation sector

Distributor tariffs for the electric generation sector do not represent a charge imposed by a local distribution company; rather, they represent the difference between the average spot price in each NGTDM region and the natural gas price paid on average by electric generators in each NGTDM/EMM region, and can be negative. A single markup or tariff (i.e., no distinction between core and noncore) is projected for each season and region using the equation below. The current version of the model (as used for *AEO2014*) assigns this same value to both the core and noncore segments.[83] The equation for the distributor tariffs for electric generators is set as a function of natural gas consumption by the electric sector relative to consumption by the other sectors. The greater the electric consumption share, the greater the price difference between the electric sector and the average, as they are anticipated to need to reserve more space on the pipeline system. The specific equation follows:

$$UDTAR\_SF_{n,j} = (UDTAR\_SFPREV_{n,j} + NODE\_SHRPR_{n,r})* \left(\frac{1 + \dfrac{qelec_{n,j} - qeleclag_{n,j}}{qelec_{n,j}}}{1 + \dfrac{OTHR_r - OTHRLAG_r}{OTHR_r}} \right)^{0.1} - NODE\_SHRPR_{n,r} \qquad (123)$$

where,

$$qelec_{n,j} = (BASUQTY\_SF_{n,j} + BASUQTY\_SI_{n,j}) * 1000 \qquad (124)$$

$$qeleclag_{n,j} = (BASUQTY\_SFPREV_{n,j} + BASUQTY\_SIPREV_{n,j}) * 1000 \qquad (125)$$

[83] This distinction was eliminated several years ago because of operational concerns in the Electricity Market Module. In addition, there are some remaining issues concerning the historical data necessary to generate separate price series for the two segments.

$$UDTAR\_SI_{n,j} = UDTAR\_SF_{n,j} \text{ for all n and j,} \tag{126}$$

where,

$UDTAR\_SF_{n,j}$	=	seasonal core electric generation sector distributor tariff, current forecast year ($/Mcf)
$UDTAR\_SI_{n,j}$	=	seasonal noncore electric generation sector distributor tariff, current forecast year ($/Mcf)
$UDTAR\_SFPREV_{n,j}$	=	seasonal core electric generation sector distributor tariff, previous forecast year ($/Mcf)
$BASUQTY\_SF_{n,j}$	=	core electric generator gas consumption, current forecast year (Bcf)
$BASUQTY\_SI_{n,j}$	=	noncore electric generator gas consumption, current forecast year (Bcf)
$BASUQTY\_SFPREV_{n,j}$	=	core electric generator gas consumption in previous forecast year (Bcf)
$BASUQTY\_SIPREV_{n,j}$	=	noncore electric generator gas consumption in previous forecast year (Bcf)
OTHRr	=	total consumption by other end-use sectors (residential, commercial, industrial, transportation) in associated NGTDM region for given network/season (Bcf)
$OTHRLAG_r$	=	last year's value for OTHRr
$NODE\_SHRPR_{n,r}$	=	spot price in associated NGTDM region for given network/season ($/Mcf)
n	=	network (peak=1 or off-peak=2)
j	=	NGTDM/EMM region (see chapter 2)
r	=	NGTDM region (see chapter 2)

Transportation sector

The transportation sector now includes compressed and liquefied natural gas for ships, trains, and vehicles. Consumers of compressed natural gas (CNG) and liquefied natural gas (LNG) for vehicles are further classified into either fleet vehicles or personal vehicles (i.e., sold at retail). A distributor tariff markup is set for each fuel and for both categories to capture the total markup from city gate to vehicle, that is: 1) the cost of the natural gas delivered to the dispensing station or liquefaction facility above the city gate price; 2) in the case of LNG, the cost of liquefying and transporting the LNG to the dispensing station; 3) the per-unit cost or charge for dispensing the gas; and 4) federal and state motor fuels taxes and credits. While both rail and ship use are also further disaggregated (freight, intercity, transit, and commuter, and domestic, international, and recreational boats, respectively), there is no price distinction at these lower levels.

The cost related to moving natural gas from the city gate to a CNG station is based on the historical difference between the price reported for the transportation sector in EIA's *Natural Gas Annual* (which should reflect this delivered price) and the city gate price. For LNG, natural gas delivered to a liquefaction facility (a large-volume customer) is assumed to see the same price as an electric generator in the region. An analysis was performed exogenously to establish separate retail markups (RETAIL_COST and RETAIL_COSTL) for the four categories of natural gas vehicle fuel which encompass the total markup from the point it exits the distribution pipeline until it enters the vehicle, short of taxes. Details about the derivation of the retail markups are provided in the AEO Assumptions document. Finally, appropriate federal and state motor fuels taxes, net of credits, are added to the distributor tariff and held constant in nominal dollars throughout the forecast period.[84] The equations for setting distribution markups for natural gas vehicles follow:

$$DTAR\_TRFV\_SF_{n,r} = \{HDTAR\_SF_{n,s=4,r,EHISYR} * (1 - TRN\_DECL)^{YR\_DECL}\} + RETAIL\_COST_2 + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \quad (127)$$

$$DTAR\_TRPV\_SF_{n,r} = \{HDTAR\_SF_{n,s=4,r,EHISYR} * (1 - TRN\_DECL)^{YR\_DECL}\} + RETAIL\_COST_1 + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \quad (128)$$

$$DTAR\_TRFV\_SL_{n,r} = UTARNG_{n,r} + RETAIL\_COSTL_2 + \frac{(STAXL_r + FTAXL)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \quad (129)$$

$$DTAR\_TRPV\_SL_{n,r} = UTARNG_{n,r} + RETAIL\_COSTL_1 + \frac{(STAXL_r + FTAXL)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \quad (130)$$

where,

$DTAR\_TRFV\_SF_{n,r}$	=	CNG distributor tariff for the fleet vehicle transportation sector (1987$/Mcf)
$DTAR\_TRPV\_SF_{n,r}$	=	CNG distributor tariff markup for the personal vehicle transportation sector (1987$/Mcf)
$DTAR\_TRFV\_SL_{n,r}$	=	LNG distributor tariff markup for the fleet vehicle transportation sector (1987$/Mcf)
$DTAR\_TRPV\_SL_{n,r}$	=	LNG distributor tariff markup for the personal vehicle transportation sector (1987$/Mcf)
$HDTAR\_SF_{n,s,r,EHISYR}$	=	historical (2011) distributor tariff for the transportation sector to deliver the CNG to the station[85] (1987$/ Mcf)
$UTARNG_{n,r}$	=	quantity-weighted average distributor tariff markup for electric generators in the region and network
TRN_DECL	=	fleet vehicle distributor decline rate, set to zero for *AEO2014* (fraction, Appendix E)
YR_DECL	=	difference between the current year and the last historical year over which the decline rate is applied

[84] Motor vehicle fuel taxes are assumed constant in current-year dollars throughout the forecast to reflect current laws. Within the model these taxes are specified in 1987 dollars.

[85] EIA-published, annual, state-level data are used to set regional historical end-use prices for CNG vehicles. Since monthly data are not available for this sector, seasonal differentials for the industrial sector are applied to annual CNG data to approximate seasonal CNG prices.

RETAIL_COST	=	assumed additional charge related to providing CNG dispensing service to customers, at a refueling station for personal (index=1) or fleet (index=2) station (1987$/Mcf, Appendix E)
RETAIL_COSTL	=	assumed additional charge related to liquefying and transporting LNG and dispensing it to customers at a refueling station for personal (index=1) or fleet (index=2) vehicles (1987$/Mcf, Appendix E)
$STAX_r$	=	State motor vehicle fuel tax for CNG (current year $/Mcf, Appendix E)
$STAXL_r$	=	State motor vehicle fuel tax for LNG (current year $/Mcf, Appendix E)
FTAX	=	Federal motor vehicle fuel tax minus any federal excise motor fuel credit for CNG (current year $/Mcf, TFD, Appendix E)
FTAXL	=	Federal motor vehicle fuel tax minus any federal excise motor fuel credit for CNG (current year $/Mcf, TFDL, Appendix E)
MC_PCWGDP_t	=	GDP conversion from current year dollars to 1987 dollars [from the NEMS macroeconomic module]
n	=	network (peak or off-peak)
s	=	end-use sector index (s=4 for transportation sector)
r	=	NGTDM region
EHISYR	=	index defining last year that historical data are available
t	=	forecast year

The model does not calculate a distributor tariff for CNG and LNG for ships and trains as the prices for these categories are set based on the fleet vehicle prices as described in the previous chapter.

6. Pipeline Tariff Submodule Solution Methodology

The Pipeline Tariff Submodule (PTS) sets rates charged for storage services and interstate pipeline transportation. The rates developed are based on actual costs for transportation and storage services. These cost-based rates are used as a basis for developing tariff curves for the Interstate Transmission Submodule (ITS). The PTS tariff calculation is divided into two phases: an historical year initialization phase and a forecast year update phase. Each of these two phases includes the following steps: (1) determine the various components, in nominal dollars, of the total cost-of-service; (2) classify these components as fixed and variable costs based on the rate design (for transportation); (3) allocate these fixed and variable costs to rate components (reservation and usage costs) based on the rate design (for transportation); and (4) for transportation, compute rates for services during peak and off-peak time periods; for storage, compute annual regional tariffs. For the historical year phase, the cost of service is developed from historical financial data on 28 major U.S. interstate pipeline companies; while for the forecast year update phase the costs are estimated using a set of econometric equations and an accounting algorithm. The pipeline tariff calculations are described first, followed by the storage tariff calculations, and finally a description of the calculation of the tariffs for moving gas by pipeline from Alaska and from the Mackenzie Delta to Alberta. A general overview of the methodology for deriving rates is presented in the following box. The PTS system diagram is presented in **Figure 6-1**.

The purpose of the historical year initialization phase is to provide an initial set of transportation revenue requirements and tariffs. The last historical year for the PTS is currently 2006, which need not align with the last historical year for the rest of the NGTDM. Ultimately the ITS requires pipeline and storage tariffs; whether they are based on historical or projected financial data is mechanically irrelevant. The historical year information is developed from existing pipeline company transportation data. The historical year initialization process draws heavily on three databases: (1) a pipeline financial database (1990-2006) of 28 major interstate natural gas pipelines developed by Foster Associates,[86] (2) "a competitive profile of natural gas services" database developed by Foster Associates,[87] and (3) a pipeline capacity database developed by the former Office of Oil and Gas, EIA.[88] The first database represents the existing physical U.S. interstate pipeline and storage system, which includes production processing, gathering, transmission, storage, and other. The physical system is at a more disaggregate level than the NGTDM network. This database provides detailed company-level financial, cost, and rate base parameters. It contains information on capital structure, rate base, and revenue requirements by major line item of the cost of service for the historical years of the model. The second Foster database contains detailed data on gross and net plant in service and depreciation, depletion, and amortization

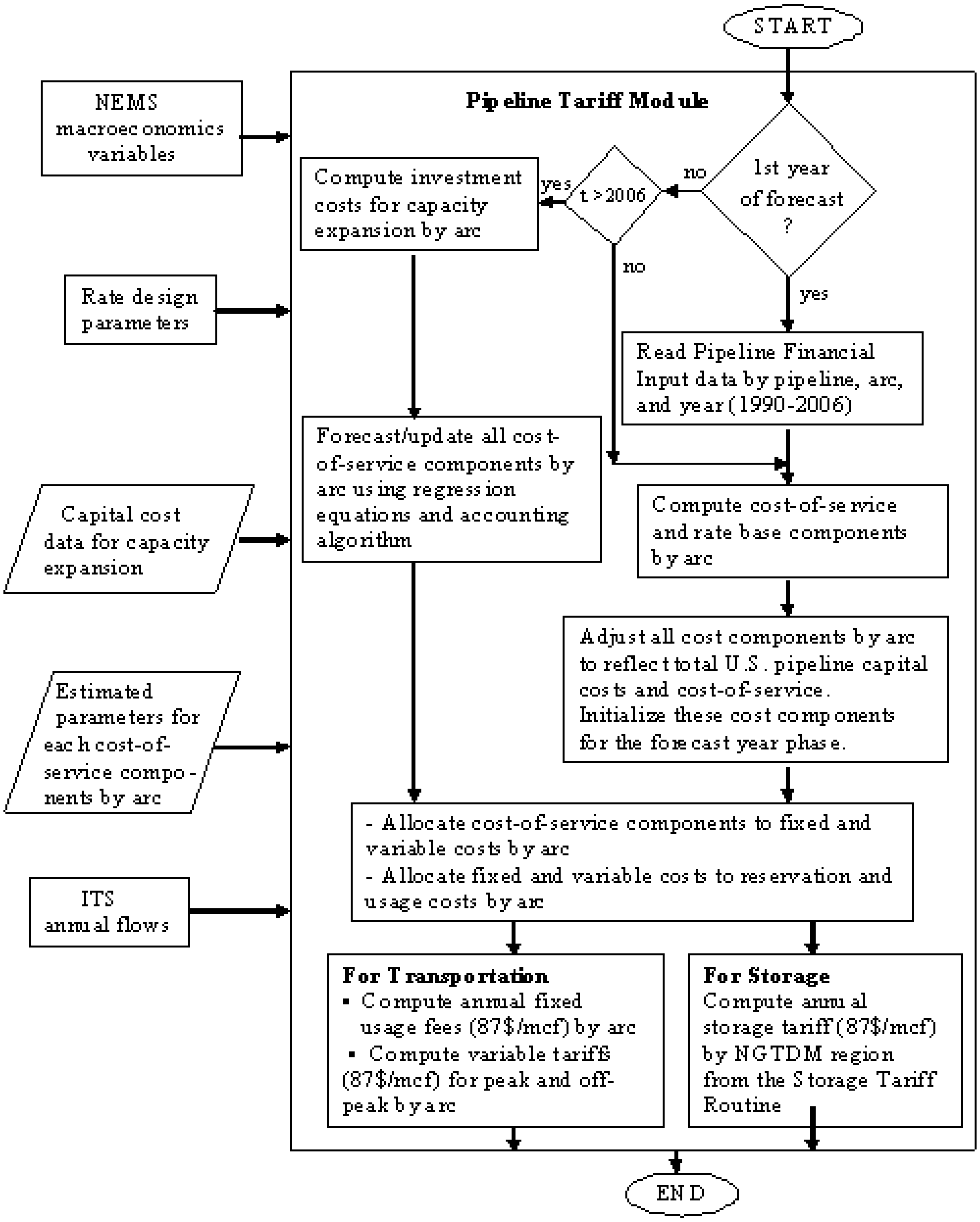
[86] Foster Financial Reports, 28 Major Interstate Natural Gas Pipelines, 2000, 2004, and 2007 Editions, Foster Associates, Inc., Bethesda, Maryland. The primary sources of data for these reports are FERC Form 2 and the monthly FERC Form 11 pipeline company filings. These reports can be purchased from Foster Associates.

[87] Competitive Profile of Natural Gas Services, Individual Pipelines, December 1997, Foster Associates, Inc., Bethesda, Maryland. Volumes III and IV of this report contain detailed information on the major interstate pipelines, including a pipeline system map, capacity, rates, gas plant accounts, rate base, capitalization, cost of service, etc. This report can be purchased from Foster Associates.

[88] A spreadsheet compiled by James Tobin of the Office of Oil and Gas containing historical and proposed state-to-state pipeline construction project costs, mileage, capacity levels and additions by year from 1996 to 2011, by pipeline company (data as of August 16, 2007).

for individual plants (production processing and gathering plants, gas storage plants, gas transmission plants, and other plants) and is used to compute sharing factors by pipeline company and year to single out financial cost data for transmission plants from the "total plants" data in the first database.

Figure 6-1. Pipeline tariff submodule system diagram



The third database contains information on pipeline financial construction projects by pipeline company, state-to-state transfer, and year (1996-2011). This database is used to determine factors to allocate the pipeline company financial data to the NGTDM interstate pipeline arcs based on capacity level in each historical year. These three databases are pre-processed offline to generate the pipeline transmission financial data by pipeline company, NGTDM interstate arc, and historical year (1990-2006) used as input into the PTS.

PTS Process for Deriving Rates

For Each Pipeline Arc

- Read historical financial database for 28 major interstate natural gas pipelines by pipeline company, arc, and historical year (1990-2006).
- Derive the total pipeline cost of service (TCOS)
  - Historical years
  - Aggregate pipeline TCOS items to network arcs
    - Adjust TCOS components to reflect all U.S. pipelines based on annual "Pipeline Economics" special reports in the Oil & Gas Journal
  - Forecast years
    - Include capital costs for capacity expansion
    - Estimate TCOS components from forecasting equations and accounting algorithm
- Allocate total cost of service to fixed and variable costs based on rate design
- Allocate costs to rate components (reservation and usage costs) based on rate design
- Compute rates for services for peak and off-peak time periods

For Each Storage Region:

- Derive the total storage cost of service (STCOS)
  - Historical years: read regional financial data for 33 storage facilities by node (NGTDM region) and historical year (1990-1998)
  - Forecast years:
    - Estimate STCOS components from forecasting equations and accounting algorithm
    - Adjust STCOS to reflect total U.S. storage facilities based on annual storage capacity data reported by EIA
- Compute annual regional storage rates for services

Historical year initialization phase

The following section discusses two separate processes that occur during the historical year initialization phase: (1) the computation and initialization of the cost-of-service components, and (2) the computation of rates for services. The computation of historical year cost-of-service components and rates for services involves four distinct procedures as outlined in the above box and discussed below. Rates are calculated in nominal dollars and then converted to real dollars for use in the ITS.

Computation and initialization of pipeline cost-of-service components

In the historical year initialization phase of the PTS, rates are computed using the following process: (Step 1) derivation and initialization of the total cost-of-service components, (Step 2) classification of cost-of-service components as fixed and variable costs, (Step 3) allocation of fixed and variable costs to rate components (reservation and usage costs) based on rate design, and (Step 4) computation of rates at the arc level for transportation services.

Step 1: Derivation and initialization of the total cost-of-service components

The total cost-of-service for existing capacity on an arc consists of a just and reasonable return on the rate base plus total normal operating expenses. Derivations of return on rate base and total normal operating expenses are presented in the following subsections. The total cost of service is computed as follows:

$$TCOS_{a,t} = TRRB_{a,t} + TNOE_{a,t} \tag{131}$$

where,

$TCOS_{a,t}$ = total cost-of-service (dollars)
$TRRB_{a,t}$ = total return on rate base (dollars)
$TNOE_{a,t}$ = total normal operating expenses (dollars)
a = arc
t = historical year

Just and Reasonable Return. In order to compute the return portion of the cost-of-service at the arc level, the determination of capital structure and adjusted rate base is necessary. Capital structure is important because it determines the cost of capital to the pipeline companies associated with a network arc. The weighted average cost of capital is applied to the rate base to determine the return component of the cost-of-service, as follows:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \tag{132}$$

where,

$TRRB_{a,t}$ = total return on rate base after taxes (dollars)
$WAROR_{a,t}$ = weighted-average after-tax return on capital (fraction)
$APRB_{a,t}$ = adjusted pipeline rate base (dollars)
a = arc
t = historical year

In addition, the return on rate base $TRRB_{a,t}$ is broken out into the three components as shown below.

$$PFEN_{a,t} = \sum_p [(PFES_{a,p,t} / TOTCAP_{a,p,t}) * PFER_{a,p,t} * APRB_{a,p,t}] \tag{133}$$

$$CMEN_{a,t} = \sum_p [(CMES_{a,p,t} / TOTCAP_{a,p,t}) * CMER_{a,p,t} * APRB_{a,p,t}] \tag{134}$$

$$LTDN_{a,t} = \sum_p [(LTDS_{a,p,t} / TOTCAP_{a,p,t}) * LTDR_{a,p,t} * APRB_{a,p,t}] \tag{135}$$

such that,

$$TRRB_{a,t} = (PFEN_{a,t} + CMEN_{a,t} + LTDN_{a,t}) \tag{136}$$

where,

$PFEN_{a,t}$	=	total return on preferred stock (dollars)
$PFES_{a,p,t}$	=	value of preferred stock (dollars)
$TOTCAP_{a,p,t}$	=	total capitalization (dollars)
$PFER_{a,p,t}$	=	coupon rate for preferred stock (fraction) [read as D_PFER]
$APRB_{a,p,t}$	=	adjusted pipeline rate base (dollars) [read as D_APRB]
$CMEN_{a,t}$	=	total return on common stock equity (dollars)
$CMES_{a,p,t}$	=	value of common stock equity (dollars)
$CMER_{a,p,t}$	=	common equity rate of return (fraction) [read as D_CMER]
$LTDN_{a,t}$	=	total return on long-term debt (dollars)
$LTDS_{a,p,t}$	=	value of long-term debt (dollars)
$LTDR_{a,p,t}$	=	long-term debt rate (fraction) [read as D_LTDR]
p	=	pipeline company
a	=	arc
t	=	historical year

Note that the first terms (fractions) in parentheses on the right-hand side of equations 133 to 135 represent the capital structure ratios for each pipeline company associated with a network arc. These fractions are computed exogenously and read in along with the rates of return and the adjusted rate base. The total returns on preferred stock, common equity, and long-term debt at the arc level are computed immediately after all the input variables are read in. The capital structure ratios are exogenously determined as follows:

$$GPFESTR_{a,p,t} = PFES_{a,p,t} / TOTCAP_{a,p,t} \tag{137}$$

$$GCMESTR_{a,p,t} = CMES_{a,p,t} / TOTCAP_{a,p,t} \tag{138}$$

$$GLTDSTR_{a,p,t} = LTDS_{a,p,t} / TOTCAP_{a,p,t} \tag{139}$$

where,

$GPFESTR_{a,p,t}$	=	capital structure ratio for preferred stock for existing pipeline (fraction) [read as D_GPFES]
$GCMESTR_{a,p,t}$	=	capital structure ratio for common equity for existing pipeline (fraction) [read as D_GCMES]
$GLTDSTR_{a,p,t}$	=	capital structure ratio for long-term debt for existing pipeline (fraction) [read as D_GLTDS] value of long-term debt (dollars)
$TOTCAP_{a,p,t}$	=	total capitalization (dollars), equal to the sum of value of preferred stock, common stock equity, and long-term debt
p	=	pipeline company
a	=	arc
t	=	historical year

In the financial database, the estimated capital (capitalization) for each interstate pipeline is by definition equal to its adjusted rate base. Hence, the estimated capital $TOTCAP_{a,p,t}$ defined in the above equations is equal to the adjusted rate base $APRB_{a,p,t.}$

$$TOTCAP_{a,p,t} = APRB_{a,p,t} \tag{140}$$

where,

$TOTCAP_{a,p,t}$	=	total capitalization (dollars)
$APRB_{a,p,t}$	=	adjusted rate base (dollars)
a	=	arc
p	=	pipeline company
t	=	historical year

Substituting the adjusted rate base $APRB_{a,t}$ for the estimated capital $TOTCAP_{a,t}$ in equations 137 to 139, the values of preferred stock, common stock, and long-term debt by pipeline and arc can be computed by applying the capital structure ratios to the adjusted rate base, as follows:

$$\begin{aligned} PFES_{a,p,t} &= GPFESTR_{a,p,t} * APRB_{a,p,t} \\ CMES_{a,p,t} &= GCMESTR_{a,p,t} * APRB_{a,p,t} \\ LTDS_{a,p,t} &= GLTDSTR_{a,p,t} * APRB_{a,p,t} \\ GPFESTR_{a,p,t} &+ GCMESTR_{a,p,t} + GLTDSTR_{a,p,t} = 1.0 \end{aligned} \tag{141}$$

where,

$PFES_{a,p,t}$	=	value of preferred stock in nominal dollars
$CMES_{a,p,t}$	=	value of common equity in nominal dollars
$LTDS_{a,p,t}$	=	long-term debt in nominal dollars
$GPFESTR_{a,p,t}$	=	capital structure ratio for preferred stock for existing pipeline (fraction)
$GCMESTR_{a,p,t}$	=	capital structure ratio of common stock for existing pipeline (fraction)
$GLTDSTR_{a,p,t}$	=	capital structure ratio of long-term debt for existing pipeline (fraction)
$APRB_{a,p,t}$	=	adjusted rate base (dollars)
p	=	pipeline
a	=	arc
t	=	forecast year

The cost of capital at the arc level (WARORa,t) is computed as the weighted average cost of capital for preferred stock, common stock equity, and long-term debt for all pipeline companies associated with that arc, as follows:

$$\begin{aligned} WAROR_{a,t} = \sum_p [(&PFES_{a,p,t} * PFER_{a,p,t} + CMES_{a,p,t} * CMER_{a,p,t} + \\ &LTDS_{a,p,t} * LTDR_{a,p,t})] / APRB_{a,t} \end{aligned} \tag{142}$$

$$APRB_{a,t} = PFES_{a,t} + CMES_{a,t} + LTDS_{a,t} \tag{143}$$

where,

$WAROR_{a,t}$	=	weighted-average after-tax return on capital (fraction)
$PFES_{a,p,t}$	=	value of preferred stock (dollars)
$PFER_{a,p,t}$	=	preferred stock rate (fraction)

$CMES_{a,p,t}$ = value of common stock equity (dollars)
$CMER_{a,p,t}$ = common equity rate of return (fraction)
$LTDS_{a,p,t}$ = value of long-term debt (dollars)
$LTDR_{a,p,t}$ = long-term debt rate (fraction)
$APRB_{a,p,t}$ = adjusted rate base (dollars)
p = pipeline
a = arc
t = historical year

The adjusted rate base by pipeline and arc is computed as the sum of net plant in service and total cash working capital (which includes plant held for future use, materials and supplies, and other working capital) minus accumulated deferred income taxes. This rate base is computed offline and read in by the PTS. The computation is as follows:

$$APRB_{a,p,t} = NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t} \tag{144}$$

where,

$APRB_{a,p,t}$ = adjusted rate base (dollars)
$NPIS_{a,p,t}$ = net capital cost of plant in service (dollars) [read as D_NPIS]
$CWC_{a,p,t}$ = total cash working capital (dollars) [read as D_CWC]
$ADIT_{a,p,t}$ = accumulated deferred income taxes (dollars) [read as D_ADIT]
p = pipeline company
a = arc
t = historical year

The net plant in service by pipeline and arc is the original capital cost of plant in service minus the accumulated depreciation. It is computed offline and then read in by the PTS. The computation is as follows:

$$NPIS_{a,p,t} = GPIS_{a,p,t} - ADDA_{a,p,t} \tag{145}$$

where,

$NPIS_{a,p,t}$ = net capital cost of plant in service (dollars)
$GPIS_{a,p,t}$ = original capital cost of plant in service (dollars) [read as D_GPIS]
$ADDA_{a,p,t}$ = accumulated depreciation, depletion, and amortization (dollars) [read as D_ADDA]
p = pipeline company
a = arc
t = historical year

The adjusted rate base at the arc level is computed as follows:

$$\begin{aligned} APRB_{a,,t} &= \sum_p APRB_{a,p,t} = \sum_p (NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t}) \\ &= (NPIS_{a,t} + CWC_{a,t} - ADIT_{a,t}) \end{aligned} \tag{146}$$

with,

$$NPIS_{a,,t} = \sum_{p} (GPIS_{a,p,t} - ADDA_{a,p,t}) \\ = (GPIS_{a,t} - ADDA_{a,t}) \tag{147}$$

where,

$APRB_{a,p,t}$	=	adjusted rate base (dollars) at the arc level
$NPIS_{a,p,t}$	=	net capital cost of plant in service (dollars) at the arc level
$CWC_{a,t}$	=	total cash working capital (dollars) at the arc level
$ADIT_{a,t}$	=	accumulated deferred income taxes (dollars) at the arc level
$GPIS_{a,p,t}$	=	original capital cost of plant in service (dollars) at the arc level
$ADDA_{a,t}$	=	accumulated depreciation, depletion, and amortization (dollars) at the arc level
p	=	pipeline company
a	=	arc
t	=	historical year

Total Normal Operating Expenses. Total normal operating expense line items include depreciation, taxes, and total operating and maintenance expenses. Total operating and maintenance expenses include administrative and general expenses, customer expenses, and other operating and maintenance expenses. In the PTS, taxes are disaggregated further into federal, state, and other taxes and deferred income taxes. The equation for total normal operating expenses at the arc level is given as follows:

$$TNOE_{a,t} = \sum_{p} (DDA_{a,p,t} + TOTAX_{a,p,t} + TOM_{a,p,t}) \tag{148}$$

where,

$TNOE_{a,t}$	=	total normal operating expenses (dollars)
$DDA_{a,p,t}$	=	depreciation, depletion, and amortization costs (dollars) [read as D_DDA]
$TOTAX_{a,p,t}$	=	total federal and state income tax liability (dollars)
$TOM_{a,p,t}$	=	total operating and maintenance expense (dollars) [read as D_TOM]
p	=	pipeline
a	=	arc
t	=	historical year

Depreciation, depletion, and amortization costs, and total operating and maintenance expense are available directly from the financial database. The equations to compute these costs at the arc level are as follows:

$$DDA_{a,t} = \sum_{p} DDA_{a,p,t} \tag{149}$$

$$TOM_{a,t} = \sum_{p} TOM_{a,p,t} \tag{150}$$

Total taxes at the arc level are computed as the sum of federal and state income taxes, other taxes, and deferred income taxes, as follows:

$$TOTAX_{a,t} = \sum_{p} (FSIT_{a,p,t} + OTTAX_{a,p,t} + DIT_{a,p,t}) \tag{151}$$

$$FSIT_{a,t} = \sum_{p} FSIT_{a,p,t} = \sum_{p} (FIT_{a,p,t} + SIT_{a,p,t}) \tag{152}$$

where,

$TOTAX_{a,t}$	=	total federal and state income tax liability (dollars)
$FSIT_{a,p,t}$	=	federal and state income tax (dollars)
$OTTAX_{a,p,t}$	=	all other taxes assessed by federal, state, or local governments except income taxes and deferred income tax (dollars) [read as D_OTTAX]
$DIT_{a,p,t}$	=	deferred income taxes (dollars) [read as D_DIT]
$FIT_{a,p,t}$	=	federal income tax (dollars)
$SIT_{a,p,t}$	=	state income tax (dollars)
p	=	pipeline company
a	=	arc
t	=	historical year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the federal tax rate. The after-tax profit at the arc level is determined as follows:

$$ATP_{a,t} = \sum_{p} (PFER_{a,p,t} * PFES_{a,p,t} + CMER_{a,p,t} * CMES_{a,p,t}) \tag{153}$$

where,

$ATP_{a,t}$	=	after-tax profit (dollars) at the arc level
$PFER_{a,p,t}$	=	preferred stock rate (fraction)
$PFES_{a,p,t}$	=	value of preferred stock (dollars)
$CMER_{a,p,t}$	=	common equity rate of return (fraction)
$CMES_{a,p,t}$	=	value of common stock equity (dollars)
a	=	arc
t	=	historical year

and the federal income taxes at the arc level are,

$$FIT_{a,t} = \frac{FRATE * ATP_{a,t}}{(1.-FRATE)} \tag{154}$$

where,

$FIT_{a,t}$	=	federal income tax (dollars) at the arc level
FRATE	=	federal income tax rate (fraction) (Appendix E)
$ATP_{a,t}$	=	after-tax profit (dollars)

State income taxes are computed by multiplying the sum of taxable profit and the associated federal income tax by a weighted-average state tax rate associated with each pipeline company. The weighted-average state tax rate is based on peak service volumes in each state delivered by the pipeline company. State income taxes at the arc level are computed as follows:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{155}$$

where,

$SIT_{a,t}$	=	state income tax (dollars) at the arc level
SRATE	=	average state income tax rate (fraction) (Appendix E)
$FIT_{a,t}$	=	federal income tax (dollars) at the arc level
$ATP_{a,t}$	=	after-tax profits (dollars) at the arc level

Thus, total taxes at the arc level can be expressed by the following equation:

$$TOTAX_{a,t} = (FSIT_{a,t} + OTTAX_{a,t} + DIT_{a,t}) \tag{156}$$

where,

$TOTAX_{a,t}$	=	total federal and state income tax liability (dollars) at the arc level
$FSIT_{a,t}$	=	federal and state income tax (dollars) at the arc level
$OTTAX_{a,t}$	=	all other taxes assessed by federal, state, or local governments except income taxes and deferred income taxes (dollars), at the arc level
$DIT_{a,t}$	=	deferred income taxes (dollars) at the arc level
a	=	arc
t	=	historical year

All other taxes and deferred income taxes at the arc level are expressed as follows:

$$OTTAX_{a,t} = \sum_{p} OTTAX_{a,p,t} \tag{157}$$

$$DIT_{a,t} = \sum_{p} DIT_{a,p,t} \tag{158}$$

Adjustment from 28 major pipelines to U.S. total. Note that all cost-of-service and rate base components computed so far are based on the financial database of 28 major interstate pipelines. According to the U.S. natural gas pipeline construction and financial reports filed with FERC and published in the Oil and Gas Journal,[89] there were more than 100 interstate natural gas pipelines operating in the United States in 2006. The total annual gross plant in service and operating revenues for all these pipelines are much higher than those for the 28 major interstate pipelines in the financial database. All the cost-of-service and rate base components at the arc level computed in the above sections are scaled up as follows:

[89] *Pipeline Economics*, Oil and Gas Journal, 1994, 1995, 1997, 1999, 2001, 2002, 2003, 2004, 2005, 2006.

For the capital costs and adjusted rate base components,

$$
\begin{aligned}
GPIS_{a,t} &= GPIS_{a,t} * HFAC\_GPIS_t \\
ADDA_{a,t} &= ADDA_{a,t} * HFAC\_GPIS_t \\
NPIS_{a,t} &= NPIS_{a,t} * HFAC\_GPIS_t \\
CWC_{a,t} &= CWC_{a,t} * HFAC\_GPIS_t \\
ADIT_{a,t} &= ADIT_{a,t} * HFAC\_GPIS_t \\
APRB_{a,t} &= APRB_{a,t} * HFAC\_GPIS_t
\end{aligned}
\tag{159}
$$

For the cost-of-service components,

$$
\begin{aligned}
PFEN_{a,t} &= PFEN_{a,t} * HFAC\_REV_t \\
CMEN_{a,t} &= CMEN_{a,t} * HFAC\_REV_t \\
LTDN_{a,t} &= LTDN_{a,t} * HFAC\_REV_t \\
DDA_{a,t} &= DDA_{a,t} * HFAC\_REV_t \\
FSIT_{a,t} &= FSIT_{a,t} * HFAC\_REV_t \\
OTTAX_{a,t} &= OTTAX_{a,t} * HFAC\_REV_t \\
DIT_{a,t} &= DIT_{a,t} * HFAC\_REV_t \\
TOM_{a,t} &= TOM_{a,t} * HFAC\_REV_t
\end{aligned}
\tag{160}
$$

where,

$GPIS_{a,t}$	=	original capital cost of plant in service (dollars)
$HFAC\_GPIS_t$	=	adjustment factor for capital costs to total U.S. (Appendix E)
$ADDA_{a,t}$	=	accumulated depreciation, depletion, and amortization (dollars)
$NPIS_{a,t}$	=	net capital cost of plant in service (dollars)
$CWC_{a,t}$	=	total cash working capital (dollars)
$ADIT_{a,t}$	=	accumulated deferred income taxes (dollars)
$APRB_{a,t}$	=	adjusted pipeline rate base (dollars)
$PFEN_{a,t}$	=	total return on preferred stock (dollars)
$HFAC\_REV_t$	=	adjustment factor for operation revenues to total U.S. (Appendix E)
$CMEN_{a,t}$	=	total return on common stock equity (dollars)
$LTDN_{a,t}$	=	total return on long-term debt (dollars)
$DDA_{a,t}$	=	depreciation, depletion, and amortization costs (dollars)
$FSIT_{a,t}$	=	federal and state income tax (dollars)
$OTTAX_{a,t}$	=	all other taxes assessed by federal, state, or local governments except income taxes and deferred income taxes (dollars)
$DIT_{a,t}$	=	deferred income taxes (dollars)
$TOM_{a,t}$	=	total operations and maintenance expense (dollars)
a	=	arc
t	=	historical year

Except for the federal and state income taxes and returns on capital, all the cost-of-service and rate base components computed at the arc level above are also used as initial values in the forecast year update phase that starts in 2007.

Step 2: Classification of cost-of-service line items as fixed and variable costs

The PTS breaks each line item of the cost of service (computed in Step 1) into fixed and variable costs. Fixed costs are independent of storage/transportation usage, while variable costs are a function of usage. Fixed and variable costs are computed by multiplying each line item of the cost of service by the percentage of the cost that is fixed and the percentage of the cost that is variable. The classification of fixed and variable costs is defined by the user as part of the scenario specification. The classification of line item cost Ri to fixed and variable cost is determined as follows:

$$R_{i,f} = ALL_f * R_i / 100 \quad (161)$$

$$R_{i,v} = ALL_v * R_i / 100 \quad (162)$$

where,

$R_{i,f}$	=	fixed cost portion of line item Ri (dollars)
ALL_f	=	percentage of line item Ri representing fixed cost
R_i	=	total cost of line item i (dollars)
$R_{i,v}$	=	variable cost portion of line item Ri (dollars)
ALLv	=	percentage of line item Ri representing variable cost
i	=	line item index
f,v	=	fixed or variable
100	=	ALLf + ALLv

An example of this procedure is illustrated in **Table 6-1**.

Table 6-1. Illustration of fixed and variable cost classification

		Cost Allocation Factors		Cost Component	
	Total	(percent)		(dollars)	
Cost of Service Line Item	(dollars)	Fixed	Variable	Fixed	Variable
Total Return					
Preferred Stock	1,000	100	0	1,000	0
Common Stock	30,000	100	0	30,000	0
Long-Term Debt	29,000	100	0	29,000	0
Normal Operating Expenses					
Depreciation	30,000	100	0	30,000	0
Taxes					
Federal Tax	25,000	100	0	25,000	0
State Tax	5,000	100	0	5,000	0
Other Tax	1,000	100	0	1,000	0
Deferred Income Taxes	1,000	100	0	1,000	0
Total Operation & Maintenance	105,000	60	40	63,000	42,000
Total Cost-of-Service	227,000			185,000	42,000

The resulting fixed and variable costs at the arc level are obtained by summing all line items for each cost category from the above equations, as follows:

$$FC_a = \sum_i R_{i,f} \tag{163}$$

$$VC_a = \sum_i R_{i,v} \tag{164}$$

where,

FC_a = total fixed cost (dollars) at the arc level
VC_a = total variable cost (dollars) at the arc level
a = arc

Step 3: Allocation of fixed and variable costs to rate components

Allocation of fixed and variable costs to rate components is conducted only for transportation services because storage service is modeled in a more simplified manner using a one-part rate. The rate design to be used within the PTS is specified by input parameters, which can be modified by the user to reflect changes in rate design over time. The PTS allocates the fixed and variable costs computed in Step 2 to rate components as specified by the rate design. For transportation service, the components of the rate consist of a reservation and a usage fee. The reservation fee is a charge assessed based on the amount of capacity reserved. It typically is a monthly fee that does not vary with throughput. The usage fee is a charge assessed for each unit of gas that moves through the system.

The actual reservation and usage fees that pipelines are allowed to charge are regulated by the Federal Energy Regulatory Commission (FERC). How costs are allocated determines the extent of differences in the rates charged for different classes of customers for different types of services. In general, if more fixed costs are allocated to usage fees, more costs are allowed to be recovered based on throughput.

Costs are assigned either to the reservation fee or to the usage fee according to the rate design specified for the pipeline company. The rate design can vary among pipeline companies. Three typical rate designs are described in **Table 6-2**. The PTS provides two options for specifying the rate design. In the first option, a rate design for each pipeline company can be specified for each forecast year. This option permits different rate designs to be used for different pipeline companies while also allowing individual company rate designs to change over time. Since pipeline company data subsequently are aggregated to network arcs, the composite rate design at the arc level is the quantity-weighted average of the pipeline company rate designs. The second option permits a global specification of the rate design, where all pipeline companies have the same rate design for a specific time period but can switch to another rate design in a different time period.

The allocation of fixed costs to reservation and usage fees entails multiplying each fixed cost line item of the total cost of service by the corresponding fixed cost rate design classification factor. A similar process is carried out for variable costs. This procedure is illustrated in **Tables 6-3a and 6-3b** and is generalized in the equations that follow. The classification of transportation line item costs $R_{i,f}$ and $R_{i,v}$ to reservation and usage cost is determined as follows:

Table 6-2. Approaches to rate design

Modified Fixed Variable (Three-Part Rate)	Modified Fixed Variable (Two-Part Rate)	Straight Fixed Variable (Two-Part Rate)
●Two-part reservation fee - Return on equity and related taxes are held at risk to achieving throughput targets by allocating these costs to the usage fee. Of the remaining fixed costs, 50% are recovered from a peak day reservation fee and 50% are recovered through an annual reservation fee.	●Reservation fee based on peak day requirements - all fixed costs except return on equity and related taxes recovered through this fee.	●One-part capacity reservation fee. All fixed costs are recovered through the reservation fee, which is assessed based on peak day capacity requirements.
●Variable costs allocated to the usage fee. In addition, return on equity and related taxes are also recovered through the usage fee.	●Variable costs plus return on equity and related taxes are recovered through the usage fee.	●Variable costs are recovered through the usage fee.

$$R_{i,f,r} = ALL_{f,r} * R_{i,f} / 100 \quad (165)$$

$$R_{i,f,u} = ALL_{f,u} * R_{i,f} / 100 \quad (166)$$

$$R_{i,v,r} = ALL_{v,r} * R_{i,v} / 100 \quad (167)$$

$$R_{i,v,u} = ALL_{v,u} * R_{i,v} / 100 \quad (168)$$

where,

R = line item cost (dollars)
ALL = percentage of reservation or usage line item R representing fixed or variable cost (Appendix E -- AFR, AVR, AFU=1-AFR, AVU=1-AVR)
100 = $ALL_{f,r} + ALL_{f,u}$
100 = $ALL_{v,r} + ALL_{v,u}$
i = line item number index
f = fixed cost index
v = variable cost index
r = reservation cost index
u = usage cost index

At this stage in the procedure, the line items comprising the fixed and variable cost components of the reservation and usage fees can be summed to obtain total reservation and usage components of the rates.

Table 6-3a. Illustration of allocation of fixed costs to rate components

Cost of Service Line Item	Total (dollars)	Allocation Factors (percent) Reservation	Usage	Cost Assigned to Rate Component (dollars) Reservation	Usage
Total Return					
Preferred Stock	1,000	100	0	0	1,000
Common Stock	30,000	100	0	0	30,000
Long-Term Debt	29,000	100	0	29,000	0
Normal Operating Expenses					
Depreciation	30,000	100	0	30,000	0
Taxes					
Federal Tax	25,000	0	100	0	25,000
State Tax	5,000	0	100	0	5,000
Other Tax	1,000	100	0	1,000	0
Deferred Income Taxes	1,000	100	0	1,000	0
Total Operations & Maintenance	63,000	100	0	63,000	0
Total Cost-of-Service	185,000			124,000	61,000

Table 6-3b. Illustration of allocation of variable costs to rate components

Cost of Service Line Item	Total (dollars)	Allocation Factors (percent) Reservation	Usage	Cost Assigned to Rate Component (dollars) Reservation	Usage
Total Return					
Preferred Stock	0	0	100	0	0
Common Stock	0	0	100	0	0
Long-Term Debt	0	0	100	0	0
Normal Operating Expenses					
Depreciation	0	0	100	0	0
Taxes					
Federal Tax	0	0	100	0	0
State Tax	0	0	100	0	0
Other Tax	0	0	100	0	0
Deferred Income Taxes	0	0	100	0	0
Total Operation & Maintenance	42,000	0	100	0	42,000
Total Cost-of-Service	42,000			0	42,000

$$\text{RCOST}_a = \sum_i (R_{i,f,r} + R_{i,v,r}) \tag{169}$$

$$\text{UCOST}_a = \sum_i (R_{i,f,u} + R_{i,v,u}) \tag{170}$$

where,

$RCOST_a$ = total reservation cost (dollars) at the arc level
$UCOST_a$ = total usage cost (dollars) at the arc level
a = arc

After ratemaking Steps 1, 2 and 3 are completed for each arc by historical year, the rates are computed below.

Computation of rates for historical years

The reservation and usage costs-of-service (RCOST and UCOST) developed above are used separately to develop two types of rates at the arc level: *variable tariffs* and *annual fixed usage fees*, although the fixed usage fees were replaced with basis differential estimates in *AEO2014* as they are used in the setting of regional spot prices.

Variable tariff curves

Variable tariffs are proportional to reservation charges and are broken up into peak and off-peak time periods. Variable tariffs are derived directly from variable tariff curves which are developed based on reservation costs, utilization rates, annual flows, and other parameters.

In the PTS code, these variable tariff curves are defined by FUNCTION (NGPIPE_VARTAR) which is used by the ITS to compute the variable peak and off-peak tariffs by arc and by forecast year. The pipeline tariff curves are a function of peak or off-peak flow and are specified using a base point [price and quantity (PNOD, QNOD)] and an assumed price elasticity, as follows:

$$\text{NGPIPE\_VARTAR}_{a,t} = \text{PNOD}_{a,t} * (Q_{a,t} / \text{QNOD}_{a,t})^{\text{ALPHA\_PIPE}} \tag{171}$$

such that,

For peak transmission tariffs:

$$\text{PNOD}_{a,t} = \frac{\text{RCOST}_{a,t} * \text{PKSHR\_YR}}{(\text{QNOD}_{a,t} * \text{MC\_PCWGDP}_t)} \tag{172}$$

$$\text{QNOD}_{a,t} = \text{PTNETFLOW}_{a,t} \tag{173}$$

For off-peak transmission tariffs:

$$\text{PNOD}_{a,t} = \frac{\text{RCOST}_{a,t} * (1.0 - \text{PKSHR\_YR})}{(\text{QNOD}_{a,t} * \text{MC\_PCWGDP}_t)} \tag{174}$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \tag{175}$$

where,

$NGPIPE\_VARTAR_{a,t}$	=	function to define pipeline tariffs (1987$/Mcf)
$PNOD_{a,t}$	=	base point, price (1987$/Mcf)
$QNOD_{a,t}$	=	base point, quantity (Bcf)
$Q_{a,t}$	=	flow along pipeline arc (Bcf), dependent variable for the function
ALPHA_PIPE	=	price elasticity for pipeline tariff curve for current capacity
$RCOST_{a,t}$	=	reservation cost-of-service (dollars)
$PTNETFLOW_{a,t}$	=	natural gas network flow (throughput, Bcf)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	historical year

Annual fixed usage fees

The annual fixed usage fees (volumetric charges) can be derived directly from the usage costs, utilization rates for peak and off-peak time periods, and annual arc capacity. In the past these fees were computed as the average fees over each historical year, as follows:

$$\begin{aligned} FIXTAR_{a,t} = UCOST_{a,t} / [(&PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + \\ &(1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_t] \end{aligned} \tag{176}$$

where,

$FIXTAR_{a,t}$	=	annual fixed usage fees for existing and new capacity (1987$/Mcf)
$UCOST_{a,t}$	=	annual usage cost of service for existing and new capacity (dollars)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$	=	peak pipeline utilization (fraction)
$PTCURPCAP_{a,t}$	=	current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$	=	off-peak pipeline utilization (fraction)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	historical year

However, for *AEO2014* the usage fee was set based on historical basis differentials between representative regional spot prices, the average from 2005 to 2012. Theoretically, the regulated usage fee would be expected to be closer to the minimum basis differential. However, this fee is now being used in the model to approximate the basis differential, which is why historical differentials are being used as a basis. The approach of setting the differentials to an historical average is a first step, as eventually a more dynamic approach will be used to set these values.

Canadian tariffs

In the historical year phase, Canadian tariffs are set to the historical differences between the import prices and the Western Canada Sedimentary Basin (WCSB) wellhead price.

Computation of storage rates

The annual storage tariff for each NGTDM region and year is defined as a function of storage flow and is specified using a base point [price and quantity (PNOD, QNOD)] and an assumed price elasticity, as follows:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA\_STR} \quad (177)$$

such that,

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC\_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP\_ADJ_{r,t} * ADJ\_STR \quad (178)$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \quad (179)$$

where,

$X1NGSTR\_VARTAR_{r,t}$	=	function to define storage tariffs (1987$/Mcf)
$Q_{r,t}$	=	peak period net storage withdrawals (Bcf)
$PNOD_{r,t}$	=	base point, price (1987$/Mcf)
$QNOD_{r,t}$	=	base point, quantity (Bcf)
ALPHA_STR	=	price elasticity for storage tariff curve (ratio, Appendix E)
$STCOS_{r,t}$	=	existing storage capacity cost of service, computed from historical cost-of-service components
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
$STRATIO_{r,t}$	=	portion of revenue requirement obtained by moving gas from the off-peak to the peak period (fraction, Appendix E)
$STCAP\_ADJ_{r,t}$	=	adjustment factor for the cost of service to total U.S. (ratio), defined as annual storage working gas capacity divided by Foster storage working gas capacity
ADJ_STR	=	storage tariff curve adjustment factor (fraction, Appendix E)
$PTSTUTZ_{r,t}$	=	storage utilization (fraction)
$PTCURPSTR_{r,t}$	=	annual storage working gas capacity (Bcf)
r	=	NGTDM region
t	=	historical year

Forecast year update phase

The purpose of the forecast year update phase is to project, for each arc and subsequent year of the forecast period, the cost-of-service components that are used to develop rates for the peak and off-peak periods. For each year, the PTS forecasts the adjusted rate base, cost of capital, return on rate base, depreciation, taxes, and operation and maintenance expenses. The forecasting relationships are discussed in detail below.

After all of the components of the cost-of-service at the arc level are forecast, the PTS proceeds to: (1) classify the components of the cost of service as fixed and variable costs, (2) allocate fixed and variable costs to rate components (reservation and usage costs) based on the rate design, and (3) compute arc-specific rates (variable and fixed tariffs) for peak and off-peak periods.

Investment costs for generic pipelines

The PTS projects the capital costs to expand pipeline capacity at the arc level, as opposed to determining the costs of expansion for individual pipelines. The PTS represents arc-specific generic pipelines to generate the cost of capacity expansion by arc. Thus, the PTS tracks costs attributable to capacity added during the forecast period separately from the costs attributable to facilities in service in the historical years. The PTS estimates the capital costs associated with the level of capacity expansion forecast by the ITS in the previous forecast year based on exogenously specified estimates for the average pipeline capital costs at the arc level ($AVG\_CAPCOST_a$) associated with expanding capacity for compression, looping, and new pipeline. These average capital costs per unit of expansion (2005 dollars per Mcf) were computed based on a pipeline construction project cost database[90] compiled by the Office of Oil and Gas. These costs are adjusted for inflation from 2007 throughout the forecast period (i.e., they are held constant in real terms).

The average capital cost to expand capacity on a network arc is estimated given the level of capacity additions in year t provided by the ITS and the associated assumed average unit capital cost. This average unit capital cost represents the investment cost for a generic pipeline associated with a given arc, as follows:

$$CCOST_{a,t} = AVG\_CAPCOST_a * MC\_PCWGDP_t / MC\_PCWGDP_{2000} \qquad (180)$$

where,

$CCOST_{a,t}$	=	average pipeline capital cost per unit of expanded capacity (nominal dollars per Mcf)
$AVG\_CAPCOST_a$	=	average pipeline capital cost per unit of expanded capacity in 2000 dollars per Mcf (Appendix E, AVG_CAPCOST)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	forecast year

The new capacity expansion expenditures allowed in the rate base within a forecast year are derived from the above average unit capital cost and the amount of incremental capacity additions determined by the ITS for each arc, as follows:

[90] A spreadsheet compiled by James Tobin of EIA's Office of Oil and Gas containing historical and proposed state-to-state pipeline construction project costs, mileage, and capacity levels and additions by year from 1996 to 2011, by pipeline company (data as of August 16, 2007).

$$NCAE_{a,t} = CCOST_{a,t} * CAPADD_{a,t} * 1{,}000{,}000 * (1 + PCNT\_R) \tag{181}$$

where,

$NCAE_{a,t}$	=	capital cost to expand capacity on a network arc (dollars)
$CCOST_{a,t}$	=	average capital cost per unit of expansion (dollars per Mcf)
$CAPADDa_{,t}$	=	capacity additions for an arc as determined in the ITS (Bcf/yr)
PCNT_R	=	assumed average percentage (fraction) for pipeline replacement costs (Appendix E)
t	=	forecast year

To account for additional costs due to pipeline replacements, the PTS increases the capital costs to expand capacity by a small percentage (PCNT_R). Once the capital cost of new plant in service is computed by arc in year t, this amount is used in an accounting algorithm for the computation of gross plant in service for new capacity expansion, along with its depreciation, depletion, and amortization. These will in turn be used in the computation of updated cost-of-service components for the existing and new capacity for an arc.

Forecasting cost-of-service[91]

The primary purpose in forecasting cost-of-service is to capture major changes in the composition of the revenue requirements and major changes in cost trends through the forecast period. These changes may be caused by capacity expansion or maintenance and life extension of nearly depreciated plants, as well as by changes in the cost and availability of capital.

The projection of the cost-of-service is approached from the viewpoint of a long-run marginal cost analysis for gas pipeline systems. This differs from the determination of cost-of-service for the purpose of a rate case. Costs that are viewed as fixed for the purposes of a rate case actually vary in the long-run with one or more external measures of size or activity levels in the industry. For example, capital investments for replacement and refurbishment of existing facilities are a long-run marginal cost of the pipeline system. Once in place, however, the capital investments are viewed as fixed costs for the purposes of rate cases. The same is true of operations and maintenance expenses that, except for short-run variable costs such as fuel, are most commonly classified as fixed costs in rate cases. For example, customer expenses logically vary over time based on the number of customers served and the cost of serving each customer. The unit cost of serving each customer, itself, depends on changes in the rate base and individual cost-of-service components, the extent and/or complexity of service provided to each customer, and the efficiency of the technology level employed in providing the service.

The long-run marginal cost approach generally projects total costs as the product of unit cost for the activity multiplied by the incidence of the activity. Unit costs are projected from cost-of-service components combined with time trends describing changes in level of service, complexity, or technology. The level of activity is projected in terms of variables external to the PTS (e.g., annual throughput) that are both logically and empirically related to the incurrence of costs. Implementation of the long-run marginal cost approach involves forecasting relationships developed through empirical

[91] All cost components in the forecast equations in this section are in nominal dollars, unless explicitly stated otherwise.

studies of historical change in pipeline costs, accounting algorithms, exogenous assumptions, and inputs from other NEMS modules. These forecasting algorithms may be classified into three distinct areas, as follows:

- The projection of adjusted rate base and cost of capital for the combined existing and new capacity.
- The projection of components of the revenue requirements.
- The computation of variable and fixed rates for peak and off-peak periods.

The empirically derived forecasting algorithms discussed below are determined for each network arc.

Projection of adjusted rate base and cost of capital

The approach for projecting adjusted rate base and cost of capital at the arc level is summarized in **Table 6-4**. Long-run marginal capital costs of pipeline companies reflect changes in the AA utility bond index rate. Once projected, the adjusted rate base is translated into capital-related components of the revenue requirements based on projections of the cost of capital, total operating and maintenance expenses, and algorithms for depreciation and tax effects.

Table 6-4. Approach to projection of rate base and capital costs

Projection Component	Approach
1. Adjusted Rate Base	
a. Gross plant in service in year t	
I. Capital cost of existing plant in service	Gross plant in service in the last historical year (2006)
II. Capacity expansion costs for new capacity	Accounting algorithm [equation 184]
b. Accumulated Depreciation, Depletion & Amortization	Accounting algorithm [equations 190, 191, 193] and empirically estimated for existing capacity [equation 192]
c. Cash and other working capital	User-defined option for the combined existing and new capacity [equation 194]
d. Accumulated deferred income taxes	Empirically estimated for the combined existing and new capacity [equation 145]
f. Depreciation, depletion, and amortization	Existing Capacity: empirically estimated [equation 192] New Capacity: accounting algorithm [equation 193]
2. Cost of Capital	
a. Long-term debt rate	Projected AA utility bond yields adjusted by historical average deviation constant for long-term debt rate
b. Preferred equity rate	Projected AA utility bond yields adjusted by historical average deviation constant for preferred equity rate
c. Common equity return	Projected AA utility bond yields adjusted by historical average deviation constant for common equity return
3. Capital Structure	Held constant at average historical values

The projected adjusted rate base for the combined existing and new pipelines at the arc level in year t is computed as the amount of gross plant in service in year t minus previous year's accumulated depreciation, depletion, and amortization plus total cash working capital minus accumulated deferred income taxes in year t.

$$APRB_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} + CWC_{a,t} - ADIT_{a,t} \tag{182}$$

where,

$APRB_{a,t}$	=	adjusted rate base in dollars
$GPIS_{a,t}$	=	total capital cost of plant in service (gross plant in service) in dollars
ADDAa,t	=	accumulated depreciation, depletion, and amortization in dollars
CWCa,t	=	total cash working capital including other cash working capital in dollars
ADITa,t	=	accumulated deferred income taxes in dollars
a	=	arc
t	=	forecast year

All the variables in the above equation represent the aggregate variables for all interstate pipelines associated with an arc. The aggregate variables on the right-hand side of the adjusted rate base equation are forecast by the equations below. First, total (existing and new) gross plant in service in the forecast year is determined as the sum of existing gross plant in service and new capacity expansion expenditures added to existing gross plant in service. New capacity expansion can be compression, looping, and new pipelines. For simplification, the replacement, refurbishment, retirement, and cost associated with new facilities for complying with Order 636 are not accounted for in projecting total gross plant in service in year t. Total gross plant in service for a network arc is forecast as follows:

$$GPIS_{a,t} = GPIS\_E_{a,t} + GPIS\_N_{a,t} \tag{183}$$

where,

$GPIS_{a,t}$	=	total capital cost of plant in service (gross plant in service) in dollars
$GPIS\_E_{a,t}$	=	gross plant in service in the last historical year (2006)
$GPIS\_N_{a,t}$	=	capital cost of new plant in service in dollars
a	=	arc
t	=	forecast year

In the above equation, the capital cost of existing plant in service (GPIS_Ea,t) reflects the amount of gross plant in service in the last historical year (2006). The capital cost of new plant in service (GPIS_Na,t) in year t is computed as the accumulated new capacity expansion expenditures from 2007 to year t and is determined by the following equation:

$$GPIS\_N_{a,t} = \sum_{s=2004}^{t} NCAE_{a,s} \tag{184}$$

where,

$GPIS\_N_{a,t}$ = gross plant in service for new capacity expansion in dollars
$NCAE_{a,s}$ = new capacity expansion expenditures occurring in years after 2006 (in dollars) [equation 181]
s = the year new expansion occurred
a = arc
t = forecast year

Next, net plant in service in year t is determined as the difference between total capital cost of plant in service (gross plant in service) in year t and previous year's accumulated depreciation, depletion, and amortization.

$$NPIS_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} \tag{185}$$

where,

$NPIS_{a,t}$ = total net plant in service in dollars
$GPIS_{a,t}$ = total capital cost of plant in service (gross plant in service) in dollars
$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
a = arc
t = forecast year

Accumulated depreciation, depletion, and amortization for the combined existing and new capacity in year t is determined by the following equation:

$$ADDA_{a,t} = ADDA\_E_{a,t} + ADDA\_N_{a,t} \tag{186}$$

where,

$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
$ADDA\_E_{a,t}$ = accumulated depreciation, depletion, and amortization for existing capacity in dollars
$ADDA\_N_{a,t}$ = accumulated depreciation, depletion, and amortization for new capacity in dollars
a = arc
t = forecast year

With this and the relationship between the capital costs of existing and new plants in service from equation 183, total net plant in service (NPISa,t) is set equal to the sum of net plant in service for existing pipelines and new capacity expansions, as follows:

$$NPIS_{a,t} = NPIS\_E_{a,t} + NPIS\_N_{a,t} \tag{187}$$

$$NPIS\_E_{a,t} = GPIS\_E_{a,t} - ADDA\_E_{a,t-1} \tag{188}$$

$$NPIS\_N_{a,t} = GPIS\_N_{a,t} - ADDA\_N_{a,t-1} \tag{189}$$

where,

$NPIS_{a,t}$	=	total net plant in service in dollars
$NPIS\_E_{a,t}$	=	net plant in service for existing capacity in dollars
$NPIS\_N_{a,t}$	=	net plant in service for new capacity in dollars
$GPIS\_E_{a,t}$	=	gross plant in service in the last historical year (2006)
$ADDA\_E_{a,t}$	=	accumulated depreciation, depletion, and amortization for existing capacity in dollars
$ADDA\_N_{a,t}$	=	accumulated depreciation, depletion, and amortization for new capacity in dollars
$GPIS\_N$	=	gross plant in service for new capacity in dollars
a	=	arc
t	=	forecast year

Accumulated depreciation, depletion, and amortization for a network arc in year t is determined as the sum of previous year's accumulated depreciation, depletion, and amortization and current year's depreciation, depletion, and amortization.

$$ADDA_{a,t} = ADDA_{a,t-1} + DDA_{a,t} \qquad (190)$$

where,

$ADDA_{a,t}$	=	accumulated depreciation, depletion, and amortization in dollars
$DDA_{a,t}$	=	annual depreciation, depletion, and amortization costs in dollars
a	=	arc
t	=	forecast year

Annual depreciation, depletion, and amortization for a network arc in year t equal the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with the arc.

$$DDA_{a,t} = DDA\_E_{a,t} + DDA\_N_{a,t} \qquad (191)$$

where,

$DDA_{a,t}$	=	annual depreciation, depletion, and amortization in dollars
$DDA\_E_{a,t}$	=	depreciation, depletion, and amortization costs for existing capacity in dollars
$DDA\_N_{a,t}$	=	depreciation, depletion, and amortization costs for new capacity in dollars
a	=	arc
t	=	forecast year

A regression equation is used to determine the annual depreciation, depletion, and amortization for existing capacity associated with an arc, while an accounting algorithm is used for new capacity. For existing capacity, this expense is forecast as follows:

$$DDA\_E_{a,t} = \beta_{0,a} + \beta_1 * NPIS\_E_{a,t-1} + \beta_2 * NEWCAP\_E_{a,t} \tag{192}$$

where,

$DDA\_E_{a,t}$	=	annual depreciation, depletion, and amortization costs for existing capacity in nominal dollars
$\beta0_{,a}$	=	DDA_Ca, constant term estimated by arc (Appendix F, Table F3.3, β0,a = B_ARCxx_yy)
β_1	=	DDA_NPIS, estimated coefficient for net plant in service for existing capacity (Appendix F, Table F3.3)
β_2	=	DDA_NEWCAP, estimated coefficient for the change in gross plant in service for existing capacity (Appendix F, Table F3.3)
$NPIS\_E_{a,t}$	=	net plant in service for existing capacity (dollars)
$NEWCAP\_E_{a,t}$	=	change in gross plant in service for existing capacity between t and t-1 (dollars)
a	=	arc
t	=	forecast year

The accounting algorithm used to define the annual depreciation, depletion, and amortization for new capacity assumes straight-line depreciation over a 30-year life, as follows:

$$DDA\_N_{a,t} = GPIS\_N_{a,t} / 30 \tag{193}$$

where,

$DDA\_N_{a,t}$	=	annual depreciation, depletion, and amortization for new capacity in dollars
$GPIS\_N_{a,t}$	=	gross plant in service for new capacity in dollars [equation 184]
30	=	30 years of plant life
a	=	arc
t	=	forecast year

Next, total cash working capital ($CWC_{a,t}$) for the combined existing and new capacity by arc in the adjusted rate base equation consists of cash working capital, material and supplies, and other components that vary by company. Total cash working capital for pipeline transmission for existing and new capacity at the arc level is deflated using the chain-weighted GDP price index with 2005 as a base. This level of cash working capital ($R\_CWC_{a,t}$) is determined using a log-linear specification with correction for serial correlation given the economies in cash management in gas transmission. The estimated equation used for R_CWC (Appendix F, Table F3) is determined as a function of total operation and maintenance expenses, as defined below:

$$R\_CWC_{a,t} = CWC\_K * e^{(\beta_{0,a} * (1-\rho) + CWC\_TOM * \log(R\_TOM_{a,t}) + \rho * \log(R\_CWC_{a,t-1}) - \rho * CWC\_TOM * \log(R\_TOM_{a,t-1}))} \tag{194}$$

where,

$R\_CWC_{a,t}$ = total pipeline transmission cash working capital for existing and new capacity (2005 dollars)
$\beta_{0,a}$ = CWC_C_a, estimated arc-specific constant for gas transported from node to node (Appendix F, Table F3.2, $\beta_{0,a}$ = $B\_ARC_{xx\_yy}$)
CWC_TOM = estimated R_TOM coefficient (Appendix F, Table F3.2)
$R\_TOM_{a,t}$ = total operation and maintenance expenses in 2005 dollars
CWC_K = correction factor estimated in stage 2 of the regression equation estimation process (Appendix F, Table F3)
ρ = autocorrelation coefficient from estimation (Appendix F, Table F3.2 CWC_RHO)
a = arc
t = forecast year

Last, the level of accumulated deferred income taxes for the combined existing and new capacity on a network arc in year t in the adjusted rate base equation depends on income tax regulations in effect, differences in tax and book depreciation, and the time vintage of past construction. The level of accumulated deferred income taxes for the combined existing and new capacity is derived as follows:

$$\begin{aligned} ADIT_{a,t} = \beta_{0,a} + \beta_1 * NEWCAP_{a,t} + \beta_2 * NEWCAP_{a,t} + \\ \beta_3 * NEWCAP_{a,t} + ADIT_{a,t-1} \end{aligned} \quad (195)$$

where,

$ADIT_{a,t}$ = accumulated deferred income taxes in dollars
$\beta_{0,a}$ = ADIT_Ca, constant term estimated by arc (Appendix F, Table F3.5, $\beta^{0,a}$ = $B\_ARC_{xx\_yy}$)
β_1 = BNEWCAP_PRE2003, estimated coefficient on the change in gross plant in service in the pre-2003 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
β_2 = BNEWCAP_2003_2004, estimated coefficient on the change in gross plant in service for the years 2003/2004 because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
β_3 = BNEWCAP_POST2004, estimated coefficient on the change in gross plant in service in the post-2004 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
$NEWCAP_{a,t}$ = change in gross plant in service for the combined existing and new capacity between years t and t-1 (in dollars)
a = arc
t = forecast year

Cost of capital. The capital-related components of the revenue requirement at the arc level depend upon the size of the adjusted rate base and the cost of capital to the pipeline companies associated with that arc. In turn, the company-level costs of capital depend upon the rates of return on debt, preferred stock and common equity, and the amounts of debt and equity in the overall capitalization. Cost of capital for a company is the weighted average after-tax rate of return (WAROR) which is a function of long-term debt, preferred stock, and common equity. The rate of return variables for preferred stock, common equity, and debt are related to forecast macroeconomic variables. For the combined existing and new capacity at the arc level, it is assumed that these rates will vary as a function of the yield on AA utility bonds (provided by the Macroeconomic Activity Module as a percent) in year t adjusted by a historical average deviation constant, as follows:

$$PFER_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_PFER_a \tag{196}$$

$$CMER_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_CMER_a \tag{197}$$

$$LTDR_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_LTDR_a \tag{198}$$

where,

$PFER_{a,t}$	=	rate of return for preferred stock
$CMER_{a,t}$	=	common equity rate of return
$LTDR_{a,t}$	=	long-term debt rate
$MC\_RMPUAANS_t$	=	AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPPUAA, percentage)
ADJ_PFER_a	=	historical average deviation constant (fraction) for rate of return for preferred stock (1994-2003, over 28 major gas pipeline companies) (D_PFER/100., Appendix E)
ADJ_CMER_a	=	historical average deviation constant (fraction) for rate of return for common equity (1994-2003, over 28 major gas pipeline companies) (D_CMER/100., Appendix E)
ADJ_LTDR_a	=	historical average deviation constant (fraction) for long-term debt rate (1994-2003, over 28 major gas pipeline companies) (D_LTDR/100., Appendix E)
a	=	arc
t	=	forecast year

The weighted average cost of capital in the forecast year is computed as the sum of the capital-weighted rates of return for preferred stock, common equity, and debt, as follows:

$$WAROR_{a,t} = \frac{(PFER_{a,t} * PFES_{a,t}) + (CMER_{a,t} * CMES_{a,t}) + (LTDR_{a,t} * LTDS_{a,t})}{TOTCAP_{a,t}} \tag{199}$$

$$TOTCAP_{a,t} = (PFES_{a,t} + CMES_{a,t} + LTDS_{a,t}) \tag{200}$$

where,

$WAROR_{a,t}$	=	weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$	=	rate of return for preferred stock (fraction)
$PFES_{a,t}$	=	value of preferred stock (dollars)
$CMER_{a,t}$	=	common equity rate of return (fraction)
$CMES_{a,t}$	=	value of common stock (dollars)
$LTDR_{a,t}$	=	long-term debt rate (fraction)
$LTDS_{a,t}$	=	value of long-term debt (dollars)
$TOTCAP_{a,t}$	=	sum of the value of long-term debt, preferred stock, and common stock equity (dollars)

a = arc
t = forecast year

The above equation can be written as a function of the rates of return and capital structure ratios:

$$WAROR_{a,t} = (PFER_{a,t} * GPFESTR_{a,t}) + (CMER_{a,t} * GCMESTR_{a,t}) + (LTDR_{a,t} * GLTDSTR_{a,t}) \quad (201)$$

where,

$$GPFESTR_{a,t} = PFES_{a,t} / TOTCAP_{a,t} \quad (202)$$

$$GCMESTR_{a,t} = CMES_{a,t} / TOTCAP_{a,t} \quad (203)$$

$$GLTDSTR_{a,t} = LTDS_{a,t} / TOTCAP_{a,t} \quad (204)$$

and,

$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$ = coupon rate for preferred stock (fraction)
$CMER_{a,t}$ = common equity rate of return (fraction)
$LTDR_{a,t}$ = long-term debt rate (fraction)
$GPFESTR_{a}$ = ratio of preferred stock to estimated capital for existing and new capacity (fraction) [referred to as capital structure for preferred stock]
$GCMESTR_{a}$ = ratio of common stock to estimated capital for existing and new capacity (fraction)[referred to as capital structure for common stock]
$GLTDSTR_{a}$ = ratio of long-term debt to estimated capital for existing and new capacity (fraction)[referred to as capital structure for long-term debt]
$PFES_{a,t}$ = value of preferred stock (dollars)
$CMES_{a,t}$ = value of common stock (dollars)
$LTDS_{a,t}$ = value of long-term debt (dollars)
$TOTCAP_{a,t}$ = estimated capital equal to the sum of the value of preferred stock, common stock equity, and long-term debt (dollars)
a = arc
t = forecast year

In the financial database, the estimated capital for each interstate pipeline is by definition equal to its adjusted rate base. Hence, the estimated capital ($TOTCAP_{a,t}$) defined in equation 200 is equal to the adjusted rate base ($APRB_{a,t}$) defined in equation 182:

$$TOTCAP_{a,t} = APRB_{a,t} \quad (205)$$

where,

$TOTCAP_{a,t}$ = estimated capital in dollars
$APRB_{a,t}$ = adjusted rate base in dollars
a = arc
t = forecast year

Substituting the adjusted rate base variable $APRB_{a,t}$ for the estimated capital $TOTCAP_{a,t}$ in equations 202 to 204, the values of preferred stock, common stock, and long-term debt by arc can be derived as functions of the capital structure ratios and the adjusted rate base. Capital structure is the percent of total capitalization (adjusted rate base) represented by each of the three capital components: preferred equity, common equity, and long-term debt. The percentages of total capitalization due to common stock, preferred stock, and long-term debt are considered fixed throughout the forecast. Assuming that the total capitalization fractions remain the same over the forecast horizon, the values of preferred stock, common stock, and long-term debt can be derived as follows:

$$\begin{aligned} PFES_{a,t} &= GPFESTR_a * APRB_{a,t} \\ CMES_{a,t} &= GCMESTR_a * APRB_{a,t} \\ LTDS_{a,t} &= GLTDSTR_a * APRB_{a,t} \end{aligned} \qquad (206)$$

where,

$PFES_{a,t}$	=	value of preferred stock in nominal dollars
$CMES_{a,t}$	=	value of common equity in nominal dollars
$LTDS_{a,t}$	=	long-term debt in nominal dollars
$GPFESTR_a$	=	ratio of preferred stock to adjusted rate base for existing and new capacity (fraction) [referred to as capital structure for preferred stock]
$GCMESTR_a$	=	ratio of common stock to adjusted rate base for existing and new capacity (fraction)[referred to as capital structure for common stock]
$GLTDSTR_a$	=	ratio of long-term debt to adjusted rate base for existing and new capacity (fraction)[referred to as capital structure for long-term debt]
$APRB_{a,t}$	=	adjusted pipeline rate base (dollars)
a	=	arc
t	=	forecast year

In the forecast year update phase, the capital structures ($GPFESTR_a$, $GCMESTR_a$, and $GLTDSTR_a$) at the arc level in the above equations are held constant over the forecast period. They are defined below as the average adjusted rate base weighted capital structures over all pipelines associated with an arc and over the historical time period (1997-2006).

$$GPFESTR_a = \frac{\sum_{t=1997}^{2006} \sum_{p} (GPFESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_{p} APRB_{a,p,t}} \qquad (207)$$

$$GCMESTR_a = \frac{\sum_{t=1997}^{2006} \sum_{p} (GCMESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_{p} APRB_{a,p,t}} \qquad (208)$$

$$GLTDSTR_{a} = \frac{\sum_{t=1997}^{2006} \sum_{p} (GLTDSTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_{p} APRB_{a,p,t}} \quad (209)$$

where,

$GPFESTR_{a}$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$GCMESTR_{a}$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$GLTDSTR_{a}$	=	historical average capital structure for long-term debt for existing and new capacity (fraction), held constant over the forecast period
$GPFESTR_{a,p,t}$	=	capital structure for preferred stock (fraction) by pipeline company in the historical years (1997-2006) (Appendix E, D_PFES)
$GCMESTR_{a,p,t}$	=	capital structure for common stock (fraction) by pipeline company in the historical years (1997-2006) (Appendix E, D_CMES)
$GLTDSTR_{a,p,t}$	=	capital structure for long-term debt (fraction) by pipeline company in the historical years (1997-2006) (Appendix E,D_LTDS)
$APRB_{a,p,t}$	=	adjusted rate base (capitalization) by pipeline company in the historical years (1997-2006) (Appendix E, D_APRB)
P	=	pipeline company
a	=	arc
t	=	historical year

The weighted average cost of capital in the forecast year in equation 201 is forecast as follows:

$$WAROR_{a,t} = (PFER_{a,t} * GPFESTR_{a}) + (CMER_{a,t} * GCMESTR_{a}) + (LTDR_{a,t} * GLTDSTR_{a}) \quad (210)$$

where,

$WAROR_{a,t}$	=	weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$	=	coupon rate for preferred stock (fraction), function of AA utility bond rate [equation 196]
$CMER_{a,t}$	=	common equity rate of return (fraction), function of AA utility bond rate [equation 197]
$LTDR_{a,t}$	=	long-term debt rate (fraction), function of AA utility bond rate [equation 198]
$GPFESTR_{a}$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$GCMESTR_{a}$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$GLTDSTR_{a}$	=	historical average capital structure for long-term debt for existing and new capacity (fraction), held constant over the forecast period
a	=	arc
t	=	forecast year

The weighted-average after-tax rate of return on capital (WARORa,t) is applied to the adjusted rate base (APRBa,t) to project the total return on rate base (after taxes), also known as the after-tax operating income, which is a major component of the revenue requirement.

Projection of revenue requirement components

The approach to the projection of revenue requirement components is summarized in **Table 6-5**. Given the rate base, rates of return, and capitalization structure projections discussed above, the revenue requirement components are relatively straightforward to project. The capital-related components include total return on rate base (after taxes); federal and state income taxes; deferred income taxes; other taxes; and depreciation, depletion, and amortization costs. Other components include total operating and maintenance expenses, and regulatory amortization, which is small and thus assumed to be negligible in the forecast period. The total operating and maintenance expense variable includes expenses for transmission of gas for others; administrative and general expenses; and sales, customer accounts and other expenses. The total cost of service (revenue requirement) at the arc level for a forecast year is determined as follows:

$$TCOS_{a,t} = TRRB_{a,t} + DDA_{a,t} + TOTAX_{a,t} + TOM_{a,t} \quad (211)$$

where,

$TCOSa_{,t}$ = total cost-of-service or revenue requirement for existing and new capacity (dollars)
$TRRB_{a,t}$ = total return on rate base for existing and new capacity after taxes (dollars)
$DDA_{a,t}$ = depreciation, depletion, and amortization for existing and new capacity (dollars)
$TOTAX_{a,t}$ = total federal and state income tax liability for existing and new capacity (dollars)
$TOM_{a,t}$ = total operating and maintenance expenses for existing and new capacity (dollars)
a = arc
t = forecast year

Table 6-5. Approach to projection of revenue requirements

Projection Component	Approach
1. Capital-Related Costs	
a. Total return on rate base	Direct calculation from projected rate base and rates of return
b. Federal/State income taxes	Accounting algorithms based on tax rates
c. Deferred income taxes	Difference in the accumulated deferred income taxes between years t and t-1
2. Depreciation, Depletion, and Amortization	Estimated equation and accounting algorithm
3. Total Operating and Maintenance Expenses	Estimated equation
4. Other Taxes	Previous year's other taxes adjusted to inflation rate and growth in capacity

The total return on rate base for existing and new capacity is computed from the projected weighted cost of capital and estimated rate base, as follows:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \tag{212}$$

where,

$TRRB_{a,t}$	=	total return on rate base (after taxes) for existing and new capacity in dollars
$WAROR_{a,t}$	=	weighted-average after-tax rate of return on capital for existing and new capacity (fraction)
$APRB_{a,t}$	=	adjusted pipeline rate base for existing and new capacity in dollars
a	=	arc
t	=	forecast year

The return on rate base for existing and new capacity on an arc can be broken out into the three components:

$$PFEN_{a,t} = GPFESTR_{a} * PFER_{a,t} * APRB_{a,t} \tag{213}$$

$$CMEN_{a,t} = GCMESTR_{a} * CMER_{a,t} * APRB_{a,t} \tag{214}$$

$$LTDN_{a,t} = GLTDSTR_{a} * LTDR_{a,t} * APRB_{a,t} \tag{215}$$

where,

$PFEN_{a,t}$	=	total return on preferred stock for existing and new capacity (dollars)
$GPFESTR_{a}$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$PFER_{a,t}$	=	coupon rate for preferred stock for existing and new capacity (fraction)
$APRB_{a,t}$	=	adjusted rate base for existing and new capacity (dollars)
$CMEN_{a,t}$	=	total return on common stock equity for existing and new capacity (dollars)
$GCMESTR_{a}$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$CMER_{a,t}$	=	common equity rate of return for existing and new capacity (fraction)
$LTDN_{a,t}$	=	total return on long-term debt for existing and new capacity (dollars)
$GLTDSTR_{a}$	=	historical average capital structure ratio for long-term debt for existing and new capacity (fraction), held constant over the forecast period
$LTDR_{a,t}$	=	long-term debt rate for existing and new capacity (fraction)
a	=	arc
t	=	forecast year

Next, annual depreciation, depletion, and amortization $DDA_{a,t}$ for a network arc in year t is calculated as the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with the arc. $DDA_{a,t}$ is defined earlier in equation 191.

Next, total taxes consist of federal income taxes, state income taxes, deferred income taxes, and other taxes. Federal income taxes and state income taxes are calculated using average tax rates. The equation for total taxes is as follows:

$$TOTAX_{a,t} = FSIT_{a,t} + DIT_{a,t} + OTTAX_{a,t} \tag{216}$$

$$FSIT_{a,t} = FIT_{a,t} + SIT_{a,t} \tag{217}$$

where,

$TOTAX_{a,t}$	=	total federal and state income tax liability for existing and new capacity (dollars)
$FSIT_{a,t}$	=	federal and state income tax for existing and new capacity (dollars)
$FIT_{a,t}$	=	federal income tax for existing and new capacity (dollars)
$SIT_{a,t}$	=	state income tax for existing and new capacity (dollars)
$DIT_{a,t}$	=	deferred income taxes for existing and new capacity (dollars)
$OTTAX_{a,t}$	=	all other federal, state, or local taxes for existing and new capacity (dollars)
a	=	arc
t	=	forecast year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the federal tax rate. The after-tax profit is determined as follows:

$$ATP_{a,t} = APRB_{a,t} * (PFER_{a,t} * GPFESTR_{a} + CMER_{a,t} * GCMESTR_{a}) \tag{218}$$

where,

$ATP_{a,t}$	=	after-tax profit for existing and new capacity (dollars)
$APRB_{a,t}$	=	adjusted pipeline rate base for existing and new capacity (dollars)
$PFER_{a,t}$	=	coupon rate for preferred stock for existing and new capacity (fraction)
$GPFESTR_{a}$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$CMER_{a,t}$	=	common equity rate of return for existing and new capacity (fraction)
$GCMESTR_{a}$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
a	=	arc
t	=	forecast year

and the federal income taxes are:

$$FIT_{a,t} = (FRATE * ATP_{a,t} / 1. - FRATE) \tag{219}$$

where,

$FIT_{a,t}$	=	federal income tax for existing and new capacity (dollars)
FRATE	=	federal income tax rate (fraction, Appendix E)
$ATP_{a,t}$	=	after-tax profit for existing and new capacity (dollars)

a = arc
t = forecast year

State income taxes are computed by multiplying the sum of taxable profit and the associated federal income tax by a weighted-average state tax rate associated with each pipeline company. The weighted-average state tax rate is based on peak service volumes in each state served by the pipeline company. State income taxes are computed as follows:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{220}$$

where,

$SIT_{a,t}$ = state income tax for existing and new capacity (dollars)
$SRATE$ = average state income tax rate (fraction, Appendix E)
$FIT_{a,t}$ = federal income tax for existing and new capacity (dollars)
$ATP_{a,t}$ = after-tax profits for existing and new capacity (dollars)
a = arc
t = forecast year

Deferred income taxes for existing and new capacity at the arc level are the differences in the accumulated deferred income taxes between year t and year t-1.

$$DIT_{a,t} = ADIT_{a,t} - ADIT_{a,t-1} \tag{221}$$

where,

$DIT_{a,t}$ = deferred income taxes for existing and new capacity (dollars)
$ADIT_{a,t}$ = accumulated deferred income taxes for existing and new capacity (dollars)
a = arc
t = forecast year

Other taxes consist of a combination of ad valorem taxes (which grow with company revenue), property taxes (which grow in proportion to gross plant), and all other taxes (assumed constant in real terms). Other taxes in year t are determined as the previous year's other taxes adjusted for inflation and capacity expansion.

$$OTTAX_{a,t} = OTTAX_{a,t-1} * EXPFAC_{a,t} * (MC\_PCWGDP_t / MC\_PCWGDP_{t-1}) \tag{222}$$

where,

$OTTAX_{a,t}$ = all other taxes assessed by federal, state, or local governments except income taxes for existing and new capacity (dollars)
$EXPFAC_{a,t}$ = capacity expansion factor (see below)
MC_PCWGDP_t = GDP chain-type price deflator (Macroeconomic Activity Module)
a = arc
t = forecast year

The capacity expansion factor is expressed as follows:

$$EXPFAC_{a,t} = PTCURPCAP_{a,t} \,/\, PTCURPCAP_{a,t-1} \tag{223}$$

where,

$EXPFAC_{a,t}$ = capacity expansion factor (growth in capacity)
$PTCURPCAP_{a,t}$ = current pipeline capacity (Bcf) for existing and new capacity
a = arc
t = forecast year

Last, the total operating and maintenance costs for existing and new capacity by arc ($R\_TOM_{a,t}$) are determined using a log-linear form, given the economies of scale inherent in gas transmission. The estimated equation used for R_TOM (Appendix F, Table F3) is determined as a function of gross plant in service, $GPIS_a$, a level of accumulated depreciation relative to gross plant in service, $DEPSHR_a$, and a time trend, TECHYEAR, that proxies the state of technology, as defined below:

$$R\_TOM_{a,t} = TOM\_K * e^{(\beta_{0,a} * (1-\rho) + G2 + G3 + G4 + G5 + G6 - \rho * (G7 + G8 + G4 + G9))} \tag{224}$$

where,

$R\_TOM_{a,t}$ = total operating and maintenance cost for existing and new capacity (2005 dollars)
TOM_K = correction factor estimated in stage 2 of the regression equation estimation process (Appendix F, Table F3)
$\beta_{0,a}$ = TOM_C, constant term estimated by arc (Appendix F, Table F3.6, $\beta_{0,a}$ = $B\_ARC_{xx\_yy}$)
G_2 = $\beta_1 * \log(GPIS_{a,t-1})$
G_3 = $\beta_2 * DEPSHR_{a,t-1}$
G_4 = $\beta_3 * 2006.0$
G_5 = $\beta_4 * (TECHYEAR-2006.0)$
G_6 = $\rho * \log(R\_TOMa,t-1)$
G_7 = $\beta1 * \log(GPISa,t-2)$
G_8 = $\beta2 * DEPSHRa,t-2$
G_9 = $\beta4 * (TECHYEAR - 1.0- 2006.0)$
log = natural logarithm operator
ρ = estimated autocorrelation coefficient (Appendix F, Table F3.6 -- TOM_RHO)
β_1 = TOM_GPIS1, estimated coefficient on the change in gross plant in service (Appendix F, Table F3.6)
β_2 = TOM_DEPSHR, estimated coefficient for the accumulated depreciation of the plant relative to the GPIS (Appendix F, Table F3.6)
β_3 = TOM_BYEAR, estimated coefficient for the time trend variable TECHYEAR (Appendix F, Table F3.6)
β_4 = TOM_BYEAR_EIA = TOM_BYEAR, estimated future rate of decline in R_TOM due to technology improvements and efficiency gains. EIA

assumes that this coefficient is the same as the coefficient for the time trend variable TECHYEAR (Appendix F, Table F3.6)

$DEPSHR_{a,t}$ = level of the accumulated depreciation of the plant relative to the gross plant in service for existing and new capacity at the beginning of year t. This variable is a proxy for the age of the capital stock.

$GPIS_{a,t}$ = capital cost of plant in service for existing and new capacity in dollars (not deflated)

TECHYEAR = MODYEAR (time trend in 4-digit Julian units, the minimum value of this variable in the sample being 1997, otherwise TECHYEAR=0 if less than 1997)

a = arc

t = forecast year

For consistency, the total operating and maintenance costs are converted to nominal dollars:

$$TOM_{a,t} = R\_TOM_{a,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{2000}} \quad (225)$$

where,

$TOM_{a,t}$ = total operating and maintenance costs for existing and new capacity (nominal dollars)

$R\_TOM_{a,t}$ = total operating and maintenance costs for existing and new capacity (2005 dollars)

MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)

a = arc

t = forecast year

Once all four components ($TRRB_{a,t}$, $DDA_{a,t}$, $TOTAX_{a,t}$, $TOM_{a,t}$) of the cost-of-service $TCOST_{a,t}$ of equation 211 are computed by arc in year t, each of them will be disaggregated into fixed and variable costs, which in turn will be disaggregated further into reservation and usage costs using the allocation factors for a straight fixed variable (SFV) rate design summarized in **Table 6-6**.[92] Note that the return on rate base ($TRRB_{a,t}$) has three components ($PFEN_{a,t}$, $CMEN_{a,t}$, and $LTDN_{a,t}$ [equations 213, 214, and 215]).

Disaggregation of cost-of-service components into fixed and variable costs

Let $Item_{i,a,t}$ be a cost-of-service component (i=cost component index, a=arc, and t=forecast year). Using the first group of rate design allocation factors ξ_i (**Table 6-6**), all the components of cost-of-service computed in the above section can be split into fixed and variable costs, and then summed over the cost categories to determine fixed and variable costs-of-service as follows:

$$FC_{a,t} = \sum_i (\xi_i * Item_{i,a,t}) \quad (226)$$

[92] The allocation factors of SFV rate design are given in percent in this table for illustration purposes. They are converted into ratios immediately after they are read in from the input file by dividing by 100.

$$VC_{a,t} = \sum_{i}[(1.0 - \xi_i) * Item_{i,a,t}] \quad (227)$$

$$TCOS_{a,t} = FC_{a,t} + VC_{a,t} \quad (228)$$

where,

$TCOS_{a,t}$	=	total cost-of-service for existing and new capacity (dollars)
$FC_{a,t}$	=	fixed cost for existing and new capacity (dollars)
$VC_{a,t}$	=	variable cost for existing and new capacity (dollars)
$Item_{i,a,t}$		cost-of-service component index at the arc level
ξ_i	=	first group of allocation factors (ratios) to disaggregate the cost-of-service components into fixed and variable costs
i	=	subscript to designate a cost-of-service component (i=1 for PFEN, i=2 for CMEN, i=3 for LTDN, i=4 for DDA, i=5 for FSIT, i=6 for DIT, i=7 for OTTAX, and i=8 for TOM)
a	=	arc
t	=	forecast year

Table 6-6. Percentage allocation factors for a straight fixed variable (SFV) rate design

Cost-of-service Items (percentage) [$Item_{i,a,t}$, i=cost component index, a=arc, t=year]	**Break up cost-of-service items into fixed and variable costs**		**Break up fixed cost items into reservation and usage costs**		**Break up variable cost items into reservation and usage costs**	
$Item_{i,a,t}$	**$FC_{i,a,t}$**	**$VC_{i,a,t}$**	**$RFC_{i,a,t}$**	**$UFC_{i,a,t}$**	**$RVC_{i,a,t}$**	**$UVC_{i,a,t}$**
Cost Allocation Factors	ξ_i	$100 - \xi_i$	λ_i	$100 - \lambda_i$	μ_i	$100 - \mu_i$
After-tax Operating Income						
Return on Preferred Stocks	100	0	100	0	0	100
Return on Common Stocks	100	0	100	0	0	100
Return on Long-Term Debt	100	0	100	0	0	100
Normal Operating Expenses						
Depreciation	100	0	100	0	0	100
Income Taxes	100	0	100	0	0	100
Deferred Income Taxes	100	0	100	0	0	100
Other Taxes	100	0	100	0	0	100
Total O&M	60	40	100	0	0	100

Disaggregation of fixed and variable costs into reservation and usage costs

Each type of cost-of-service component (fixed or variable) in the above equations can be further disaggregated into reservation and usage costs using the second and third groups of rate design allocation factors λi and μi (**Table 6-6**), as follows:

$$RFC_{a,t} = \sum_i (\lambda_i * \xi_i * Item_{i,a,t}) \tag{229}$$

$$UFC_{a,t} = \sum_i [(1.0 - \lambda_i) * \xi_i * Item_{i,a,t}] \tag{230}$$

$$RVC_{a,t} = \sum_i [\mu_i * (1.0 - \xi_i) * Item_{i,a,t}] \tag{231}$$

$$UVC_{a,t} = \sum_i [(1.0 - \mu_i) * (1.0 - \xi_i) * Item_{i,a,t}] \tag{232}$$

$$TCOS_{a,t} = RFC_{a,t} + UFC_{a,t} + RVC_{a,t} + UVC_{a,t} \tag{233}$$

where,

$TCOS_{a,t}$	=	total cost-of-service for existing and new capacity (dollars)
$RFC_{a,t}$	=	fixed reservation cost for existing and new capacity (dollars)
$UFC_{a,t}$	=	fixed usage cost for existing and new capacity (dollars)
$RVC_{a,t}$	=	variable reservation cost for existing and new capacity (dollars)
$UVC_{a,t}$	=	variable usage cost for existing and new capacity (dollars)
$Item_{i,a,t}$	=	cost-of-service component index at the arc level
ξ_i	=	first group of allocation factors to disaggregate cost-of-service components into fixed and variable costs
λ_i	=	second group of allocation factors to disaggregate fixed costs into reservation and usage costs
μ_i	=	third group of allocation factors to disaggregate variable costsinto reservation and usage costs
i	=	subscript to designate a cost-of-service component (i=1 for PFEN, i=2 for CMEN, i=3 for LTDN, i=4 for DDA, i=5 for FSIT, i=6 for DIT, i=7 for OTTAX, and i=8 for TOM)
a	=	arc
t	=	forecast year

The summation of fixed and variable reservation costs (RFC and RVC) yields the total reservation cost (RCOST). This can be disaggregated further into peak and off-peak reservation costs, which are used to develop variable tariffs for peak and off-peak time periods. The summation of fixed and variable usage costs (UFC and UVC), which yields the total usage cost (UCOST), is used to compute the annual average fixed usage fees. Both types of rates are developed in the next section. The equations for the reservation and usage costs can be expressed as follows:

$$RCOST_{a,t} = (RFC_{a,t} + RVC_{a,t}) \tag{234}$$

$$UCOST_{a,t} = (UFC_{a,t} + UVC_{a,t}) \tag{235}$$

where,

$RCOST_{a,t}$ = reservation cost for existing and new capacity (dollars)
$UCOST_{a,t}$ = annual usage cost for existing and new capacity (dollars)
$RFC_{a,t}$ = fixed reservation cost for existing and new capacity (dollars)
$UFC_{a,t}$ = fixed usage cost for existing and new capacity (dollars)
$RVC_{a,t}$ = variable reservation cost for existing and new capacity (dollars)
$UVC_{a,t}$ = variable usage cost for existing and new capacity (dollars)
a = arc
t = forecast period

As **Table 6-6** indicates, all the fixed costs are included in the reservation costs and all the variable costs are included in the usage costs.

Computation of rates for forecast years

The reservation and usage costs-of-service RCOST and UCOST determined above are used separately to develop two types of rates at the arc level: variable tariffs and annual fixed usage fees. The determination of both rates is described below.

Variable tariff curves

Variable tariffs are proportional to reservation charges and are broken up into peak and off-peak time periods. Variable tariffs are derived directly from variable tariff curves which are developed based on reservation costs, utilization rates, annual flows, and other curve parameters.

In the PTS code, these variable curves are defined by a FUNCTION (NGPIPE_VARTAR) which is called by the ITS to compute the variable tariffs for peak and off-peak by arc and by forecast year. In this pipeline function, the tariff curves are segmented such that tariffs associated with current capacity and capacity expansion are represented by separate but similar equations. A uniform functional form is used to define these tariff curves for both the current capacity and capacity expansion segments of the tariff curves. It is defined as a function of a base point [price and quantity (PNOD, QNOD)] using different process-specific parameters, peak or off-peak flow, and a price elasticity. This functional form is presented below:

current capacity segment:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA\_PIPE} \tag{236}$$

capacity expansion segment:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA2\_PIPE} \tag{237}$$

such that,

for peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR\_YR}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{238}$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \tag{239}$$

for off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{240}$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \tag{241}$$

where,

$NGPIPE\_VARTAR_{a,t}$	=	function to define pipeline tariffs (1987$/Mcf)
$PNOD_{a,t}$	=	base point, price (1987$/Mcf)
$QNOD_{a,t}$	=	base point, quantity (Bcf)
$Q_{a,t}$	=	flow along pipeline arc (Bcf)
ALPHA_PIPE	=	price elasticity for pipeline tariff curve for current capacity (Appendix E)
ALPHA2_PIPE	=	price elasticity for pipeline tariff curve for capacity expansion segment (Appendix E)
$RCOST_{a,t}$	=	reservation cost-of-service (million dollars)
$PTNETFLOW_{a,t}$	=	natural gas network flow (throughput, Bcf)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	forecast year

Annual fixed usage fees

The annual fixed usage fees (volumetric charges) are derived directly from the usage costs, peak and off-peak utilization rates, and annual arc capacity. These fees are computed as the average fees over each forecast year, as follows:

$$\begin{aligned} FIXTAR_{a,t} = UCOST_{a,t} / [(PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + \\ (1 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_t \end{aligned} \tag{242}$$

where,

$FIXTAR_{a,t}$	=	annual fixed usage fees for existing and new capacity (1987$/Mcf)
$UCOST_{a,t}$	=	annual usage cost for existing and new capacity (million dollars)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
$PTCURPCAP_{a,t}$	=	current pipeline capacity (Bcf)
$PTPKUTZ_{a,t}$	=	peak pipeline utilization (fraction)
$PTOPUTZ_{a,t}$	=	off-peak pipeline utilization (fraction)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	forecast year

As can be seen from the allocation factors in Table 6-6, usage costs (UCOST) are less than 10% of reservation costs (RCOST). Therefore, annual fixed usage fees which are proportional to usage costs are expected to be less than 10% of the variable tariffs. In general, these fixed fees are within the range of 5% of the variable tariffs which are charged to firm customers.

Canadian fixed and variable tariffs

Fixed and variable tariffs along Canadian import arcs are defined using input data. Fixed tariffs are obtained directly from the data (Appendix E, $ARC\_FIXTAR_{n,a,t}$), while variable tariffs are calculated in the FUNCTION subroutine (NGPIPE_VARTAR) and are based on pipeline utilization and a maximum expected tariff, CNMAXTAR. If the pipeline utilization along a Canadian arc for any time period (peak or off-peak) is less than 50%, then the pipeline tariff is set to a low level (70% of CNMAXTAR). If the Canadian pipeline utilization is between 50% and 90%, then the pipeline tariff is set to a level between 70% and 80% of CNMAXTAR. The sliding scale is determined using the corresponding utilization factor, as follows:

$$\begin{aligned} NGPIPE\_VARTAR_{a,t} = {} & CNMAXTAR - [CNMAXTAR * (1.0 - 0.9) * 2.0] - \\ & [CNMAXTAR * (0.9 - CANUTIL_{a,t}) * 0.25] \end{aligned} \tag{243}$$

If the Canadian pipeline utilization is greater than 90 percent, then the pipeline tariff is set to between 80% and 100% of CNMAXTAR. This is accomplished again using Canadian pipeline utilization, as follows:

$$\begin{aligned} NGPIPE\_VARTAR_{a,t} = {} & CNMAXTAR - \\ & [CNMAXTAR * (1.0 - CANUTIL_{a,t}) * 2.0] \end{aligned} \tag{244}$$

where,

$$CANUTIL_{a,t} = \frac{Q_{a,t}}{QNOD_{a,t}} \tag{245}$$

for peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * PKSHR\_YR * PTPKUTZ_{a,t} \tag{246}$$

for off-peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} \tag{247}$$

and,

$NGPIPE\_VARTAR_{a,t}$	=	function to define pipeline tariffs (1987$/Mcf)
CNMAXTAR	=	maximum effective tariff (1987$/Mcf, ARC_VARTAR, Appendix E)
$CANUTIL_{a,t}$	=	pipeline utilization (fraction)
$QNOD_{a,t}$	=	base point, quantity (Bcf)
$Q_{a,t}$	=	flow along pipeline arc (Bcf)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$	=	peak pipeline utilization (fraction)

$PTCURPCAP_{a,t}$ = current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$ = off-peak pipeline utilization (fraction)
a = arc
t = forecast year

For the eastern and western Canadian storage regions, the “variable” tariff is set to zero and only the assumed “fixed” tariff (Appendix E, ARC_FIXTAR) is applied.

Storage tariff routine methodology

Background

This section describes the methodology used to assign a storage tariff for each of the 12 NGTDM regions. All variables and equations presented below are used for the forecast time period (1999-2040). If the time period t is less than 1999, the associated variables are set to the initial values read in from the input file (Foster’s storage financial database[93] by region and year, 1990-1998).

This section starts with the presentation of the natural gas storage cost-of-service equation by region. The equation sums four components to be forecast: after-tax[94] total return on rate base (operating income); total taxes; depreciation, depletion, and amortization; and total operating and maintenance expenses. Once these four components are computed, the regional storage cost of service is projected and, with the associated effective storage capacity provided by the ITS, a storage tariff curve can be established (as described at the end of this section).

Cost-of-service by storage region

The cost-of-service (or revenue requirement) for existing and new storage capacity in an NGTDM region can be written as follows:

$$STCOS_{r,t} = STBTOI_{r,t} + STDDA_{r,t} + STTOTAX_{r,t} + STTOM_{r,t} \tag{248}$$

where,

$STCOS_{r,t}$ = total cost-of-service or revenue requirement for existing and new capacity (dollars)
$STBTOI_{r,t}$ = total return on rate base for existing and new capacity (after-tax operating income) (dollars)
$STDDA_{r,t}$ = depreciation, depletion, and amortization for existing and new capacity (dollars)
$STTOTAX_{r,t}$ = total federal and state income tax liability for existing and new capacity (dollars)
$STTOM_{r,t}$ = total operating and maintenance expenses for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

[93] Natural Gas Storage Financial Data, compiled by Foster Associates, Inc., Bethesda, Maryland for EIA under purchase order #01-99EI36663 in December of 1999. This data set includes financial information on 33 major storage companies. The primary source of the data is FERC Form 2 (or Form 2A for the smaller pipelines). These data can be purchased from Foster Associates.
[94] ‘After-tax’ in this section refers to ‘after taxes have been taken out.’

The storage cost-of-service by region is first computed in nominal dollars and subsequently converted to 1987 dollars for use in the computation of a base for regional storage tariff, PNOD (1987$/Mcf). PNOD is used in the development of a regional storage tariff curve. An approach is developed to project the storage cost-of-service in nominal dollars by NGTDM region in year t and is provided in **Table 6-7**.

Table 6-7. Approach to projection of storage cost-of-service

Projection Component	Approach
1. Capital-Related Costs	
a. Total return in rate base	Direct calculation from projected rate base and rates of return
b. Federal/state income taxes	Accounting algorithms based on tax rates
c. Deferred income taxes	Difference in the accumulated deferred income taxes between years t and t-1
2. Depreciation, Depletion, and Amortization	Estimated equation and accounting algorithm
3. Total Operating and Maintenance Expenses	Estimated equation

Computation of total return on rate base (after-tax operating income), STBTOIr,t

The total return on rate base for existing and new capacity is computed from the projected weighted cost of capital and estimated rate base, as follows:

$$STBTOI_{r,t} = STWAROR_{r,t} * STAPRB_{r,t} \tag{249}$$

where,

$STBTOI_{r,t}$ = total return on rate base (after-tax operating income) for existing and new capacity in dollars
$STWAROR_{r,t}$ = weighted-average after-tax rate of return on capital for existing and new capacity (fraction)
$STAPRB_{r,t}$ = adjusted storage rate base for existing and new capacity in dollars
r = NGTDM region
t = forecast year

The return on rate base for existing and new storage capacity in an NGTDM region can be broken out into three components as shown below.

$$STPFEN_{r,t} = STGPFESTR_r * STPFER_{r,t} * STAPRB_{r,t} \tag{250}$$

$$STCMEN_{r,t} = STGCMESTR_r * STCMER_{r,t} * STAPRB_{r,t} \tag{251}$$

$$STLTDN_{r,t} = STGLTDSTR_r * STLTDR_{r,t} * STAPRB_{r,t} \tag{252}$$

where,

$STPFEN_{r,t}$ = total return on preferred stock for existing and new capacity (dollars)
$STPFER_{r,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)
$STGPFESTR_{r}$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STAPRB_{r,t}$ = adjusted rate base for existing and new capacity (dollars)
$STCMEN_{r,t}$ = total return on common stock equity for existing and new capacity (dollars)
$STGCMESTR_{r}$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$STCMER_{r,t}$ = common equity rate of return for existing and new capacity (fraction)
$STLTDN_{r,t}$ = total return on long-term debt for existing and new capacity (dollars)
$STGLTDSTR_{r}$ = historical average capital structure ratio for long-term debt for existing and new capacity (fraction), held constant over the forecast period
$STLTDR_{r,t}$ = long-term debt rate for existing and new capacity (fraction)
r = NGTDM region
t = forecast year

Note that the total return on rate base is the sum of the above equations and can be expressed as:

$$STBTOI_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t} + STLTDN_{r,t}) \tag{253}$$

It can be seen from the above equations that the weighted average rate of return on capital for existing and new storage capacity, STWARORr,t, can be determined as follows:

$$\begin{aligned} STWAROR_{r,t} = {} & STPFER_{r,t} * STGPFESTR_{r} + STCMER_{r,t} * STGCMESTR_{r} + \\ & STLTDR_{r,t} * STGLTDSTR_{r} \end{aligned} \tag{254}$$

The historical average capital structure ratios STGPFESTRr, STGCMESTRr, and STGLTDSTRr in the above equation are computed as follows:

$$STGPFESTR_{r} = \frac{\sum_{t=1990}^{1998} STPFES_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \tag{255}$$

$$STGCMESTR_{r} = \frac{\sum_{t=1990}^{1998} STCMES_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \tag{256}$$

$$STGLTDSTR_{r} = \frac{\sum_{t=1990}^{1998} STLTDS_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \tag{257}$$

where,

$STGPFESTR_r$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STGCMESTR_r$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$STGLTDSTR_r$	=	historical average capital structure ratio for long-term debt for existing and new capacity (fraction), held constant over the forecast period
$STPFES_{r,t}$	=	value of preferred stock for existing capacity (dollars) [read in as D_PFES]
$STCMES_{r,t}$	=	value of common stock equity for existing capacity (dollars) [read in as D_CMES]
$STLTDS_{r,t}$	=	value of long-term debt for existing capacity (dollars) [read in as D_LTDS]
$STAPRB_{r,t}$	=	adjusted rate base for existing capacity (dollars) [read in as D_APRB]
r	=	NGTDM region
t	=	forecast year

In the STWAROR equation, the rate of return variables for preferred stock, common equity, and debt ($STPFER_{r,t}$, $STCMER_{r,t}$, and $STLTDR_{r,t}$) are related to forecast macroeconomic variables. These rates of return can be determined as a function of nominal AA utility bond index rate (provided by the Macroeconomic Module) and a regional historical average constant deviation as follows:

$$STPFER_{r,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_STPFER_r \tag{258}$$

$$STCMER_{r,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_STCMER_r \tag{259}$$

$$STLTDR_{r,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_STLTDR_r \tag{260}$$

where,

$STPFER_{r,t}$	=	rate of return for preferred stock
$STCMER_{r,t}$	=	common equity rate of return
$STLTDR_{r,t}$	=	long-term debt rate
$MC\_RMPUAANS_t$	=	AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPUAA, percentage)
ADJ_STPFER_r	=	historical weighted average deviation constant (fraction) for preferred stock rate of return (1990-1998)
ADJ_STCMER_r	=	historical weighted average deviation constant (fraction) for ommon equity rate of return (1990-1998)
ADJ_STLTDR_r	=	historical weighted average deviation constant (fraction) for long-term debt rate (1990-1998)
r	=	NGTDM region
t	=	forecast year

The historical weighted average deviation constants by NGTDM region are computed as follows:

$$ADJ\_STLTDR_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STLTDN_{r,t}}{STLTDS_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \tag{261}$$

$$ADJ\_STPFER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STPFEN_{r,t}}{STPFES_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \tag{262}$$

$$ADJ\_STCMER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STCMEN_{r,t}}{STCMES_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \tag{263}$$

where,

ADJ_STLTDR_r	=	historical weighted average deviation constant (fraction) for long-term debt rate
ADJ_STCMER_r	=	historical weighted average deviation constant (fraction) for common equity rate of return
ADJ_STPFER_r	=	historical weighted average deviation constant (fraction) for preferred stock rate of return
$STPFEN_{r,t}$	=	total return on preferred stock for existing capacity (dollars) [read in as D_PFEN]
$STCMEN_{r,t}$	=	total return on common stock equity for existing capacity (dollars) [read in as D_CMEN]
$STLTDN_{r,t}$	=	total return on long-term debt for existing capacity (dollars) read in as D_LTDN]
$STPFES_{r,t}$	=	value of preferred stock for existing capacity (dollars) [read in as D_PFES]
$STCMES_r$	=	value of common stock equity for existing capacity (dollars) [read in as D_CMES]
$STLTDS_r$	=	value of long-term debt for existing capacity (dollars) [read in as D_LTDS]
$MC\_RMPUAANS_t$	=	AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPPUAA, percentage)
$STGPIS_{r,t}$	=	original capital cost of plant in service (dollars) [read in as D_GPIS]
r	=	NGTDM region
t	=	forecast year

Computation of adjusted rate base, $STAPRB_{r,t}$ [95]

The adjusted rate base for existing and new storage facilities in an NGTDM region has three components and can be written as follows:

$$STAPRB_{r,t} = STNPIS_{r,t} + STCWC_{r,t} - STADIT_{r,t} \tag{264}$$

where,

$STAPRB_{r,t}$	=	adjusted storage rate base for existing and new capacity (dollars)
$STNPIS_{r,t}$	=	net plant in service for existing and new capacity (dollars)
$STCWC_{r,t}$	=	total cash working capital for existing and new capacity (dollars)
$STADIT_{r,t}$	=	accumulated deferred income taxes for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

The net plant in service is the level of gross plant in service minus the accumulated depreciation, depletion, and amortization. It is given by the following equation:

$$STNPIS_{r,t} = STGPIS_{r,t} - STADDA_{r,t-1} \tag{265}$$

where,

$STNPIS_{r,t}$	=	net plant in service for existing and new capacity (dollars)
$STGPIS_{r,t}$	=	gross plant in service for existing and new capacity (dollars)
$STADDA_{r,t}$	=	accumulated depreciation, depletion, and amortization for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

The gross and net plant-in-service variables can be written as the sum of their respective existing and new gross and net plants in service as follows:

$$STGPIS_{r,t} = STGPIS\_E_{r,t} + STGPIS\_N_{r,t} \tag{266}$$

$$STNPIS_{r,t} = STNPIS\_E_{r,t} + STNPIS\_N_{r,t} \tag{267}$$

where,

$STGPIS_{r,t}$	=	gross plant in service for existing and new capacity (dollars)
$STNPIS_{r,t}$	=	net plant in service for existing and new capacity (dollars)
$STGPIS\_E_{r,t}$	=	gross plant in service for existing capacity (dollars)
$STGPIS\_N_{r,t}$	=	gross plant in service for new capacity (dollars)
$STNPIS\_E_{r,t}$	=	net plant in service for existing capacity (dollars)
$STNPIS\_N_{r,t}$	=	net plant in service for new capacity (dollars)

[95] In this section, any variable ending with "_E" will signify that the variable is for the existing storage capacity as of the end of 1998, and any variable ending with "_N" will mean that the variable is for the new storage capacity added from 1999 to 2025.

r = NGTDM region
t = forecast year

For the same reason as above, the accumulated depreciation, depletion, and amortization for t-1 can be split into its existing and new accumulated depreciation:

$$STADDA_{r,t-1} = STADDA\_E_{r,t-1} + STADDA\_N_{r,t-1} \tag{268}$$

where,

$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity (dollars)
$STADDA\_E_{r,t}$ = accumulated depreciation, depletion, and amortization for existing capacity (dollars)
$STADDA\_N_{r,t}$ = accumulated depreciation, depletion, and amortization for new capacity (dollars)
r = NGTDM region
t = forecast year

The accumulated depreciation for the current year t is expressed as last year's accumulated depreciation plus this year's depreciation. For the separate existing and new storage capacity, their accumulated depreciation, depletion, and amortization can be expressed separately as follows:

$$STADDA\_E_{r,t} = STADDA\_E_{r,t-1} + STDDA\_E_{r,t} \tag{269}$$

$$STADDA\_N_{r,t} = STADDA\_N_{r,t-1} + STDDA\_N_{r,t} \tag{270}$$

where,

$STADDA\_E_{r,t}$ = accumulated depreciation, depletion, and amortization for existing capacity (dollars)
$STADDA\_N_{r,t}$ = accumulated depreciation, depletion, and amortization for new capacity (dollars)
$STDDA\_E_{r,t}$ = depreciation, depletion, and amortization for existing capacity (dollars)
$STDDA\_N_{r,t}$ = depreciation, depletion, and amortization for new capacity (dollars)
r = NGTDM region
t = forecast year

Total accumulated depreciation, depletion, and amortization for the combined existing and new capacity by storage region in year t is determined as the sum of previous year's accumulated depreciation, depletion, and amortization and current year's depreciation, depletion, and amortization for that total capacity.

$$STADDA_{r,t} = STADDA_{r,t-1} + STDDA_{r,t} \tag{271}$$

where,

$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity in dollars
$STDDA_{r,t}$ = annual depreciation, depletion, and amortization for existing and new capacity in dollars
r = NGTDM region
t = forecast year

Computation of annual depreciation, depletion, and amortization, $STDDA_{r,t}$

Annual depreciation, depletion, and amortization for a storage region in year t is the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with that region.

$$STDDA_{r,t} = STDDA\_E_{r,t} + STDDA\_N_{r,t} \tag{272}$$

where,

$STDDA_{r,t}$ = annual depreciation, depletion, and amortization for existing and new capacity in dollars
$STDDA\_E_{r,t}$ = depreciation, depletion, and amortization costs for existing capacity in dollars
$STDDA\_N_{r,t}$ = depreciation, depletion, and amortization costs for new capacity in dollars
r = NGTDM region
t = forecast year

A regression equation is used to determine the annual depreciation, depletion, and amortization for existing capacity associated with an NGTDM region, while an accounting algorithm is used for new storage capacity. For existing capacity, this depreciation expense by NGTDM region is forecast as follows:

$$\begin{aligned} STDDA\_E_{r,t} = {} & STDDA\_CREG_r + STDDA\_NPIS * STNPIS\_E_{r,t-1} \\ & + STDDA\_NEWCAP * STNEWCAP_{r,t} \end{aligned} \tag{273}$$

where,

$STDDA\_E_{r,t}$ = annual depreciation, depletion, and amortization costs for existing capacity in dollars
$STDDA\_CREG_r$ = constant term estimated by region (Appendix F, Table F3)
STDDA_NPIS = estimated coefficient for net plant in service for existing capacity (Appendix F, Table F3)
STDDA_NEWCAP = estimated coefficient for the change in gross plant in service for existing capacity (Appendix F, Table F3)
$STNPIS\_E_{r,t}$ = net plant in service for existing capacity (dollars)
$STNEWCAP_{r,t}$ = change in gross plant in service for existing capacity (dollars)
r = NGTDM region
t = forecast year

The accounting algorithm used to define the annual depreciation, depletion, and amortization for new capacity assumes straight-line depreciation over a 30-year life, as follows:

$$STDDA\_N_{r,t} = STGPIS\_N_{r,t} / 30 \tag{274}$$

where,

$STDDA\_N_{r,t}$	=	annual depreciation, depletion, and amortization for new capacity in dollars
$STGPIS\_N_{r,t}$	=	gross plant in service for new capacity in dollars
30	=	30 years of plant life
r	=	NGTDM region
t	=	forecast year

In the above equation, the capital cost of new plant in service (STGPIS_Nr,t) in year t is computed as the accumulated new capacity expansion expenditures from 1999 to year t and is determined by the following equation:

$$STGPIS\_N_{r,t} = \sum_{s=1999}^{t} STNCAE_{r,s} \tag{275}$$

where,

$STGPIS\_N_{r,t}$	=	gross plant in service for new capacity expansion in dollars
$STNCAE_{r,s}$	=	new capacity expansion expenditures occurring in year s after 1998 (in dollars)
s	=	the year new expansion occurred
r	=	NGTDM region
t	=	forecast year

The new capacity expansion expenditures allowed in the rate base within a forecast year are derived for each NGTDM region from the amount of incremental capacity additions determined by the ITS:

$$STNCAE_{r,t} = STCCOST_{r,t} * STCAPADD_{r,t} * 1{,}000{,}000. \tag{276}$$

where,

$STNCAE_{r,t}$	=	total capital cost to expand capacity for an NGTDM region (dollars)
$STCCOST_{r,t}$	=	capital cost per unit of natural gas storage expansion (dollars per Mcf)
$STCAPADD_{r,t}$	=	storage capacity additions as determined in the ITS (Bcf/yr)
r	=	NGTDM region
t	=	forecast year

The capital cost per unit of natural gas storage expansion in an NGTDM region (STCCOSTr,t) is computed as its 1998 unit capital cost times a function of a capacity expansion factor relative to the 1998 storage capacity. This expansion factor represents a relative change in capacity since 1998. Whenever the ITS forecasts storage capacity additions in year t in an NGTDM region, the increased capacity is computed for that region from 1998 and the unit capital cost is computed. Hence, the capital cost to expand capacity in an NGTDM region can be estimated from any amount of capacity additions in year t provided by the ITS and the associated unit capital cost. This capital cost represents the investment cost for generic storage companies associated with that region. The unit capital cost (STCCOSTr,t) is computed by the following equations:

$$STCCOST_{r,t} = STCCOST\_CREG_r * e^{(BETAREG_r * STEXPFAC98_r)} * (1.0 + STCSTFAC) \tag{277}$$

where,

$STCCOSTr_{,t}$	=	capital cost per unit of natural gas storage expansion (dollars per Mcf)
STCCOST_CREG	=	1998 capital cost per unit of natural gas storage expansion (1998 dollars per Mcf)
$BETAREG_r$	=	expansion factor parameter (set to STCCOST_BETAREG, Appendix E)
$STEXPFAC98_r$	=	relative change in storage capacity since 1998
STCSTFAC	=	factor to set a particular storage region's expansion cost, based on an average [Appendix E]
r	=	NGTDM region
t	=	forecast year

The relative change in storage capacity is computed as follows:

$$STEXPFAC98_r = \frac{PTCURPSTR_{r,t}}{PTCURPSTR_{r,1998}} - 1.0 \tag{278}$$

where,

$PTCURPSTR_{r,t}$	=	current storage capacity (Bcf)
$PTCURPSTR_{r,1998}$	=	1998 storage capacity (Bcf)
r	=	NGTDM region
t	=	forecast year

Computation of total cash working capital, $STCWC_{r,t}$

The total cash working capital represents the level of working capital at the beginning of year t deflated using the chain-weighted GDP price index with 1996 as a base year. This cash working capital variable is expressed as a non-linear function of total gas storage capacity (base gas capacity plus working gas capacity) as follows:

$$\begin{aligned} R\_STCWC_{r,t} = {} & e^{(STCWC\_CREG_r * (1-\rho))} * DSTTCAP_{r,t-1}^{STCWC\_TOTCAP} * \\ & R\_STCWC_{r,t-1}^{\rho} * DSTTCAP_{r,t-2}^{-\rho * STCWC\_TOTCAP} \end{aligned} \tag{279}$$

where,

$R\_STCWC_{r,t}$	=	total cash working capital at the beginning of year t for existing and new capacity (1996 dollars)
$STCWC\_CREG_r$	=	constant term, estimated by region (Appendix F, Table F3)

ρ = autocorrelation coefficient from estimation (Appendix F, Table F3 – STCWC_RHO)
$STTCAP_{r,t}$ = total gas storage capacity (Bcf)
STCWC_TOTCAP = estimated DSTTCAP coefficient (Appendix F, Table F3)
r = NGTDM region
t = forecast year

This total cash working capital in 1996 dollars is converted to nominal dollars to be consistent with the convention used in this submodule.

$$STCWC_{r,t} = R\_STCWC_{r,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{1996}} \quad (280)$$

where,

$STCWC_{r,t}$ = total cash working capital at the beginning of year t for existing and new capacity (nominal dollars)
$R\_STCWC_{r,t}$ = total cash working capital at the beginning of year t for existing and new capacity (1996 dollars)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
r = NGTDM region
t = forecast year

Computation of accumulated deferred income taxes, $STADIT_{r,t}$

The level of accumulated deferred income taxes for the combined existing and new capacity in year t in the adjusted rate base equation is a stock (not a flow) and depends on income tax regulations in effect, differences in tax, and book depreciation. It can be expressed as a linear function of its own lagged variable and the change in the level of gross plant in service between time t and t-1. The forecasting equation can be written as follows:

$$\begin{aligned} STADIT_{r,t} = {} & STADIT\_C + (STADIT\_ADIT * STADIT_{r,t-1}) + \\ & (STADIT\_NEWCAP * NEWCAP_{r,t}) \end{aligned} \quad (281)$$

where,

$STADIT_{r,t}$ = accumulated deferred income taxes in dollars
STADIT_C = constant term from estimation (Appendix F, Table F3)
STADIT_ADIT = estimated coefficient for lagged accumulated deferred income taxes (Appendix F, Table F3)
STADIT_NEWCAP = estimated coefficient for change in gross plant in service (Appendix F, Table F3)
$NEWCAP_{r,t}$ = change in gross plant in service for the combined existing and new capacity between years t and t-1 (in dollars)
r = NGTDM region
t = forecast year

Computation of total taxes, $STTOTAX_{r,t}$

Total taxes consist of Federal income taxes, State income taxes, deferred income taxes, and other taxes. Federal income taxes and State income taxes are calculated using average tax rates. The equation for total taxes is as follows:

$$STTOTAX_{r,t} = STFSIT_{r,t} + STDIT_{r,t} + STOTTAX_{r,t} \qquad (282)$$

$$STFSIT_{r,t} = STFIT_{r,t} + STSIT_{r,t} \qquad (283)$$

where,

$STTOTAX_{r,t}$	=	total federal and state income tax liability for existing and new capacity (dollars)
$STFSIT_{r,t}$	=	federal and state income tax for existing and new capacity (dollars)
$STFIT_{r,t}$	=	federal income tax for existing and new capacity (dollars)
$STSIT_{r,t}$	=	state income tax for existing and new capacity (dollars)
$STDIT_{r,t}$	=	deferred income taxes for existing and new capacity (dollars)
STOTTAX	=	all other taxes assessed by federal, state, or local governmentsfor existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the federal tax rate. The after-tax profit is the operating income excluding the total long-term debt, which is determined as follows:

$$STATP_{r,t} = STAPRB_{r,t} * (STPFER_{r,t} * STGPFESTR_r + STCMER_{r,t} * STGCMESTR_r) \qquad (284)$$

$$STATP_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t}) \qquad (285)$$

where,

$STATP_{r,t}$	=	after-tax profit for existing and new capacity (dollars)
$STAPRB_{r,t}$	=	adjusted pipeline rate base for existing and new capacity (dollars)
$STPFER_{r,t}$	=	coupon rate for preferred stock for existing and new capacity (fraction)
$STGPFESTR_r$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STCMER_{r,t}$	=	common equity rate of return for existing and new capacity (fraction)
$STGCMESTR_r$	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$STPFEN_{r,t}$	=	total return on preferred stock for existing and new capacity (dollars)
$STCMEN_{r,t}$	=	total return on common stock equity for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

and the federal income taxes are

$$STFIT_{r,t} = (FRATE * STATP_{r,t}) / (1. - FRATE) \tag{286}$$

where,

$STFIT_{r,t}$	=	federal income tax for existing and new capacity (dollars)
FRATE	=	federal income tax rate (fraction, Appendix E)
$STATP_{r,t}$	=	after-tax profit for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

State income taxes are computed by multiplying the sum of taxable profit and the associated federal income tax by a weighted-average state tax rate associated with each NGTDM region. State income taxes are computed as follows:

$$STSIT_{r,t} = SRATE * (STFIT_{r,t} + STATP_{r,t}) \tag{287}$$

where,

$STSIT_{r,t}$	=	state income tax for existing and new capacity (dollars)
SRATE	=	average state income tax rate (fraction, Appendix E)
$STFIT_{r,t}$	=	federal income tax for existing and new capacity (dollars)
$STATP_{r,t}$	=	after-tax profits for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

Deferred income taxes for existing and new capacity at the arc level are the differences in the accumulated deferred income taxes between year t and year t-1.

$$STDIT_{r,t} = STADIT_{r,t} - STADIT_{r,t-1} \tag{288}$$

where,

$STDIT_{r,t}$	=	deferred income taxes for existing and new capacity (dollars)
$STADIT_{r,t}$	=	accumulated deferred income taxes for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

Other taxes consist of a combination of ad valorem taxes (which grow with company revenue), property taxes (which grow in proportion to gross plant), and all other taxes (assumed constant in real terms). Other taxes in year t are determined as the previous year's other taxes adjusted for inflation.

$$STOTTAX_{r,t} = STOTTAX_{r,t-1} * (MC\_PCWGDP_t / MC\_PCWGDP_{t-1}) \tag{289}$$

where,

$STOTTAX_{r,t}$	=	all other taxes assessed by federal, state, or local governments except income taxes for existing and new capacity (dollars) [read in asD_OTTAXr,t , t=1990-1998]
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
r	=	NGTDM region
t	=	forecast year

Computation of total operating and maintenance expenses, $STTOM_{r,t}$

The total operating and maintenance costs (including administrative costs) for existing and new capacity in an NGTDM region are determined in 1996 real dollars using a log-linear form with correction for serial correlation. The estimated equation is determined as a function of working gas storage capacity for region r at the beginning of period t. In developing the estimations, the impact of regulatory change and the differences between producing and consuming regions were analyzed.[96] Because their impacts were not supported by the data, they were not accounted for in the estimations. The final estimating equation is:

$$R\_STTOM_{r,t} = e^{(STTOM\_C*(1-\rho))} * DSTWCAP_{r,t-1}^{STTOM\_WORKCAP} * R\_STTOM_{r,t-1}^{\rho} * DSTWCAP_{r,t-2}^{-\rho*STTOM\_WORKCAP} \qquad (290)$$

where,

$R\_STTOM_{r,t}$	=	total operating and maintenance cost for existing and new capacity (1996 dollars)
STTOM_C	=	constant term from estimation (Appendix F, Table F3)
ρ	=	autocorrelation coefficient from estimation (Appendix F, Table F3 -- STTOM_RHO)
$DSTWCAP_{r,t}$	=	level of gas working capacity for region r during year t
STTOM_WORKCAP	=	estimated DSTWCAP coefficient (Appendix F, Table F3)
r	=	NGTDM region
t	=	forecast year

Finally, the total operating and maintenance costs are converted to nominal dollars to be consistent with the convention used in this submodule.

$$STTOM_{r,t} = R\_STTOM_{r,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{1996}} \qquad (291)$$

[96] The gas storage industry changed substantially when in 1994 FERC Order 636 required jurisdictional pipeline companies to operate their storage facilities on an open-access basis. The primary customers and use of storage in producing regions are significantly different from consuming regions.

where,

$STTOM_{r,t}$	=	total operating and maintenance costs for existing and new capacity (nominal dollars)
$R\_STTOM_{r,t}$	=	total operating and maintenance costs for existing and new capacity (1996 dollars)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
r	=	NGTDM region
t	=	forecast year

Computation of storage tariff

The regional storage tariff depends on the storage cost of service, current working gas capacity, utilization rate, natural gas storage activity, and other factors. The functional form is similar to the pipeline tariff curve, in that it will be built from a regional base point [price and quantity (PNOD,QNOD)]. The base regional storage tariff ($PNOD_{r,t}$) is determined as a function of the cost of service ($STCOS_{r,t}$ (equation 248)) and other factors discussed below. $QNOD_{r,t}$ is set to an effective working gas storage capacity by region, which is defined as a regional working gas capacity times its utilization rate. Hence, once the storage cost of service is computed by region, the base point can be established. Minor adjustments to the storage tariff routine will be necessary in order to obtain the desired results.

In the model, the storage cost of service used represents only a portion of the total storage cost of service, the revenue collected from the customers for withdrawing during the peak period the quantity of natural gas stored during the off-peak period. This portion is defined as a user-set percentage (STRATIO, Appendix E) representing the portion (ratio) of revenue requirement obtained by storage companies for storing gas during the off-peak and withdrawing it for the customers during the peak period. This would include charges for injections, withdrawals, and reserving capacity.

The cost of service $STCOS_{r,t}$ is computed using the Foster storage financial database which represents only the storage facilities owned by the interstate natural gas pipelines in the United States which have filed a Form 2 financial report with the FERC. Therefore, an adjustment to this cost of service to account for all the storage companies by region is needed. For example, at the national level, the Foster database shows the underground storage working gas capacity at 2.3 Tcf in 1998 and the EIA storage gas capacity data show much higher working gas capacity at 3.8 Tcf. Thus, the average adjustment factor to obtain the “actual” cost of service across all regions in the U.S. is 165%. This adjustment factor, STCAP_ADJr,t, varies from region to region.

To complete the design of the storage tariff computation, two more factors need to be incorporated: the regional storage tariff curve adjustment factor and the regional efficiency factor for storage operations, which makes the storage tariff more competitive in the long run.

Hence, the regional average storage tariff charged to customers for moving natural gas stored during the off-peak period and withdrawn during the peak period can be computed as follows:

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC\_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP\_ADJ_{r,t} * ADJ\_STR * (1.0 - STR\_EFF/100.)^t \tag{292}$$

where,

$$STCAP\_ADJ_{r,t} = \frac{PTCURPSTR_{r,t}}{FS\_PTCURPSTR_{r,t}} \tag{293}$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \tag{294}$$

and,

$PNOD_{r,t}$	=	base point, price (1987$/Mcf)
$STCOS_{r,t}$	=	storage cost of service for existing and new capacity (dollars)
$QNOD_{r,t}$	=	base point, quantity (Bcf)
MC_PCWGDP_t	=	GDP chain-type price deflator (from Macroeconomic Activity Module)
$STRATIO_{r,t}$	=	portion of revenue requirement obtained by moving gas from the off-peak to the peak period (fraction, Appendix E)
$STCAP\_ADJ_{r,t}$	=	adjustment factor for the cost of service to total U.S. (ratio)
ADJ_STR	=	storage tariff curve adjustment factor (fraction, Appendix E)
STR_EFF	=	efficiency factor (percent) for storage operations (Appendix E)
$PTSTUTZ_{r,t}$	=	storage utilization (fraction)
$PTCURPSTR_{r,t}$	=	current storage capacity (Bcf)
$FS\_PTCURPSTR_{r,t}$	=	Foster storage working gas capacity (Bcf) [read in as D_WCAP]
r	=	NGTDM region
t	=	forecast year

Finally, the storage tariff curve by region can be expressed as a function of a base point [price and quantity (PNOD, QNOD)], storage flow, and a price elasticity, as follows:

current capacity segment:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA\_STR} \tag{295}$$

capacity expansion segment:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA2\_STR} \tag{296}$$

where,

$X1NGSTR\_VARTAR_{r,t}$	=	function to define storage tariffs (1987$/Mcf)
$PNOD_{r,t}$	=	base point, price (1987$/Mcf)
$QNOD_{r,t}$	=	base point, quantity (Bcf)
$Q_{r,t}$	=	regional storage flow (Bcf)

ALPHA_STR = price elasticity for storage tariff curve for current capacity (Appendix E)
ALPHA2_STR = price elasticity for storage tariff curve for capacity expansion segment (Appendix E)
r = NGTDM region
t = forecast year

Alaska and Mackenzie delta pipeline tariff routine

A single routine (FUNCTION NGFRPIPE_TAR) estimates the potential per-unit pipeline tariff for moving natural gas from either the North Slope of Alaska or the Mackenzie Delta to the market hub in Alberta, Canada for the years beyond the specified in-service date. The tariff estimates are based on a simple cost-of-service rate base methodology, given the infrastructure's initial capital cost at the beginning of the construction period (FR_CAPITL0 in billion dollars, Appendix E), the assumed number of years for the project to be completed (FR_PCNSYR, Appendix E), the associated discount rate for the project (FR_DISCRT, Appendix E), the initial capacity (a function of delivered volume FR_PVOL, Appendix E), and the number of years over which the final cost of capitalization is assumed completely amortized (INVEST_YR=15). The input values vary depending on whether the tariff being calculated is associated with a pipeline for Alaska or for Mackenzie Delta gas. The cost of service consists of the following four components: depreciation, depletion, and amortization; after-tax operating income (known as the return on rate base); total operating and maintenance expenses; and total income taxes. The computation of each of the four components in nominal dollars per Mcf is described below:

Depreciation, depletion, and amortization, FR_DDA_t

The depreciation is computed as the final cost of capitalization at the start of operations divided by the amortization period. The depreciation equation is provided below:

$$FR\_DDA_t = FR\_CAPITL1 / INVEST\_YR \tag{297}$$

where,

FR_DDA_t = depreciation, depletion, and amortization costs (thousand nominal dollars)
FR_CAPITL1 = final cost of capitalization at the start of operations (thousand nominal dollars)
INVEST_YR = investment period allowing recovery (parameter, INVEST_YR=15)
t = forecast year

The structure of the final cost of capitalization, FR_CAPITL1, is computed as follows:

$$FR\_CAPITL1 = FR\_CAPIT0 / FR\_PCNSYR * [(1+r)+(1+r)^2+...+(1+r)^{FR\_PCNSYR}] \tag{298}$$

where,

FR_CAPITL1 = final cost of capitalization at the start of operations (thousand nominal dollars)

FR_CAPITL0 = initial capitalization (thousand FR_CAPYR dollars), where FR_CAPYR is the year dollars associated with this assumed capital cost (Appendix E)
FR_PCNSYR = number of construction years (Appendix E)
r = cost of debt, fraction, which is equal to the nominal 10-year Treasury bill (MC_RMTCM10Y or TNOTE, in percent) plus a debt premium in percent (debt premium set to FR_DISCRT, Appendix E)

The net plant in service is tied to the depreciation by the following formulas:

$$\begin{aligned} FR\_NPIS_t &= FR\_GPIS_t - FR\_ADDA_t \\ FR\_ADDA_t &= FR\_ADDA_{t-1} + FR\_DDA_t \end{aligned} \qquad (299)$$

where,

FR_GPIS_t = original capital cost of plant in service (gross plant in service) in thousand nominal dollars, set to FR_CAPITL1.
FR_NPIS_t = net plant in service (thousand nominal dollars)
FR_ADDA_t = accumulated depreciation, depletion, and amortization in thousand nominal dollars
t = forecast year

After-tax operating income (return on rate base), FR_TRRB_t

This after-tax operating income, also known as the return on rate base, is computed as the net plant in service times an annual rate of return (FR_ROR, Appendix E). The net plant in service, FR_NPIS_t, is updated each year and is equal to the initial gross plant in service minus accumulated depreciation. Net plant in service becomes the adjusted rate base when other capital-related costs such as materials and supplies, cash working capital, and accumulated deferred income taxes are equal to zero.

The return on rate base is computed as follows:

$$FR\_TRRB_t = WACC_t * FR\_NPIS_t \qquad (300)$$

where,

$$\begin{aligned} WACC_t = {} & FR\_DEBTRATIO * COST\_OF\_DEBT_t + \\ & (1.0 - FR\_DEBTRATIO) * COST\_OF\_EQUITY_t \end{aligned} \qquad (301)$$

and

$$COST\_OF\_DEBT_t = (TNOTE_t + FR\_DISCRT) / 100. \qquad (302)$$

$$COST\_OF\_EQUITY_t = (TNOTE_t \; / 100. \qquad (303)$$

where,

FR_TRRB_t = after-tax operating income or return on rate base (thousand nominal dollars)
$WACC_t$ = weighted average cost of capital (fraction), nominal
FR_NPIS_t = net plant in service (thousand nominal dollars)

$COST\_OF\_DEBT_t$	=	cost of debt (fraction)
$COST\_OF\_EQUITY_t$	=	cost of equity (fraction)
$TNOTE_t$	=	nominal 10-year Treasury bill rate, (MC_RMTCM10Yt, percent) provided by the Macroeconomic Activity Module
FR_DISCRT	=	user-set debt premium, percent (Appendix E)
FR_ROR_PREM	=	user-set risk premium, percent (Appendix E)
t	=	forecast year

Total taxes, FR_TAXES_t

Total taxes consist of federal and state income taxes and taxes other than income taxes. Each tax category is computed based on a percentage times net profit. These percentages are drawn from the Foster financial report's 28 major interstate natural gas pipeline companies. The percentage for income taxes (FR_TXR) is computed as the average over five years (1992-1996) of tax-to-net-operating-income ratio from the Foster report. Likewise, the percentage (FR_OTXR) for taxes other than income taxes is computed as the average over five years (1992-1996) of taxes-other-than-income-taxes-to-net-operating-income ratio from the same report. Total taxes are computed as follows:

$$FR\_TAXES_t = (FR\_TXR + FR\_OTXR) * FR\_NETPFT_t \tag{304}$$

where,

FR_TAXES_t	=	total taxes (thousand nominal dollars)
FR_NETPFT_t	=	net profit (thousand nominal dollars)
FR_TXR	=	5-year average Lower 48 pipeline proxy income tax rate (Appendix E)
FR_OTXR	=	5-year average Lower 48 pipeline proxy other income tax rate (Appendix E)
t	=	forecast year

Net profit, FR_NETPFT, is computed as the return on rate base (FR_TRRB_t) minus the long-term debt (FR_LTDt), which is calculated as the return on rate base times long-term debt rate times the debt to capital structure ratio. The net profit and long-term debt equations are provided below:

$$FR\_NETPFT_t = (FR\_TRRB_t - FR\_LTD_t) \tag{305}$$

$$\begin{aligned} FR\_LTD_t = {} & FR\_DEBTRATIO * \\ & (TNOTE_t + FR\_DISCRT) / 100.0 * FR\_NPIS_t \end{aligned} \tag{306}$$

where,

FR_LTD_t	=	long-term debt (thousand nominal dollars)
FR_NPIS_t	=	net plant in service (thousand nominal dollars)
FR_DEBTRATIO	=	5-year average Lower 48 pipeline debt structure ratio (Appendix E)
FR_NETPFT_t	=	net profit (thousand nominal dollars)
FR_TRRB_t	=	return on rate base (thousand nominal dollars)
$TNOTE_t$	=	nominal 10-year Treasury bill, (MC_RMTCM10Y, percent) provided by the Macroeconomic Activity Module
FR_DISCRT	=	user-set debt premium, percent (Appendix E)

t = forecast year

In the above equations, the long-term debt rate is assumed equal to the 10-year Treasury bill plus a debt premium, which represents a risk premium generally charged by financial institutions. When 10-year Treasury bill rates are needed for years beyond the last forecast year (LASTYR), the variable $TNOTE_t$ becomes the average over a number of years (FR_ESTNYR, Appendix E) of the 10-year Treasury bill rates for the last forecast years.

Cost of service, FR_COS_t

The cost of service is the sum of four cost-of-service components computed above, as follows:

$$\begin{aligned} FR\_COS_t &= FR\_TRRB_t + FR\_DDA_t + FR\_TAXES_t + \\ &(FR\_PVOL * 1.1484 * 1000.0 * \\ &FR\_TOM_{FR\_CAPYR} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{FR\_CAPYR}}) \end{aligned} \tag{307}$$

where,

FR_COS_t = cost of service (thousand nominal dollars)
FR_TRRB_t = return on rate base (thousand nominal dollars)
FR_DDA_t = depreciation (thousand nominal dollars)
FR_TAXES_t = total taxes (thousand nominal dollars)
$FR\_TOM_{FR\_CAPYR}$ = total operating and maintenance expenses (in nominal dollars per Mcf, set constant in real terms) (Appendix E)
MC_PCWGDP_t = GDP price deflator (from Macroeconomic Activity Module)
FR_PVOL = maximum volume delivered to Alberta in dry terms (Bcf/year)
1.1484 = factor to convert delivered dry volume to wet gas volume entering the pipeline as a proxy for the pipeline capacity
t = forecast year

Hence, the annual pipeline tariff in nominal dollars is computed by dividing the above cost of service by total pipeline capacity, as follows:

$$COS_t = FR\_COS_t / (FR\_PVOL * 1.1484 * 1000.0) \tag{308}$$

where,

COS_t = per-unit cost of service or annual pipeline tariff (nominal dollars/Mcf)
t = forecast year

To convert this nominal tariff to 1987 dollars per Mcf, the GDP implicit price deflator variable provided by the Macroeconomic Activity Module is needed. The real tariff equation is written as follows:

$$COSR_t = COS_t / MC\_PCWGDP_t \tag{309}$$

where,

$COSR_t$ = annual real pipeline tariff (1987$/Mcf)
MC_PCWGDP_t = GDP price deflator (from Macroeconomic Activity Module)
t = forecast year

Last, the annual average tariff is computed as the average over a number of years (FR_AVGTARYR, Appendix E) of the first successive annual cost of services.

7. Model Assumptions, Inputs, and Outputs

This last chapter summarizes the model and data assumptions used by the Natural Gas Transmission and Distribution Module (NGTDM), and lists the primary data inputs to and outputs from the NGTDM.

Assumptions

This section presents a brief summary of the assumptions used within the NGTDM. Generally, there are two types of data assumptions that affect the NGTDM solution values. The first type can be derived based on historical data (past events), and the second type is based on experience and/or events that are likely to occur (expert or analyst judgment). A discussion of the rationale behind assumed values based on analyst judgment is beyond the scope of this report. Most of the FORTRAN variables related to model input assumptions, both those derived from known sources and those derived through analyst judgment, are identified in this chapter, with background information and actual values referenced in Appendix E.

The assumptions summarized in this section are mentioned in Chapters 2 through 6. They are used in NGTDM equations as starting values, coefficients, factors, shares, bounds, or user-specified parameters. Six general categories of data assumptions have been defined: classification of market services; demand, transmission and distribution service pricing; pipeline tariffs and associated regulation; pipeline capacity and utilization; and supply (including imports). These assumptions, along with their variable names, are summarized below.

Market service classification

Non-electric sector natural gas customers are classified as either core or noncore customers, with core customers defined as the type of customer that is expected to generally transport their gas under firm (or near-firm) transportation agreements and noncore customers expected to generally transport their gas under non-firm (interruptible or short-term capacity release) transportation agreements. The residential, commercial, and transportation (natural gas vehicles) sectors are assumed to be core customers. The transportation sector is further subdivided into fleet and personal vehicle customers with LNG and CNG vehicles, as well as CNG and LNG use in trains and ships. Industrial and electric generator end users fall into both categories, with energy-intensive industries and refineries assumed to be noncore and all other industrial users assumed to be core, and gas steam units or gas combined-cycle units assumed to be core and all other electric generators assumed to be noncore. Currently the core/noncore distinction for electric generators is not being used in the model.

Demand

The peak period is defined (*using PKOPMON*) to run from December through March, with the off-peak period filling up the remainder of the year.

The Alaskan natural gas consumption levels for residential and commercial sectors are primarily defined as a function of the number of customers (*AK_RN, AK_CM, Tables F1, F2*), which in turn are set based on an exogenous projection of the population in Alaska (*AK_POP*). Alaskan gas consumption is disaggregated into North and South Alaska in order to separately compute the natural gas production forecasts in these regions. Lease, plant, and pipeline fuel related to an Alaska pipeline to Alberta or to a new LNG export facility is set at an assumed percentage of their associated gas volumes (*AK_PCTPLT, AK_PCTPIP, AK_PCTLSE*).

The remaining lease and plant fuel is assumed to be consumed in the North and set based on historical trends. The amount of gas consumed by other sectors in North Alaska is small enough to assume as zero and to allow for the setting of South Alaska volumes equal to the totals for the State. Industrial consumption in South Alaska is set to the exogenously specified sum of the level of gas consumed at the Agrium fertilizer plant and at the liquefied natural gas plant (*AK_QIND_S*). Pipeline fuel in the South is set as a percentage (*AK_PCTPIP*) of consumption and exports. Production in the south is set to total consumption levels in the region. In the North, production equals the flow along an Alaska pipeline to Alberta or to a new LNG export facility, associated lease, plant, and pipeline fuel for either of these two projects, and the other calculated lease and plant fuel. The forecast for reporting discrepancy in Alaska (*AK_DISCR*) is set to an average historical value. To compute natural gas prices by end-use sector for Alaska, fixed markups derived from historical data (*AK_RM, AK_CM, AK_IN, AK_EM*) are added to the average Alaskan natural gas wellhead price over the North and South regions. The wellhead price is set using a simple estimated equation (*AK_F*). Historically based percentages and markups are held constant throughout the forecast period.

The shares (NG_CENSHR) for disaggregating non-electric Census Division demands to NGTDM regions are held constant throughout the forecast period and are based on average historical relationships (SQRS, SQCM, SQIN, SQTR). Similarly, the shares for disaggregating end-use consumption levels to peak and off-peak periods are held constant throughout the forecast, and are directly (*United States -- PKSHR_DMD, PKSHR_UDMD_F, PKSHR_UDMD_I*) or partially (*Canada -- PKSHR_CDMD*) historically based.

Canadian consumption levels are set exogenously (*CN_DMD*) based on another published forecast, and adjusted if the associated world oil price changes. Consumption, base-level production, and domestically consumed LNG imports into Mexico are set exogenously (*PEMEX_GFAC, IND_GFAC, ELE_GFAC, RC_GFAC, PRD_GFAC, MEXLNG*). After the base-level production is adjusted based on the average U.S. spot price, exports to Mexico are set to balance supply and consumption. Historically based shares (*PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, PKSHR_ILNG, PKSHR_ELNG*) are applied to projected/historical values for natural gas exports and imports (*SEXP, SIMP, CANEXP, Q23TO3, FLO_THRU_IN,OGQNGEXP*). These historically based shares are generated from monthly historical data (*MON_QEXP, MON_QIMP*). LNG exports of domestically produced natural gas (*OGQNGEXP*) are set endogenously based on assumptions driving the price of natural gas in Europe and Asia relative to domestic prices. Reexported LNG volues (*REEXP*), are set exogenously.

Lease and plant fuel consumption in each NGTDM region is computed as an historically derived percentage (*using SQLP*) of dry gas production (*PCTLP*) in each NGTDM/OGSM region. These percentages are held constant throughout the forecast period. Natural gas used in the process of liquefying natural gas for export or for use in vehicles is added to this base-level lease and plant fuel projection and set as a percentage (PERLIQFUEL) of the associated LNG volumes. Pipeline fuel use is derived using historically (*SQPF*) based factors (*PFUEL_FAC*) relating pipeline fuel use to the quantity of natural gas exiting a regional node. Values for the most recent historical year are derived from monthly-published figures (*QLP_LHIS, NQPF_TOT*).

Projections of LNG exports of domestically produced gas depend on estimates of natural gas prices in Europe and Asia, set as a function of projections flexibly priced LNG in the market (*FLEXLNG*), for natural gas consumption in OECD Europe, Japan, and South Korea, and production and consumption in China

(*QOECD_EUR, QJAP, QSKOR, QCHINA, PCHINA*), as well as world oil prices. Domestic prices plus LNG related costs for liquefaction, shipping, and regasification (*CST_LIQ, CST_SHP, CST_RGAS, CST_RISK, BONUS, LOSSTO, PERFUELCST, DCF_RATE, BONUS*) are compared against these world natural gas price estimates to determine the economic viability over the next 20 years for building a generic liquefaction facility and ultimately the level of LNG exports. Each generic project consists of two trains of standard size (*EVOL_INCR*), with a limit of three trains allowed to come online in each calendar year. The siting of a new project depends on relative expected profitability and assumed regional limitations (*FYREXP, MAXEXP*).

Pricing of Distribution Services

End-use prices for residential, commercial, industrial, and transportation customers are derived by adding markups to the regional hub price of natural gas which has pipeline reservation charges added. Each regional end-use markup consists of an intraregional interstate tariff (*INTRAREG_TAR*), an intrastate tariff (*INTRAST_TAR*), a distribution tariff (*endogenously defined*), and a city gate benchmark factor [endogenously defined based on historical seasonal city gate prices (*HCGPR*)]. Historical distributor tariffs are derived for all end-use sectors as the difference between historical city gate and end-use prices (*SPRS, SPCM, SPIN, SPEU, SPTR, PRS, PCM PIN, PEU*).[97] Historical industrial end-use prices for core (non-energy-intensive) and noncore (energy-intensive) customers are derived in the module using econometrically estimated equations (Table F5). The residential, commercial, and industrial distributor tariffs are also based on econometrically estimated equations (Tables F4, F6, and F7). The electric generator distributor markup, and therefore the associated delivered price (*SPEU, PEU*), is based on the regional hub price that does not include pipeline reservation fees and is assumed to change in response to the market share of electric generator natural gas consumption relative to that of the other sectors. In this case the markup is set directly off of the regional hub price, which is benchmarked to an historical representative regionalspot price by adding a spot price benchmark factor (*BSPOT*). The distributor tariffs for the personal (PV) and fleet vehicle (FV) customers of LNG and CNG vehicle fuels are set using using historical data on natural gas delivery charges, electric generator markups (as a proxy), a decline rate (*TRN_DECL*), state and federal taxes (*STAX, FTAX*), and assumed dispensing costs/charges (*RETAIL_COST*) which include relevant costs for LNG liquefaction/distribution. CNG and LNG for ships and trains are priced the same as for fleet vehicles except state only and state and federal, respectively, motor fuels taxes are not included and LNG for trains is assumed to have lower liquefaction charges (TRAIN_DISC).

Prices for exports (and fixed volume imports) are based on historical differences between border prices (SPIM, SPEX, MON_PIMP, MON_PEXP) and their closest market hub price (as determined in the module when executed during the historical years).

Pipeline and storage tariffs and regulation

Peak and off-peak 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. Peak and off-peak market transmission service rates are based on a cost-of-service/rate-of-return calculation for current pipeline capacity times an assumed utilization rate (*PKUTZ, OPUTZ*). To reflect recent regulatory changes related to alternative ratemaking and capacity release

[97] All historical prices are converted from nominal to real 1987 dollars using a price deflator (GDP_B87).

developments, these tariffs are discounted (based on an assumed price elasticity) as pipeline utilization rates decline.

In the computation of natural gas pipeline transportation and storage rates, the Pipeline Tariff Submodule uses a set of data assumptions based on historical data or expert judgment. These include the following:

- Factors (*AFX, AFR, AVR*) to allocate each company's line-item costs into the fixed and variable cost components of the reservation and usage fees
- Historical regional spot prices (HNSPOT)to set usage fees to align with historical basis differentials
- Capacity reservation shares used to allocate cost-of-service components to portions of the pipeline network
- Average pipeline capital cost (2005 dollars) per unit of expanded capacity by arc (*AVG_CAPCOST*) used to derive total capital costs to expand pipeline capacity
- Storage capacity expansion cost parameters (*STCCOST_CREG, STCCOST_BETAREG, STCSTFAC*) used to derive total capital costs to expand regional storage capacity
- Input coefficients (ALPHA_PIPE, ALPH2_PIPE, ALPHA_STR, ALPHA2_STR, ADJ_STR, STR_EFF) for transportation and storage rates
- Pipeline tariff curve parameters by arc (PKSHR_YR, PTPKUTZ, PTOPUTZ, ALPHA_PIPE, ALPHA2_PIPE)
- Storage tariff curve parameters by region (STRATIO, STCAP_ADJ, PTSTUTZ, ADJ_STR, STR_EFF, ALPHA_STR, ALPHA2_STR)

In order to determine when a pipeline from either Alaska or the Mackenzie Delta to Alberta could be economic, the model estimates the tariff that would be charged on both pipelines should they be built, based on a number of assumed values. A simple cost-of-service/rate-of-return calculation is used, incorporating the following: initial capitalization (*FR_CAPITLO*); return on debt (*FR_DISCRT*) and return on equity (*FR_ROR_PREM*) (both specified as a premium added to the 10-year Treasury bill rate); total debt as a fraction of total capital (*FR_DEBTRATIO*); operation and maintenance expenses (*FR_TOM0*); federal income tax rate (*FR_TXR*); other tax rate (*FR_OTXR*); levelized cost period (*FR_AVGTARYR*); and depreciation period (*INVEST_YR*). In order to establish the ultimate charge for the gas in the Lower 48 states, assumptions were made for the minimum spot price (FR_PMINWPC) including production, treatment, and fuel costs, as well as the average differential between Alberta and the lower 48 (*ALB_TO_L48*) and a risk premium (*FR_PRISK*) to reflect cost and market uncertainties. The market price in the Lower 48 states must be maintained over a planning horizon (*FR_PPLNYR*) before construction would begin. Construction is assumed to take a set number of years (*FR_PCNSYR*) and result in a given initial capacity based on initial delivered volumes (*FR_PVOL*). An additional expansion is assumed on the condition of an increase in the market price (*FR_PADDTAR, FR_PEXPFAC*).

Pipeline and storage capacity and utilization

Historical and planned interregional, intraregional, and Canadian pipeline capacities are assigned in the module for the historical years and the first few years (*NOBLDYR*) into the forecast (*ACTPCAP, PTACTPCAP, PLANPCAP, SPLANPCAP, PER_YROPEN, CNPER_YROPEN*). The flow of natural gas along these pipeline corridors in the peak and off-peak periods of the historical years is set, starting with historical shares (*HPKSHR_FLOW*), to be consistent with the annual flows (*HAFLOW, SAFLOW*) and other known seasonal network volumes (e.g., consumption, production).

A similar assignment is used for storage capacities (*PLANPCAP, ADDYR*). The module only represents net storage withdrawals in the peak period and net storage injections in the off-peak period, which are known historically (*HNETWTH, HNETINJ, SNETWTH, NWTH_TOT, NINJ_TOT*).

For the forecast years, the use of both pipeline and storage capacity in each seasonal period is limited by exogenously set maximum utilization rates (*PKUTZ, OPUTZ, SUTZ*), not currently active for pipelines. They were intended to reflect an expected variant in the load throughout a season, but now adjustments are made within the module during the flow-sharing algorithm to reflect the seasonal load variation.

The decision concerning the share of gas that will come from each incoming source into a region for the purpose of satisfying the region's consumption levels (and some of the consumption upstream) is based on the relative costs of the incoming sources and assumed parameters (*GAMMAFAC, MUFAC*). During the process of deciding the flow of gas through the network, an iterative process is used that requires a set of assumed parameters for assessing and responding to nonconvergence (*PSUP_DELTA, QSUP_DELTA, QSUP_SMALL, QSUP_WT, MAXCYCLE*).

Supply

The supply curves for domestic lower 48 nonassociated dry gas production and for tight and other gas production from the WCSB are based on an expected production level, the former of which is set in the OGSM. Expected production from the WCSB is set in the NGTDM using a series of three econometric equations for new successful wells drilled, quantity proved per well drilled, and expected quantity produced per current level proved, and is dependent on resource assumptions (*RESBASE, RESTECH*). A set of parameters (*PARM_SUPCRV3, PARM_SUPCRV5, SUPCRV, PARM_SUPELAS*) defines the price change from a base or expected price as production deviates from this expected level. These supply curves are limited by minimum and maximum levels, calculated as a factor (*PARM_MINPR, MAXPRRFAC, MAXPRRCAN*) times the expected production levels. Domestic associated-dissolved gas production is provided by the Oil and Gas Supply Module. Eastern Canadian production from other than the WCSB is set exogenously (*CN_FIXSUP*). Natural gas production in Canada from both coal beds and shale is based on assumed production withdrawal profiles from their perspective resource base totals (*ULTRES, ULTSHL*) at an assumed exogenously specified price path and is adjusted relative to how much the actual western Canadian price differs from the assumed. Production from the frontier areas in Canada (i.e., the Mackenzie Delta) is set based on the assumed size of the pipeline to transport the gas to Alberta, should the pipeline be built. Production from Alaska is a function of the consumption in Alaska and the potential capacity of a pipeline from Alaska to Alberta or to an LNG export facility.

Imports from Mexico and Canada at each border crossing point are represented as follows: (1) Mexican imports are set exogenously (*EXP_FRMEX*) with the exception of LNG imported into Baja for U.S. markets; (2) Canadian imports are set endogenously (except for the imports into the East North Central region, (*Q23TO3*) and limited to Canadian pipeline capacities (*ACTPCAP, CNPER_YROPEN*), which are set in the module, and expand largely in response to the introduction of Alaskan gas into the Alberta system. Total gas imports from Canada exclude the amount of gas that travels into the United States and then back into Canada (*FLO_THRU_IN*).

Liquefied natural gas imports are represented with an east and west supply curves to North America generated based on output results from EIA's International Natural Gas Model and shared to representative regional terminals based on regasification capacity, last year's imports, and relative prices. Regasification capacity is set based on known facilities, either already constructed or highly likely to be (*LNGCAP*).

The three supplemental production categories (synthetic production of natural gas from coal and liquids and other supplemental fuels) are represented as constant supplies within the Interstate Transmission Submodule, with the exception of any production from potential new coal-to-gas plants. Synthetic production from the existing coal plant is set exogenously (*SNGCOAL*). Forecast values for the other two categories are held constant throughout the forecast and are set to historical values (*SNGLIQ, SUPPLM*) within the module. The algorithm for determining the potential construction of new coal-to-gas plants uses an extensive set of detailed cost figures to estimate the total investment and operating costs of a plant (including accounting for emissions costs, electricity credits, and lower costs over time due to learning) for use within a discounted cash flow calculation. If positive cash flow is estimated to occur the number of generic plants built is based on a Mansfield-Blackman market penetration algorithm. Throughout the forecast, the annual synthetic gas production levels are split into seasonal periods using an historically (*NSUPLM_TOT*) based share (*PKSHR_SUPLM*).

The supply component uses an assortment of input values in defining historical production levels and prices (or revenues) by the regions and categories required by the module (*QOF_ALST, QOF_ALFD, QOF_LAST, QOF_LAFD, QOF_CA, ROF_CA, QOF_LA, ROF_LA, QOF_TX, ROF_TX, AL_ONSH, AL_OFST, AL_OFFD, LA_ONSH, LA_OFST, lA_OFFD , ADW, NAW, TGD, MISC_ST, MISC_GAS, MISC_OIL, SMKT_PRD, SDRY_PRD, HQSUP, HPSUP, WHP_LHIS, SPWH*). A set of seasonal shares (*PKSHR_PROD*) have been defined based on historical values (*MONMKT_PRD*) to split production levels of supply sources that are nonvariant with price (*CN_FIXSUP* and others) into peak and off-peak categories.

Discrepancies that exist between historical supply and disposition level data are modeled at historical levels (*SBAL_ITM*) in the NGTDM and kept constant throughout the forecast years at average historical levels (*DISCR, CN_DISCR*).

Model inputs

The NGTDM inputs are grouped into six categories: mapping and control variables, annual historical values, monthly historical values, Alaskan and Canadian demand/supply variables, supply inputs, pipeline and storage financial and regulatory inputs, pipeline and storage capacity and utilization-related inputs, end-use pricing inputs, and miscellaneous inputs. Short input data descriptions and identification of variable names that provide more detail (via Appendix E) on the sources and transformation of the input data are provided below.

Mapping and control variables

- Variables for mapping from states to regions (SNUM_ID, SCH_ID, SCEN_DIV, SITM_REG, SNG_EM, SNG_OG, SIM_EX, MAP_PRDST)

- Variables for mapping import/export borders to states and to nodes (*CAN_XMAPUS, CAN_XMAPCN, MEX_XMAP, CAN_XMAP*)
- Variables for handling and mapping arcs and nodes (PROC_ORD,ARC_2NODE, NODE_2ARC, ARC_LOOP, SARC_2NODE, SNODE_2ARC, NODE_ANGTS, CAN_XMAPUS)
- Variables for mapping supply regions (NODE_SNGCOAL, MAPLNG_NG, OCSMAP, PMMMAP_NG, SUPSUB_NG, SUPSUB_OG)
- Variables for mapping demand regions (*EMMSUB_NG, EMMSUB_EL, NGCENMAP*)

Annual historical values

- Offshore natural gas production and revenue data (QOF_ALST, QOF_ALFD, QOF_LAST, QOF_LAFD, QOF_CA, ROF_CA, QOF_LA, ROF_LA, QOF_TX, ROF_TX, QOF_AL, ROF_AL, QOF_MS, ROF_MS, QOF_GM, ROF_GM, PRICE_CA, PRICE_LA, PRICE_AL, PRICE_TX, GOF_LA, GOF_AL, GOF_TX, GOF_CA, AL_ONSH, AL_OFST, AL_OFFD, LA_ONSH, LA_OFST, LA_OFFD, AL_ONSH2, AL_OFST2, AL_ADJ)
- State-level supply prices (*SPIM, SPWH*)
- State/sub-state-level natural gas production and other supply/storage data (ADW, NAW, TGD, TGW, MISC_ST, MISC_GAS, MISC_OIL, SMKT_PRD, SDRY_PRD, SIMP, SNET_WTH, SUPPLM)
- State-level consumption levels (SBAL_ITM, SEXP, SQPF, SQLP, SQRS, SQCM, SQIN, SQEU, SQTR)
- State-level end-use prices (SPEX, SPRS, SPCM, SPIN, SPEU, SPTR)
- Regional spot prices (*HNSPOT*)
- Miscellaneous (GDP_B87, OGHHPRNG)

Monthly historical values

- State-level natural gas production data (*MONMKT_PRD*)
- Import/export volumes and prices by source (*MON_QIMP, MON_PIMP, MON_QEXP, MON_PEXP, HQIMP*)
- Storage data (NWTH_TOT, NINJ_TOT, HNETWTH, HNETINJ)
- State-level consumption and prices (CON & PRC -- QRS, QCM, QIN, QEU, PRS, PCM, PIN, PEU)
- Electric power gas consumption and prices (*CON_ELCD, PRC_EPMCD, CON_EPMGR, PRC_EPMGR*)
- Miscellaneous monthly/seasonal data (NQPF_TOT, NSUPLM_TOT, WHP_LHIS, QLP_LHIS, HCGPR)

Alaskan, Canadian, & Mexican demand/supply variables

- Alaskan lease, plant, and pipeline fuel parameters (*AK_PCTPLT, AK_PCTPIP, AK_PCTLSE*)
- Alaskan consumption parameters (AK_QIND_S, AK_RN, AK_CM, AK_POP, AK_HDD, HI_RN)
- Alaskan pricing parameters (*AK_RM, AK_CM, AK_IN, AK_EM*)
- Canadian production and end-use consumption (*CN_FIXSUP, CN_DMD, PKSHR_PROD, PKSHR_CDMD*)
- Exogenously specified Canadian import/export related volumes (*CANEXP, Q23TO3, FLO_THRU_IN*)
- Historical western Canadian production and wellhead prices (*HQSUP, HPSUP*)
- Shale/coalbed western Canadian production parameters (ULTRES, ULTSHL, RESBASE, PKIYR, LSTYR0, PERRES, RESTECH, TECHGRW)
- Mexican production, LNG imports, and end-use consumption (*PEMEX_GFAC, IND_GFAC,ELE_GFAC,RC_GFAC, PRD_GFAC, MEXLNG*)

Supply inputs

- Liquefied natural gas supply curves and pricing (LNGCAP, PARM_LNGCRV3, PARM_LNGCRV5,PARM_LNGELAS, LNGPPT, LNGQPT, LNGMIN,PERQ, BETA,LNGTAR)
- Supply curve parameters (SUPCRV, PARM_MINPR, PARM_SUPCRV3, PARM_SUPCRV5, PARM_SUPELAS, MAXPRRFAC, MAXPRRNG, PARM_MINPR)
- Synthetic natural gas projection (SNGCOAL, SNGLIQ, NRCI_INV, NRCI_LABOR_NRCI_OPER,INFL_RT, FEDTAX_RT, STTAX_RT, INS_FAC, TAX_FAC, MAINT_FAC, OTH_FAC,BEQ_OPRAVG, BEQ_OPRHRSK, EMRP_OPRAVG, EMRP_OPRHRSK, EQUITY_OPRAVG, EQUITY_OPRHRSK, BEQ_BLDAVG, BEQ_BLDHRSK, EMRP_BLDAVG, EMRP_BLDHRSK, EQUITY_BLDAVG, EQUITY_BLDHRSK, BA_PREM, PCLADJ, CTG_CAPYR$, PRJSDECOM, CTG_BLDYRS, CTG_PRJLIFE, CTG_OSBLFAC, CTG_PCTENV, CTG_PCTCNTG, CTG_PCTLND, CTG_PCTSPECL, CTG_PCTWC, CTG_STAFF_LCFAC, CTG_OH_LCFAC, CTG_FSIYR, CTG_INCBLD, CTG_DCLCAPCST, CTG_DCLOPRCST, CTG_BASHHV, CTG_BASCOL, CTG_BCLTON, CTG_BASSIZ, CTG_BASCGS, CTG_BASCGSCO2, CTG_BASCGG, CTG_BASCGGCO2,CTG_NCL, CTG_NAM, CTG_CO2,LABORLOC, CTG_PUCAP, XBM_ISBL, XBM_LABOR, CTG_BLDX, CTG_IINDX, CTG_SINVST)

Pipeline and storage financial and regulatory inputs

- Rate design specification (AFX_PFEN, AFR_PFEN, AVR_PFEN, AFX_CMEN, AFR_CMEN, AVR_CMEN, AFX_LTDN, AFR_LTDN, AVR_LTDN, AFX_DDA, AFR_DDA, AVR_DDA, AFX_FSIT, AFR_FSIT, AVR_FSIT, AFX_DIT, AFR_DIT, AVR_DIT, AFX_OTTAX, AFR_OTTAX, AVR_OTTAX, AFX_TOM, AFR_TOM, AVR_TOM)
- Pipeline rate base parameters (D_TOM, D_DDA, D_OTTAX, D_DIT, D_GPIS, D_ADDA, D_NPIS, D_CWC, D_ADIT, D_APRB, D_GPFES, D_GCMES, D_GLTDS, D_PFER, D_CMER, D_LTDR)
- Storage rate base parameters (D_TOM, D_DDA, D_ADDA, D_OTTAX, D_FSIT, D_DIT, D_LTDN, D_PFEN, D_CMEN, D_GPIS, D_NPIS, D_CWC, D_ADIT, D_APRB, D_LTDS, D_PFES, D_CMES, D_TCAP D_WCAP)
- Pipeline and storage revenue requirement forecasting equation parameters (Table F3)
- Rate of return set for generic pipeline companies (*MC_RMPUAANS, ADJ_PFER, ADJ_CMER, ADJ_LTDR*)
- Rate of return set for existing and new storage capacity (*MC_RMPUAANS, ADJ_STPFER, ADJ_STCMER, ADJ_STLTDR*)
- Federal and state income tax rates (*FRATE, SRATE*)
- Depreciation schedule (30-year life)
- Pipeline capacity expansion cost parameter for capital cost equations (*AVG_CAPCOST*)
- Pipeline capacity replacement cost parameter (*PCNT_R*)
- Storage capacity expansion cost parameters for capital cost equations (*STCCOST_CREG, STCCOST_BETAREG, STCSTFAC*)
- Parameters for interstate pipeline transportation rates (PKSHR_YR, PTPKUTZ, PTOPUTZ, ALPHA_PIPE, ALPHA2_PIPE, HNSPOT)
- Canadian pipeline and storage tariff parameters (*ARC_FIXTAR, ARC_VARTAR, CN_FIXSHR*)
- Parameters for storage rates (STRATIO, STCAP_ADJ, PTSTUTZ, ADJ_STR, STR_EFF, ALPHA_STR, ALPHA2_STR)

- Parameters for Alaska-to-Alberta and Mackenzie Delta-to-Alberta pipelines (FR_CAPITL0, FR_CAPYR, FR_PCNSYR, FR_DISCRT, FR_PVOL, INVEST_YR,FR_ROR_PREM, FR_TOM0, FR_DEBTRATIO, FR_TXR, FR_OTXR, FR_ESTNYR, FR_AVGTARYR)

Pipeline and storage capacity and utilization related inputs

- Canadian natural gas pipeline capacity and planned capacity additions (*ACTPCAP, PTACTPCAP, PLANPCAP, CNPER_YROPEN*)
- Maximum peak and off-peak primary and secondary pipeline utilizations (*PKUTZ, OPUTZ, SUTZ, MAXUTZ, XBLD*)
- Interregional planned pipeline capacity additions along primary and secondary arcs (*PLANPCAP, SPLANPCAP, PER_YROPEN*)
- Maximum storage utilization (*PKUTZ*)
- Existing storage capacity and planned additions (*PLANPCAP, ADDYR*)
- Net storage withdrawals (peak) and injections (off-peak) in Canada (*HNETWTH, HNETINJ*)
- Historical flow data (HPKSHR_FLOW, HAFLOW, SAFLOW)
- Alaska-to-Alberta and Mackenzie Delta-to-Alberta pipeline (FR_PMINYR, FR_PVOL, FR_PCNSYR, FR_PPLNYR, FR_PEXPFAC, FR_PADDTAR, FR_PMINWPR, FR_PRISK, FR_PDRPFAC, FR_PTREAT, FR_PFUEL)

End-use pricing inputs

- Residential, commercial, industrial, and electric generator distributor tariffs (*OPTIND, OPTCOM, OPTRES, OPTELP, OPTELO, RECS_ALIGN, NUM_REGSHR, HHDD*)
- Intrastate and intraregional tariffs (*INTRAST_TAR, INTRAREG_TAR*)
- Historical city gate prices (*HCGPR*)
- State and federal taxes, costs to dispense, and other transportation sector pricing variables (*STAX, FTAX, RETAIL_COST, TRN_DECL,TRAIN_DISC*)

Miscellaneous

- Network processing control variables (MAXCYCLE, NOBLDYR,ALPHAFAC, GAMMAFAC, PSUP_DELTA, QSUP_DELTA, QSUP_SMALL, QSUP_WT, PCT_FLO, SHR_OPT, PCTADJSHR)
- Miscellaneous control variables (PKOPMON, NGDBGRPT, SHR_OPT, NOBLDYR)
- World volume and price indicators driving U.S. LNG exports (*FLEXLNG, OECD_EUR, QJAP, QSKOR, QCHINA, PCHINA, NGP87, JAP87*)
- Costs related to exporting LNG and associated modeling parameters (FYREXP, MAXEXP, CST_LIQ, CST_SHP, CST_RGAS, CST_RISK, PREFUELCCST, PKSHR_ELNG, LOSSTO, BONUS, EVOL_INCR, PERTOFLEX, DCF_RATE)
- STEO input data (STEOYRS, STQGPTR, STQLPIN, STOGWPRNG, STPNGRS, STPNGIN, STPNGCM, STPNGEL, STOGPRSUP, NNETWITH, STDISCR, STENDCON, STSCAL_CAN, STINPUT_SCAL, STSCAL_PFUEL, STSCAL_LPLT, STSCAL_WPR, STSCAL_DISCR, STSCAL_SUPLM, STSCAL_NETSTR, STSCAL_FPR, STSCAL_IPR, STPHAS_YR, STLNGIMP)

Model outputs

Once a set of solution values are determined within the NGTDM, those values required by other modules of NEMS are passed accordingly. In addition, the NGTDM module results are presented in a series of internal and external reports, as outlined below.

Outputs to NEMS modules

The NGTDM passes its solution values to different NEMS modules as follows:

- Pipeline fuel consumption and lease and plant fuel consumption by Census Division (to NEMS PROPER and REPORTS)
- Natural gas wellhead prices by Oil and Gas Supply Module region (to NEMS REPORTS, Oil and Gas Supply Module, and Liquid Fuels Market Module) and Henry Hub spot price (to NEMS REPORTS)
- Core and noncore natural gas prices by sector and Census Division (to NEMS PROPER and REPORTS, and NEMS demand modules)
- Dry natural gas production and supplemental gas supplies by Oil and Gas Supply Module region (NEMS REPORTS and Oil and Gas Supply Module)
- Peak/off-peak, core/noncore natural gas prices to electric generators by NGTDM/Electricity Market Module region (to NEMS PROPER and REPORTS and Electricity Market Module)
- Coal consumed, electricity generated, and CO_2 produced in the process of converting coal into pipeline-quality synthetic gas in newly constructed plants (to Coal Market Module, Electricity Market Module, and NEMS PROPER)
- Dry natural gas production by PADD region (to Liquid Fuels Market Module)
- Nonassociated dry natural gas production by NGTDM/Oil and Gas Supply Module region (to NEMS REPORTS and Oil and Gas Supply Module)
- Natural gas imports, exports, and associated prices by border crossing (to NEMS REPORTS)

Internal reports

The NGTDM produces reports designed to assist in the analysis of NGTDM model results. These reports are controlled with a user-defined variable (NGDBGRPT), include the following information, and are written to the indicated output file:

- Primary peak and off-peak flows, shares, and maximum constraints going into each node (NGOBAL)
- Intermediate results from the Distributor Tariff Submodule (NGODTM)
- Historical and forecast values historically based factors applied in the module (NGOBENCH)
- Intermediate results from the Pipeline Tariff Submodule (NGOPTM)
- Convergence tracking and error message report (NGOERR)
- Aggregate/average historical values for most model elements (NGOHIST)
- Node and arc level prices and quantities along the network by cycle (NGOTREE)

External reports

In addition to the reports described above, the NGTDM produces external reports to support recurring publications. These reports contain the following information:

- Natural gas end-use prices and consumption levels by end-use sector, type of service (core and noncore), and Census Division (and for the United States)
- Natural gas spot prices and production levels by NGTDM region (and the average for the Lower 48 states), including a price for the Henry Hub
- Natural gas end-use and city gate prices and margins
- Natural gas import and export volumes and import prices by source or destination
- Pipeline fuel consumption by NGTDM region (and for the United States)
- Natural gas pipeline capacity (entering and exiting a region) by NGTDM region and by Census Division
- Natural gas flows (entering and exiting a region) by NGTDM region and Census Division
- Natural gas pipeline capacity between NGTDM regions
- Natural gas flows between NGTDM regions
- Natural gas underground storage and pipeline capacity by NGTDM region
- Unaccounted-for natural gas[98]

[98] Unaccounted-for natural gas is a balancing item between the amount of natural gas consumed and the amount supplied. It includes reporting discrepancies, net storage withdrawals (in historical years), and differences due to convergence tolerance levels.

Appendix A. NGTDM Model Abstract

Model Name: Natural Gas Transmission and Distribution Module

Acronym: NGTDM

Title: Natural Gas Transmission and Distribution Module

Purpose: The NGTDM is the component of the National Energy Modeling System (NEMS) that represents the mid-term natural gas market. The purpose of the NGTDM is to derive natural gas supply and end-use prices and flow patterns for movements of natural gas through the regional interstate network. The prices and flow patterns are derived by obtaining a 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.

Status: ACTIVE

Use: BASIC

Sponsor: Office of Energy Analysis
Office of Petroleum, Natural Gas, and Biofuels Analysis, EI-33
Model Contact: Joe Benneche
Telephone: (202) 586-6132

Documentation: U.S. Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, July 2013).

Previous Documentation: U.S. Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, September 2012).

U.S. Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, February 2012).

U.S. Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, June 2010).

U.S. Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, June 2009).

U.S. Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, January 2009).

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U.S. Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, March 2004).

U.S. Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, May 2003).

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U.S. Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062/1 (Washington, DC, February 1995).

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Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Capacity Expansion Module (CEM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, April 30, 1993.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Pipeline Tariff Module (PTM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, April 30, 1993.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Distributor Tariff Module (DTM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, April 30, 1993.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Final Review of the National Energy Modeling System (NEMS) Natural Gas Transmission and Distribution Model (NGTDM)." Boston, MA, January 4, 1995.

Archival: The NGTDM is archived as a component of NEMS on compact disc storage compatible with the PC multiprocessor computing platform upon completion of the NEMS production runs to generate the *Annual Energy Outlook 2014*, DOE/EIA-0383(2014). Instructions for downloading the archival package can be found at: http://www.eia.gov/forecasts/aeo/info_nems_archive.cfm.

Energy System: The NGTDM models the U.S. natural gas transmission and distribution network that links the suppliers (including importers) and consumers of natural gas, and in so doing determines the regional market clearing natural gas end-use and supply (including border) prices.

Coverage: Geographic: Demand regions are the 12 NGTDM regions, which are based on the nine Census Divisions with Census Division 5 split further into South Atlantic and Florida, Census Division 8 split further into Mountain and Arizona/New Mexico, and Census Division 9 split further into California and Pacific with Alaska and Hawaii handled separately. Production is represented in the lower 48 at 17 onshore and 3 offshore regions. Import/export border crossings include three at the Mexican border, seven at the Canadian border, and 12 potential liquefied natural gas import and export regions. A simplified Canadian representation is subdivided into an eastern and western region, with potential LNG import facilities on both shores. Consumption, production, and LNG imports to serve the Mexico gas market are largely assumption-based and serve to set the level of exports to Mexico from the United States.

Time Unit/Frequency: Annually through 2040, including a peak (December through March) and off-peak forecast.

Product(s): Natural gas

Economic Sector(s): Residential, commercial, industrial, electric generators and transportation

Data Input Sources: (Non-DOE)

- The Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU), Section 1113.
  — Federal vehicle natural gas (VNG) taxes
- Canadian Association of Petroleum Producers Statistical Handbook
  — Historical Canadian supply and consumption data
- Office of Natural Resources Revenue

— Revenues and volumes for offshore production in Texas, California, and Louisiana

- Foster Pipeline and Storage Financial Cost Data
  — pipeline and storage financial data
- Data Resources Inc., U.S. Quarterly Model
  — Various macroeconomic data
- *Oil and Gas Journal*, "Pipeline Economics"
  — Pipeline annual capitalization and operating revenues
- Board of Governors of the Federal Reserve System Statistical Release, "Selected Interest Rates and Bond Prices"
  — Real average yield on 10-year U.S. government bonds
- International Fuel Tax Association, Inc.
  — compressed natural gas and liquefied natural gas vehicle taxes by state
- National Oceanic and Atmospheric Administration
  — State-level heating degree days
- U.S. Census
  — State-level population data for heating degree day weights
- Natural Gas Week
  — Canada storage withdrawal and capacity data
- PEMEX
  — Historical Mexico raw gas production by region
- Informes y Publicaciones, Anuario Estadísticas, Estadísticas Operativas, Producción de gas natural
  — Historical Mexico raw gas production by region
- Sener Prospectiva del Mercado de gas natural 2006-2015
  — Mexico LNG import projections
- Natural Gas Intelligence
  — Historical spot prices
- PFC Energy
  — Historical world flexibly priced LNG volumes

Data Input Sources

(DOE) Forms and/or Publications:

- *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216
  — Annual estimate of gas production for associated-dissolved and nonassociated categories by State/sub-state.
- *Natural Gas Annual*, DOE/EIA-0131
  — By state -- natural gas consumption by sector, dry production, imports, exports, storage injections and withdrawals, balancing item, state transfers, number of residential customers, fraction of industrial

market represented by historical prices, and city gate and end-use prices.
  - Supplemental supplies

- *Natural Gas Monthly*, DOE/EIA-0130
  - By month and state – natural gas consumption by sector, marketed production, net storage withdrawals, end-use prices by sector, city gate prices
  - By month – quantity and price of imports and exports by country, lease and plant consumption, pipeline consumption, supplemental supplies
- State Energy Data System (SEDS)
  - State-level annual delivered natural gas prices when not available in the Natural Gas Annual.
- *Electric Power Monthly*, DOE/EIA-0226
  - Monthly volume and price paid for natural gas by electric generators
- *Annual Energy Review*, DOE/EIA-0384
  - Gross domestic product and implicit price deflator
- EIA-846, "Manufacturing Energy Consumption Survey"
  - Base year average annual core industrial end-use prices
- *Short-Term Energy Outlook*, DOE/EIA-0131
  - National natural gas projections for first two years beyond history
  - Historical natural gas prices at the Henry Hub
- Department of Energy, *Natural Gas Imports and Exports*, Office of Fossil Energy
  - Import and export volumes and prices by border location
- Department of Energy, Alternative Fuels & Advanced Vehicles Data Center, including *Alternative Fuel Price Report*, Office of Energy Efficiency and Renewable Energy
  - Sample of retail prices paid for compressed natural gas for vehicles
  - State motor fuel taxes
- EIA-191, "Underground Gas Storage Report"
  - Used in part to develop working gas storage capacity data
- EIA-457, "Residential Energy Consumption Survey"
  - Number of residential natural gas customers
- *International Energy Outlook*, DOE/EIA-0484
  - Projection of natural gas consumption in Canada and Mexico
- *International Energy Annual*, DOE/EIA-0484
  - Historical natural gas data on Canada and Mexico

Models and other:
- National Energy Modeling System (NEMS)
  - Domestic supply and demand representations are provided interactively as inputs to the NGTDM from other NEMS models

- International Natural Gas Model (INGM)
  - — Provides information for setting LNG supply curves exogenously in the NGTDM

General Output Descriptions:

- Average natural gas end-use prices levels by sector and region
- Average natural gas production volumes and prices by region
- Average natural gas import and export volumes and prices by region and type
- Pipeline fuel consumption by region
- Lease and plant fuel consumption by region
- Flow of gas between regions by peak and off-peak period
- Pipeline capacity additions and utilization levels by arc
- Storage capacity additions by region

Related Models: NEMS (part of)

Model Features:

- Model Structure: Modular; three major components: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS).
  - — ITS Integrating submodule of the NGTDM. Simulates the natural gas price determination process by bringing together all major economic and technological factors that influence regional natural gas trade in the United States. Determines natural gas production and imports, flows, exports, and prices, pipeline capacity expansion and utilization, and storage capacity expansion and utilization for a simplified network representing the interstate natural gas pipeline system
  - — PTS Develops parameters for setting tariffs in the ITM for transportation and storage services provided by interstate pipeline companies
  - — DTS Develops markups for distribution services provided by LDCs and intrastate pipeline companies.

- Modeling Technique:
  - — ITS Heuristic algorithm, operates iteratively until supply/demand convergence is realized across the network
  - — PTS Econometric estimation and accounting algorithm
  - — DTS Econometric estimation
  - — Canada and Mexico supplies based on a combination of estimated equations and basic assumptions.

Model Interfaces: NEMS

Computing Environment:

- Hardware Used: Personal Computer
- Operating System: UNIX simulation
- Language/Software Used: FORTRAN
- Storage Requirement: 2,700K bytes for input data storage; 1,100K bytes for source code storage; and 17,500K bytes for compiled code storage
- Estimated Run Time: Varies from NEMS iteration and from computer processor, but rarely exceeds a quarter of a second per iteration and generally is less than 5 hundredths of a second.

Status of Evaluation Efforts:

Model developer's report entitled "Natural Gas Transmission and Distribution Model, Model Developer's Report for the National Energy Modeling System," dated November 14, 1994.

Date of Last Update: October 2013.

Appendix B. References

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National Energy Board, *Canada’s Energy Future: Energy Supply and Demand Projections to 2035*, November 2011.

Oil and Gas Journal, “Pipeline Economics,” published annually in various editions.

Woolridge, Jeffrey M., Introductory Econometrics: A Modern Approach, South-Western College Publishing, 2000.

Appendix C. NEMS Model Documentation Reports

The National Energy Modeling System is documented in a series of 15 model documentation reports, most of which are updated on an annual basis. Copies of these reports are available by contacting the National Energy Information Center, 202/586-8800.

Energy Information Administration, *Integrating Module of the National Energy Modeling System: Model Documentation 2012*, DOE/EIA-M057.

Energy Information Administration, *Model Documentation Report: Macroeconomic Activity Module (MAM) of the National Energy Modeling System*.

Energy Information Administration, *International Energy Module of the National Energy Modeling System: Model Documentation 2011*.

Energy Information Administration, *Model Documentation Report: Residential Demand Module of the National Energy Modeling System*.

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Energy Information Administration, *The Electricity Market Module of the National Energy Modeling System*.

Energy Information Administration, *Documentation of the Oil and Gas Supply Module*.

Energy Information Administration, *Liquid Fuels Market Model of the National Energy Modeling System*.

Energy Information Administration, *Coal Market Module of the National Energy Modeling System, Model Documentation 2011*.

Energy Information Administration, *Model Documentation, Renewable Fuels Module of the National Energy Modeling System*.

Appendix D. Model Equations

This appendix presents the mapping of each equation (by equation number) in the documentation with the subroutine in the NGTDM code where the equation is used or referenced.

Equation number in documentation	SUBROUTINE (or FUNCTION*) in code
Chapter 2 Equations	
1	NGDMD_CRVF* (core), NGDMD_CRVI* (noncore)
2-19	NGSUP_PR*
20-25	NGOUT_CAN
26-39	NGCAN_FXADJ
40	NGOUT_MEX
41	NGSETLNG_INGM
42-44	NGDOMEXP
45-56	NGTDM_DMDALK
Chapter 4 Equations	
55,608	NGSET_NODEDMD, NGDOWN_TREE
e	NGSET_NODECDMD
59, 62	NGSET_YEARCDMD
63, 64	NGDOWN_TREE
65	NGSET_INTRAFLO
66	NGSET_INTRAFLO
67	NGSHR_CALC
68	NGDOWN_TREE
69	NGSET_MAXFLO*
70-73	NGSET_MAXPCAP
74-78	NGSET_MAXFLO*
79-81	NGSET_ACTPCAP
82-83	NGSHR_MTHCHK
84-87	NGSET_SUPPR
88-90	NGSTEO_BENCHWPR
91-92	NGSET_ARCFEE
93-96	NGUP_TREE
97	NGSET_STORPR
98-99	NGUP_TREE
100	NGCHK_CONVNG
101	NGSET_SECPR
102	NGSET_BENCH, HNGSET_CGPR
103-108	NGSET_SECPR
Chapter 5 Equations	
109-113	NGDTM_FORECAST_DTARF

Equation number in documentation	SUBROUTINE (or FUNCTION*) in code
114-115	NGHIST_IPR
116-121	NGDTM_FORECAST_DTARF
122-125	NGDTM_FORECAST_TRNF
Chapter 6 Equations	
126-131, 135-153, 202-204	NGPREAD
132-134, 154-155	NGPIPREAD
175-193, 205, 207-220	NGPSET_PLCOS_COMPONENTS
156-165, 171, 206, 221-230, 237	NGPSET_PLINE_COSTS
166-170, 231-236, 237-242	NGPIPE_VARTAR*
250-252	NGSTREAD
243-249, 253-255, 259-286	NGPSET_STCOS_COMPONENTS
256-258	NGPST_DEVCONST
172-174, 287-291	X1NGSTR_VARTAR*
194-201	(accounting relationships, not part of code)
292-304	NGFRPIPE_TAR*

Appendix E. Model Input Variables Mapped to Data Input Files

This appendix provides a list of the FORTRAN variables, and their associated input files, that are assigned values through FORTRAN READ statements in the source code of the NGTDM. Information about all of these variables and their assigned values (including sources, derivations, units, and definitions) are provided in the indicated input files of the NGTDM. The data file names and versions used for *AEO2014* are identified below. These files are located on the EIA NEMS-F8 NT server. Electronic copies of these input files are available as part of the NEMS2014 archive package. The archive package can be downloaded from http://www.eia.gov/forecasts/aeo/info_nems_archive.cfm. In addition, the files are available upon request from Joe Benneche at (202) 586-6132 or Joseph.Benneche@eia.doe.gov.

ngcan.txt	V1.92	nghismn.txt	V1.40	ngptar.txt	V1.29
ngcap.txt	V1.40	nglngdat.txt	V1.117	nguser.txt	V1.192
ngdtar.txt	V1.51	ngmap.txt	V1.10		
nghisan.txt	V1.46	ngmisc.txt	V1.188		

File	Variable
NGCAN	ACTPCAP
NGCAP	ACTPCAP
NGCAP	ADDYR
NGPTAR	ADIT_C
NGPTAR	ADJ_PIP
NGPTAR	ADJ_STR
NGHISAN	ADW
NGPTAR	AFR_CMEN
NGPTAR	AFR_DDA
NGPTAR	AFR_DIT
NGPTAR	AFR_FSIT
NGPTAR	AFR_LTDN
NGPTAR	AFR_OTTAX
NGPTAR	AFR_PFEN
NGPTAR	AFR_TOM
NGPTAR	AFX_CMEN
NGPTAR	AFX_DDA
NGPTAR	AFX_DIT
NGPTAR	AFX_FSIT
NGPTAR	AFX_LTDN
NGPTAR	AFX_OTTAX
NGPTAR	AFX_PFEN
NGPTAR	AFX_TOM
NGDTAR	AHDD
NGMISC	AK_C
NGMISC	AK_CM
NGMISC	AK_CN
NGMISC	AK_D
NGMISC	AK_E
NGMISC	AK_EM
NGMISC	AK_ENDCONS_N
NGMISC	AK_F
NGMISC	AK_G
NGMISC	AK_HDD
NGMISC	AK_IN
NGMISC	AK_PCTLSE
NGMISC	AK_PCTPIP
NGMISC	AK_PCTPLT
NGMISC	AK_POP
NGMISC	AK_QIND_S
NGMISC	AK_RN
NGMISC	AKPIP1
NGMISC	AKPIP2

File	Variable
NGHISAN	AL_ADJ
NGHISAN	AL_FYR
NGHISAN	AL_LYR
NGHISAN	AL_OFFD
NGHISAN	AL_OFST
NGHISAN	AL_OFST2
NGHISAN	AL_ONSH
NGHISAN	AL_ONSH2
NGMISC	ALB_TO_L48
NGLNGDAT	ALNGA
NGLNGDAT	ALNGB
NGLNGDAT	ALP
NGPTAR	ALPHA_PIPE
NGPTAR	ALPHA_STR
NGPTAR	ALPHA2_PIPE
NGPTAR	ALPHA2_STR
NGUSER	ALPHAFAC
NGMAP	AMAP
NGCAN	ARC_FIXTAR
NGCAN	ARC_VARTAR
NGPTAR	AVG_CAPCOST
NGPTAR	AVR_CMEN
NGPTAR	AVR_DDA
NGPTAR	AVR_DIT
NGPTAR	AVR_FSIT
NGPTAR	AVR_LTDN
NGPTAR	AVR_OTTAX
NGPTAR	AVR_PFEN
NGPTAR	AVR_TOM
NGMISC	BA_PREM
NGMISC	BAJA_FIX
NGMISC	BAJA_LAG
NGMISC	BAJA_MAX
NGMISC	BAJA_STAGE
NGMISC	BAJA_STEP
NGMISC	BEQ_BLDAVG
NGMISC	BEQ_BLDHRSK
NGMISC	BEQ_OPRAVG
NGMISC	BEQ_OPRHRSK
NGLNGDAT	BET
NGPTAR	BNEWCAP_2003_2004
NGPTAR	BNEWCAP_POST2004
NGPTAR	BNEWCAP_PRE2003

File	Variable	File	Variable
NGLNGDAT	BONUS	NGMISC	CTG_BLDYRS
NGCAN	BPPrc	NGMISC	CTG_CAPYR$
NGCAN	BPPrcGr	NGMISC	CTG_CO2
NGLNGDAT	BUILT	NGMISC	CTG_DCLCAPCST
NGMAP	CAN_XMAPCN	NGMISC	CTG_DCLOPRCST
NGMAP	CAN_XMAPUS	NGMISC	CTG_FSTYR
NGCAN	CANEXP	NGMISC	CTG_IINDX
NGDTAR	CM_ADJ	NGMISC	CTG_INCBLD
NGDTAR	CM_ALP	NGMISC	CTG_INVLOC
NGDTAR	CM_LNQ	NGMISC	CTG_NAM
NGDTAR	CM_PKALP	NGMISC	CTG_NCL
NGDTAR	CM_RHO	NGMISC	CTG_OH_LCFAC
NGCAN	CN_DMD	NGMISC	CTG_OSBLFAC
NGCAN	CN_FIXSHR	NGMISC	CTG_PCTCNTG
NGCAN	CN_FIXSUP	NGMISC	CTG_PCTENV
NGCAN	CN_OILSND	NGMISC	CTG_PCTLND
NGCAN	CN_UNPRC	NGMISC	CTG_PCTSPECL
NGCAN	CN_WOP	NGMISC	CTG_PCTWC
NGUSER	CNCAPSW	NGMISC	CTG_PRJLIFE
NGDTAR	CNG_BUILDCOST	NGMISC	CTG_PUCAP
NGDTAR	CNG_HRZ	NGMISC	CTG_SINVST
NGDTAR	CNG_MARKUP	NGMISC	CTG_STAFF_LCFAC
NGDTAR	CNG_RETAIL_MARKU	NGPTAR	CWC_C
NGDTAR	CNG_WACC	NGPTAR	CWC_DISC
NGCAP	CNPER_YROPEN	NGPTAR	CWC_K
NGCAN	CNPLANYR	NGPTAR	CWC_RHO
NGHISMN	CON_ELCD	NGPTAR	CWC_TOM
NGHISMN	CON_EPMGR	NGPTAR	D_ADDA
NGCAN	CONNOL_ELAS	NGPTAR	D_ADIT
NGLNGDAT	CST_LIQ	NGPTAR	D_APRB
NGLNGDAT	CST_RGAS	NGPTAR	D_CMEN
NGLNGDAT	CST_RISK	NGPTAR	D_CMER
NGLNGDAT	CST_SHP	NGPTAR	D_CMES
NGLNGDAT	CST_SUNK	NGPTAR	D_CWC
NGMISC	CTG_BASCGG	NGPTAR	D_DDA
NGMISC	CTG_BASCGGCO2	NGPTAR	D_DIT
NGMISC	CTG_BASCGS	NGPTAR	D_FLO
NGMISC	CTG_BASCGSCO2	NGPTAR	D_FSIT
NGMISC	CTG_BASCOL	NGPTAR	D_GCMES
NGMISC	CTG_BASHHV	NGPTAR	D_GLTDS
NGMISC	CTG_BASSIZ	NGPTAR	D_GPFES
NGMISC	CTG_BCLTON	NGPTAR	D_GPIS
NGMISC	CTG_BLDX	NGPTAR	D_LTDN

File	Variable	File	Variable
NGPTAR	D_LTDR	NGDTAR	FDIFF
NGPTAR	D_LTDS	NGMISC	FE_CCOST
NGPTAR	D_MXPKFLO	NGMISC	FE_EXPFAC
NGPTAR	D_NPIS	NGMISC	FE_FR_TOM
NGPTAR	D_OTTAX	NGMISC	FE_PFUEL_FAC
NGPTAR	D_PFEN	NGMISC	FE_R_STTOM
NGPTAR	D_PFER	NGMISC	FE_R_TOM
NGPTAR	D_PFES	NGMISC	FE_STCCOST
NGPTAR	D_TCAP	NGMISC	FE_STEXPFAC
NGPTAR	D_TOM	NGMISC	FEDTAX_RT
NGPTAR	D_WCAP	NGLNGDAT	FLEXLNG
NGLNGDAT	DCF_RATE	NGCAN	FLO_THRU_IN
NGPTAR	DDA_C	NGCAN	FMASP
NGPTAR	DDA_NEWCAP	NGMISC	FR_AVGTARYR
NGPTAR	DDA_NPIS	NGMISC	FR_BETA
NGCAN	DECL_GASREQ	NGMISC	FR_CAPITL0
NGMISC	DEXP_FRMEX	NGMISC	FR_CAPYR
NGMISC	DFAC_TOMEX	NGMISC	FR_DEBTRATIO
NGCAN	DFr	NGMISC	FR_DISCRT
NGMAP	DMAP	NGMISC	FR_ESTNYR
NGCAN	DMASP	NGMISC	FR_OTXR
NGLNGDAT	DOMEXP	NGMISC	FR_PADDTAR
NGDTAR	EL_ALP	NGMISC	FR_PCNSYR
NGDTAR	EL_CNST	NGMISC	FR_PDRPFAC
NGDTAR	EL_PARM	NGMISC	FR_PEXPFAC
NGDTAR	EL_RESID	NGMISC	FR_PFUEL
NGDTAR	EL_RHO	NGMISC	FR_PMINWPR
NGMISC	ELE_GFAC	NGMISC	FR_PMINYR
NGMAP	EMMSUB_EL	NGMISC	FR_PPLNYR
NGMAP	EMMSUB_NG	NGMISC	FR_PRISK
NGMISC	EMRP_BLDAVG	NGMISC	FR_PTREAT
NGMISC	EMRP_BLDHRSK	NGMISC	FR_PVOL
NGMISC	EMRP_OPRAVG	NGMISC	FR_ROR_PREM
NGMISC	EMRP_OPRHRSK	NGMISC	FR_TOM0
NGMISC	EQUITY_BLDAVG	NGMISC	FR_TXR
NGMISC	EQUITY_BLDHRSK	NGPTAR	FRATE
NGMISC	EQUITY_OPRAVG	NGDTAR	FREE_YRS
NGMISC	EQUITY_OPRHRSK	NGCAN	FRMETH
NGPTAR	EXP_A	NGMAP	FSRGN
NGPTAR	EXP_B	NGHISAN	FSTYR_GOM
NGPTAR	EXP_C	NGMISC	FUTWTS
NGMISC	EXP_FRMEX	NGLNGDAT	FYREXP
NGHISAN	FDGOM	NGUSER	GAMMAFAC

File	Variable	File	Variable
NGHISAN	GATHER	NGMISC	IEA_PRD
NGMISC	GDP_B87	NGMISC	IFLG
NGLNGDAT	GEN_EVOL_INCR	NGCAN	IMASP
NGHISAN	GOF_AL	NGMISC	IMP_TOMEX
NGHISAN	GOF_CA	NGDTAR	IN_ALP
NGHISAN	GOF_LA	NGDTAR	IN_CNST
NGHISAN	GOF_TX	NGDTAR	IN_DIST
NGDTAR	HCG_BENCH	NGDTAR	IN_LNQ
NGHISAN	HCGPR	NGDTAR	IN_PKALP
NGCAN	HCUMSUCWEL	NGDTAR	IN_RHO
NGDTAR	HDYWHTLAG	NGMISC	IND_GFAC
NGMISC	HELE_SHR	NGMISC	INFL_RT
NGPTAR	HFAC_GPIS	NGCAN	INIT_GASREQ
NGPTAR	HFAC_REV	NGMISC	INS_FAC
NGDTAR	HHDD	NGDTAR	INTRAREG_TAR
NGMISC	HI_RN	NGDTAR	INTRAST_TAR
NGMISC	HIND_SHR	NGCAN	IRigA
NGCAN	HISTRESCAN	NGLNGDAT	JAP87
NGCAN	HISTWELCAN	NGHISMN	JNETWTH
NGCAN	HNETINJ	NGHISAN	LA_OFFD
NGHISAN	HNETINJ	NGHISAN	LA_OFST
NGCAN	HNETWTH	NGHISAN	LA_ONSH
NGHISAN	HNETWTH	NGMISC	LABORLOC
NGMISC	HPEMEX_SHR	NGPTAR	LEVELYRS
NGHISAN	HPIMP	NGMAP	LNG_XMAP
NGHISAN	HPIN	NGLNGDAT	LNGA
NGMISC	HPKSHR_FLOW	NGLNGDAT	LNGB
NGHISAN	HPKSHR_PROD	NGLNGDAT	LNGCAP
NGCAP	HPKUTZ	NGLNGDAT	LNGCRVOPT
NGHISAN	HPRC	NGMISC	LNGDATA
NGHISAN	HPSPOT	NGLNGDAT	LNGDIF_GULF
NGHISAN	HQIMP	NGMISC	LNGDIFF
NGHISAN	HQLNG	NGLNGDAT	LNGEXPCAP
NGCAN	HQSUP	NGLNGDAT	LNGFIX
NGHISMN	HQTY	NGLNGDAT	LNGFXEX
NGLNGDAT	HRATIO	NGLNGDAT	LNGHYR
NGMISC	HRC_SHR	NGLNGDAT	LNGMIN
NGDTAR	HW_ADJ	NGLNGDAT	LNGPPT
NGDTAR	HW_BETA0	NGLNGDAT	LNGPS
NGDTAR	HW_BETA1	NGLNGDAT	LNGQPT
NGDTAR	HW_RHO	NGLNGDAT	LNGQS
NGCAN	ICNBYR	NGLNGDAT	LNGTAR
NGMISC	IEA_CON	NGLNGDAT	LNGTRAIN

File	Variable	File	Variable
NGDTAR	LNGV_LOSS	NGCAN	NCNMX
NGLNGDAT	LOOKYR	NGHISMN	NEET_CON
NGLNGDAT	LOSSTO	NGMISC	NELE_SHR
NGLNGDAT	LOW_UTIL	NGHISAN	NET_CONP
NGLNGDAT	LRATIO	NGHISAN	NET_PRC
NGHISAN	LSTYR_MMS	NGMAP	NG_CENMAP
NGMISC	MAINT_FAC	NGHISMN	NGCFEL
NGMAP	MAP_NG	NGUSER	NGDBGCNTL
NGDTAR	MAP_NRG_CRG	NGUSER	NGDBGRPT
NGMAP	MAP_OG	NGMISC	NIND_SHR
NGMAP	MAPLNG_NEW	NGHISAN	NINJ_TOT
NGMAP	MAPLNG_NG	NGLNGDAT	NLNGA
NGLNGDAT	MAPLNGE_W	NGLNGDAT	NLNGB
NGDTAR	MAX_CNG_BUILD	NGUSER	NNETWITH
NGUSER	MAXCYCLE	NGUSER	NOBLDYR
NGLNGDAT	MAXEXP	NGMAP	NODE_ANGTS
NGLNGDAT	MAXPLNG	NGMAP	NODE_SNGCOAL
NGMISC	MAXPRRFAC	NGDTAR	NONU_ELAS_F
NGMISC	MAXPRRNG	NGDTAR	NONU_ELAS_I
NGLNGDAT	MAXTR	NGMISC	NPEMEX_SHR
NGCAP	MAXUTZ	NGHISAN	NQPF_TOT
NGMISC	MBAJA	NGMISC	NRC_SHR
NGMISC	MDPIP1	NGMISC	NRCI_INV
NGMISC	MDPIP2	NGMISC	NRCI_LABOR
NGMAP	MEX_XMAP	NGMISC	NRCI_OPER
NGMISC	MEXEXP_SHR	NGMAP	NSRGN
NGLNGDAT	MEXFXEX	NGDTAR	NSTAT
NGMISC	MEXIMP_SHR	NGHISMN	NSTSTOR
NGMISC	MEXLNG	NGHISAN	NSUPLM_TOT
NGLNGDAT	MEXLNGMIN	NGDTAR	NUM_REGSHR
NGPTAR	MILES	NGDTAR	NUMRS
NGPTAR	MINYR	NGHISMN	NWTH_TOT
NGHISAN	MISC_OIL	NGHISAN	NYR_MISS
NGHISAN	MON_PEXP	NGMAP	OCSMAP
NGHISAN	MON_PIMP	NGDTAR	oEL_MRKUP_BETA
NGHISAN	MON_QEXP	NGMISC	oEQGCELGR
NGHISMN	MON_QIMP	NGMISC	oEQGFELGR
NGHISMN	MONMKT_PRD	NGMISC	oEQGIELGR
NGHISMN	MSPLIT_STSUB	NGHISAN	OF_GM
NGUSER	MUFAC	NGMISC	oOGHHPRNG
NGHISAN	NAW	NGLNGDAT	OGQNGEXP
NGLNGDAT	NBP87	NGMISC	OGQNGEXP
NGLNGDAT	NCASE	NGCAP	OPPK

File	Variable
NGDTAR	OPTCOM
NGDTAR	OPTELO
NGDTAR	OPTELP
NGDTAR	OPTELS
NGDTAR	OPTIND
NGDTAR	OPTRES
NGMISC	oQGCELGR
NGMISC	oQGFEL
NGMISC	oQGFELGR
NGMISC	oQGIEL
NGMISC	oQGIELGR
NGMISC	oQNGEL
NGMISC	oSQGFELGR
NGMISC	oSQGIELGR
NGMISC	OTH_FAC
NGLNGDAT	PARM_LNGCRV3
NGLNGDAT	PARM_LNGCRV5
NGLNGDAT	PARM_LNGELAS
NGUSER	PARM_MINPR
NGUSER	PARM_SUPCRV3
NGUSER	PARM_SUPCRV5
NGUSER	PARM_SUPELAS
NGLNGDAT	PCHINA
NGMISC	PCLADJ
NGPTAR	PCNT_R
NGHISAN	PCT_AL
NGHISAN	PCT_LA
NGHISAN	PCT_MS
NGHISAN	PCT_TX
NGUSER	PCTADJSHR
NGUSER	PCTFLO
NGCAP	PEAK
NGMISC	PEMEX_GFAC
NGMISC	PEMEX_PRD
NGCAP	PER_YROPEN
NGHISAN	PERFDTX
NGLNGDAT	PERFUELCST
NGLNGDAT	PERLIQFUEL
NGDTAR	PERMG
NGLNGDAT	PERTOFLEX
NGPTAR	PIPE_FACTOR
NGCAN	PKSHR_CDMD
NGLNGDAT	PKSHR_ELNG

File	Variable
NGCAN	PKSHR_PROD
NGLNGDAT	PL1STCAP
NGLNGDAT	PL1STYR
NGCAP	PLANPCAP
NGLNGDAT	PLCAP
NGLNGDAT	PLNUM
NGLNGDAT	PLPRJ
NGLNGDAT	PLREG
NGLNGDAT	PLRISK
NGMAP	PMMMAP_NG
NGLNGDAT	PNGIMP
NGCAN	PRat
NGHISMN	PRC_EPMCD
NGHISMN	PRC_EPMGR
NGMISC	PRCWTS
NGMISC	PRCWTS2
NGMISC	PRD_GFAC
NGHISMN	PRD_MLHIS
NGHISAN	PRICE_AL
NGHISAN	PRICE_CA
NGHISAN	PRICE_LA
NGHISAN	PRICE_TX
NGMISC	PRJSDECOM
NGCAN	PRMETH
NGUSER	PSUP_DELTA
NGCAP	PTCURPCAP
NGCAN	PTMAXPCAP
NGPTAR	PTMBYR
NGPTAR	PTMSTBYR
NGHISAN	PUTL_POW
NGHISAN	PUTLFYR
NGHISAN	PUTLLYR
NGCAN	Q23TO3
NGMISC	QAK_ALB
NGLNGDAT	QCHINA
NGLNGDAT	QJAP
NGHISMN	QLP_LHIS
NGMISC	QMD_ALB
NGLNGDAT	QNGIMP
NGLNGDAT	QOECD_EUR
NGHISAN	QOF_AL
NGHISAN	QOF_ALFD
NGHISAN	QOF_ALST

File	Variable	File	Variable
NGHISAN	QOF_CA	NGHISAN	SPCM
NGHISAN	QOF_LA	NGPTAR	SPCNEWFAC
NGHISAN	QOF_LAFD	NGPTAR	SPCNODID
NGHISAN	QOF_LAST	NGPTAR	SPCNODN
NGHISAN	QOF_MS	NGPTAR	SPCPNODBAS
NGHISAN	QOF_TX	NGMISC	SPEMEX_SHR
NGLNGDAT	QSKOR	NGHISAN	SPEU
NGUSER	QSUP_DELTA	NGHISAN	SPEX
NGUSER	QSUP_SMALL	NGHISAN	SPIM
NGUSER	QSUP_WT	NGHISAN	SPIN
NGDTAR	RECS_ALIGN	NGHISAN	SPIN_PER
NGLNGDAT	REEXP	NGHISAN	SPRS
NGCAN	RESBASE	NGHISAN	SPTR
NGCAN	RESBASYR	NGHISAN	SPWH
NGCAN	RESTECH	NGHISAN	SQCM
NGDTAR	RETAIL_COST	NGHISAN	SQEU
NGDTAR	RETAIL_COSTL	NGHISAN	SQIN
NGCAN	RGrwth	NGHISAN	SQLP
NGHISAN	ROF_AL	NGHISAN	SQPF
NGHISAN	ROF_CA	NGHISAN	SQRS
NGHISAN	ROF_GM	NGHISAN	SQTR
NGHISAN	ROF_LA	NGPTAR	SRATE
NGHISAN	ROF_MS	NGMISC	SRC_SHR
NGHISAN	ROF_TX	NGHISAN	SSUPLM
NGDTAR	RS_ADJ	NGPTAR	STADIT_ADIT
NGDTAR	RS_ALP	NGPTAR	STADIT_C
NGDTAR	RS_COST	NGPTAR	STADIT_NEWCAP
NGDTAR	RS_LNQ	NGDTAR	STAX
NGDTAR	RS_PARM	NGDTAR	STAXL
NGDTAR	RS_PKALP	NGPTAR	STCCOST_BETAREG
NGDTAR	RS_RHO	NGPTAR	STCCOST_CREG
NGHISAN	SBAL_ITM	NGPTAR	STCSTFAC
NGHISAN	SDRY_PRD	NGPTAR	STCWC_CREG
NGMISC	SELE_SHR	NGPTAR	STCWC_RHO
NGHISAN	SEXP	NGPTAR	STCWC_TOTCAP
NGUSER	SHR_OPT	NGPTAR	STDDA_CREG
NGHISAN	SIMP	NGPTAR	STDDA_NEWCAP
NGMISC	SIND_SHR	NGPTAR	STDDA_NPIS
NGHISAN	SMKT_PRD	NGUSER	STDISCR
NGHISAN	SNET_WTH	NGUSER	STENDCON
NGHISAN	SNET_WTH	NGUSER	STEOYRS
NGHISAN	SNGCOAL	NGCAN	STEP_MX
NGMISC	SNGCOAL	NGUSER	STLNGIMP

File	Variable	File	Variable
NGUSER	STLNGRG	NGUSER	SUPCRV
NGUSER	STLNGRGN	NGMAP	SUPREG
NGUSER	STLNGYR	NGMAP	SUPSUB_NG
NGUSER	STLNGYRN	NGMAP	SUPSUB_OG
NGUSER	STOGPRSUP	NGMAP	SUPTYPE
NGUSER	STOGWPRNG	NGCAP	SUTZ
NGUSER	STPHAS_YR	NGMISC	TAX_FAC
NGUSER	STPIN_FLG	NGDTAR	TFD
NGUSER	STPNGCM	NGDTAR	TFDL
NGUSER	STPNGEL	NGDTAR	TFDYR
NGUSER	STPNGIN	NGDTAR	TFDYRL
NGUSER	STPNGRS	NGPTAR	TOM_BYEAR
NGUSER	STQGPTR	NGPTAR	TOM_BYEAR_EIA
NGUSER	STQLPIN	NGPTAR	TOM_C
NGPTAR	STR_EFF	NGPTAR	TOM_DEPSHR
NGPTAR	STR_FACTOR	NGPTAR	TOM_GPIS1
NGPTAR	STRATIO	NGPTAR	TOM_K
NGUSER	STSCAL_CAN	NGPTAR	TOM_RHO
NGUSER	STSCAL_DISCR	NGPTAR	TOM_YR
NGUSER	STSCAL_FPR	NGDTAR	TRN_DECL
NGUSER	STSCAL_IPR	NGCAN	TTRNCAN
NGUSER	STSCAL_LPLT	NGCAN	Ures
NGUSER	STSCAL_NETSTR	NGCAN	URG
NGUSER	STSCAL_PFUEL	NGDTAR	UTIL_ELAS_F
NGUSER	STSCAL_SUPLM	NGDTAR	UTIL_ELAS_I
NGUSER	STSCAL_WPR	NGHISMN	WHP_LHIS
NGHISAN	STSTATE	NGCAN	WLMETH
NGMISC	STTAX_RT	NGUSER	WPR4CAST_FLG
NGPTAR	STTOM_C	NGCAP	XBLD
NGPTAR	STTOM_RHO	NGMISC	XBM_ISBL
NGPTAR	STTOM_WORKCAP	NGMISC	XBM_LABOR
NGPTAR	STTOM_YR	NGCAN	YDCL_GASREQ
NGMAP	SUPARRAY	NGMISC	YR1$4

Appendix F. Derived Data

Table F1

Data: Parameter estimates for the Alaskan natural gas consumption equations for the residential and commercial sectors and the Alaskan natural gas wellhead price.

Author: John Zyren, EIA, 2012; Margaret Leddy, EIA, 2009

Source: Consumption, number of customers, wellhead price – Natural Gas Annual, DOE/EIA-0131; Alaska population – U.S. Census Bureau, Population Division; Unemployment rate – NEMS Macroeconomic Activity Module; Heating degree days – National Oceanic and Atmospheric Administration (Anchorage International Airport); Oil price – Petroluem Marketing Annual, DOE/EIA-0487.

Residential Natural Gas Consumption

The estimated equation for residential natural gas consumption is shown below:

$$CONS\_R_t = \beta_0 + (\beta_1 * CUST\_R_t) + (\beta_2 * HDD\_DVN_t)$$

where,

$CONS\_R_t$ = Alaska residential natural gas consumption in MMcf (AKQTY_F(1) in code)
$CUST\_R_t$ = thousands of Alaska residential gas customers (AK_RN in code). See the forecast equation for Alaska residential gas customers in Table F2.
HDD_DVN_t = the deviation from the normal heating degree day first lag (0 in forecast).
t = year

Regression diagnostics and parameters estimates:

Dependent Variable: CONS_R
Method: Least Squares
Date: 09/06/12 Time: 13:08
Sample: 1984 2011
Included observations: 28

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	4129.965	502.6366	8.216603	0.0000
CUST_R	133.6638	5.508943	24.26305	0.0000
HDD_DVN	1.154430	0.207722	5.557574	0.0000

R-squared	0.961437	Mean dependent var	16010.38
Adjusted R-squared	0.958352	S.D. dependent var	2755.974
S.E. of regression	562.4381	Akaike info criterion	15.60340
Sum squared resid	7908416.	Schwarz criterion	15.74613
Log likelihood	-215.4475	Hannan-Quinn criter.	15.64703
F-statistic	311.6415	Durbin-Watson stat	0.723680
Prob(F-statistic)	0.000000		

Commercial Natural Gas Consumption

A visual display of the data for commercial natural gas consumption shows clear discontinuities in the series. The particular reasons were not identified, but dummy variables were used in the estimation to account for the shifts. The estimated equation follows:

$$CONS\_C_t = \beta_0 + (\beta_1 * CUST\_C_t) + (\beta_2 * HDD\_DVN_t) + (\beta_3 * UNEMP_t) + (\beta_4 * L1995\_00) + (\beta_5 * L1982\_4) + (\beta_6 * 1985\_94)$$

where,

$CONS\_C_t$	=	Alaska commercial natural gas consumption in MMcf (AKQTY_F(2) in code)
$CUST\_C_t$	=	thousands of Alaska commercial gas customers (AK_CN in code). See the forecast equation in Table F2.
$UNEMP_t$	=	U.S. civilian unemployment rate as a percent (MC_RUC in code, set by NEMS Macroeconomic Activity Module)
HDD_DVNt	=	deviation of heating degree days from normal (10137.5)
L1995_00	=	dummy variable with value of 1 from 1995 through 2000, 0 elsewhere
L1982_4	=	dummy variable with value of 1 from 1982 through 1984, 0 elsewhere
L1985_94	=	dummy variable with value of 1 from 1985 through 1994, 0 elsewhere
t	=	year

Regression diagnostics and parameters estimates:

Dependent Variable: CONS_C
Method: Least Squares
Date: 09/10/12 Time: 10:30
Sample: 1977 2011
Included observations: 35

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	17251.45	966.5315	17.84882	0.0000
CUST_C	124.4554	47.10005	2.642361	0.0133
HDD_DVN	0.704712	0.224793	3.134944	0.0040
UNEMP	-285.1327	100.7858	-2.829095	0.0085
L1995_00	9134.813	389.9092	23.42805	0.0000
L1982_4	8688.231	511.1704	16.99674	0.0000
L1985_94	3942.051	290.8965	13.55138	0.0000

R-squared	0.975410	Mean dependent var	20228.66
Adjusted R-squared	0.970141	S.D. dependent var	4037.064
S.E. of regression	697.5924	Akaike info criterion	16.11000
Sum squared resid	13625786	Schwarz criterion	16.42107
Log likelihood	-274.9251	Hannan-Quinn criter.	16.21738
F-statistic	185.1155	Durbin-Watson stat	1.707457
Prob(F-statistic)	0.000000		

So, the equation in the code for the Alaska commercial natural gas consumption is:

$$AKQTY\_F(2)_t = (17251.45 + (124.4554 * AK\_CN_t) + (-285.1327 * MC\_RUC_t))/1000$$

Natural Gas Wellhead Price

The forecast equation for the natural gas wellhead price in South Alaska is estimated as follows, using AR(1) to correct for first-order serial correlation:

$$LNWELLHEAD\_PRICE_t = \beta_1 * LN\_IRAC87$$

where,

$LN\_WELLHEAD\_PRICE_t$ = average natural gas wellhead price in Alaska (1987$/Mcf) (AK_WPRC in code)
$IRAC87_t$ = World oil price (Imported Refinery Acquisition Cost) (1987$/barrel) (IT_WOP(1) in the code, which has been redefined as the Brent price and is set centrally in NEMS)
t = year

Regression diagnostics and parameters estimates:

Dependent Variable: LN_WELLHEAD_PRICE
Method: Least Squares
Date: 07/22/09 Time: 13:25
Sample (adjusted): 1974 2008
Included observations: 35 after adjustments
Convergence achieved after 6 iterations

	Coefficient	Std. Error
LN_IRAC87	0.280760	0.101743
AR(1)	0.934077	0.040455

R-squared	0.881227	Mean dependent var
Adjusted R-squared	0.877628	S.D. dependent var
S.E. of regression	0.189122	Akaike info criterion
Sum squared resid	1.180310	Schwarz criterion
Log likelihood	9.654637	Hannan-Quinn criter.
Durbin-Watson stat	2.121742	

Inverted AR Roots	.93

The forecast equation becomes:

$$AK\_WPRC_t = AK\_WPRC_{t-1}^{0.934077} * oIT\_WOP_{y,1}^{(0.280760*(1-0.934077))}$$

Data used in estimating parameters in Tables F1 and F2

	CONS_R	CONS_C	CUST_R	CUST_C	AK_POP	UNEMP	HDD_DVN	AK_WPRC	IT_WOP
	mmcf	mmcf	thousand	thousand	thousand	percent		87$/Mcf	87$/bbl
1977	11282	14564	30.00	5.00	397.220	7.10	-869.1	0.68	24.88
1978	12166	15208	33.00	5.00	402.051	6.10	-1078.4	0.83	23.31
1979	7313	15862	36.00	6.00	403.367	5.80	-807.8	0.77	32.01
1980	7917	16513	37.00	6.00	405.315	7.10	415.0	0.99	45.90
1981	7904	16149	40.00	6.00	418.488	7.60	-667.5	0.77	45.87
1982	10554	24232	48.00	7.00	449.611	9.70	1050.3	0.74	39.15
1983	10434	24693	55.00	8.00	488.417	9.60	-69.6	0.82	32.89
1984	11833	24654	63.00	10.00	513.703	7.50	-569.0	0.79	31.25
1985	13256	20344	65.00	10.00	532.492	7.20	406.6	0.78	28.34
1986	12091	20874	66.00	11.00	544.269	7.00	-375.3	0.51	14.38
1987	12256	20224	67.65	11.48	539.310	6.20	-419.8	0.94	18.13
1988	12529	20842	68.61	11.65	541.982	5.50	-180.7	1.23	14.08
1989	13589	21738	69.54	11.81	547.153	5.30	398.2	1.27	16.85
1990	14165	21622	70.81	11.92	553.120	5.62	712.4	1.24	19.52
1991	13562	20897	72.57	12.07	569.273	6.85	79.5	1.28	16.21
1992	14350	21299	74.27	12.20	587.073	7.49	532.3	1.19	15.42
1993	13858	20003	75.84	12.36	596.993	6.91	-811.6	1.18	13.37
1994	14895	20698	77.67	12.48	600.624	6.10	147.2	1.03	12.58
1995	15231	24979	79.47	12.58	601.345	5.59	-135.5	1.30	13.62
1996	16179	27315	81.35	12.73	604.918	5.41	839.7	1.26	16.10
1997	15146	26908	83.60	12.95	608.846	4.94	-419.9	1.40	14.22
1998	15617	27079	86.24	13.18	615.205	4.50	-86.0	1.00	9.14
1999	17634	27667	88.92	13.41	619.500	4.22	870.2	1.02	12.91
2000	15987	26485	91.30	13.71	626.932	3.97	-358.8	1.29	20.28
2001	16818	15849	93.90	14.00	632.716	4.74	-87.9	1.42	15.73
2002	16191	15691	97.08	14.34	641.729	5.78	-770.2	1.50	16.66
2003	16853	17270	100.40	14.50	649.466	5.99	-736.5	1.66	19.06
2004	18200	18373	104.36	14.00	659.653	5.54	-538.0	2.29	24.01
2005	18029	16903	108.40	14.12	667.146	5.08	-829.4	3.08	31.65
2006	20616	18544	112.27	14.38	674.583	4.61	396.5	3.64	37.06
2007	19843	18756	115.50	13.41	680.169	4.62	60.8	3.44	41.01
2008	21439	17025	119.04	12.76	686.818	5.80	864.2	3.88	55.44
2009	19978	16620	120.12	13.22	697.828	9.28	193.5	--	--
2010	18714	15920	121.17	13.00	710.231	9.63	-140.0	--	--
2011	19432	16203	122.21	12.78	716.575	9.07	80.8	--	--

Table F2

Data: Equations for the number of residential and commercial customers in Alaska

Author: John Zyren, EIA, 2012

Source: Number of customers – *Natural Gas Annual*, DOE/EIA-0131; Alaska population – U.S. Census Bureau, Population Division; Unemployment rate – NEMS Macroeconomic Activity Module; Heating degree days – National Oceanic and Atmospheric Administration (Anchorage International Airport).

a. Residential customers

The number of residential customers was estimated as a function of the population in Alaska as well as the U.S. unemployment rate. Visual analysis of the available data shows a definite disconnect in the percent change data beginning in the year 1986. Since stability tests indicate a significant regime shift after 1985, only data for subsequent years (1986 to 2011) were used in the current analysis. The estimating method was Ordinary Least Squares (OLS) using EViews Version 7 with lagged dependent variables used to correct for first-order serial correlation. The forecast equation follows:

$$CUST\_R_t = \beta_0 + \beta_1 * POP\_AK_t + \beta_2 * UNEMP_t + \beta_3 * CUST\_R_{t-1} + \beta_4 * CUST\_R_{t-2}$$

where,

$CUST\_R_e$ = thousands of Alaska residential gas customers (AK_RN in code)

POP_AK_t = Alaska population in thousands (AK_POP in code, Appendix E)

$UNEMP_t$ = U.S. civilian unemployment rate as a percent (MC_RUC in code, set by NEMS Macroeconomic Activity Module)

Regression diagnostics and parameters estimates:

Method: Least Squares
Date: 09/05/12 Time: 16:07
Sample (adjusted): 1986 2011
Included observations: 26 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-4.690027	3.624917	-1.293830	0.2098
POP_AK	0.017224	0.009672	1.780721	0.0894
UNEMP	-0.310546	0.091090	-3.409216	0.0026
CUST_R(-1)	1.464274	0.158065	9.263773	0.0000
CUST_R(-2)	-0.498923	0.161537	-3.088594	0.0056

R-squared	0.999411	Mean dependent var	91.08808
Adjusted R-squared	0.999299	S.D. dependent var	19.03747
S.E. of regression	0.504127	Akaike info criterion	1.639064
Sum squared resid	5.337026	Schwarz criterion	1.881006
Log likelihood	-16.30784	Hannan-Quinn criter.	1.708735
F-statistic	8907.635	Durbin-Watson stat	1.876857
Prob(F-statistic)	0.000000		

b. Commercial customers

The number of commercial consumers was estimated as a function of the population in Alaska, the deviation from normal heating degree days, and the U.S. civilian unemployment rate. Visual analysis of the data from 1973 through 2011 shows a definite disconnect in the percent change data beginning in the year 1988, so only data for subsequent years were used in the current analysis. There is some indication that another change may have occurred in 2003, hence the dummy variable (L2006) in the selected equation. The forecast equation was estimated using OLS and EViews Version 7, with data from 1987 to 2011 as follows:

$$CUST\_C_t = \beta 0 + (\beta_1 *POP\_AK_t) + (\beta_2 *HDD\_DVN_t)+(\beta_3 *UNEMP_t)+(\beta_4 *UNEMP_{t-1})+(\beta_5 *L2006)$$

where,

$CUST\_C_t$ = number of Alaska commercial gas customers, in thousands (AK_CM in the code)
POP_AK_t = Alaska population in thousands (AK_POP in code, Appendix E)
HDD_DVN_t = the deviation from normal heating degree days in Alaska (10137.5)
$UNEMP_t$ = U.S. civilian unemployment rate as a percent (MC_RUC in code, set by NEMS Macroeconomic Activity Module)
L2006 = dummy variable equal to 0 from 1987 through 2003 and 1 from 2004 forward.
t = year

Regression diagnostics and parameters estimates:

Dependent Variable: CUST_C
Method: Least Squares
Date: 09/05/12 Time: 16:19
Sample (adjusted): 1987 2011
Included observations: 25 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	4.053311	1.676962	2.417056	0.0259
POP_AK	0.017833	0.002733	6.524092	0.0000
HDD_DVN	-0.000497	0.000159	-3.136025	0.0054
UNEMP	-0.157808	0.094370	-1.672229	0.1109
UNEMP(-1)	-0.182030	0.100340	-1.814137	0.0855
L2006	-0.625477	0.298387	-2.096195	0.0497

R-squared	0.851056	Mean dependent var	13.00160
Adjusted R-squared	0.811860	S.D. dependent var	0.898692
S.E. of regression	0.389809	Akaike info criterion	1.159242
Sum squared resid	2.887065	Schwarz criterion	1.451772
Log likelihood	-8.490520	Hannan-Quinn criter.	1.240377
F-statistic	21.71291	Durbin-Watson stat	1.716340
Prob(F-statistic)	0.000000		

Table F3

Data: Coefficients for the following Pipeline Tariff Submodule forecasting equations for pipeline and storage: total cash working capital for the combined existing and new capacity; depreciation, depletion, and amortization expenses for existing capacity; accumulated deferred income taxes for the combined existing and new capacity; and total operating and maintenance expense for the combined existing and new capacity.

Author: Science Applications International Corporation (SAIC)

Source: Foster Pipeline Financial Data, 1997-2006
Foster Storage Financial Data, 1990-1998

Variables:

For Transportation:

R_CWC = total pipeline transmission cash working capital for existing and new capacity (2005 dollars)
DDA_E = annual depreciation, depletion, and amortization costs for existing capacity (nominal dollars)
NPIS_E = net plant in service for existing capacity in dollars (nominal dollars)
NEWCAP_E = change in existing gross plant in service (nominal dollars) between t and t-1 (set to zero during the forecast year phase since $GPIS\_E_{a,t} = GPIS\_E_{a,t+1}$ for year t >= 2007)
ADIT = accumulated deferred income taxes (nominal dollars)
NEWCAP = change in gross plant in service between t and t-1 (nominal dollars)
R_TOM = total operating and maintenance cost for existing and new capacity (2005 dollars)
GPIS = capital cost of plant in service for existing and new capacity (nominal dollars)
DEPSHR = level of the accumulated depreciation of the plant relative to the gross plant in service for existing and new capacity at the beginning of year t. This variable is a proxy for the age of the capital stock.
TECHYEAR = MODYEAR (time trend in Julian units, the minimum value of this variable in the sample being 1997, otherwise TECHYEAR=0 if less than 1997)
a = arc
t = forecast year

For Storage:

R_STCWC = total cash working capital at the beginning of year t for existing and new capacity (1996 dollars)
DSTTCAP = total gas storage capacity (Bcf)
STDDA_E = annual depreciation, depletion, and amortization costs for existing capacity (nominal dollars)
STNPIS_E = net plant in service for existing capacity (nominal dollars)

STNEWCAP = change in gross plant in service for existing capacity (nominal dollars)
STADIT = accumulated deferred income taxes (nominal dollars)
NEWCAP = change in gross plant in service for the combined existing and new capacity between years t and t-1 (nominal dollars)
R_STTOM = total operating and maintenance cost for existing and new capacity (1996 dollars)
DSTWCAP = level of gas working capacity for region r during year t (Bcf)
r = NGTDM region
t = forecast year

References: For transportation: “Memorandum describing the estimated and forecast equations for TOM, DDA, CWC, and ADIT for the new PTM,” by SAIC, June 23-July 22, 2008.

For storage: “Memorandum describing the estimated and forecast equations for TOM, DDA, CWC, and ADIT for the new PTM,” by SAIC, May 31, 2000.

Derivation: Estimations were done by using an accounting algorithm in combination with estimation software. Projections are based on a series of econometric equations which have been estimated using the Time Series Package (TSP) software. Equations were estimated by arc for pipelines and by NGTDM region for storage, as follows: total cash working capital for the combined existing and new capacity; depreciation, depletion, and amortization expenses for existing capacity; accumulated deferred income taxes for the combined existing and new capacity; and total operating and maintenance expense for the combined existing and new capacity. These equations are defined as follows:

(1) Total Cash Working Capital for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model.

Because of economies in cash management, a log-linear specification between total operating and maintenance expenses, R_TOM_a, and the level of cash working capital, R_CWC_a was assumed. To control for arc-specific effects, a binary variable was created for each of the arcs. The associated coefficient represents the arc-specific constant term.

The underlying notion of this equation is that working capital represents funds to maintain the capital stock and is therefore driven by changes in R_TOM.

The forecasting equation is presented in two stages.

Stage 1:

$$Ln(R\_CWC_{a,t}) = CWC\_C_a * (1-\rho) + CWC\_TOM * Ln(R\_TOM_{a,t}) + \rho * Ln(R\_CWC_{a,t-1}) - \rho * CWC\_TOM * Ln(R\_TOM_{a,t-1})$$

Stage 2:

$$R\_CWC_{a,t} = CWC\_K * \exp(Ln(R\_CWC_{a,t}))$$

where,

R_CWC	=	total pipeline transmission cash working capital for existing and new capacity (2005 dollars)
CWC_C_a	=	estimated arc-specific constant for gas transported from node to node (see Table F3.2)
CWC_TOM	=	estimated R_TOM coefficient (see Table F3.2)
R_TOM	=	total operation and maintenance expenses in 2005 dollars
CWC_K	=	correction factor estimated in stage 2 of the regression equation estimation process
ρ	=	autocorrelation coefficient from estimation (see Table F3.2 -- CWC_RHO)

Ln is a natural logarithm operator and CWC_K is the correction factor estimated in equation two.

The results of this regression are reported below:

Dependent variable: R_CWC
Number of observations: 396

Mean of dep. var.	= 18503.0	LM het. Test	= 135.638 [.000]
Std. dev. of dep. var.	= 283454.4	Durbin-Watson	= 2.29318 [<1.00]
Sum of squared residuals	= .116124E+11	Jarque-Bera test	= 6902.15 [.000]
Variance of residuals	= .293986E+08	Ramsey's RESET2	= .849453 [.357]
Std. error of regression	= 5422.05	Schwarz B.I.C.	= 3969.29
R-squared	= .963435	Log likelihood	= -3966.30
Adjusted R-squared	= .963435		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
CWC_K	1.01813	8.31E-03	122.551	[.000]

For Storage:

$$R\_STCWC_{r,t} = e^{(\beta_{0,r} * (1-\rho))} * DSTTCAP_{r,t-1}^{\beta_1} * R\_STCWC_{r,t-1}^{\rho} * DSTTCAP_{r,t-2}^{-\rho * \beta_1}$$

where,

$\beta_{0,a}$	=	constant term estimated by region (see Table F3.1, $\beta_{0,r}$ = REG_r)
	=	STCWC_CREG (Appendix E)
β_1	=	1.07386
	=	STCWC_TOTCAP (Appendix E), t-statistic (2.8)
ρ	=	0.668332
	=	STCWC_RHO (Appendix E), t-statistic (6.8)
DW	=	1.53
R-Squared	=	0.99

(2) Total Depreciation, Depletion, and Amortization for Existing Capacity

(a) existing capacity (up to 2000 for pipeline and up to 1998 for storage)

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. A linear specification was chosen given that DDA_E is generally believed to be proportional to the level of net plant. The forecasting equation was estimated with a correction for first order serial correlation.

$$\begin{aligned} DDA\_E_{a,t} = {} & DDA\_C_a * ARC_a + DDA\_NPIS * NPIS_{a,t-1} + \\ & DDA\_NEWCAP * NEWCAP\_E_{a,t} \end{aligned}$$

where,

DDA_C_a	=	constant term estimated by arc for the binary variable ARC_a (see Table F3.3, $DDA\_C_a = B\_ARC_{xx\_yy}$)
ARC_a	=	binary variable created for each arc to control for arc specific effects
DDA_NPIS	=	estimated coefficient (see Table F3.3)
DDA_NEWCAP	=	estimated coefficient (see Table F3.3)

The standard errors in Table F3.3 are computed from heteroscedastic-consistent matrix (Robust-White).

The results of this regression are reported below:

Dependent variable: DDA_E
Number of observations: 446

Mean of dep. var.	= 25154.4	R-squared	= .995361
Std. dev. of dep. var.	= 33518.3	Adjusted R-squared	= .994761
Sum of squared residuals	= .231907E+10	LM het. Test	= 30.7086 [.000]
Variance of residuals	= .588597E+07	Durbin-Watson = 2.06651 [<1.00]	
Std. error of regression	= 2426.10		

For Storage:

$$STDDA\_E_{r,t} = \beta_{0,r} + \beta_1 * STNPIS\_E_{r,t-1} + \beta_2 * STNEWCAP_{r,t}$$

where,

$\beta_{0,a}$	=	constant term estimated by region (see Table F3.4, $\beta_{0,r}$ = REG_r)
	=	STDDA_CREG (Appendix E)
β_1, β_2	=	(0.032004, 0.028197)
	=	STDDA_NPIS, STDDA_NEWCAP (Appendix E)
t-statistic	=	(10.3) (16.9)
DW	=	1.62
R-Squared	=	0.97

(b) new capacity (generic pipelines and storage)

A regression equation is not used for the new capacity; instead, an accounting algorithm is used (presented in Chapter 6).

(3) Accumulated Deferred Income Taxes for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. To control for arc-specific effects, a binary variable ARC_a was created for each of the arcs. The associated coefficient represents the arc-specific constant term.

Because the level of deferred income taxes is a stock (and not a flow) it was hypothesized that a formulation that focused on the change in the level of accumulated deferred income taxes from the previous year, $deltaADIT_{a,t}$, would be appropriate. Specifically, a linear relationship between the change in ADIT and the change in the level of gross plant in service, $NEWCAP_{a,t}$, and the change in tax policy, POLICY_CHG, was assumed. The form of the estimating equation is:

$$deltaADIT_{a,t} = ADIT\_C_a * ARC_a + \beta_1 * NEWCAP_{a,t} + \beta_2 * NEWCAP_{a,t} + \beta_3 * NEWCAP_{a,t}$$

where,

$ADIT\_C_a$	=	constant term estimated by arc for the binary variable ARC_a (see Table F3.5, $ADIT\_C_a$ = $B\_ARC_{xx\_yy}$)
β_1	=	BNEWCAP_PRE2003, estimated coefficient on the change in gross plant in service in the pre-2003 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.

β_2 = BNEWCAP_2003_2004, estimated coefficient on the change in gross plant in service for the years 2003 and 2004 because of changes in tax policy (Appendix F, Table F3.5). It is zero otherwise.

β_3 = BNEWCAP_POST2004, estimated coefficient on the change in gross plant in service in the post-2004 period because of changes in tax policy (Appendix F, Table F3.5). It is zero otherwise.

The estimation results are:

Dependent variable: DELTAADIT
Number of observations: 396

Mean of dep. var.	= 6493.50	R-squared	= .464802
Std. dev. of dep. var.	= 17140.8	Adjusted R-squared	= .383664
Sum of squared residuals	= .621120E+11	LM het. test	= 4.03824 [.044]
Variance of residuals	= .181084E+09	Durbin-Watson = 2.44866 [<1.00]	
Std. error of regression	= 13456.8		

For Storage:

$$\mathrm{STADIT}_{r,t} = \beta_0 + \beta_1 * \mathrm{STADIT}_{r,t-1} + \beta_2 * \mathrm{NEWCAP}_{r,t}$$

where,

β_0	=	-212.535
	=	STADIT_C (Appendix E)
β_1, β_2	=	(0.921962, 0.212610)
	=	STADIT_ADIT, STADIT_NEWCAP (Appendix E)
t-statistic	=	(58.8) (8.4)
DW	=	1.69
R-Squared	=	0.98

(4) Total Operating and Maintenance Expense for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. To control for arc-specific effects, a binary variable ARC_a was created for each of the arcs. The associated coefficient represents the arc-specific constant term.

The forecasting equation is presented in two stages.

Stage 1:

$$\begin{aligned}\mathrm{Ln}(R\_TOM_{a,t}) = {} & TOM\_C_a * ARC_a * (1-\rho) + TOM\_GPIS1 * \mathrm{Ln}(GPIS_{a,t-1}) \\ & + TOM\_DEPSHR * DEPSHR_{a,\,t-1} + TOM\_BYEAR * 2006 \\ & + TOM\_BYEAR\_EIA * (TECHYEAR - 2006.0) + \rho * \mathrm{Ln}(R\_TOM_{a,t-1}) \\ & - \rho * (TOM\_GPIS1 * \mathrm{Ln}(GPIS_{a,t-2}) + TOM\_DESHR * DEPSHR_{a,\,t-2} \\ & + TOM\_BYEAR * 2006 + TOM\_BYEAR\_EIA * (TECHYEAR - 1 - 2006.0))\end{aligned}$$

Stage 2:

$$R\_TOM_{a,t} = TOM\_K * \exp(\mathrm{Ln}(R\_TOM_{a,t}))$$

where Ln is a natural logarithm operator and TOM_K is the correction factor estimated in equation two, and where,

TOM_C_a	=	constant term estimated by arc for the binary variable ARCa (see Table F3.6, TOM_Ca = B_ARCxx_yy)
ARC_a	=	binary variable created for each arc to control for arc specific effects
TOM_GPIS1	=	estimated coefficient (see Table F3.6)
TOM_DEPSHR	=	estimated coefficient (see Table F3.6)
TOM_BYEAR	=	estimated coefficient (see Table F3.6)
TOM_BYEAR_EIA	=	future rate of decline in R_TOM due to technology improvements and efficiency gains. EIA assumes that this rate is the same as TOM_BYEAR (see Table F3.6)
ρ	=	first-order autocorrelation, TOM_RHO (see Table F3.6)

The results of this regression are reported below:

Dependent variable: R_TOM
Number of observations: 396

Mean of dep. var.	= 52822.9	LM het. test	= 28.7074 [.000]
Std. dev. of dep. var.	= 76354.9	Durbin-Watson	= 2.01148 [<1.00]
Sum of squared residuals	= .668483E+11	Jarque-Bera test	= 13559.1 [.000]
Variance of residuals	= .169236E+09	Ramsey's RESET2	= 4.03086 [.045]
Std. error of regression	= 13009.1	Schwarz B.I.C.	= 4215.86
R-squared	= .971019	Log likelihood	= -4312.87
Adjusted R-squared	= .971019		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
TOM_K	0.940181	6.691E-03	140.504	[.000]

For Storage:

$$R\_STTOM_{r,t} = e^{(\beta_0 * (1-\rho))} * DSTWCAP_{r,t-1}^{\beta_1} * R\_STTOM_{r,t-1}^{\rho} * DSTWCAP_{r,t-2}^{-\rho * \beta_1}$$

where,

β_0	=	-6.6702
	=	STTOM_C (Appendix E)
β_1	=	1.44442
	=	STTOM_WORKCAP (Appendix E), t-statistic (33.6)
ρ	=	0.761238
	=	STTOM_RHO (Appendix E), t-statistic (10.2)
DW	=	1.39
R-Squared	=	0.99

Table F3.1. Summary statistics for storage total cash working capital equation

Variable	Coefficient	Standard Error	t-statistic
REG2	-2.30334	5.25413	-.438386
REG3	-1.51115	5.33882	-.283049
REG4	-2.11195	5.19899	-.406224
REG5	-2.07950	5.06766	-.410346
REG6	-1.24091	4.97239	-.249559
REG7	-1.63716	5.27950	-.310097
REG8	-2.48339	4.68793	-.529740
REG9	-3.23625	4.09158	-.790954
REG11	-2.15877	4.33364	-.498143

Table F3.2. Summary statistics for pipeline total cash working capital equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
CWC_TOM	0.381679	.062976	6.06073	[.000]
B_ARC01_01	4.83845	.644360	7.50892	[.000]
B_ARC02_01	5.19554	.644074	8.06668	[.000]
B_ARC02_02	6.37816	.781655	8.15982	[.000]
B_ARC02_03	4.38403	.594344	7.37625	[.000]
B_ARC02_05	5.02364	.684640	7.33764	[.000]
B_ARC03_02	5.51162	.651682	8.45754	[.000]
B_ARC03_03	6.10201	.772378	7.90028	[.000]
B_ARC03_04	4.10475	.572836	7.16566	[.000]
B_ARC03_05	4.69978	.665214	7.06507	[.000]
B_ARC03_15	4.99465	.600910	8.31180	[.000]
B_ARC04_03	5.56047	.718330	7.74083	[.000]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC04_04	6.15095	.783539	7.85021	[.000]
B_ARC04_07	4.26747	.590736	7.22400	[.000]
B_ARC04_08	4.12216	.611516	6.74089	[.000]
B_ARC05_02	5.50272	.732227	7.51505	[.000]
B_ARC05_03	4.93360	.667589	7.39018	[.000]
B_ARC05_05	6.03791	.774677	7.79409	[.000]
B_ARC05_06	3.27334	.516303	6.33995	[.000]
B_ARC06_03	5.80098	.714338	8.12078	[.000]
B_ARC06_05	5.76939	.741907	7.77644	[.000]
B_ARC06_06	6.73455	.807246	8.34262	[.000]
B_ARC06_07	3.52000	.555549	6.33606	[.000]
B_ARC06_10	4.64811	.665947	6.97970	[.000]
B_ARC07_04	5.60946	.732039	7.66279	[.000]
B_ARC07_06	6.35683	.778573	8.16471	[.000]
B_ARC07_07	6.81298	.828208	8.22616	[.000]
B_ARC07_08	3.60827	.543296	6.64144	[.000]
B_ARC07_11	5.89640	.708385	8.32373	[.000]
B_ARC07_21	4.85140	.621031	7.81185	[.000]
B_ARC08_04	4.94307	.678799	7.28208	[.000]
B_ARC08_07	3.97367	.579267	6.85982	[.000]
B_ARC08_08	5.58162	.723678	7.71286	[.000]
B_ARC08_09	5.19274	.635784	8.16746	[.000]
B_ARC08_11	5.12277	.637835	8.03148	[.000]
B_ARC08_12	4.29097	.593945	7.22452	[.000]
B_ARC09_08	4.10222	.576694	7.11333	[.000]
B_ARC09_09	5.44178	.684020	7.95558	[.000]
B_ARC09_12	4.96229	.600227	8.26735	[.000]
B_ARC09_20	2.63716	.448339	5.88207	[.000]
B_ARC11_07	5.58226	.687702	8.11726	[.000]
B_ARC11_08	4.36952	.548152	7.97137	[.000]
B_ARC11_11	6.13044	.728452	8.41571	[.000]
B_ARC11_12	5.93253	.710336	8.35173	[.000]
B_ARC11_22	4.33062	.545420	7.93998	[.000]
B_ARC15_02	5.09861	.583090	8.74412	[.000]
B_ARC16_04	5.03673	.592859	8.49567	[.000]
B_ARC17_04	4.17798	.576943	7.24158	[.000]
B_ARC19_09	5.14500	.618100	8.32389	[.000]
B_ARC20_09	4.58498	.624006	7.34766	[.000]
B_ARC21_07	4.26846	.563536	7.57441	[.000]
CWC_RHO	0.527389	.048379	10.9011	[.000]

Table F3.3. Summary statistics for pipeline depreciation, depletion, and amortization equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
DDA_NEWCAP	.725948E-02	.200846E-02	3.61446	[.000]
DDA_NPIS	.023390	.103991E-02	22.4923	[.000]
B_ARC01_01	4699.58	862.825	5.44674	[.000]
B_ARC02_01	5081.37	853.478	5.95372	[.000]
B_ARC02_02	43769.1	1954.50	22.3940	[.000]
B_ARC02_03	2050.29	814.056	2.51861	[.012]
B_ARC02_05	7876.12	880.047	8.94965	[.000]
B_ARC03_02	5973.21	842.863	7.08681	[.000]
B_ARC03_03	33063.3	1489.77	22.1936	[.000]
B_ARC03_04	1032.74	809.439	1.27588	[.202]
B_ARC03_05	2386.89	845.864	2.82184	[.005]
B_ARC03_15	7652.92	864.810	8.84924	[.000]
B_ARC04_03	19729.5	1118.66	17.6368	[.000]
B_ARC04_04	35522.7	2267.45	15.6663	[.000]
B_ARC04_07	1919.97	811.222	2.36677	[.018]
B_ARC04_08	747.069	822.607	.908172	[.364]
B_ARC05_02	15678.2	1114.41	14.0686	[.000]
B_ARC05_03	6452.49	855.092	7.54596	[.000]
B_ARC05_05	45000.5	1771.82	25.3979	[.000]
B_ARC05_06	446.742	809.035	.552191	[.581]
B_ARC06_03	11967.8	942.879	12.6928	[.000]
B_ARC06_05	22576.3	1243.19	18.1599	[.000]
B_ARC06_06	67252.9	2892.23	23.2530	[.000]
B_ARC06_07	1134.14	809.115	1.40170	[.161]
B_ARC06_10	15821.4	989.531	15.9888	[.000]
B_ARC07_04	15041.4	984.735	15.2746	[.000]
B_ARC07_06	48087.6	1908.12	25.2015	[.000]
B_ARC07_07	80361.2	3384.54	23.7436	[.000]
B_ARC07_08	833.829	809.565	1.02997	[.303]
B_ARC07_11	4732.17	928.814	5.09486	[.000]
B_ARC07_21	1452.16	922.486	1.57418	[.115]
B_ARC08_04	4920.06	1022.86	4.81008	[.000]
B_ARC08_07	1425.79	811.348	1.75731	[.079]
B_ARC08_08	34661.3	1694.49	20.4553	[.000]
B_ARC08_09	5962.90	873.649	6.82528	[.000]
B_ARC08_11	1088.95	824.202	1.32122	[.186]
B_ARC08_12	7610.79	899.215	8.46382	[.000]
B_ARC09_08	2857.54	814.127	3.50994	[.000]
B_ARC09_09	15070.9	1021.78	14.7496	[.000]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC09_12	3120.00	833.569	3.74295	[.000]
B_ARC09_20	279.322	917.025	.304595	[.761]
B_ARC11_07	4022.68	871.680	4.61485	[.000]
B_ARC11_08	325.210	809.288	.401846	[.688]
B_ARC11_11	5616.89	1025.31	5.47822	[.000]
B_ARC11_12	4041.93	940.189	4.29906	[.000]
B_ARC11_22	259.293	809.060	.320487	[.749]
B_ARC15_02	2125.53	812.198	2.61701	[.009]
B_ARC16_04	8017.53	871.030	9.20465	[.000]
B_ARC17_04	3316.38	860.323	3.85481	[.000]
B_ARC19_09	4216.02	853.774	4.93810	[.000]
B_ARC20_09	6238.31	834.249	7.47776	[.000]
B_ARC21_07	666.813	810.034	.823192	[.410]

Table F3.4. Summary statistics for storage depreciation, depletion, and amortization equation

Variable	Coefficient	Standard-Error	t-statistic
REG2	4485.56	1204.28	3.72467
REG3	6267.52	1806.17	3.47006
REG4	3552.55	728.230	4.87833
REG5	2075.31	646.561	3.20976
REG6	1560.07	383.150	4.07169
REG7	4522.42	1268.87	3.56412
REG8	1102.49	622.420	1.77129
REG9	65.2731	10.1903	6.40542
REG11	134.692	494.392	.272439

Table F3.5. Summary statistics for pipeline accumulated deferred income tax equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
BNEWCAP_PRE2003	.067242	.023235	2.89405	[.004]
BNEWCAP_2003_2004	.132014	.013088	10.0865	[.000]
BNEWCAP_POST2004	.109336	.028196	3.87766	[.000]
B_ARC01_01	3529.80	4775.58	.739134	[.460]
B_ARC02_01	2793.71	4766.40	.586125	[.558]
B_ARC02_02	15255.3	5318.30	2.86844	[.004]
B_ARC02_03	767.648	4758.23	.161331	[.872]
B_ARC02_05	2479.86	4768.91	.520005	[.603]
B_ARC03_02	1663.09	4761.98	.349243	[.727]
B_ARC03_03	6184.51	4966.65	1.24521	[.213]
B_ARC03_04	-14.6495	4757.75	-.307908E-02	[.998]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC03_05	3183.89	4761.49	.668676	[.504]
B_ARC03_15	2531.19	4759.07	.531866	[.595]
B_ARC04_03	3660.65	4780.00	.765826	[.444]
B_ARC04_04	6076.87	4900.20	1.24013	[.215]
B_ARC04_07	-391.339	4757.90	-.082250	[.934]
B_ARC04_08	1798.04	4758.19	.377884	[.706]
B_ARC05_02	6654.17	4801.91	1.38573	[.166]
B_ARC05_03	1842.90	4762.25	.386982	[.699]
B_ARC05_05	6344.87	5220.98	1.21526	[.224]
B_ARC05_06	148.421	4757.73	.031196	[.975]
B_ARC06_03	2475.65	4775.18	.518441	[.604]
B_ARC06_05	5193.49	4996.38	1.03945	[.299]
B_ARC06_06	24991.1	5803.11	4.30650	[.000]
B_ARC06_07	-259.276	4757.72	-.054496	[.957]
B_ARC06_10	13015.7	4862.80	2.67659	[.007]
B_ARC07_04	189.221	4776.34	.039616	[.968]
B_ARC07_06	14166.3	5012.13	2.82640	[.005]
B_ARC07_07	16102.7	5680.52	2.83472	[.005]
B_ARC07_08	118.047	4758.11	.024810	[.980]
B_ARC07_11	-434.842	4808.84	-.090426	[.928]
B_ARC07_21	495.934	5498.36	.090197	[.928]
B_ARC08_04	4679.95	4780.56	.978955	[.328]
B_ARC08_07	365.793	4762.84	.076801	[.939]
B_ARC08_08	5133.64	5235.92	.980466	[.327]
B_ARC08_09	-3672.71	4770.23	-.769923	[.441]
B_ARC08_11	-1856.45	4762.76	-.389784	[.697]
B_ARC08_12	795.831	4808.51	.165505	[.869]
B_ARC09_08	537.433	4759.95	.112907	[.910]
B_ARC09_09	-1812.27	4829.76	-.375230	[.707]
B_ARC09_12	-2803.40	4761.86	-.588719	[.556]
B_ARC09_20	55.5366	5493.73	.010109	[.992]
B_ARC11_07	-1137.92	4772.21	-.238448	[.812]
B_ARC11_08	276.612	4757.86	.058138	[.954]
B_ARC11_11	7.99239	4874.89	.163950E-02	[.999]
B_ARC11_12	-1079.76	4825.77	-.223750	[.823]
B_ARC11_22	337.987	4759.18	.071018	[.943]
B_ARC15_02	429.875	4758.19	.090344	[.928]
B_ARC16_04	2744.23	4759.07	.576631	[.564]
B_ARC17_04	935.795	4757.97	.196680	[.844]
B_ARC19_09	-3806.27	4762.95	-.799141	[.424]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC20_09	1173.22	4768.48	.246037	[.806]
B_ARC21_07	586.673	4759.84	.123255	[.902]

Table F3.6. Summary statistics for pipeline total operating and maintenance expense equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
TOM_GPIS1	.256869	.114518	2.24304	[.025]
TOM_DEPSHR	1.69807	.429440	3.95415	[.000]
TOM_BYEAR	-.019974	.718590E-02	-2.77955	[.005]
B_ARC01_01	45.8116	13.5505	3.38081	[.001]
B_ARC02_01	45.7428	13.5502	3.37580	[.001]
B_ARC02_02	47.4313	13.4380	3.52963	[.000]
B_ARC02_03	45.3570	13.6230	3.32944	[.001]
B_ARC02_05	46.3936	13.5393	3.42658	[.001]
B_ARC03_02	45.8277	13.5539	3.38115	[.001]
B_ARC03_03	47.1662	13.4461	3.50779	[.000]
B_ARC03_04	44.5365	13.6401	3.26512	[.001]
B_ARC03_05	45.9318	13.5464	3.39071	[.001]
B_ARC03_15	45.1262	13.5508	3.33015	[.001]
B_ARC04_03	46.5137	13.4799	3.45060	[.001]
B_ARC04_04	47.4725	13.4290	3.53508	[.000]
B_ARC04_07	45.0325	13.6249	3.30516	[.001]
B_ARC04_08	45.6096	13.5965	3.35451	[.001]
B_ARC05_02	46.8361	13.4859	3.47298	[.001]
B_ARC05_03	46.2316	13.5556	3.41052	[.001]
B_ARC05_05	47.2881	13.4422	3.51788	[.000]
B_ARC05_06	44.2555	13.6969	3.23105	[.001]
B_ARC06_03	46.4249	13.4976	3.43948	[.001]
B_ARC06_05	46.9210	13.4730	3.48260	[.000]
B_ARC06_06	47.6072	13.4045	3.55157	[.000]
B_ARC06_07	44.5090	13.6696	3.25606	[.001]
B_ARC06_10	46.0547	13.5171	3.40715	[.001]
B_ARC07_04	46.6884	13.4905	3.46084	[.001]
B_ARC07_06	47.2664	13.4316	3.51904	[.000]
B_ARC07_07	47.8651	13.3928	3.57395	[.000]
B_ARC07_08	44.7096	13.6750	3.26944	[.001]
B_ARC07_11	46.7847	13.5263	3.45880	[.001]
B_ARC07_21	45.4067	13.6138	3.33535	[.001]
B_ARC08_04	46.3290	13.5124	3.42864	[.001]
B_ARC08_07	45.1349	13.6437	3.30810	[.001]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC08_08	46.8373	13.4658	3.47825	[.001]
B_ARC08_09	45.7056	13.5495	3.37323	[.001]
B_ARC08_11	45.9766	13.5925	3.38250	[.001]
B_ARC08_12	45.1596	13.5537	3.33190	[.001]
B_ARC09_08	44.9927	13.6211	3.30317	[.001]
B_ARC09_09	46.2997	13.5103	3.42699	[.001]
B_ARC09_12	45.2655	13.5793	3.33342	[.001]
B_ARC09_20	43.2644	13.7686	3.14226	[.002]
B_ARC11_07	46.4472	13.5409	3.43015	[.001]
B_ARC11_08	44.9105	13.6898	3.28058	[.001]
B_ARC11_11	47.0985	13.5107	3.48603	[.000]
B_ARC11_12	46.8744	13.5270	3.46526	[.001]
B_ARC11_22	44.8071	13.7118	3.26778	[.001]
B_ARC15_02	44.8267	13.6116	3.29327	[.001]
B_ARC16_04	45.0068	13.5491	3.32175	[.001]
B_ARC17_04	44.8832	13.5582	3.31042	[.001]
B_ARC19_09	45.4861	13.5613	3.35412	[.001]
B_ARC20_09	45.5729	13.5745	3.35725	[.001]
B_ARC21_07	44.6298	13.6465	3.27041	[.001]
TOM_RHO	.297716	.052442	5.67707	[.000]

Table F4

Data: Equations for industrial distribution tariffs

Author: Joe Benneche, EIA, 2012.

Source: Annual historical industrial prices for the core and noncore categories are generated as described in Table F5. Seasonal prices are generated from these annual prices based on the derived seasonal price differentials shown from the industrial prices published in the Natural Gas Monthly, DOE/EIA-0130. This same source is used to derive seasonal shares for breaking out noncore industrial consumption into peak and off-peak figures. The noncore consumption values were taken from the National Energy Modeling System and set within its Industrial Demand Module. State-level city gate prices by month were averaged using quantity weights to arrive at seasonal (peak and off-peak), regional-level (12 NGTDM regions) prices. The quantity weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. Historical distributor tariffs are set by subtracting these city gate prices from the delivered industrial prices.

Variables:

$TINDI_{r,n,t}$	=	noncore industrial distributor tariff in region r, network n (1987$/Mcf) [$DTAR_SI_{3,n,r}$]
$TINDF_{r,n,t}$	=	core industrial distributor tariff in region r, network n (1987$/Mcf) [$DTAR_SF_{3,n,r}$]
$REGION_r$	=	1, if observation is in region r, =0 otherwise
$QINDI_{r,n,t}$	=	noncore industrial gas consumption in region r, in season n (Bcf) [$BASQTY\_SI_{3,r}$]
n	=	period or season
r	=	NGTDM region
t	=	year
α_r, $\alpha_{r,n}$	=	estimated parameters for noncore regional constants [$PINREG19I_r$, $PINREGPK19I_{r,n}$]
δ_r, $\delta_{r,n}$	=	estimated parameters for core regional constants [$PINREG19F_r$, $PINREGPK19F_{r,n}$]
β_1	=	estimated parameter for noncore consumption (QINDI)
β_2	=	estimated parameter for noncore distributor tariff (TINDI)
ρ_1, ρ_2	=	autocorrelation coefficient for noncore (1) and core (2) equation

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The industrial distributor tariff equations were estimated using backcasted data for the 12 NGTDM regions over the 1990 to 2010 time period. The equations were estimated in linear form with corrections for cross-sectional heteroscedasticity and first order serial correlation using Eviews. The forms of the estimating equations follow:

$$TINDI_{r,n,t} = \sum_{r}(\alpha_r + \alpha_{r,pk}) * REGION_r + \beta_1 * QINDI_{r,n,t} + \rho_1 * TINDI_{r,n,t-1}$$
$$\rho_1 * (\sum_{r}(\alpha_r + \alpha_{r,pk}) * REGION_r + \beta_1 * QINDI_{r,n,t-1})$$

$$TINDF_{r,n,t} = \sum_{r}(\delta_r + \delta_{r,pk}) * REGION_r + \beta_2 * TINDI_{r,n,t} + \rho_2 * TINDF_{r,n,t-1}$$
$$\rho_2 * (\sum_{r}(\delta_r + \delta_{r,pk}) * REGION_r + \beta_2 * TINDI_{r,n,t-1})$$

Regression diagnostics and parameter estimates:

Dependent Variable: TINDI
Method: Least Squares
Date: 08/31/12 Time: 08:41
Sample (adjusted): 2 528
Included observations: 527 after adjustments
Convergence achieved after 5 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
REGION3	0.344421	0.088710	3.882560	0.0001
REGION9	0.396508	0.084572	4.688415	0.0000
REGION10	0.510307	0.084641	6.029082	0.0000
REGION11	0.583418	0.084894	6.872320	0.0000
REGION12	0.948548	0.087723	10.81295	0.0000
REGION1PK	1.178899	0.127891	9.217992	0.0000
REGION2PK	0.743417	0.119956	6.197433	0.0000
REGION7PK	-0.396888	0.131651	-3.014689	0.0027
QINDI	-0.000651	0.000116	-5.591997	0.0000
AR(1)	0.434485	0.039870	10.89760	0.0000

e	0.666366	Mean dependent var	0.203239
Adjusted R-squared	0.660558	S.D. dependent var	0.575396
S.E. of regression	0.335235	Akaike info criterion	0.670824
Sum squared resid	58.10183	Schwarz criterion	0.751796
Log likelihood	-166.7622	Hannan-Quinn criter.	0.702526
Durbin-Watson stat	2.153064		

Inverted AR Roots	.43

Dependent Variable: TINDF
Method: Least Squares
Date: 08/31/12 Time: 08:40
Sample (adjusted): 2 528
Included observations: 527 after adjustments
Convergence achieved after 6 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
REGION1	0.400924	0.043226	9.275039	0.0000
REGION2	0.315417	0.041171	7.661055	0.0000
REGION3	0.284744	0.040598	7.013804	0.0000

REGION4	0.309361	0.040660	7.608395	0.0000
REGION5	0.242834	0.040551	5.988354	0.0000
REGION6	0.280499	0.040492	6.927322	0.0000
REGION7	0.191963	0.042020	4.568344	0.0000
REGION8	0.389896	0.040483	9.630995	0.0000
REGION9	0.378518	0.041065	9.217440	0.0000
REGION10	0.353700	0.041426	8.538151	0.0000
REGION11	0.412150	0.041581	9.911945	0.0000
REGION12	0.354604	0.043591	8.134719	0.0000
TINDI	1.017384	0.017454	58.28946	0.0000
AR(1)	0.533751	0.037522	14.22489	0.0000

R-squared	0.956133	Mean dependent var	0.532939
Adjusted R-squared	0.955021	S.D. dependent var	0.647040
S.E. of regression	0.137226	Akaike info criterion	-1.108167
Sum squared resid	9.660308	Schwarz criterion	-0.994807
Log likelihood	306.0020	Hannan-Quinn criter.	-1.063785
Durbin-Watson stat	2.183486		

Inverted AR Roots	.53

Data used for estimation

			1	2	3	4	5	6	7	8	9	10	11	12
	Vari-		New		E.N.	W.N.		E.S.	W.S.	Mtn-	WA/			
Year	able	Season	Engl	Mid Atl	Cntrl	Cntrl	S.Atl-FL	Cntrl	Cntrl	AZ/NM	OR	Florida	AZ/NM	CA/HI
1990	tindi	peak	1.319	0.932	0.365	0.024	0.425	0.049	-0.735	0.097	0.613	0.471	0.544	0.887
1990	tindi	off-peak	0.402	0.525	0.376	-0.137	0.082	-0.09	-0.915	-0.542	0.411	0.575	0.659	0.608
1991	tindi	peak	1.233	0.914	0.281	-0.06	0.244	-0.028	-0.864	-0.276	0.554	0.241	0.597	1.022
1991	tindi	off-peak	0.268	0.272	0.166	-0.29	-0.21	-0.214	-0.837	-0.776	0.487	0.329	0.464	0.622
1992	tindi	peak	1.451	0.83	0.258	0.06	0.303	0.034	-0.789	-0.211	0.583	0.365	1.598	1.106
1992	tindi	off-peak	0.01	-0.049	-0.028	-0.204	-0.244	-0.269	-0.754	-1.03	0.625	0.283	1.343	0.294
1993	tindi	peak	1.5	0.662	0.276	0.035	0.318	0.106	-0.702	-0.274	0.555	0.534	0.963	0.146
1993	tindi	off-peak	-0.234	-0.023	0.13	-0.289	-0.304	-0.191	-0.622	-0.663	0.477	0.674	0.848	-0.318
1994	tindi	peak	1.535	0.855	0.533	0.175	0.272	0.288	-0.654	-0.543	0.466	0.132	1.163	0.603
1994	tindi	off-peak	-0.5	0.198	0.35	-0.33	-0.359	-0.108	-0.531	-0.785	0.232	0.294	0.651	0.319
1995	tindi	peak	1.136	0.582	0.116	0.047	0.293	0.234	-0.784	-0.154	0.35	-0.035	1.29	1.539
1995	tindi	off-peak	-0.569	0.187	-0.107	-0.405	-0.186	-0.206	-0.716	-0.148	0.33	0.104	1.038	0.897
1996	tindi	peak	1.599	0.74	0.181	0.349	0.367	-0.021	-0.257	0.084	0.442	0.156	1.005	1.071
1996	tindi	off-peak	-0.207	0.125	0.206	-0.303	-0.004	0.045	-0.311	0.11	0.151	0.376	0.943	0.817
1997	tindi	peak	1.447	0.824	0.462	0.126	0.368	0.218	-0.55	0.05	0.621	-0.095	0.506	1.373
1997	tindi	off-peak	-0.011	-0.741	0.103	-0.514	-0.152	-0.005	-0.275	0.214	0.179	0.288	0.38	0.689
1998	tindi	peak	1.074	0.082	0.393	0.135	0.15	0.209	-0.287	-0.025	0.275	0.146	0.692	1.375
1998	tindi	off-peak	-0.561	-0.464	0.308	-0.354	-0.408	-0.168	-0.197	0.178	0.173	0.133	0.308	0.67
1999	tindi	peak	0.568	0.107	0.339	0.049	-0.141	0.158	-0.488	0.568	0.151	0.687	0.489	0.636

			1	2	3	4	5	6	7	8	9	10	11	12
Year	Vari-able	Season	New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/ OR	Florida	AZ/NM	CA/HI
1999	tindi	off-peak	-0.64	-0.793	-0.045	-0.404	-0.584	-0.174	-0.303	0.226	0.032	-0.092	0.059	0.218
2000	tindi	peak	0.7	0.442	0.19	-0.072	-0.095	-0.031	-0.474	0.364	0.479	0.152	0.021	0.796
2000	tindi	off-peak	-0.378	-0.448	0.132	-0.501	-0.499	-0.221	-0.302	0.327	-0.138	0.493	0.043	0.664
2001	tindi	peak	0.359	0.772	0.321	-0.276	-0.189	-0.14	-0.814	0.259	-0.36	-0.146	-0.025	-0.661
2001	tindi	off-peak	0.214	0.378	0.469	-0.412	-0.518	0.003	-0.462	0.846	0.302	1.07	0.768	0.668
2002	tindi	peak	0.786	0.488	-0.188	-0.192	-0.226	0.183	-0.685	0.961	0.836	0.832	1.389	1.078
2002	tindi	off-peak	-0.728	0.179	-0.487	-0.342	-0.616	-0.008	-0.563	1	0.003	0.417	0.811	0.718
2003	tindi	peak	1.186	1.499	0.269	-0.276	-0.07	0.309	-0.31	0.583	0.221	-0.39	0.419	1.153
2003	tindi	off-peak	0.552	1.044	0.426	-0.47	-0.552	-0.394	-0.292	0.653	0.105	0.672	0.725	0.97
2004	tindi	peak	1.857	1.123	0.475	-0.166	0.065	0.123	-0.527	0.306	0.417	0.479	0.495	1.3
2004	tindi	off-peak	0.693	0.427	0.046	-0.577	-0.477	-0.182	-0.267	0.292	0.043	0.73	0.541	0.567
2005	tindi	peak	1.791	1.213	0.439	0.225	0.324	0.474	-0.49	0.561	0.626	0.363	0.558	1.653
2005	tindi	off-peak	0.4	0.417	-0.063	-0.713	-0.501	-0.002	-0.234	0.333	0.099	-0.249	0.647	0.568
2006	tindi	peak	1.271	0.604	-0.035	0.056	-0.327	-0.003	-0.919	0.362	0.42	0.872	0.428	1.255
2006	tindi	off-peak	0.484	-0.13	0.043	-0.671	-0.553	-0.47	-0.622	0.189	0.278	1.44	1.114	0.959
2007	tindi	peak	1.755	0.359	0.071	0.002	-0.077	-0.252	-0.925	0.036	0.742	0.849	0.765	0.95
2007	tindi	off-peak	0.599	-0.064	0.197	-0.364	-0.444	-0.42	-0.84	0.298	0.608	1.027	0.938	0.939
2008	tindi	peak	1.43	0.823	0.28	0.208	0.293	0.017	-0.633	0.238	0.943	0.666	0.619	1.271
2008	tindi	off-peak	1.159	0.651	0.876	0.132	0.22	0.034	-0.587	0.241	-0.007	0.967	1.292	1.471
2009	tindi	peak	0.697	0.023	0.29	-0.154	-0.859	-0.576	-1.469	-0.169	0.51	0.314	-0.231	0.857
2009	tindi	off-peak	0.094	-0.073	-0.121	-0.631	-0.868	-0.56	-1.189	0.151	0.975	1.456	0.387	0.71
2010	tindi	peak	0.918	0.27	-0.181	-0.096	-0.047	0.016	-0.876	-0.015	-0.006	0.677	0.052	0.567
2010	tindi	off-peak	0.067	-0.029	0.169	-0.434	-0.683	-0.376	-1.175	-0.021	0.179	1.06	0.236	0.872
2011	tindi	peak	0.936	0.641	0.146	-0.077	-0.295	-0.4	-1.145	-0.019	0.53	0.747	-0.021	0.948
2011	tindi	off-peak	0.025	0.57	0.17	-0.562	-0.65	-0.584	-1.255	-0.198	0.207	0.917	0.035	0.713
1990	tindf	peak	1.786	1.434	0.71	0.551	0.666	0.438	-0.36	0.67	1.115	0.909	1.129	1.363
1990	tindf	off-peak	0.736	0.959	0.687	0.313	0.292	0.247	-0.622	-0.034	0.851	0.979	1.276	1.044
1991	tindf	peak	1.639	1.389	0.632	0.445	0.491	0.367	-0.557	0.239	1.068	0.537	1.253	1.488
1991	tindf	off-peak	0.553	0.668	0.48	0.162	-0.009	0.134	-0.57	-0.296	0.965	0.61	1.111	1.016
1992	tindf	peak	1.915	1.283	0.64	0.552	0.559	0.423	-0.516	0.295	1.106	0.668	2.369	1.585
1992	tindf	off-peak	0.342	0.341	0.332	0.289	-0.004	0.115	-0.457	-0.566	1.155	0.579	2.088	0.669
1993	tindf	peak	2.178	1.084	0.705	0.503	0.543	0.511	-0.43	0.099	1.018	0.996	1.57	0.456
1993	tindf	off-peak	0.273	0.369	0.563	0.147	-0.094	0.205	-0.335	-0.311	0.962	1.158	1.458	-0.054
1994	tindf	peak	2.21	1.333	1.075	0.677	0.667	0.77	-0.343	-0.084	0.949	0.824	1.87	1.283
1994	tindf	off-peak	-0.029	0.582	0.844	0.125	-0.024	0.328	-0.258	-0.35	0.687	0.94	1.197	0.864
1995	tindf	peak	1.682	0.989	0.613	0.51	0.724	0.762	-0.501	0.481	0.954	0.554	2.024	2.196
1995	tindf	off-peak	-0.179	0.543	0.357	0.007	0.194	0.253	-0.454	0.476	0.911	0.735	1.707	1.444
1996	tindf	peak	2.201	1.161	0.447	0.821	0.848	0.466	-0.016	0.586	0.995	0.616	1.554	1.734

			1	2	3	4	5	6	7	8	9	10	11	12
Year	Vari-able	Season	New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA/HI
1996	tindf	off-peak	0.212	0.469	0.474	0.105	0.422	0.477	-0.104	0.624	0.686	0.817	1.477	1.393
1997	tindf	peak	2.079	1.278	0.919	0.563	0.841	0.722	-0.24	0.524	1.178	0.503	0.93	2.019
1997	tindf	off-peak	0.438	-0.409	0.511	-0.151	0.252	0.423	-0.006	0.689	0.655	0.88	0.794	1.187
1998	tindf	peak	1.67	0.423	0.897	0.56	0.536	0.723	0.012	0.429	0.732	0.723	1.17	1.934
1998	tindf	off-peak	-0.11	-0.176	0.802	0.038	-0.066	0.311	0.079	0.619	0.628	0.69	0.736	1.1
1999	tindf	peak	1.084	0.422	0.759	0.402	0.244	0.544	-0.25	1.02	0.504	1.241	0.872	1.012
1999	tindf	off-peak	-0.164	-0.5	0.39	-0.043	-0.178	0.21	-0.019	0.63	0.404	0.342	0.437	0.587
2000	tindf	peak	1.08	0.649	0.348	0.095	0.215	0.141	-0.377	0.576	0.612	0.395	0.208	0.764
2000	tindf	off-peak	-0.015	-0.243	0.302	-0.324	-0.171	-0.041	-0.193	0.543	-0.024	0.784	0.242	0.631
2001	tindf	peak	0.875	1.143	0.75	0.07	0.119	0.284	-0.566	0.654	-0.217	0.334	0.347	-0.672
2001	tindf	off-peak	0.653	0.642	0.821	-0.178	-0.31	0.308	-0.307	1.223	0.432	1.483	1.117	0.66
2002	tindf	peak	1.269	0.848	0.059	0.104	0.023	0.525	-0.513	1.604	1.332	1.203	1.934	1.473
2002	tindf	off-peak	-0.32	0.509	-0.235	-0.03	-0.348	0.316	-0.37	1.597	0.449	0.768	1.298	1.095
2003	tindf	peak	1.642	1.759	0.433	-0.152	0.166	0.464	-0.242	0.803	0.402	-0.251	0.627	1.428
2003	tindf	off-peak	0.91	1.273	0.595	-0.356	-0.339	-0.262	-0.234	0.874	0.296	0.841	0.937	1.23
2004	tindf	peak	2.364	1.288	0.655	-0.041	0.174	0.267	-0.459	0.478	0.61	0.674	0.689	1.578
2004	tindf	off-peak	1.165	0.571	0.221	-0.457	-0.372	-0.046	-0.196	0.457	0.231	0.932	0.739	0.815
2005	tindf	peak	2.028	1.144	0.414	0.201	0.268	0.361	-0.596	0.58	0.697	0.224	0.602	1.765
2005	tindf	off-peak	0.638	0.349	-0.09	-0.737	-0.563	-0.122	-0.362	0.352	0.169	-0.391	0.695	0.677
2006	tindf	peak	1.626	0.823	0.211	0.203	-0.178	0.181	-0.868	0.712	0.687	1.197	0.769	1.576
2006	tindf	off-peak	0.77	0.036	0.249	-0.56	-0.435	-0.33	-0.58	0.498	0.527	1.738	1.448	1.201
2007	tindf	peak	2.105	0.518	0.234	0.117	0.029	-0.171	-0.896	0.426	0.963	1.043	1.095	1.173
2007	tindf	off-peak	0.914	0.081	0.357	-0.264	-0.343	-0.345	-0.81	0.655	0.82	1.211	1.265	1.151
2008	tindf	peak	1.484	0.877	0.309	0.219	0.281	0.012	-0.621	0.369	0.988	0.721	0.832	1.424
2008	tindf	off-peak	1.22	0.709	0.909	0.144	0.205	0.028	-0.572	0.382	0.038	1.031	1.524	1.651
2009	tindf	peak	1.161	0.531	0.819	0.227	-0.489	-0.178	-1.252	0.386	1.171	0.9	0.303	1.314
2009	tindf	off-peak	0.457	0.323	0.282	-0.363	-0.588	-0.272	-1.016	0.639	1.665	2.036	0.888	1.075
2010	tindf	peak	1.46	0.594	0.171	0.178	0.185	0.316	-0.693	0.342	0.425	1.121	0.461	0.957
2010	tindf	off-peak	0.534	0.27	0.501	-0.203	-0.489	-0.128	-1.027	0.31	0.613	1.486	0.597	1.217
2011	tindf	peak	1.432	1.075	0.504	0.194	-0.061	-0.162	-0.995	0.325	0.973	1.199	0.342	1.326
2011	tindf	off-peak	0.484	1.004	0.522	-0.309	-0.42	-0.354	-1.097	0.149	0.649	1.375	0.4	1.081
1990	qindi	peak	10.6	71.3	177.5	53.8	81.1	74.6	489.0	32.4	29.4	13.2	7.5	112.7
1990	qindi	off-peak	23.5	123.7	285.7	93.5	153.8	133.5	1024.6	53.7	51.7	24.0	14.0	247.0
1991	qindi	peak	18.7	85.2	190.5	58.2	74.5	77.2	504.6	38.1	29.4	13.2	8.2	125.4
1991	qindi	off-peak	39.2	142.4	288.4	98.9	143.9	140.3	1032.4	62.7	54.4	23.1	13.9	249.6
1992	qindi	peak	30.7	120.3	191.9	58.6	83.0	83.1	542.6	42.3	31.3	13.4	7.8	136.6
1992	qindi	off-peak	61.7	209.1	299.5	99.2	158.4	152.2	1034.8	73.3	55.7	24.6	13.1	237.4
1993	qindi	peak	24.7	132.9	190.8	61.9	83.5	88.0	536.2	45.0	32.6	15.4	7.1	129.0

			1	2	3	4	5	6	7	8	9	10	11	12
	Vari-		New		E.N.	W.N.		E.S.	W.S.	Mtn-	WA/			
Year	able	Season	Engl	Mid Atl	Cntrl	Cntrl	S.Atl-FL	Cntrl	Cntrl	AZ/NM	OR	Florida	AZ/NM	CA/HI
1993	qindi	off-peak	49.2	217.5	283.5	105.0	161.2	152.5	1081.8	79.9	59.3	29.7	13.5	267.4
1994	qindi	peak	29.4	133.9	203.1	72.9	85.7	87.5	571.7	55.4	40.5	20.1	8.3	146.7
1994	qindi	off-peak	53.9	218.8	292.2	122.4	178.3	154.1	1086.6	91.1	78.3	39.4	18.8	311.9
1995	qindi	peak	30.1	152.9	208.4	67.0	93.1	93.9	575.5	55.6	43.0	23.3	11.1	147.3
1995	qindi	off-peak	52.2	257.4	311.2	116.0	192.0	167.9	1159.8	92.8	79.1	39.5	18.3	321.9
1996	qindi	peak	25.2	149.2	207.7	63.1	91.0	91.9	630.7	56.3	47.1	21.6	10.8	163.7
1996	qindi	off-peak	52.4	251.7	314.3	107.4	181.2	166.6	1228.7	101.3	95.6	42.6	19.2	326.3
1997	qindi	peak	28.6	143.6	206.1	69.5	101.3	96.2	643.0	53.4	52.1	19.9	12.6	171.6
1997	qindi	off-peak	50.9	246.6	318.1	112.2	189.1	173.1	1246.9	93.1	96.6	39.5	24.2	359.4
1998	qindi	peak	16.4	83.5	175.7	58.9	70.3	75.4	512.8	37.8	38.4	14.3	7.2	107.3
1998	qindi	off-peak	29.9	138.5	267.3	106.0	129.8	132.7	980.7	61.7	70.5	28.5	14.1	237.2
1999	qindi	peak	17.8	75.0	182.2	57.9	79.1	81.3	456.7	32.1	37.8	15.7	7.7	94.3
1999	qindi	off-peak	32.5	126.1	280.1	98.8	121.9	148.4	907.1	60.8	69.8	32.3	14.2	242.1
2000	qindi	peak	18.0	58.9	189.7	59.3	69.9	81.7	482.2	35.6	25.0	12.6	7.0	95.5
2000	qindi	off-peak	28.4	101.1	277.2	103.9	131.0	141.7	995.0	56.8	45.0	25.0	13.8	244.4
2001	qindi	peak	17.3	55.8	170.8	55.6	55.5	68.3	464.8	41.6	23.2	11.0	7.6	96.3
2001	qindi	off-peak	29.8	91.6	248.3	95.6	108.6	121.3	872.6	66.7	42.8	22.9	14.1	207.9
2002	qindi	peak	23.3	78.3	169.1	59.5	57.7	66.7	452.6	33.8	25.4	9.6	5.3	119.0
2002	qindi	off-peak	38.3	127.2	272.8	108.3	109.4	115.2	897.3	62.4	42.8	18.3	9.6	246.4
2003	qindi	peak	16.7	66.7	166.3	62.0	56.0	65.3	420.2	32.3	21.5	8.1	5.0	115.2
2003	qindi	off-peak	19.4	102.9	234.5	101.8	95.1	106.2	815.2	52.6	39.4	15.3	9.3	240.5
2004	qindi	peak	15.5	66.1	166.4	64.2	53.2	60.6	425.9	33.0	21.7	7.1	5.8	118.4
2004	qindi	off-peak	19.1	103.8	233.1	109.1	92.2	105.7	833.9	53.0	39.2	12.1	9.6	246.4
2005	qindi	peak	18.8	71.9	184.4	73.9	54.2	61.5	380.6	37.6	23.4	7.2	5.6	129.4
2005	qindi	off-peak	21.4	109.2	262.4	121.9	91.5	103.3	724.7	64.1	42.6	12.6	11.1	248.5
2006	qindi	peak	10.3	47.4	167.7	79.2	62.2	68.2	410.5	34.7	21.9	9.4	4.9	105.8
2006	qindi	off-peak	14.2	79.0	263.1	143.8	117.8	126.6	820.1	54.0	39.0	17.5	8.2	211.2
2007	qindi	peak	12.8	45.7	184.2	102.6	64.1	71.7	417.5	34.7	22.5	9.3	4.9	109.3
2007	qindi	off-peak	17.0	72.5	265.3	179.6	116.4	123.9	797.3	55.7	40.1	16.7	8.3	215.9
2008	qindi	peak	14.3	51.8	203.3	133.6	64.7	76.0	432.2	38.0	25.6	10.0	5.2	111.9
2008	qindi	off-peak	19.3	76.4	290.0	221.4	116.4	130.6	832.1	58.4	41.5	17.9	9.2	223.0
2009	qindi	peak	15.3	52.3	206.5	150.6	65.5	71.5	424.0	38.8	23.4	10.3	5.0	115.9
2009	qindi	off-peak	22.3	76.5	285.2	245.9	119.1	130.5	834.8	59.8	40.7	19.2	8.9	236.3
2010	qindi	peak	16.5	53.1	221.8	167.7	71.0	79.3	455.1	37.8	22.3	12.7	5.4	114.0
2010	qindi	off-peak	22.2	78.4	330.3	282.7	125.5	136.3	866.9	58.8	40.8	22.1	9.2	235.5
2011	qindi	peak	19.1	60.5	233.9	175.3	72.5	81.9	469.0	36.4	24.2	13.9	6.5	111.8
2011	qindi	off-peak	26.5	88.6	355.5	308.0	132.1	143.9	902.6	58.2	41.6	25.6	10.9	238.0

Table F5

Data: Historical industrial sector natural gas prices by type of service, NGTDM region.

Author: Joe Benneche, EIA, 2012.

Source: The source for core and noncore industrial prices is EIA's Manufacturing Energy Consumption Survey. The industrial prices as purchased from a local distribution company come from the Natural Gas Monthly, DOE/EIA-0130. Prices for imports and production, and their associated weights, largely come from EIA data, with production prices set at a regional spot price minus an assumed gathering charge.

Variables:

$mecs87_{type}$ = core and noncore industrial prices across Census Division and year (1987$/Mcf), used to estimate PIN_FNG (core) and PIN_ING (noncore) prices by NGTDM region

ngap87 = natural gas price to industrial customers who purchase gas from a local distributor across Census Division and year (1987$/Mcf)

supplyp87 = quantity-weighted average supply (import and production) price across Census Division and year

α_{type} = estimated constant term for core and noncore

$\beta_{1,type}$, $\beta_{2,type}$ = estimated coefficients for core and noncore

Derivation: Historically the price paid for natural gas by energy-intensive industries is notably lower than the price paid by non-energy-intensive industries based on data from EIA's Manufacturing Energy Consumption Survey (MECS). Therefore, within the industrial module of NEMS the lower noncore price generated by the NGTDM is assigned to energy-intensive industries and the core price is assigned to non-energy-intensive industries. Since the MECS data are only available every four years by the four Census Divisions, two equations were estimated to derive core and noncore prices for the 12 NGTDM regions in all historical years (HPGFINGR, HPGIINGR). MECS data for the years 1994, 1998, 2002, and 2006 were used to estimate a core and noncore price equation for the regional MECS price as a function of the regional Natural Gas Annual (NGA) industrial price and the regional supply price (quantity-weighted average of the gas wellhead price and import price). The resulting regional prices are scaled to insure that the resulting quantity-average regional price equals the price published in the NGA. The general form of the estimated equation follows:

$$mecs87_{type} = \alpha_{type} + (\beta_{1,type} * supplyp87) + (\beta_{2,type} * ngap87)$$

The equations were estimated using a basic ordinary least squares approach applied to the data provided below.

Regression diagnostics and parameter estimates:

Dependent Variable: MECS87 (Core)
Method: Least Squares
Date: 08/30/12 Time: 17:58
Sample: 1 16
Included observations: 16

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.657744	0.248773	2.643956	0.0202
SUPPLYP87	0.398046	0.219644	1.812228	0.0931
NGAP87	0.530439	0.160211	3.310884	0.0056

R-squared	0.927584	Mean dependent var	3.552521
Adjusted R-squared	0.916443	S.D. dependent var	1.281307
S.E. of regression	0.370378	Akaike info criterion	1.018773
Sum squared resid	1.783334	Schwarz criterion	1.163634
Log likelihood	-5.150185	Hannan-Quinn criter.	1.026191
F-statistic	83.25902	Durbin-Watson stat	1.868392
Prob(F-statistic)	0.000000		

Dependent Variable: MECS87 (noncore)
Method: Least Squares
Date: 08/30/12 Time: 17:59
Sample: 17 32
Included observations: 16

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.220117	0.145436	1.513495	0.1541
SUPPLYP87	0.602180	0.128408	4.689603	0.0004
NGAP87	0.421469	0.093662	4.499908	0.0006

R-squared	0.976230	Mean dependent var	3.197442
Adjusted R-squared	0.972573	S.D. dependent var	1.307442
S.E. of regression	0.216528	Akaike info criterion	-0.054829
Sum squared resid	0.609499	Schwarz criterion	0.090031
Log likelihood	3.438634	Hannan-Quinn criter.	-0.047411
F-statistic	266.9491	Durbin-Watson stat	2.528349
Prob(F-statistic)	0.000000		

Data used for estimation

obs	year	Census Division	type	mecs87	ngap87	supplyp87
1	1994	Northeast	Core	3.670585	3.408	2.005362
2	1998	Northeast	Core	3.1393	2.775	1.956774
3	2002	Northeast	Core	3.600087	4.099	2.520687
4	2006	Northeast	Core	6.468766	7.495	4.699691
5	1994	Midwest	Core	2.721138	3.072	1.473176
6	1998	Midwest	Core	2.603661	2.804	1.571211
7	2002	Midwest	Core	2.90596	3.004	2.211106
8	2006	Midwest	Core	5.194191	5.716	4.107197
9	1994	South	Core	2.846393	2.156	1.515677
10	1998	South	Core	1.995999	2.244	1.551466
11	2002	South	Core	2.578564	2.657	2.307403
12	2006	South	Core	4.988157	4.66	4.046488
13	1994	West	Core	3.134492	2.56	1.244672
14	1998	West	Core	2.700268	2.612	1.341248
15	2002	West	Core	2.787593	3.692	1.737192
16	2006	West	Core	5.505184	5.923	3.610242
17	1994	Northeast	Noncore	2.756907	3.408	2.005362
18	1998	Northeast	Noncore	2.699863	2.775	1.956774
19	2002	Northeast	Noncore	3.375998	4.099	2.520687
20	2006	Northeast	Noncore	6.220472	7.495	4.699691
21	1994	Midwest	Noncore	2.259632	3.072	1.473176
22	1998	Midwest	Noncore	2.205087	2.804	1.571211
23	2002	Midwest	Noncore	2.986226	3.004	2.211106
24	2006	Midwest	Noncore	4.807767	5.716	4.107197
25	1994	South	Noncore	2.205068	2.156	1.515677
26	1998	South	Noncore	1.816138	2.244	1.551466
27	2002	South	Noncore	2.52904	2.657	2.307403

obs	year	Census Division	type	mecs87	ngap87	supplyp87
28	2006	South	Noncore	4.937482	4.66	4.046488
29	1994	West	Noncore	2.209961	2.56	1.244672
30	1998	West	Noncore	2.059031	2.612	1.341248
31	2002	West	Noncore	3.193424	3.692	1.737192
32	2006	West	Noncore	4.896972	5.923	3.610242

Table F6

Data: Equations for residential distribution tariffs

Author: Joe Benneche, EIA, 2013.

Source: The source for the peak and off-peak data used in this estimation was the *Natural Gas Monthly*, DOE/EIA-0130. State-level city gate and residential prices by month were averaged using quantity weights to arrive at seasonal (peak and off-peak), regional-level (12 NGTDM regions) prices. The quantity weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. The source for the number of residential customers was the Natural Gas Annual, DOE/EIA-0131.

Variables:

$TRS_{r,n,t}$	=	residential distributor tariff in the period n for region r (1987$/Mcf) [$DTAR_SF_1$]
$REGION_r$	=	1, if observation is in region r, =0 otherwise
$QRS\_NUMR_{r,n,t}$	=	residential gas consumption per customer in the period for region r in year t (Bcf per thousand customers) [($BASQTY\_SF_1$+$BASQTY\_SI_1$)/NUMRS]
$NUMR\_ANN_{r,t}$	=	number of residential customers (thousands) [NUMRS]
r	=	NGTDM region
n	=	network (1=peak, 2=off-peak)
t	=	year
$\alpha_{r,n}$	=	estimated parameters for regional dummy variables [PRSREGPK23]
$\beta_{1,n}$, $\beta_{2,n}$	=	estimated parameters
ρ_n	=	autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Residential distributor tariff equations were estimated using panel data for the 12 NGTDM regions and two periods over the 1990 to 2012 time period. The equations were estimated in log-linear form with corrections for cross-sectional heteroscedasticity and first-order serial correlation using EViews. The general form for the estimating equation follows:

$$\ln TRS_{r,n,t} = \sum_r (\alpha_{r,n} * REGION_r) + \beta_{1,n} * \ln QRS\_NUMR_{r,n,t} + \beta_{2,n} * \ln NUMR\_ANN_{r,t} +$$
$$\rho_n * \ln TRS_{r,n,t-1} - \rho_n * (\sum_r (\alpha_{r,n} * REGION_r) + \beta_{1,n} * \ln QRS\_NUMR_{r,n,t-1} +$$
$$\beta_{2,n} * \ln NUMR\_ANN_{r,t-1})$$

Regression diagnostics and parameter estimates for the peak period:

Dependent Variable: LNTRS87
Method: Least Squares
Date: 08/14/13 Time: 16:42
Sample (adjusted): 2 276
Included observations: 275 after adjustments
Convergence achieved after 7 iterations
HAC standard errors & covariance (Bartlett kernel, Newey-West fixed bandwidth = 6.0000)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQRS_NUMR	-0.524533	0.075185	-6.976558	0.0000
LN_NUMR_ANN	0.200862	0.079130	2.538369	0.0117
REGION=1	-6.691147	0.869667	-7.693923	0.0000
REGION=2	-7.226076	0.962481	-7.507757	0.0000
REGION=3	-7.857060	0.983787	-7.986542	0.0000
REGION=4	-7.647609	0.921548	-8.298652	0.0000
REGION=5	-7.223522	0.916514	-7.881523	0.0000
REGION=6	-7.392293	0.888119	-8.323541	0.0000
REGION=7	-7.795917	0.933115	-8.354719	0.0000
REGION=8	-7.736822	0.887855	-8.714063	0.0000
REGION=9	-7.010122	0.830697	-8.438845	0.0000
REGION=10	-6.850380	0.809596	-8.461483	0.0000
REGION=11	-7.207645	0.850857	-8.471045	0.0000
REGION=12	-7.705760	0.961113	-8.017535	0.0000
AR(1)	0.234747	0.061381	3.824461	0.0002

R-squared	0.917002	Mean dependent var	0.953428
Adjusted R-squared	0.912532	S.D. dependent var	0.383145
S.E. of regression	0.113315	Akaike info criterion	-1.464290
Sum squared resid	3.338470	Schwarz criterion	-1.267012
Log likelihood	216.3399	Hannan-Quinn criter.	-1.385117
Durbin-Watson stat	2.008092	Wald F-statistic	953.5011
Prob(Wald F-statistic)	0.000000		

Inverted AR Roots	.23

Regression diagnostics and parameter estimates for the off-peak period:

Dependent Variable: LNTRS87
Method: Least Squares
Date: 08/14/13 Time: 16:42
Sample: 277 552
Included observations: 276
Convergence achieved after 6 iterations
HAC standard errors & covariance (Bartlett kernel, Newey-West fixed bandwidth = 6.0000)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQRS_NUMR	-0.861027	0.077882	-11.05550	0.0000
LN_NUMR_ANN	0.243360	0.098955	2.459302	0.0146
REGION=1	-10.96627	1.083343	-10.12262	0.0000
REGION=2	-11.33113	1.204882	-9.404344	0.0000
REGION=3	-11.79276	1.233702	-9.558838	0.0000
REGION=4	-11.67908	1.150023	-10.15552	0.0000
REGION=5	-11.38714	1.152462	-9.880711	0.0000
REGION=6	-11.57883	1.100525	-10.52119	0.0000
REGION=7	-11.74449	1.159252	-10.13110	0.0000
REGION=8	-11.72552	1.115682	-10.50973	0.0000
REGION=9	-11.11860	1.044252	-10.64743	0.0000
REGION=10	-10.93621	0.975503	-11.21084	0.0000
REGION=11	-11.28637	1.040311	-10.84904	0.0000
REGION=12	-11.93317	1.205229	-9.901170	0.0000
AR(1)	0.268308	0.070965	3.780834	0.0002

R-squared	0.913905	Mean dependent var	1.302749
Adjusted R-squared	0.909287	S.D. dependent var	0.372782
S.E. of regression	0.112276	Akaike info criterion	-1.482890
Sum squared resid	3.290165	Schwarz criterion	-1.286129
Log likelihood	219.6389	Hannan-Quinn criter.	-1.403933
Durbin-Watson stat	2.042698	Wald F-statistic	2520.684
Prob(Wald F-statistic)	0.000000		

Inverted AR Roots	.27

Data used for peak period estimation in log form

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA/HI
1990	TRS87	1.30	1.35	1.38	1.38	1.46	1.48	1.35	1.42	1.43	1.51	1.24	1.17
1990	NUMR_ANN	14.42	14.43	14.44	14.45	14.47	14.47	14.48	14.49	14.50	14.51	14.55	14.55
1990	QRS_NUMR	-9.81	-9.85	-9.75	-9.72	-9.68	-9.81	-9.75	-9.82	-9.92	-9.94	-9.80	-9.85
1991	TRS87	1.33	1.06	1.45	1.34	1.44	1.48	1.36	1.44	1.35	1.41	1.47	1.07
1991	NUMR_ANN	14.56	14.58	14.58	14.58	14.60	14.61	14.54	14.62	14.63	14.64	14.64	15.92
1991	QRS_NUMR	-9.90	-9.73	-9.80	-9.76	-9.96	-9.84	-9.73	-9.76	-9.82	-9.80	-9.95	-9.83
1992	TRS87	1.12	1.17	1.15	1.21	1.24	1.08	1.26	1.29	1.27	0.96	0.84	1.01
1992	NUMR_ANN	15.99	16.00	15.95	15.95	15.96	15.97	15.98	16.00	16.00	16.02	16.04	16.04
1992	QRS_NUMR	-9.87	-9.80	-9.70	-9.63	-9.72	-9.66	-9.75	-9.89	-9.76	-9.71	-9.78	-9.84
1993	TRS87	0.97	1.11	1.01	1.07	1.09	1.12	1.25	1.12	1.15	1.21	0.40	0.43
1993	NUMR_ANN	16.05	16.05	16.05	16.07	16.08	16.07	16.08	16.08	16.09	16.10	16.22	16.24
1993	QRS_NUMR	-9.68	-9.73	-9.71	-9.91	-9.77	-9.79	-9.75	-9.76	-9.79	-9.98	-9.55	-9.49
1994	TRS87	0.42	0.47	0.56	0.42	0.18	0.52	0.49	0.47	0.28	0.42	0.17	0.23
1994	NUMR_ANN	16.25	16.26	16.28	16.30	16.31	16.32	16.34	16.35	16.37	16.38	16.39	16.40
1994	QRS_NUMR	-9.50	-9.43	-9.42	-9.45	-9.39	-9.50	-9.65	-9.55	-9.52	-9.59	-9.63	-9.51
1995	TRS87	0.45	0.52	0.59	0.44	0.48	0.73	0.41	0.63	0.65	0.40	0.41	0.48
1995	NUMR_ANN	16.41	16.44	16.42	16.43	16.43	16.42	16.42	16.43	16.45	15.25	15.27	15.28
1995	QRS_NUMR	-9.57	-9.60	-9.79	-9.64	-9.59	-9.65	-9.67	-9.69	-9.92	-9.68	-9.59	-9.70
1996	TRS87	0.41	0.54	0.54	0.51	0.52	0.61	0.60	0.56	0.51	0.55	0.31	0.59
1996	NUMR_ANN	15.31	15.32	15.33	15.35	15.36	15.40	15.39	15.41	15.42	15.43	15.44	15.45
1996	QRS_NUMR	-9.57	-9.58	-9.63	-9.52	-9.65	-9.79	-9.74	-9.71	-9.70	-9.95	-9.70	-9.76
1997	TRS87	0.60	0.78	0.67	0.52	0.71	0.59	0.74	0.75	1.02	0.99	1.06	1.03
1997	NUMR_ANN	15.46	15.47	15.47	15.48	15.48	15.49	15.49	15.58	15.24	15.26	15.31	15.32

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA/HI
1997	QRS_NUMR	-9.79	-9.96	-9.81	-9.72	-9.78	-9.78	-9.83	-10.16	-9.97	-9.94	-9.90	-9.80
1998	TRS87	1.04	1.03	0.83	1.07	1.00	0.77	1.04	0.99	1.17	0.95	1.15	1.20
1998	NUMR_ANN	15.36	15.38	15.41	15.43	15.47	15.51	15.52	15.55	15.56	15.58	15.59	15.62
1998	QRS_NUMR	-9.82	-9.83	-9.75	-9.92	-10.00	-10.01	-9.82	-9.97	-9.95	-9.83	-9.87	-9.92
1999	TRS87	1.30	1.30	1.26	1.23	1.18	1.27	1.41	0.60	0.71	0.74	0.67	0.78
1999	NUMR_ANN	15.62	15.64	15.65	15.65	15.65	15.66	15.66	14.66	14.68	14.71	14.74	14.77
1999	QRS_NUMR	-10.13	-10.05	-10.05	-9.96	-9.81	-10.04	-10.25	-9.98	-9.93	-9.92	-9.87	-9.86
2000	TRS87	0.77	0.39	0.77	0.86	0.84	0.66	0.74	0.91	0.73	0.94	1.11	1.16
2000	NUMR_ANN	14.79	14.82	14.84	14.86	14.87	14.90	14.91	14.92	14.93	14.93	14.94	14.94
2000	QRS_NUMR	-9.89	-9.81	-9.95	-10.03	-10.04	-9.94	-9.96	-9.98	-9.93	-10.02	-10.07	-10.22
2001	TRS87	0.97	0.96	1.12	0.93	1.00	1.12	0.61	0.65	0.64	0.59	0.62	0.67
2001	NUMR_ANN	14.94	14.94	14.93	14.93	14.93	14.96	15.51	15.53	15.53	15.55	15.55	15.57
2001	QRS_NUMR	-10.17	-10.08	-10.12	-9.92	-10.10	-10.41	-10.11	-10.05	-10.10	-10.03	-10.07	-10.14
2002	TRS87	0.52	0.54	0.80	0.71	0.48	0.62	0.79	0.49	0.73	0.83	0.92	0.62
2002	NUMR_ANN	15.58	15.59	15.61	15.61	15.62	15.63	15.64	15.65	15.66	15.66	15.67	15.69
2002	QRS_NUMR	-10.02	-10.06	-10.17	-10.31	-10.21	-10.13	-10.15	-10.13	-10.26	-10.30	-10.46	-10.27
2003	TRS87	0.70	0.92	0.74	0.63	1.00	0.40	0.42	0.45	0.43	0.32	0.49	0.33
2003	NUMR_ANN	15.70	15.71	15.71	15.72	15.71	14.55	14.58	14.61	14.64	14.69	14.73	14.78
2003	QRS_NUMR	-10.28	-10.34	-10.11	-10.27	-10.48	-9.84	-9.76	-9.83	-9.74	-9.85	-9.96	-9.85
2004	TRS87	0.27	0.56	0.72	0.46	0.51	0.60	0.24	0.48	0.65	0.67	0.33	0.29
2004	NUMR_ANN	14.81	14.86	14.89	14.94	14.97	15.00	15.04	15.07	15.11	15.14	15.16	15.18
2004	QRS_NUMR	-9.81	-9.87	-9.95	-9.93	-9.88	-9.90	-9.99	-9.99	-10.01	-10.05	-9.97	-9.95
2005	TRS87	0.57	0.46	0.55	0.69	1.01	0.88	0.94	0.94	1.00	1.05	0.95	0.87
2005	NUMR_ANN	15.19	15.20	15.21	15.20	13.57	13.67	13.69	13.75	13.81	13.86	13.92	13.96

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA/HI
2005	QRS_NUMR	-10.04	-10.05	-9.99	-10.13	-9.93	-9.93	-9.99	-9.82	-9.92	-10.02	-9.88	-9.98
2006	TRS87	1.00	0.92	0.88	0.92	1.35	0.88	0.99	1.10	1.19	1.31	1.15	1.30
2006	NUMR_ANN	14.01	14.06	14.11	14.14	14.17	14.24	14.24	14.28	14.31	14.34	14.36	14.37
2006	QRS_NUMR	-9.93	-9.91	-9.93	-9.90	-10.00	-10.11	-10.04	-10.07	-10.08	-10.05	-10.05	-10.00
2007	TRS87	1.11	1.25	1.35	1.45	1.56	1.53	1.63	1.57	1.55	1.47	1.59	1.60
2007	NUMR_ANN	14.38	14.39	14.41	13.03	13.05	13.06	13.09	13.12	13.15	13.16	13.19	13.20
2007	QRS_NUMR	-10.26	-10.08	-10.09	-11.09	-11.16	-11.01	-11.14	-11.10	-11.06	-10.96	-11.27	-11.21
2008	TRS87	1.64	1.57	1.69	1.77	1.70	1.83	1.85	1.96	1.84	1.76	1.95	1.76
2008	NUMR_ANN	13.23	13.26	13.29	13.31	13.33	13.37	13.39	13.42	13.43	13.43	13.42	13.42
2008	QRS_NUMR	-11.30	-11.15	-11.13	-11.20	-11.14	-11.20	-11.27	-11.30	-11.43	-11.35	-11.32	-11.02
2009	TRS87	1.81	1.91	1.01	1.02	0.98	0.98	1.10	1.16	0.80	0.82	0.95	1.07
2009	NUMR_ANN	13.43	13.43	13.77	13.84	13.81	13.82	13.86	13.90	13.93	13.97	14.01	14.06
2009	QRS_NUMR	-11.22	-11.52	-10.14	-10.20	-10.15	-10.19	-10.24	-10.41	-10.30	-10.16	-10.16	-10.33
2010	TRS87	0.84	0.80	1.28	0.97	1.05	1.08	1.24	1.26	1.15	1.28	1.14	1.13
2010	NUMR_ANN	14.10	14.13	14.17	14.19	14.22	14.27	14.30	14.33	14.34	14.34	14.35	14.36
2010	QRS_NUMR	-10.36	-10.27	-10.35	-10.43	-10.36	-10.50	-10.57	-10.45	-10.47	-10.61	-10.50	-10.48
2011	TRS87	1.24	0.95	1.07	1.02	1.02	1.06	1.25	1.04	0.96	1.22	1.16	1.02
2011	NUMR_ANN	14.35	15.96	15.97	15.98	15.99	15.99	16.00	16.01	16.02	16.04	16.05	16.06
2011	QRS_NUMR	-10.66	-10.29	-10.40	-10.41	-10.37	-10.40	-10.52	-10.53	-10.48	-10.37	-10.35	-10.48
2012	TRS87	0.76	1.01	0.97	0.99	1.06	1.05	0.94	0.95	1.06	0.93	1.10	1.12
2012	NUMR_ANN	16.08	16.09	16.10	16.12	16.13	16.15	16.16	16.17	16.17	16.17	16.18	16.21
2012	QRS_NUMR	-10.44	-10.50	-10.58	-10.51	-10.61	-10.61	-10.58	-10.56	-10.62	-10.66	-10.59	-10.65

Data used for off-peak estimation in log form

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA/HI
1990	TRS87	1.46	1.47	1.30	1.24	1.40	1.37	1.22	1.37	1.35	1.09	1.20	1.60
1990	NUMR_ANN	14.42	14.43	14.44	14.45	14.47	14.47	14.48	14.49	14.50	14.51	14.55	14.55
1990	QRS_NUMR	-10.17	-10.21	-10.03	-10.08	-10.23	-10.25	-10.18	-10.18	-10.31	-10.22	-10.29	-10.36
1991	TRS87	1.18	1.62	1.47	1.26	1.58	1.56	1.49	1.47	1.53	1.39	1.54	1.36
1991	NUMR_ANN	14.56	14.58	14.58	14.58	14.60	14.61	14.54	14.62	14.63	14.64	14.64	15.92
1991	QRS_NUMR	-10.29	-10.25	-10.34	-10.33	-10.41	-10.37	-10.14	-10.28	-10.33	-10.31	-10.31	-10.20
1992	TRS87	1.36	1.29	1.33	1.52	1.50	1.41	1.30	1.48	1.37	1.16	1.53	1.32
1992	NUMR_ANN	15.99	16.00	15.95	15.95	15.96	15.97	15.98	16.00	16.00	16.02	16.04	16.04
1992	QRS_NUMR	-10.28	-10.15	-10.15	-10.21	-10.20	-10.10	-10.14	-10.28	-10.26	-10.20	-10.32	-10.25
1993	TRS87	1.52	1.46	1.31	1.46	1.47	1.46	1.61	1.55	1.56	1.40	0.77	0.76
1993	NUMR_ANN	16.05	16.05	16.05	16.07	16.08	16.07	16.08	16.08	16.09	16.10	16.22	16.24
1993	QRS_NUMR	-10.25	-10.30	-10.31	-10.41	-10.34	-10.34	-10.38	-10.45	-10.44	-10.44	-9.93	-9.94
1994	TRS87	0.68	0.80	0.90	0.64	0.73	0.69	0.89	0.77	0.76	0.89	0.48	0.90
1994	NUMR_ANN	16.25	16.26	16.28	16.30	16.31	16.32	16.34	16.35	16.37	16.38	16.39	16.40
1994	QRS_NUMR	-9.86	-9.89	-10.03	-9.90	-9.86	-9.91	-10.15	-10.16	-10.09	-10.23	-10.04	-10.14
1995	TRS87	0.88	0.88	0.94	1.09	1.21	1.14	1.34	1.27	1.25	0.71	0.76	0.74
1995	NUMR_ANN	16.41	16.44	16.42	16.43	16.43	16.42	16.42	16.43	16.45	15.25	15.27	15.28
1995	QRS_NUMR	-10.24	-10.29	-10.25	-10.31	-10.26	-10.31	-10.41	-10.34	-10.36	-10.15	-10.15	-10.13
1996	TRS87	0.78	0.75	0.80	0.80	0.70	0.95	0.92	0.94	1.15	0.91	1.07	1.12
1996	NUMR_ANN	15.31	15.32	15.33	15.35	15.36	15.40	15.39	15.41	15.42	15.43	15.44	15.45
1996	QRS_NUMR	-10.08	-10.28	-10.13	-10.10	-10.19	-10.39	-10.38	-10.35	-10.42	-10.42	-10.41	-10.51
1997	TRS87	1.06	1.16	1.33	1.22	1.25	1.34	1.30	1.40	1.28	1.26	1.12	1.20
1997	NUMR_ANN	15.46	15.47	15.47	15.48	15.48	15.49	15.49	15.58	15.24	15.26	15.31	15.32
1997	QRS_NUMR	-10.53	-10.52	-10.58	-10.48	-10.49	-10.64	-10.57	-10.74	-10.43	-10.43	-10.33	-10.37
1998	TRS87	1.31	1.24	1.29	1.30	1.44	1.39	1.28	1.49	1.43	1.60	1.64	1.53
1998	NUMR_ANN	15.36	15.38	15.41	15.43	15.47	15.51	15.52	15.55	15.56	15.58	15.59	15.62
1998	QRS_NUMR	-10.52	-10.45	-10.37	-10.38	-10.62	-10.66	-10.48	-10.64	-10.56	-10.60	-10.67	-10.65
1999	TRS87	1.75	1.78	1.61	1.87	1.88	1.79	1.82	1.02	1.08	0.95	0.94	1.17
1999	NUMR_ANN	15.62	15.64	15.65	15.65	15.65	15.66	15.66	14.66	14.68	14.71	14.74	14.77
1999	QRS_NUMR	-10.69	-10.70	-10.62	-10.75	-10.83	-10.78	-10.72	-10.47	-10.52	-10.46	-10.42	-10.65
2000	TRS87	1.04	1.04	1.16	1.21	1.18	1.20	1.45	1.33	1.44	1.49	1.41	1.51
2000	NUMR_ANN	14.79	14.82	14.84	14.86	14.87	14.90	14.91	14.92	14.93	14.93	14.94	14.94
2000	QRS_NUMR	-10.57	-10.47	-10.55	-10.73	-10.75	-10.71	-10.80	-10.78	-10.89	-10.95	-10.85	-10.91
2001	TRS87	1.49	1.47	1.63	1.65	1.57	1.60	1.16	1.15	1.13	1.03	1.25	1.21
2001	NUMR_ANN	14.94	14.94	14.93	14.93	14.93	14.96	15.51	15.53	15.53	15.55	15.55	15.57
2001	QRS_NUMR	-11.00	-10.90	-10.95	-11.07	-10.97	-11.03	-10.53	-10.53	-10.54	-10.44	-10.63	-10.63

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/ OR	Florida	AZ/NM	CA/HI
2002	TRS87	1.15	1.16	1.31	1.27	1.24	1.35	1.24	1.51	1.53	1.51	1.64	1.56
2002	NUMR_ANN	15.58	15.59	15.61	15.61	15.62	15.63	15.64	15.65	15.66	15.66	15.67	15.69
2002	QRS_NUMR	-10.59	-10.60	-10.80	-10.83	-10.77	-10.88	-10.82	-10.96	-10.98	-11.00	-11.05	-11.04
2003	TRS87	1.47	1.62	1.66	1.63	1.78	0.51	0.52	0.37	0.51	0.54	0.70	0.59
2003	NUMR_ANN	15.70	15.71	15.71	15.72	15.71	14.55	14.58	14.61	14.64	14.69	14.73	14.78
2003	QRS_NUMR	-11.03	-11.00	-11.07	-11.09	-11.12	-10.20	-10.16	-10.29	-10.16	-10.22	-10.12	-10.18
2004	TRS87	0.73	0.98	0.90	0.77	1.28	0.97	0.97	0.96	0.98	0.89	0.96	0.76
2004	NUMR_ANN	14.81	14.86	14.89	14.94	14.97	15.00	15.04	15.07	15.11	15.14	15.16	15.18
2004	QRS_NUMR	-10.22	-10.26	-10.24	-10.30	-10.38	-10.30	-10.36	-10.38	-10.42	-10.45	-10.49	-10.43
2005	TRS87	0.99	0.86	0.80	0.97	1.22	1.14	1.19	1.08	1.14	1.22	1.05	0.96
2005	NUMR_ANN	15.19	15.20	15.21	15.20	13.57	13.67	13.69	13.75	13.81	13.86	13.92	13.96
2005	QRS_NUMR	-10.40	-10.39	-10.43	-10.58	-10.33	-10.26	-10.44	-10.29	-10.32	-10.34	-10.24	-10.26
2006	TRS87	1.08	1.04	1.03	1.43	1.31	1.03	1.17	1.15	1.42	1.49	0.99	1.59
2006	NUMR_ANN	14.01	14.06	14.11	14.14	14.17	14.24	14.24	14.28	14.31	14.34	14.36	14.37
2006	QRS_NUMR	-10.39	-10.22	-10.30	-10.17	-10.31	-10.40	-10.47	-10.45	-10.46	-10.42	-10.35	-10.45
2007	TRS87	1.33	1.37	1.43	1.81	1.87	1.87	1.93	1.94	1.92	1.91	1.98	1.94
2007	NUMR_ANN	14.38	14.39	14.41	13.03	13.05	13.06	13.09	13.12	13.15	13.16	13.19	13.20
2007	QRS_NUMR	-10.37	-10.32	-10.47	-11.25	-11.22	-11.18	-11.16	-11.27	-11.28	-11.18	-11.34	-11.30
2008	TRS87	1.95	1.95	2.19	2.09	2.21	2.19	2.09	2.21	2.19	2.07	2.28	2.21
2008	NUMR_ANN	13.23	13.26	13.29	13.31	13.33	13.37	13.39	13.42	13.43	13.43	13.42	13.42
2008	QRS_NUMR	-11.30	-11.33	-11.36	-11.38	-11.40	-11.40	-11.35	-11.42	-11.40	-11.40	-11.47	-11.39
2009	TRS87	2.22	2.24	1.41	1.39	1.37	1.35	1.39	1.43	1.24	1.50	1.61	1.41
2009	NUMR_ANN	13.43	13.43	13.77	13.84	13.81	13.82	13.86	13.90	13.93	13.97	14.01	14.06
2009	QRS_NUMR	-11.45	-11.42	-10.74	-10.70	-10.77	-10.72	-10.71	-10.76	-10.76	-10.85	-10.81	-10.76
2010	TRS87	1.05	1.55	1.64	1.62	1.64	1.50	1.84	1.80	1.81	1.82	1.74	1.71
2010	NUMR_ANN	14.10	14.13	14.17	14.19	14.22	14.27	14.30	14.33	14.34	14.34	14.35	14.36
2010	QRS_NUMR	-10.75	-10.97	-11.01	-11.00	-11.01	-11.03	-11.09	-11.16	-11.14	-11.11	-11.08	-11.15
2011	TRS87	1.83	0.95	1.13	1.01	1.05	1.17	1.27	1.16	1.18	1.26	1.08	1.14
2011	NUMR_ANN	14.35	15.96	15.97	15.98	15.99	15.99	16.00	16.01	16.02	16.04	16.05	16.06
2011	QRS_NUMR	-11.18	-10.54	-10.47	-10.59	-10.56	-10.46	-10.53	-10.56	-10.61	-10.47	-10.46	-10.52
2012	TRS87	1.12	1.03	1.05	0.91	0.93	1.14	1.19	1.24	1.17	1.19	1.20	1.24
2012	NUMR_ANN	16.08	16.09	16.10	16.12	16.13	16.15	16.16	16.17	16.17	16.17	16.18	16.21
2012	QRS_NUMR	-10.63	-10.60	-10.58	-10.64	-10.68	-10.69	-10.74	-10.79	-10.76	-10.67	-10.68	-10.81

Table F7

Data: Equation for commercial distribution tariffs

Author: Joe Benneche, EIA, 2013.

Source: The source for the peak and off-peak data used in this estimation was the *Natural Gas Monthly*, DOE/EIA-0130. State-level city gate and commercial prices by month were averaged using quantity weights to arrive at seasonal (peak and off-peak), regional-level (12 NGTDM regions) prices. The quantity weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. Historical commercial floorspace data by census division were extracted from the NEMS model and allocated to NGTDM region using Census population figures.

Variables:

$TCM87_{r,n,t}$	=	commercial distributor tariff in region r, network n (1987$/Mcf) [DTAR_SF$_2$]
$REGION_r$	=	1, if observation is in region r, =0 otherwise
$QCM\_FLRSPCr_{r,n,t}$	=	commercial gas consumption per floorspace for region r in year t (Bcf) [(BASQTY_SF$_2$+BASQTY_SI$_2$)/FLRSPC12]
$FLRSPC_{r,t}$	=	commercial floorspace for region r in year t (estimated in thousand square feet) [FLRSPC12]
r	=	NGTDM region
n	=	network (1=peak, 2=off-peak)
t	=	year
$\alpha_{r,n}$	=	estimated parameters for regional dummy variables [PCMREGPK15]
$\beta_{1,n}$,$\beta_{2,n}$	=	estimated parameters
ρ_n	=	autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The commercial distributor tariff equation was estimated using panel data for the 12 NGTDM regions over the 1990 to 2012 time period. The equation was estimated in log-linear form with corrections for cross-sectional heteroscedasticity and first-order serial correlation using EViews. The form of the estimated equation follows:

$$\begin{aligned}\ln TCM87_{r,n,t} = {} & \sum_r (\alpha_{r,n} * REGION_r) + \beta_{1,n} * \ln QCM\_FLRSPC_{r,n,t} + \beta_{2,n} * \ln FLRSPC_{r,t} + \\ & \rho_n * \ln TCM87_{r,n,t-1} - \rho_n * (\sum_r (\alpha_{r,n} * REGION_r) + \\ & \beta_{1,n} * \ln QCM\_FLRSPC_{r,n,t-1} + \beta_{2,n} * \ln FLRSPC_{r,t-1})\end{aligned}$$

Regression diagnostics and parameter estimates for the peak period

Dependent Variable: LNTCM87
Method: Least Squares
Date: 08/14/13 Time: 16:43
Sample (adjusted): 2 276
Included observations: 275 after adjustments
Convergence achieved after 8 iterations
HAC standard errors & covariance (Bartlett kernel, Newey-West fixed bandwidth = 6.0000)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQCM_FLRSPC	-0.199769	0.115555	-1.728777	0.0850
LNFLRSPC	0.233430	0.120715	1.933721	0.0542
REGION=1	-4.560833	1.258946	-3.622738	0.0004
REGION=2	-4.931959	1.346102	-3.663883	0.0003
REGION=3	-5.545319	1.376541	-4.028443	0.0001
REGION=4	-5.320967	1.296835	-4.103039	0.0001
REGION=5	-5.097883	1.335773	-3.816430	0.0002
REGION=6	-5.016108	1.271134	-3.946168	0.0001
REGION=7	-5.585699	1.330039	-4.199649	0.0000
REGION=8	-5.283073	1.232768	-4.285537	0.0000
REGION=9	-4.814545	1.222192	-3.939270	0.0001
REGION=10	-5.040924	1.292461	-3.900252	0.0001
REGION=11	-4.947742	1.203487	-4.111173	0.0001
REGION=12	-4.898302	1.331618	-3.678459	0.0003
AR(1)	0.286179	0.083303	3.435388	0.0007

R-squared	0.803541	Mean dependent var	0.601076
Adjusted R-squared	0.792962	S.D. dependent var	0.343571
S.E. of regression	0.156329	Akaike info criterion	-0.820700
Sum squared resid	6.354116	Schwarz criterion	-0.623422
Log likelihood	127.8463	Hannan-Quinn criter.	-0.741527
Durbin-Watson stat	2.003237	Wald F-statistic	284.0912
Prob(Wald F-statistic)	0.000000		

Inverted AR Roots	.29

Regression diagnostics and parameter estimates for the off-peak period

Dependent Variable: LNTCM87
Method: Least Squares
Date: 08/14/13 Time: 16:43
Sample: 277 552
Included observations: 276
Convergence achieved after 6 iterations
HAC standard errors & covariance (Bartlett kernel, Newey-West fixed bandwidth = 6.0000)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQCM_FLRSPC	-0.565362	0.200735	-2.816456	0.0052
LNFLRSPC	0.502852	0.194786	2.581559	0.0104
REGION=1	-12.95361	1.632212	-7.936229	0.0000
REGION=2	-13.22336	1.793426	-7.373236	0.0000
REGION=3	-13.52246	1.819152	-7.433386	0.0000
REGION=4	-13.35101	1.697036	-7.867251	0.0000
REGION=5	-13.40747	1.750924	-7.657371	0.0000
REGION=6	-13.03578	1.650342	-7.898834	0.0000
REGION=7	-13.55409	1.746682	-7.759911	0.0000
REGION=8	-12.92684	1.652045	-7.824749	0.0000
REGION=9	-12.76847	1.585017	-8.055731	0.0000
REGION=10	-13.29146	1.650120	-8.054844	0.0000
REGION=11	-12.61375	1.556023	-8.106401	0.0000
REGION=12	-13.12752	1.759620	-7.460428	0.0000
AR(1)	0.181133	0.085747	2.112415	0.0356

R-squared	0.623373	Mean dependent var	0.599948
Adjusted R-squared	0.603171	S.D. dependent var	0.331007
S.E. of regression	0.208516	Akaike info criterion	-0.244789
Sum squared resid	11.34797	Schwarz criterion	-0.048028
Log likelihood	48.78087	Hannan-Quinn criter.	-0.165832
Durbin-Watson stat	2.006762	Wald F-statistic	421.5618
Prob(Wald F-statistic)	0.000000		

Inverted AR Roots	.18

Data used for peak period estimation in log form

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA/HI
1990	TCM87	1.03	1.01	1.07	1.02	1.18	1.13	0.98	1.11	1.06	1.02	0.81	0.74
1990	QCM_FLRSPC	-10.81	-10.78	-10.67	-10.61	-10.36	-10.43	-10.34	-10.31	-10.40	-10.60	-10.52	-10.57
1990	FLRSPC	14.73	14.74	14.75	14.75	14.76	14.76	14.77	14.78	14.79	14.81	14.82	14.84
1991	TCM87	1.00	0.74	1.16	1.07	1.11	1.20	1.03	1.09	0.84	0.96	1.03	0.78
1991	QCM_FLRSPC	-10.63	-10.60	-10.66	-10.65	-10.80	-10.64	-10.56	-10.53	-10.54	-10.46	-10.58	-10.28
1991	FLRSPC	14.86	14.88	14.89	14.90	14.92	14.93	14.95	14.95	14.96	14.96	14.97	15.69
1992	TCM87	0.80	0.86	0.82	0.95	0.95	0.87	0.92	0.69	0.60	1.01	0.90	0.45
1992	QCM_FLRSPC	-10.22	-10.16	-10.14	-10.10	-10.10	-9.98	-10.00	-9.99	-9.93	-9.98	-10.07	-10.05
1992	FLRSPC	15.70	15.71	15.72	15.72	15.73	15.73	15.74	15.75	15.76	15.77	15.78	15.80
1993	TCM87	0.82	0.92	0.76	0.78	0.60	0.58	0.60	0.78	0.66	0.63	0.14	0.20
1993	QCM_FLRSPC	-9.93	-9.93	-10.04	-10.20	-10.08	-10.08	-10.07	-10.06	-10.07	-10.28	-10.03	-9.97
1993	FLRSPC	15.81	15.82	15.83	15.84	15.85	15.87	15.88	15.88	15.88	15.89	15.92	15.94
1994	TCM87	0.19	0.26	0.38	0.23	-0.05	0.33	0.30	0.29	0.00	0.13	0.13	-0.05
1994	QCM_FLRSPC	-9.98	-9.93	-9.89	-9.91	-9.84	-9.95	-10.10	-10.01	-9.98	-10.04	-10.13	-9.98
1994	FLRSPC	15.95	15.96	15.97	15.99	16.00	16.01	16.03	16.05	16.07	16.09	16.11	16.12
1995	TCM87	0.18	0.20	0.36	0.20	0.08	0.47	0.06	0.36	0.39	0.04	0.09	0.17
1995	QCM_FLRSPC	-10.05	-10.07	-10.26	-10.15	-10.08	-10.13	-10.20	-10.19	-10.39	-10.01	-9.93	-10.02
1995	FLRSPC	16.14	16.15	16.17	16.19	16.20	16.22	16.22	16.23	16.23	15.08	15.09	15.10
1996	TCM87	0.13	0.31	0.25	0.27	0.22	0.28	0.29	0.24	0.19	0.20	-0.01	0.28
1996	QCM_FLRSPC	-9.90	-9.91	-9.94	-9.85	-9.99	-10.07	-10.07	-10.05	-10.05	-10.28	-10.07	-10.11
1996	FLRSPC	15.11	15.12	15.14	15.15	15.17	15.18	15.20	15.22	15.24	15.26	15.28	15.30
1997	TCM87	0.32	0.51	0.41	0.24	0.44	0.29	0.39	0.37	0.69	0.64	0.71	0.68
1997	QCM_FLRSPC	-10.17	-10.32	-10.21	-10.11	-10.16	-10.19	-10.20	-10.42	-10.87	-10.77	-10.70	-10.65
1997	FLRSPC	15.32	15.33	15.35	15.36	15.37	15.38	15.39	15.40	15.52	15.55	15.57	15.59
1998	TCM87	0.71	0.71	0.55	0.74	0.72	0.56	0.68	0.77	0.76	0.52	0.76	0.73
1998	QCM_FLRSPC	-10.66	-10.64	-10.63	-10.69	-10.72	-10.72	-10.67	-10.79	-10.78	-10.73	-10.73	-10.75
1998	FLRSPC	15.60	15.62	15.64	15.67	15.70	15.73	15.76	15.80	15.83	15.86	15.88	15.91
1999	TCM87	0.84	0.90	0.81	0.81	0.81	0.88	0.94	0.43	0.52	0.56	0.52	0.65
1999	QCM_FLRSPC	-10.92	-10.86	-10.89	-10.83	-10.74	-10.91	-11.08	-10.66	-10.61	-10.61	-10.55	-10.52
1999	FLRSPC	15.93	15.96	15.99	16.01	16.02	16.04	16.05	14.83	14.84	14.85	14.87	14.88
2000	TCM87	0.62	0.13	0.55	0.67	0.64	0.40	0.57	0.73	0.51	0.67	0.94	0.92
2000	QCM_FLRSPC	-10.53	-10.45	-10.55	-10.66	-10.67	-10.61	-10.65	-10.70	-10.63	-10.71	-10.78	-10.89
2000	FLRSPC	14.90	14.92	14.94	14.97	14.99	15.02	15.05	15.07	15.09	15.11	15.13	15.15
2001	TCM87	0.70	0.68	0.93	0.70	0.75	0.86	0.21	0.22	0.32	0.29	0.26	0.28
2001	QCM_FLRSPC	-10.87	-10.82	-10.89	-10.74	-10.91	-11.15	-10.69	-10.61	-10.66	-10.69	-10.67	-10.63
2001	FLRSPC	15.17	15.19	15.21	15.23	15.23	15.24	15.51	15.52	15.53	15.54	15.55	15.57
2002	TCM87	0.13	0.19	0.45	0.28	-0.12	-0.08	0.35	0.02	0.35	0.48	0.49	0.10
2002	QCM_FLRSPC	-10.66	-10.59	-10.75	-10.77	-10.72	-10.75	-10.66	-10.68	-10.80	-10.93	-11.07	-10.95

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA/HI
2002	FLRSPC	15.58	15.60	15.62	15.65	15.68	15.71	15.73	15.76	15.78	15.80	15.82	15.85
2003	TCM87	0.14	0.45	0.23	-0.06	0.41	0.02	0.06	0.08	0.13	-0.04	0.19	-0.02
2003	QCM_FLRSPC	-10.97	-11.00	-10.86	-10.93	-11.08	-10.05	-9.99	-10.05	-9.95	-10.02	-10.11	-10.01
2003	FLRSPC	15.87	15.90	15.92	15.93	15.94	14.31	14.33	14.35	14.37	14.39	14.42	14.44
2004	TCM87	-0.14	0.27	0.46	0.11	0.24	0.35	-0.16	0.10	0.37	0.42	0.04	-0.05
2004	QCM_FLRSPC	-10.00	-10.10	-10.20	-10.17	-10.13	-10.15	-10.26	-10.25	-10.28	-10.31	-10.26	-10.25
2004	FLRSPC	14.48	14.51	14.55	14.59	14.63	14.66	14.69	14.72	14.74	14.77	14.81	14.84
2005	TCM87	0.24	0.23	0.34	0.41	0.68	0.62	0.66	0.63	0.72	0.78	0.65	0.47
2005	QCM_FLRSPC	-10.28	-10.36	-10.30	-10.41	-10.89	-10.87	-10.96	-10.77	-10.86	-10.91	-10.77	-10.86
2005	FLRSPC	14.87	14.89	14.90	14.90	14.34	14.37	14.39	14.40	14.42	14.43	14.44	14.45
2006	TCM87	0.61	0.58	0.59	0.54	1.05	0.52	0.84	0.74	0.95	1.04	0.82	0.99
2006	QCM_FLRSPC	-10.81	-10.75	-10.79	-10.77	-10.90	-10.94	-10.90	-10.91	-10.90	-10.88	-10.86	-10.84
2006	FLRSPC	14.47	14.49	14.52	14.54	14.57	14.59	14.61	14.62	14.64	14.66	14.67	14.69
2007	TCM87	0.73	0.92	1.04	0.73	0.76	0.71	0.92	0.73	0.73	0.64	0.66	0.82
2007	QCM_FLRSPC	-11.07	-10.90	-10.92	-12.20	-12.15	-12.10	-12.16	-12.17	-12.16	-12.15	-12.31	-12.33
2007	FLRSPC	14.70	14.70	14.71	14.86	14.89	14.91	14.92	14.94	14.96	14.98	15.01	15.03
2008	TCM87	0.82	0.69	1.13	1.12	1.03	1.17	1.01	1.31	1.03	0.99	1.06	1.04
2008	QCM_FLRSPC	-12.35	-12.16	-12.16	-12.08	-12.13	-12.11	-12.12	-12.29	-12.32	-12.33	-12.36	-12.23
2008	FLRSPC	15.06	15.10	15.13	15.17	15.19	15.22	15.24	15.27	15.30	15.32	15.35	15.36
2009	TCM87	1.25	1.24	0.54	0.58	0.55	0.58	0.70	0.78	0.32	0.36	0.61	0.68
2009	QCM_FLRSPC	-12.31	-12.35	-10.65	-10.67	-10.67	-10.72	-10.78	-10.88	-10.81	-10.72	-10.74	-10.84
2009	FLRSPC	15.37	15.38	13.95	13.97	13.99	14.00	14.03	14.05	14.08	14.11	14.14	14.19
2010	TCM87	0.14	0.22	0.91	0.44	0.52	0.56	0.77	0.78	0.56	0.73	0.47	0.47
2010	QCM_FLRSPC	-10.87	-10.87	-10.91	-11.00	-10.93	-11.04	-11.06	-11.02	-11.06	-11.17	-11.14	-11.14
2010	FLRSPC	14.23	14.26	14.30	14.33	14.35	14.38	14.41	14.44	14.47	14.51	14.52	14.53
2011	TCM87	0.67	0.90	1.06	1.07	1.13	1.44	1.38	1.11	1.09	1.23	1.09	0.96
2011	QCM_FLRSPC	-11.23	-10.66	-10.81	-10.77	-10.85	-10.89	-10.89	-11.04	-10.95	-10.97	-10.96	-11.04
2011	FLRSPC	14.54	15.48	15.51	15.53	15.54	15.56	15.57	15.58	15.59	15.61	15.63	15.66
2012	TCM87	0.73	0.89	0.79	0.80	0.91	0.95	0.73	0.80	0.82	0.64	0.85	0.85
2012	QCM_FLRSPC	-11.06	-11.14	-11.08	-11.14	-11.20	-11.19	-11.13	-11.14	-11.19	-11.22	-11.20	-11.17
2012	FLRSPC	15.68	15.71	15.73	15.74	15.76	15.78	15.80	15.81	15.83	15.84	15.84	15.85

Data used for off-peak period estimation in log form

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA/HI
1990	TCM87	0.82	0.81	0.51	0.15	0.36	0.44	0.25	0.53	0.38	0.35	-0.21	0.73
1990	QCM_FLRSPC	-10.90	-10.94	-10.74	-10.77	-10.58	-10.55	-10.43	-10.32	-10.47	-10.57	-10.65	-10.75
1990	FLRSPC	14.73	14.74	14.75	14.75	14.76	14.76	14.77	14.78	14.79	14.81	14.82	14.84
1991	TCM87	0.27	1.13	0.83	0.59	0.99	0.95	0.91	0.79	0.70	0.54	0.74	0.71
1991	QCM_FLRSPC	-10.70	-10.82	-10.95	-10.98	-11.03	-10.95	-10.87	-10.91	-10.91	-10.79	-10.82	-10.34
1991	FLRSPC	14.86	14.88	14.89	14.90	14.92	14.93	14.95	14.95	14.96	14.96	14.97	15.69
1992	TCM87	0.70	0.70	0.67	0.91	0.88	0.75	0.01	0.41	-0.33	-0.51	0.95	0.29
1992	QCM_FLRSPC	-10.38	-10.30	-10.33	-10.34	-10.26	-10.23	-9.96	-10.05	-9.96	-9.93	-10.04	-9.99
1992	FLRSPC	15.70	15.71	15.72	15.72	15.73	15.73	15.74	15.75	15.76	15.77	15.78	15.80
1993	TCM87	0.78	0.74	0.53	0.35	0.40	0.54	0.52	0.51	0.55	0.04	0.38	0.41
1993	QCM_FLRSPC	-10.13	-10.09	-10.26	-10.28	-10.22	-10.24	-10.27	-10.26	-10.22	-10.28	-10.31	-10.38
1993	FLRSPC	15.81	15.82	15.83	15.84	15.85	15.87	15.88	15.88	15.88	15.89	15.92	15.94
1994	TCM87	0.26	0.44	0.55	0.27	0.36	0.33	0.52	0.38	0.37	0.57	0.25	0.50
1994	QCM_FLRSPC	-10.29	-10.31	-10.39	-10.27	-10.24	-10.25	-10.42	-10.44	-10.38	-10.51	-10.35	-10.46
1994	FLRSPC	15.95	15.96	15.97	15.99	16.00	16.01	16.03	16.05	16.07	16.09	16.11	16.12
1995	TCM87	0.38	0.24	0.40	0.55	0.77	0.52	0.67	0.74	0.73	-0.17	-0.08	-0.12
1995	QCM_FLRSPC	-10.52	-10.56	-10.52	-10.58	-10.54	-10.59	-10.69	-10.57	-10.59	-10.18	-10.15	-10.19
1995	FLRSPC	16.14	16.15	16.17	16.19	16.20	16.22	16.22	16.23	16.23	15.08	15.09	15.10
1996	TCM87	0.06	-0.15	0.05	0.07	-0.20	0.17	0.04	0.17	0.49	0.30	0.41	0.36
1996	QCM_FLRSPC	-10.21	-10.28	-10.18	-10.16	-10.28	-10.48	-10.48	-10.46	-10.55	-10.52	-10.54	-10.58
1996	FLRSPC	15.11	15.12	15.14	15.15	15.17	15.18	15.20	15.22	15.24	15.26	15.28	15.30
1997	TCM87	0.18	0.41	0.58	0.49	0.43	0.58	0.50	0.57	0.63	0.58	0.43	0.50
1997	QCM_FLRSPC	-10.64	-10.61	-10.66	-10.57	-10.61	-10.71	-10.64	-10.70	-10.97	-10.90	-10.83	-10.85
1997	FLRSPC	15.32	15.33	15.35	15.36	15.37	15.38	15.39	15.40	15.52	15.55	15.57	15.59
1998	TCM87	0.56	0.56	0.60	0.70	0.74	0.63	0.58	0.91	0.66	0.80	0.71	0.47
1998	QCM_FLRSPC	-10.88	-10.84	-10.80	-10.79	-10.83	-10.91	-10.88	-10.93	-10.96	-10.94	-10.97	-10.99
1998	FLRSPC	15.60	15.62	15.64	15.67	15.70	15.73	15.76	15.80	15.83	15.86	15.88	15.91
1999	TCM87	0.94	0.84	0.62	1.11	0.94	0.96	1.03	0.53	0.56	0.43	0.44	0.62
1999	QCM_FLRSPC	-11.00	-11.03	-10.99	-11.07	-11.11	-11.07	-11.04	-10.86	-10.89	-10.84	-10.80	-10.89
1999	FLRSPC	15.93	15.96	15.99	16.01	16.02	16.04	16.05	14.83	14.84	14.85	14.87	14.88
2000	TCM87	0.52	0.65	0.69	0.60	0.60	0.62	0.96	0.82	0.77	0.82	0.79	0.92
2000	QCM_FLRSPC	-10.86	-10.77	-10.73	-10.90	-10.89	-10.97	-11.03	-11.04	-11.05	-11.05	-11.04	-11.11
2000	FLRSPC	14.90	14.92	14.94	14.97	14.99	15.02	15.05	15.07	15.09	15.11	15.13	15.15
2001	TCM87	0.85	0.91	1.08	1.01	0.96	0.97	0.19	0.22	0.08	0.13	0.37	0.17
2001	QCM_FLRSPC	-11.15	-11.14	-11.20	-11.27	-11.20	-11.21	-10.59	-10.60	-10.56	-10.58	-10.63	-10.48
2001	FLRSPC	15.17	15.19	15.21	15.23	15.23	15.24	15.51	15.52	15.53	15.54	15.55	15.57
2002	TCM87	0.16	0.36	0.51	0.42	0.23	0.45	0.31	0.68	0.65	0.54	0.79	0.61
2002	QCM_FLRSPC	-10.62	-10.49	-10.71	-10.76	-10.67	-10.86	-10.63	-10.73	-10.85	-10.97	-11.04	-11.02

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA/HI
2002	FLRSPC	15.58	15.60	15.62	15.65	15.68	15.71	15.73	15.76	15.78	15.80	15.82	15.85
2003	TCM87	0.31	0.84	0.59	0.50	0.80	-0.18	-0.18	-0.56	-0.12	-0.02	0.29	0.02
2003	QCM_FLRSPC	-10.99	-10.99	-10.97	-10.96	-10.99	-10.29	-10.25	-10.36	-10.22	-10.23	-10.15	-10.19
2003	FLRSPC	15.87	15.90	15.92	15.93	15.94	14.31	14.33	14.35	14.37	14.39	14.42	14.44
2004	TCM87	0.18	0.57	0.50	0.24	1.00	0.54	0.53	0.50	0.45	0.46	0.59	0.24
2004	QCM_FLRSPC	-10.22	-10.26	-10.31	-10.32	-10.45	-10.39	-10.43	-10.48	-10.46	-10.50	-10.57	-10.52
2004	FLRSPC	14.48	14.51	14.55	14.59	14.63	14.66	14.69	14.72	14.74	14.77	14.81	14.84
2005	TCM87	0.64	0.45	0.31	0.44	0.74	0.70	0.78	0.68	0.70	0.81	0.59	0.48
2005	QCM_FLRSPC	-10.49	-10.51	-10.53	-10.64	-11.03	-10.94	-11.11	-11.01	-10.99	-10.98	-10.90	-10.87
2005	FLRSPC	14.87	14.89	14.90	14.90	14.34	14.37	14.39	14.40	14.42	14.43	14.44	14.45
2006	TCM87	0.62	0.57	0.32	1.09	0.84	0.46	0.79	0.52	1.06	1.11	0.28	1.20
2006	QCM_FLRSPC	-10.99	-10.89	-10.90	-10.82	-11.02	-11.01	-11.08	-11.03	-11.03	-11.00	-10.95	-11.05
2006	FLRSPC	14.47	14.49	14.52	14.54	14.57	14.59	14.61	14.62	14.64	14.66	14.67	14.69
2007	TCM87	0.88	0.94	0.98	0.74	0.73	0.69	0.95	0.85	0.72	0.83	0.87	0.81
2007	QCM_FLRSPC	-10.99	-10.96	-11.02	-11.77	-11.71	-11.68	-11.69	-11.77	-11.78	-11.77	-11.92	-11.91
2007	FLRSPC	14.70	14.70	14.71	14.86	14.89	14.91	14.92	14.94	14.96	14.98	15.01	15.03
2008	TCM87	0.82	0.66	1.36	1.10	1.20	1.18	0.94	1.18	1.18	1.07	1.18	1.14
2008	QCM_FLRSPC	-12.01	-11.73	-11.74	-11.64	-11.70	-11.70	-11.69	-11.84	-11.85	-11.89	-11.93	-11.92
2008	FLRSPC	15.06	15.10	15.13	15.17	15.19	15.22	15.24	15.27	15.30	15.32	15.35	15.36
2009	TCM87	1.24	1.30	0.56	0.67	0.49	0.57	0.73	0.76	0.41	0.52	0.83	0.60
2009	QCM_FLRSPC	-11.86	-11.85	-10.73	-10.73	-10.68	-10.64	-10.68	-10.71	-10.71	-10.79	-10.78	-10.78
2009	FLRSPC	15.37	15.38	13.95	13.97	13.99	14.00	14.03	14.05	14.08	14.11	14.14	14.19
2010	TCM87	0.16	0.74	0.85	0.73	0.76	0.45	1.14	1.04	1.04	1.11	0.91	0.79
2010	QCM_FLRSPC	-10.81	-10.91	-10.98	-10.99	-11.02	-11.05	-11.08	-11.14	-11.17	-11.15	-11.21	-11.20
2010	FLRSPC	14.23	14.26	14.30	14.33	14.35	14.38	14.41	14.44	14.47	14.51	14.52	14.53
2011	TCM87	0.91	0.53	0.73	0.44	0.85	1.21	1.09	0.91	0.91	1.05	0.94	0.85
2011	QCM_FLRSPC	-11.21	-10.39	-10.32	-10.38	-10.58	-10.49	-10.41	-10.62	-10.57	-10.42	-10.70	-10.66
2011	FLRSPC	14.54	15.48	15.51	15.53	15.54	15.56	15.57	15.58	15.59	15.61	15.63	15.66
2012	TCM87	0.82	0.60	0.72	0.39	0.43	0.80	0.79	0.92	0.75	0.83	0.84	0.77
2012	QCM_FLRSPC	-10.70	-10.74	-10.85	-10.85	-10.82	-10.78	-10.81	-10.84	-10.85	-10.83	-10.87	-10.84
2012	FLRSPC	15.68	15.71	15.73	15.74	15.76	15.78	15.80	15.81	15.83	15.84	15.84	15.85

Table F8

Data: Lease and plant fuel consumption in Alaska

Author: Margaret Leddy, EIA summer intern, 2009.

Source: EIA's Petroleum Supply Annual and Natural Gas Annual.

Variables:

LSE_PLT = Lease and plant fuel consumption in Alaska [QALK_LAP_N]
OIL_PROD = Oil production in Alaska (thousand barrels) [OGPRCOAK]
[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Using EViews and annual price data from 1981 through 2007, the following equation was estimated using ordinary least squares without a constant term:

$$LSE\_PLT_t = \beta_{-1} * LSE\_PLT_{t-1} + \beta_1 * OIL\_PROD_t$$

The intent was to find an equation that demonstrated similar characteristics to the projection by the Alaska Department of Natural Resources in their "Alaska Oil and Gas Report."

Regression diagnostics and parameter estimates

Dependent Variable: LSE_PLT
Method: Least Squares
Date: 07/24/09 Time: 17:34
Sample (adjusted): 1981 2007
Included observations: 27 after adjustments

	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
OIL_PROD	0.038873	0.015357	2.531280	0.0180	β_1
LSE_PLT_PREV	0.943884	0.037324	25.28876	0.0000	β_{-1}

R-squared	0.911327	Mean dependent var	210731.2
Adjusted R-squared	0.907780	S.D. dependent var	86703.97
S.E. of regression	26329.98	Akaike info criterion	23.26599
Sum squared resid	1.73E+10	Schwarz criterion	23.36198
Log likelihood	-312.0909	Hannan-Quinn criter.	23.29453
Durbin-Watson stat	2.407017		

Data used for estimation:

Year	oil_prod	lse_plt	Year	oil_prod	lse_plt	Year	oil_prod	lse_plt
1981	587337	15249	1990	647309	193875	1999	383199	265504.375
1982	618910	94232	1991	656349	223194.366	2000	355199	269177.988
1983	625527	97828	1992	627322	234716.225	2001	351411	271448.841
1984	630401	111069	1993	577495	237701.556	2002	359335	285476.659
1985	666233	64148	1994	568951	238156.064	2003	355582	300463.487
1986	681310	72686	1995	541654	292810.594	2004	332465	281546.298
1987	715955	116682	1996	509999	295833.863	2005	315420	303215.128
1988	738143	153670	1997	472949	271284.345	2006	270486	257091.267
1989	683979	192239	1998	428850	281871.556	2007	263595	268571.098

Table F9

Data: Western Canada successful tight/other gas wells

Author: Joe Benneche, EIA, 2013

Source: Canadian Association of Petroleum Producers, Statistical Handbook. Undiscovered remaining resource based on estimates from National Energy Board of Canada.

Variables:

GWELLS = Number of successful new natural gas wells drilled in western Canada [SUCWELL]

PRICE87 = Average natural gas wellhead price in Alberta (1987 U.S. dollars per Mcf) [OGCNPPRD]

BOYREMAIN = Remaining natural gas undiscovered resources in western Canada (Bcf) [URRCAN]

PR_LAG = Production-to-reserves ratio last forecast year [CURPRRCAN]

[Note: Variables in brackets used in main body of documentation and in model code.]

Derivation: Using EViews and annual price data from 1963 through 2012, the following equation was estimated after taking natural logs of all of the variables and correcting for first-order serial correlation:

$$\ln GWELLS = \beta_0 + \beta_1 * \ln PRICE87 + \beta_2 * \ln BOYREMAIN + \beta_3 * \ln PR\_LAG + \beta_4 * AR(1)$$

Regression diagnostics and parameter estimates

Dependent Variable: LNGWELLS
Method: Least Squares
Date: 07/28/13 Time: 20:34
Sample (adjusted): 4 49
Included observations: 46 after adjustments
Convergence achieved after 6 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-22.66103	7.004419	-3.235248	0.0024
LNPRICE87	0.678076	0.104608	6.482064	0.0000
LNBOYREMAIN	3.012933	0.628560	4.793391	0.0000
LNPR_LAG	2.322307	0.307881	7.542883	0.0000
AR(1)	0.324614	0.150437	2.157815	0.0369

R-squared	0.923070	Mean dependent var	7.911444
Adjusted R-squared	0.915564	S.D. dependent var	0.942911
S.E. of regression	0.273989	Akaike info criterion	0.350866
Sum squared resid	3.077873	Schwarz criterion	0.549631
Log likelihood	-3.069910	Hannan-Quinn criter.	0.425324
F-statistic	122.9877	Durbin-Watson stat	1.991971
Prob(F-statistic)	0.000000		

Inverted AR Roots	.32

where LNGWELLS is the natural log of the number of successful gas wells drilled, C is the constant term, LNPRICE87 is the natural log of the natural gas wellhead price in 1997$ per Mcf, LNBOYREMAIN is the natural log of remaining natural gas resources, and PR_LAG is the one-year lag of the natural gas production-to-reserves ratio.

Data used for estimation:

OBS	Year	GWELLS	PRICE87	BOYREMAIN	PRLAG
1	1963	338	0.4175	--	--
2	1964	308	0.4276	322860	0.023777
3	1965	320	0.4151	313782	0.024992
4	1966	342	0.4226	311681	0.022606
5	1967	372	0.4123	307793	0.023722
6	1968	478	0.3943	304726	0.024982
7	1969	524	0.3710	299932	0.027438
8	1970	731	0.3801	294988	0.030308
9	1971	838	0.3714	290387	0.032619
10	1972	1164	0.3774	286647	0.034313
11	1973	1656	0.3909	285752	0.037697
12	1974	1902	0.5806	282996	0.041419
13	1975	2080	1.0352	282572	0.040855
14	1976	3304	1.6416	279077	0.042815
15	1977	3192	1.9065	276837	0.042731
16	1978	3319	1.9265	272038	0.044639
17	1979	3450	1.9875	266747	0.041781
18	1980	4241	2.4808	261002	0.042642
19	1981	3206	2.3618	258004	0.037496
20	1982	2555	2.3558	253019	0.036760
21	1983	1374	2.4083	250500	0.036323
22	1984	1866	2.2944	247453	0.034488
23	1985	2528	2.0411	239350	0.037176
24	1986	1298	1.5413	238329	0.038167
25	1987	1599	1.2510	237272	0.035334
26	1988	2300	1.1747	236291	0.039254
27	1989	2313	1.1983	234542	0.046734
28	1990	2226	1.1828	229410	0.051076
29	1991	1645	1.0300	226062	0.050408
30	1992	908	0.9469	222687	0.054859
31	1993	3327	1.0588	219818	0.060680
32	1994	5333	1.1100	216251	0.068904
33	1995	3325	0.8016	212248	0.075709

OBS	Year	GWELLS	PRICE87	BOYREMAIN	PRLAG
34	1996	3664	0.9190	205761	0.080323
35	1997	4820	1.0714	203289	0.082542
36	1998	4955	0.9762	201243	0.087980
37	1999	7005	1.2454	197568	0.095583
38	2000	8928	2.2920	192766	0.102053
39	2001	10529	2.5696	187856	0.104878
40	2002	8815	1.7351	181157	0.107942
41	2003	12308	3.0890	175937	0.106675
42	2004	13322	3.2989	171532	0.105396
43	2005	12996	4.5204	166436	0.108788
44	2006	11712	3.7200	160065	0.109257
45	2007	8184	3.7676	155735	0.105284
46	2008	6969	4.4680	150197	0.104160
47	2009	2683	2.0813	142204	0.098953
48	2010	2942	2.1879	138638	0.086179
49	2011	2249	2.0508	133225	0.082680
50	2012	939	1.3137	1.30726	0.078020

Appendix G. Variable Cross-Reference Table

With the exception of the Pipeline Tariff Submodule (PTS), all of the equations in this model documentation report are the same as those used in the model FORTRAN code. Table G-1 presents cross-references between model equation variables defined in this document and in the FORTRAN code for the PTS.

Table G-1. Cross-reference of PTM variables between documentation and code

Documentation	Code Variable	Equation #
$R_{i,f}$	Not represented	161
$R_{i,v}$	Not represented	162
ALL_f	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	163
ALL_v	AVA_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	162
R_i	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	161, 162
FC_a	Not represented	163
VC_a	Not represented	164
$R_{i,f,r}$	RFC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	165
$R_{i,f,u}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	166
$R_{i,v,r}$	RVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	167
$R_{i,v,u}$	UVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	168
$ALL_{f,r}$	AFR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	165
$ALL_{f,u}$	AFU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	166
$ALL_{v,r}$	AVR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	167
$ALL_{v,u}$	AVU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	168
ξ_i	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	226, 227, 229-232
$Item_{i,a,t}$	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	226, 227, 229-232
$FC_{a,t}$	Not represented	226
$VC_{a,t}$	Not represented	227
$TCOS_{a,t}$	Not represented	228, 233
$RFC_{a,t}$	RFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	229
$UFC_{a,t}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	229
$RVC_{a,t}$	RVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	231
$UVC_{a,t}$	UVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	232
λ_i	AFR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	229, 230
μ_i	AVR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	231, 232

a - arc, t - year, i - cost-of-service component index

Appendix H. Coal-to-Gas Submodule

A Coal-to-Gas (CTG) algorithm has been incorporated into the NGTDM to project potential new CTG plants at the Census Division level and the associated pipeline-quality gas production. The Coal-to-Gas process with no carbon sequestration is adopted as the generic facility for the CTG. The CTG_INVEST subroutine calculates the annualized capital costs, operating costs, and other variable costs for a generic coal-to-gas plant producing 100 MMcf/day (Appendix E, CTG_PUCAP) of pipeline-quality synthetic gas from coal. The capital costs are converted into a per-unit basis by dividing by the plant's assumed output of gas. Capital and operating costs are assumed to decline over the forecast due to technological improvements. To determine whether it is profitable to build a CTG plant, the per-unit capital and operating costs plus the coal costs are compared to the average market price of natural gas and electricity. If a CTG plant is profitable, the actual number of plants to be built is set using the Mansfield-Blackman market penetration algorithm. Any new generic plant is assumed to be built in the regions with the greatest level of profitability and to produce pipeline-quality natural gas and cogenerated electricity (cogen) for sale to the grid.

Electricity generated by a CTG facility is partially consumed in the facility, while the remainder is assumed to be sold to the grid at wholesale market prices (EWSPRCN, 1987$/MWh, from the EMM). Cogeneration for each use is set for a generic facility using assumed ratios of electricity produced to coal consumed (Appendix E, own—CTG_BASCGS, grid—CTG_BASCGG). The revenue from cogen sales is treated as a credit (CGNCRED) by the model to offset the costs (feedstock, fixed, and operation costs) of producing CTG syngas. The annualized transmission cost (CGNTRNS) for cogen sent to the grid is accounted for in the operating cost of the CTG facility.

The primary inputs to the CTG model include a mine-mouth coal price (PCLGAS, 1987$/MMBtu, from the Coal Market Module (CMM)) and a regional wholesale equivalent natural gas price (NODE_ENDPR, 1987$/Mcf). A carbon tax (JCLIN, 1987$/MMBtu from the Integration Module) is added to the coal price as well as a penalty for SO_2 and HG. If the CTG plant is deemed to be economic, the final quantity of coal demanded (QCLGAS, Quad Btu/yr) is sent back to the CMM for feedback. The final outputs from the model are coal consumed, gas produced, electricity consumed, and electricity sold to the grid.

Investment decisions for building new CTG facilities are based on the total investment cost of a CTG plant (CTG_INVCST). Actual cash flows associated with the operation of the individual plants are considered, as well as cash flows associated with capital for the construction of new plants. Terms for capital-related financial charges (CAPREC) and fixed operating costs (FXOC) are included.

$$CTG\_INVCST = CAPREC + FXOC \tag{310}$$

Once a build decision is made, a Mansfield-Blackman algorithm for market penetration is used to determine the limit on the number of plants allowed to build in a given year. The investment costs are further adjusted to account for learning and for resource competition. The methodologies used to calculate the capital-related financial charges and the fixed operating costs, the Mansfield-Blackman model, and investment cost adjustments are presented in detail below.

Capital-related financial charges for coal-to-gas

A discounted cash flow calculation is used to determine the annual capital charge for a CTG plant investment. The annual capital recovery charge assumes a discount rate equal to the cost of capital, which includes the cost of equity (CTGCOE) and interest payments on any loans or other debt instruments used as part of capital project financing (CTGCOD) with an assumed interest rate of the Industrial BAA bond rate (MC_RMCORPBAA, from MACRO) plus an additional risk premium (Appendix E, BA_PREM). Together, this translates into the capital recovery factor (CTG_RECRAT) which is calculated on an after-tax basis.

Some of the steps associated with the capital-related financial charge estimates are conducted exogenous to NEMS (Step 0 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant capital-related cost estimation algorithm are:

0) Estimation of the inside battery limit field cost (ISBL)

1) Year-dollar and location adjustments for ISBL Field Costs

2) Estimation of outside battery limit field cost (OSBL) and Total Field Cost

3) Estimation of Total Project Cost

4) Calculate Annual Capital Recovery

5) Convert capital-related financial costs to a “per-unit” basis

Step 0 involves several adjustments which must be made prior to input into the NGTDM; steps 1-4 are performed within the NGTDM.

Step 0 - Estimation of ISBL Field Cost

The inside battery limits (CTG_ISBL) field costs include direct costs such as major equipment, bulk materials, direct labor costs for installation, construction subcontracts, and indirect costs such as distributables. The ISBL investment and labor costs were provided for plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in 2004 dollars.

Step 1 - Year-Dollar and Location Adjustments to ISBL Field Costs

Before utilizing the ISBL investment cost information, the raw data must be converted according to the following steps:

a) Adjust the ISBL field and labor costs from 2004 dollars, first to the year-dollar reported by NEMS, using the Nelson-Farrar refining industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 dollars used internally by NEMS.

b) Convert the ISBL field costs in 1987 dollars from a PADD III basis (Appendix E, XBM_ISBL) to costs in the NGTDM demand regions using location multipliers (Appendix E, CTG_INVLOC). The location multipliers represent differences in material costs between the various regions.

$$CTG\_ISBL = CTG\_INVLOC * BM\_ISBL / 1000 \tag{311}$$

Step 2 - Estimation of OSBL and Total Field Cost

The outside battery-limit (OSBL) costs for CTG are included in the inside battery-limit costs.

The total field cost (CTG_TFCST) is the sum of ISBL and OSBL

$$CTG\_TFCST = (1 - CTG\_OSBLFAC) * CTG\_ISBL \tag{312}$$

The OSBL field cost is estimated as a fraction (Appendix E, CTG_OSBLFAC) of the ISBL costs.

Step 3 - Estimation of Total Project Cost

The total project investment (CTG_TPI) is the sum of the total field cost (Eq. 3) and other one-time costs (CTG_OTC).

$$CTG\_TPI = CTG\_TFCST + CTG\_OTC \tag{313}$$

Other one-time costs include the contractor's cost (such as home office costs), the contractor's fee and a contractor's contingency, the owner's cost (such as pre-startup and startup costs), and the owner's contingency and working capital. The other one-time costs are estimated as a function of total field costs using cost factors (OTCFAC):

$$CTG\_OTC = OTCFAC * CTG\_TFCST \tag{314}$$

where,

$$\begin{aligned} OTCFAC = {} & CTG\_PCTENV + CTG\_PCTCNTG + CTG\_PCTLND + \\ & CTG\_PCTSPECL + CTG\_PCTWC \end{aligned} \tag{315}$$

and,

CTG_PCTENV	=	Home, office, contractor fee
CTG_CNTG	=	Contractor & owner contingency
CTG_PCTLND	=	Land
CTG_PCTSPECL	=	Prepaid royalties, license, start-up costs
CTG_PCTWC	=	Working capital

The total project investment given above represents the total project cost for 'overnight construction.' The total project investment at project completion and startup will be discussed below.

Closely related to the total project investment are the fixed capital investment (CTG_FCI) and total depreciable investment (CTG_TDI). The fixed capital investment is equal to the total project investment less working capital. It is used to estimate capital-related fixed operating costs.

$$WRKCAP = CTG\_PCTWC * CTG\_TFCST \tag{316}$$

Thus,

$$CTG\_FCI = CTG\_TPI - WRKCAP \tag{317}$$

For the CTG plant, the total depreciable investment (CTG_TDI) is assumed to be equal to the total project investment.

Step 4 - Annual Capital Recovery

The annual capital recovery (ACAPRCV) is the difference between the total project investment (TPI) and the recoverable investment (RCI), all in terms of present value (e.g., at startup). The TPI estimated previously is for overnight construction (ONC). In reality, the TPI is spread out through the construction period. Land costs (LC) will occur as a lump-sum payment at the beginning of the project, construction expenses (TPI – WC – LC = FCI - LC) will be distributed during construction, and working capital (WC) expenses will occur as a lump-sum payment at startup. Thus, the TPI at startup (present value) is determined by discounting the construction expenses (assumed as discrete annual disbursements) and adding working capital (WC):

$$\begin{aligned} TPI\_START = {} & FVI\_CONSTR * LAND + FV\_CONSTR * \\ & (CTG\_FCI - LAND) + WRKCAP \end{aligned} \tag{318}$$

where,

FVI_CONSTR	=	Future-value compounding factor for an instantaneous payment made n years before the startup year
FV_CONSTR	=	Future-value compounding factor for discrete uniform payments made at the beginning of each year starting n years before the startup year.

The future-value factors are a function of the number of compounding periods (n), and the interest rate (r) assumed for compounding. In this case, (n) equals the construction time in years before startup, and the compounding rate used is the cost of capital (CTG_RECRAT).

The recoverable investment (RCI_START) includes the value of the land and the working capital (assumed not to depreciate over the life of the project), as well as the salvage value (PRJSDECOM) of the used equipment:

$$RCI\_START = PV\_PRJ * (LAND + WKRCAP + PRJSDECOM) \tag{319}$$

The present value of RCI is subtracted from the TPI at startup to determine the present value of the project investment (PVI):

$$PVI\_START = TPI\_START - RCI\_START \tag{320}$$

Thus, the annual capital recovery (ACAPRCV) is given by:

$$ACAPRCV = LC\_LIFE * PVI\_START \tag{321}$$

where,

LC_LIFE = uniform-value leveling factor for a periodic payment (annuity) made at the end of each year for (n) years in the future

The depreciation tax credit (DTC) is based on the depreciation schedule for the investment and the total depreciable investment (TDI). The simplest method used for depreciation calculations is the straight-line method, where the total depreciable investment is depreciated by a uniform annual amount over the tax life of the investment. Generic equations representing the present value and the levelized value of the annual depreciation charge are:

$$ADEPREC = CTG\_TDI / CTG\_PRJLIFE \tag{322}$$

$$ADEPTAXC = ADEPREC * FEDST\_TAX \tag{323}$$

$$ACAPCHRGAT = ACAPRCV - ADEPTAXC \tag{324}$$

$$DCAPCHRGAT = ACAPCHRGAT / 365 \tag{325}$$

where,

ADEPREC = annual levelized depreciation
ADEPTAXC = levelized depreciation tax credit, after federal and state taxes
ACAPCHRGAT = annual capital charge, after tax credit
DCAPCHRGAT = daily capital charge, after tax credit

Step 5 - Convert Capital Costs to a 'per-day,' 'per-capacity' Basis

The annualized capital-related financial charge is converted to a daily charge, and then converted to a "per-capacity" basis by dividing the result by the operating capacity of the unit being evaluated. The result is a fixed operating cost on a per-Mcf basis (CAPREC).

CTG plant fixed operating costs

Fixed operating costs (FXOC), a component of total product cost, are costs incurred at the plant that do not vary with plant throughput, and any other costs which cannot be controlled at the plant level. These include such items as wages, salaries and benefits; the cost of maintenance, supplies and repairs; laboratory charges; insurance, property taxes and rent; and other overhead costs. These components can be factored from either the operating labor requirement or the capital cost.

Like capital cost estimations, operating cost estimations involve a number of distinct steps. Some of the steps associated with the FXOC estimate are conducted exogenous to NEMS (Step 0 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant fixed operating cost estimation algorithm are:

0) Estimation of the annual cost of direct operating labor

1) Year-dollar and location adjustment for operating labor costs (OLC)

2) Estimation of total labor-related operating costs (LRC)

3) Estimation of capital-related operating costs (CRC)

4) Convert fixed operating costs to a "per-unit" basis

Step 0 involves several adjustments which must be made prior to input into the NGTDM; steps 1-4 are performed within the NGTDM.

Step 0 – Estimation of Direct Labor Costs

Direct labor costs are reported based on a given processing unit size. Operation and labor costs were provided for plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in 2004 dollars.

Step 1 – Year-Dollar and Location Adjustment for Operating Labor Costs

Before the labor cost data can be utilized, it must be converted via the following steps:

a) Adjust the labor costs from 2004 dollars, first to the year-dollar reported by NEMS using the Nelson-Farrar refining-industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 dollars used internally by NEMS (Appendix E, XBM_LABOR).

b) Convert the 1987 operating labor costs from a PADD III (Gulf Coast) basis into regional (other U.S. PADDs) costs using regional location factors. The location multiplier (Appendix E, LABORLOC) represents differences in labor costs between the various locations and includes adjustments for construction labor productivity.

$$CTG\_LABOR = LABORLOC * BM\_LABOR \tag{326}$$

Location multipliers are translated to the NGTDM demand regions.

Step 2 - Estimation of Labor-Related Fixed Operating Costs

Fixed operating costs related to the cost of labor include the salaries and wages of supervisory and other staffing at the plant, charges for laboratory services, and payroll benefits and other plant overhead. These labor-related fixed operating costs (FXOC_LABOR) can be factored from the direct operating labor cost. This relationship is expressed by:

$$FXOC\_STAFF = CTG\_LABOR * CTG\_STAFF\_LCFAC \tag{327}$$

$$\begin{aligned} FXOC\_OH = {} & (CTG\_LABOR + FXOC\_STAFF) \\ & * CTG\_OH\_LCFAC \end{aligned} \tag{328}$$

$$FXOC\_LABOR = CTG\_LABOR + FXOC\_STAFF + FXOC\_OH \quad (329)$$

where,

FXOC_STAFF = Supervisory and staff salary costs
FXOC_OH = Benefits and overhead

Step 3 - Estimation of Capital-Related Fixed Operating Costs

Capital-related fixed operating costs (FXOC_CAP) include insurance, local taxes, maintenance, supplies, non-labor-related plant overhead, and environmental operating costs. These costs can be factored from the fixed capital investment (CTG_FCI). This relationship is expressed by:

$$FXOC\_INS = CTG\_FCI * INS\_FAC \quad (330)$$

$$FXOC\_TAX = CTG\_FCI * TAX\_FAC \quad (331)$$

$$FXOC\_MAINT = CTG\_FCI * MAINT\_FAC \quad (332)$$

$$FXOC\_OTH = CTG\_FCI * OTH\_FAC \quad (333)$$

$$FXOC\_CAP = FXOC\_INS + FXOC\_TAX + FXOC\_MAINT + FXOC\_OTH \quad (334)$$

where,

INS_FAC = Yearly Insurance
TAX_FAC = Local Tax Rate
MAINT_FAC = Yearly Maintenance
OTH_FAC = Yearly Supplies, Overhead, Etc.

Step 4 - Convert Fixed Operating Costs to a "per-capacity" Basis

On a "per-capacity" basis, the FXOC is the sum of capital-related operating costs and labor-related operating costs, divided by the operating capacity of the unit being evaluated.

Mansfield-blackman model for market penetration

The Mansfield-Blackman model for market penetration has been incorporated to limit excessive growth of CTG (on a national level) once it becomes economically feasible.[99] The indices associated with this modeling algorithm are user inputs that define the characteristics of the CTG process. They include an innovation index of the industry (Appendix E, CTG_IINDX), the relative profitability of the investment within the industry, the relative size of the investment (per plant) as a percentage of total company

[99] E. Mansfield, "Technical Change and the Rate of Imitation," *Econometrica*, Vol. 29, No. 4 (1961), pp. 741-765.
A.W. Blackman, "The Market Dynamics of Technological Substitution," *Technological Forecasting and Social Change*, Vol. 6 (1974), pp. 41-63.

value (Appendix E, CTG_SINVST), and a maximum penetration level (total number of units, Appendix E, CTG_BLDX).[100]

$$KFAC = -LOG((CTG\_BLDX / NCTGBLT) - 1) \tag{335}$$

$$PHI = -0.3165 + (0.23221 * CTG\_IINDX) + (0.533 * CTG\_PINDX) - (0.027 * CTG\_SINVST) \tag{336}$$

$$SHRBLD = 1/(1 + EXP(-KFAC - (YR * PHI))) \tag{337}$$

$$CTGBND = CTG\_BLDX * SHRBLD \tag{338}$$

where,

CTG_BLDX	=	maximum number of plants allowed
NCTGBLT	=	number of plants already built
CTG_PINDX	=	the relative profitability of the investment within the industry, calculated as the delivered price of natural gas / (delivered price of coal + the adjusted CTG investment cost [CTG_INVADJ, shown below])
SHRBLD	=	the share of the maximum number of plants that can be built in a given year
CTGBND	=	the upper bound on the number of plants to build

Investment cost adjustments

To represent cost improvements over time (due to learning), a decline rate (CTG_DCLCAPCST) is applied to the original CTG capital costs after builds begin.

$$CTG\_INVADJ = CTG\_INVBAS * (1 - CTG\_DCLCAPCST)^{(YR - CTG\_BASYR)} \tag{339}$$

where,

CTG_INVBAS	=	the initial CTG investment cost
CTG_BASYR	=	the first year CTG plants are allowed to build
CTG_INVADJ	=	the adjusted CTG investment cost

However, once the capacity builds exceed 1.1 bcf/day, a supplemental algorithm is applied to increase costs in response to impending resource depletions (such as competition for water).[101]

$$CTG\_CSTADD = 15 * TANH(0.4 * MAX(0, (CTGPRODC/1127308) - 1))) \tag{340}$$

where,

CTGPRODC	=	current CTG production
CTG_CSTADD	=	the additional cost

[100] These have been defined in a memorandum from Andy Kydes (EIA) to Han-Lin Lee (EIA), entitled "Development of a model for optimistic growth rates for the coal-to-liquids (CTG) technology in NEMS," dated March 23, 2002.
[101] The basic algorithm is defined in a memorandum from Andy Kydes (EIA) to William Brown (EIA), entitled “CTL run-- add to total CTLCST in ADJCTLCST sub,” dated September 29, 2006.