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Model Documentation

Natural Gas Transmission and Distribution Module of the National Energy Modeling System

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Contact Information

The Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System is developed and maintained by the Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting. General questions about the use of the model can be addressed to Michael Schaal (202) 586-5590, Director of the Oil and Gas Division. Specific questions concerning the NGTDM may be addressed to:

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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 2008*, (DOE/EIA-0383(2008)). 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 2009.

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 2008*. Aside from general data and parameter updates, the notable changes include:

- Updated costs and parameters related to the MacKenzie Delta and Alaska pipelines, including lengthening the minimum number of years from initial operation to a potential expansion and allowing the Alaska pipeline to be built before the MacKenzie pipeline.

- Phased in the maximum use of new liquefied natural gas regasification capacity for the first three years of operation and changed parameters for setting the price charged to the U.S. for world liquefied natural gas supplies.

- Reestimated equations for distributor tariffs, short-term supply curves, and Alaska demand equations.

- Changed the impact of alternate fuels on compressed natural gas vehicles and assumed that credits to compressed natural gas retail stations would not pass through to the prices charged.

- Changed the setting of the base quantity used in establishing interstate pipeline tariff curves.

- Made adjustments in Canadian supply representation to better account for production from unconventional sources and to account for higher royalty rates in Alberta.

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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
IFFS	Integrated Future Forecasting System
ITS	Interstate Transmission Submodule
Mcf	Thousand cubic feet
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
PMM	Petroleum Market Module
PTS	Pipeline Tariff Submodule
STEO	Short-Term Energy Outlook
Tcf	Trillion cubic feet
WCSB	Western Canadian Sedimentary Basin

1. Background/Overview

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 Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA). NEMS is the third in a series of computer-based, midterm energy modeling systems used since 1974 by the 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 the 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 to year 2030. 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] as were earlier EIA projection models. 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. A routine was also added to the system 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 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

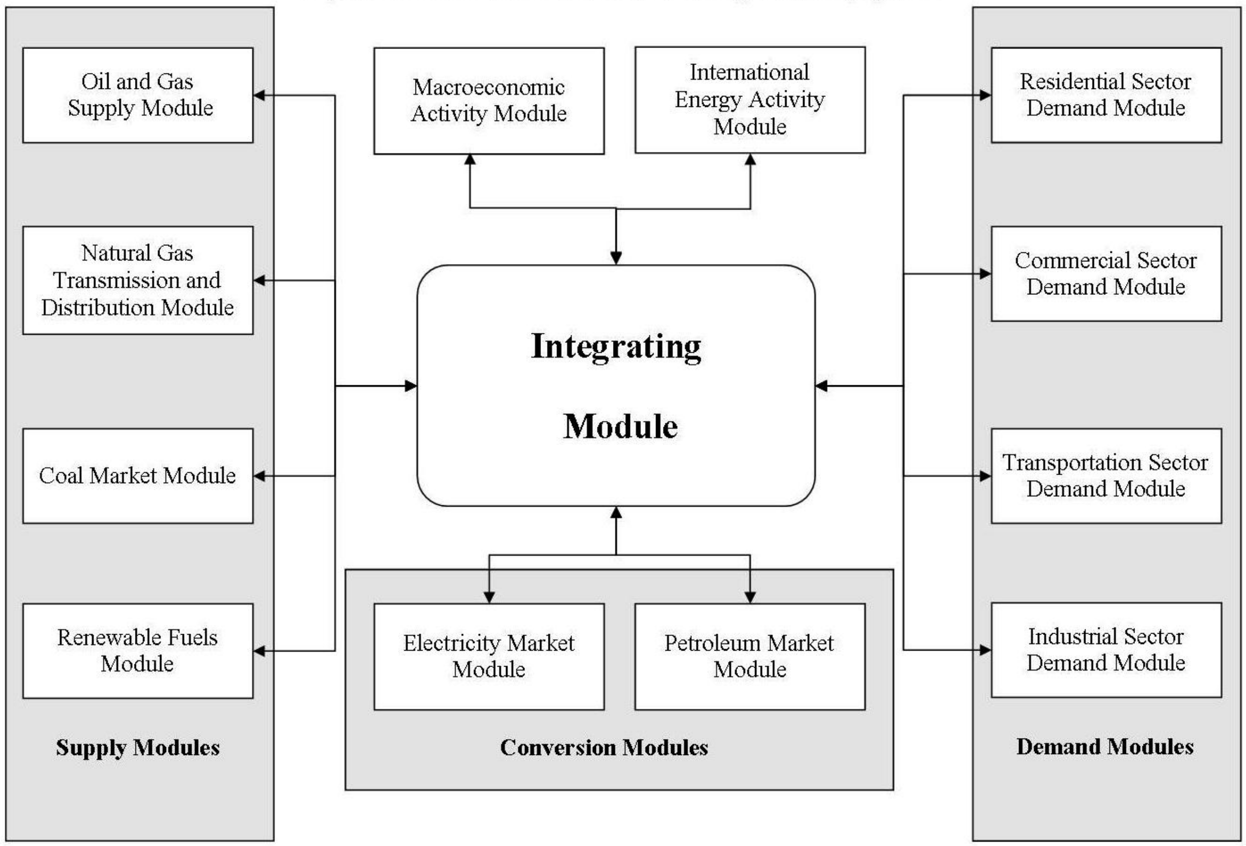
[1]Markets are said to be in equilibrium when the quantities demanded equal the quantities supplied at the same price; that is, at a price that sellers are willing to provide the commodity and consumers are willing to purchase the commodity.

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

consuming sectors. Module solutions are reported annually through the midterm horizon. A schematic of the 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

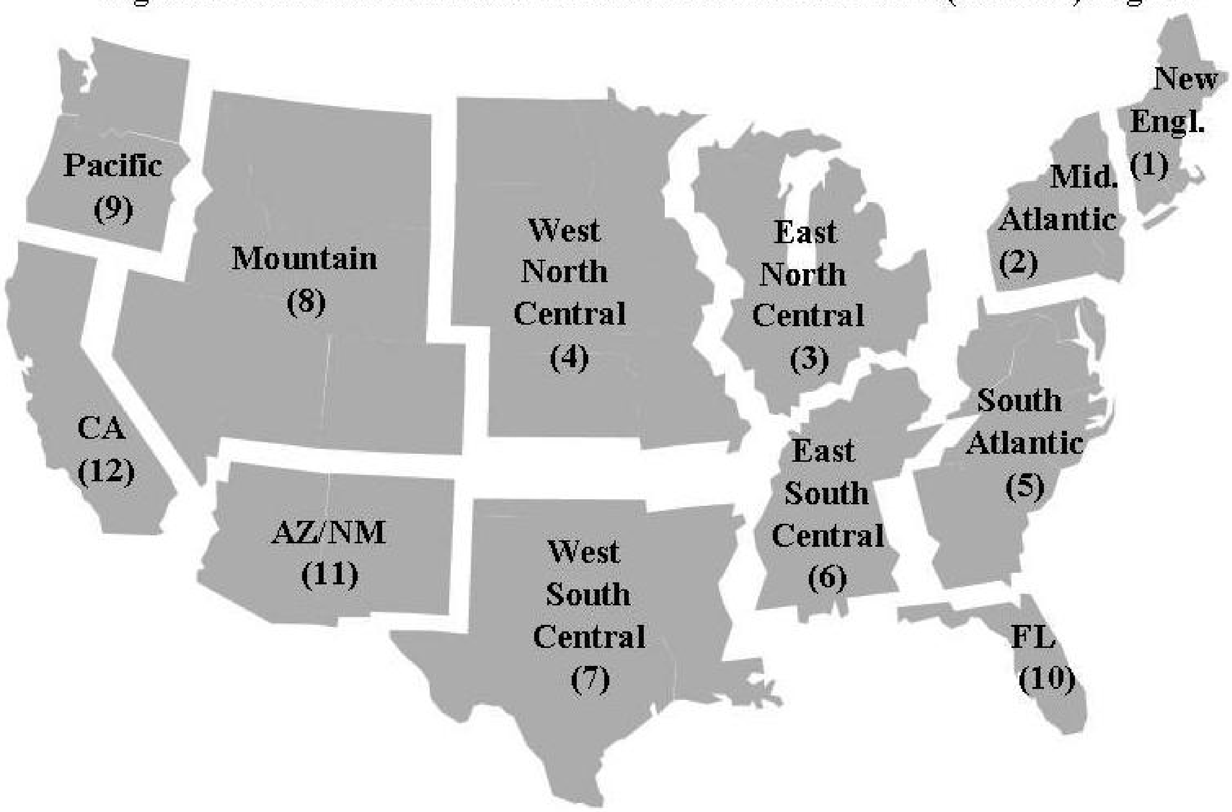
The NGTDM module within the NEMS represents the transmission, distribution, and pricing of natural gas. Based on information received from other NEMS modules, the NGTDM also includes representations of the end-use demand for natural gas, the production of domestic natural gas, and the availability of natural gas traded on the international market. The NGTDM links natural gas suppliers (including importers) and consumers in the lower 48 States 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 the 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

seasonal component, peak and offpeak[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 9 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. One or more domestic supply regions are 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

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



from Alaska to Alberta and one from the MacKenzie Delta to Alberta, if market prices are high

[4]The peak period covers the period from December through March; the offpeak period covers the remaining months.

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. Liquefied natural gas imports into North America are represented for the four existing facilities as of 2004, seven potentially new generic liquefied natural gas import regions directly into the United States (2004 and beyond), a potential import point in the Bahamas, potential import points in eastern and western Canada, and in western Mexico (if destined for the United States). Any new LNG facilities built since 2004 or under construction are forced in the model as planned expansions. Finally, LNG exports from Alaska are included, as well as three import/export border crossings at the Mexican border.

The module consists of three major components: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS). The ITS is the integrating submodule of the NGTDM. It simulates the natural gas price determination process by bringing together 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.

NGTDM Objectives

The purpose of the NGTDM is to derive natural gas delivered and wellhead prices, as well as flow patterns for movements of natural gas through the regional interstate network. Although the 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
- Determine the amount and the location of required additional pipeline and storage capacity on a regional basis, capturing the economic tradeoffs between pipeline and storage capacity additions
- Provide a peak/offpeak, or seasonal analysis capability
- Represent transmission and distribution service pricing

The implementation of these objectives will be described in greater detail in the subsequent chapters of this report that describe the individual submodules of the NGTDM.

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 2008*, DOE/EIA-0383(2008) 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 the 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 the NEMS and the NGTDM and the representation of demand and supply used 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.doe.gov) and is identified as NEMS2008 (part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 2008*, DOE/EIA-0383(2008)).

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 that are cited 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.[5] Appendix F documents the derivation of all empirical estimations used in the NGTDM. Appendix G describes the endogenous calculation of liquefied natural gas costs. Finally, variable cross-reference tables are provided in Appendix H.

[5]The NGTDM data files are available upon request by contacting Joe Benneche at Joseph.Benneche@eia.doe.gov or (202) 586-6132. Alternatively an archived version of the NEMS model (source code and data files) can be downloaded from ftp://ftp.eia.doe.gov/pub/oiaf/aeo.

2. Interface Between the NGTDM and NEMS, Demand and Supply Representation

This chapter presents the basic role that the Natural Gas Transmission and Distribution Module (NGTDM) fulfills in the NEMS. First, a general description of the NEMS is provided, along with an overview of the NGTDM. Second, the data passed to the NGTDM from other NEMS modules is described along with the methodology used within the NGTDM to transform these 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. Finally, the information that is passed to other NEMS modules from the NGTDM is described.

A Brief Overview of NEMS and the NGTDM

The 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 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.[6] 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.

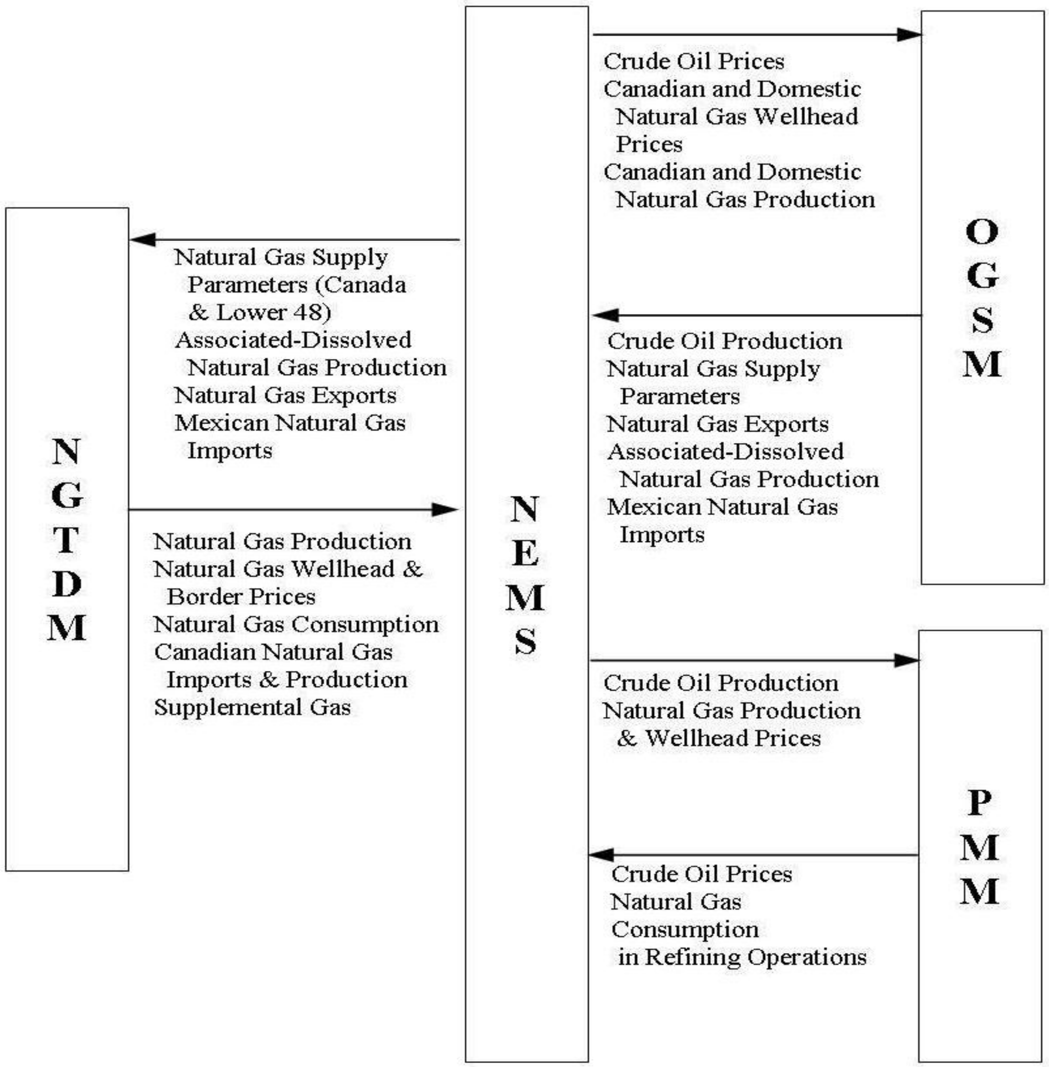
Within the NEMS system, the NGTDM provides the interface between the Oil and Gas Supply Module (OGSM) and the demand modules in NEMS, including the Electricity Market Module (EMM). Since the other modules provide little, if any, information on markets outside of the United States, the NGTDM includes a relatively simple representation of liquefied natural gas supplies and natural gas markets in Canada in order to project import levels. The NGTDM determines the price and flow of dry natural gas supplied internationally from the contiguous U.S. border[7] or domestically from the wellhead (and indirectly from natural gas processing plants) to the domestic end-user. In so doing, the NGTDM models the markets for the transmission (pipeline companies) and distribution

[6]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 2007." DOE/EIA-M057(2007), May 2007 or "The National Energy Modeling System: An Overview 2003," DOE/EIA-0581(2003), March 2003.

[7]Natural gas exports are also represented within the model.

(local distribution companies) of natural gas in the contiguous United States.[8] The primary data flows between the NGTDM and the other oil and gas modules in NEMS, the Petroleum Market Module (PMM) and the OGSM are depicted in **Figure 2-1**.

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



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, the OGSM provides an expected level of natural gas produced (domestically or in Western Canada) at the wellhead given the oil and gas wellhead prices from the previous forecast year. 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, wellhead, and border prices that represent a natural gas market equilibrium, while

[8]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 and Hawaii are modeled separately from the contiguous United States within the NGTDM.

equilibrium, while accounting for the costs and market for transmission and distribution services (including its physical and regulatory constraints).[9] 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, after the NEMS has equilibrated. Information from OGSM is passed as needed to the NGTDM to solve for the following 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[10] 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 components (e.g., pipeline fuel) are modeled exclusively in the NGTDM.

The NGTDM is called once during each iteration of NEMS, but all submodules are not run for every call. The PTS is executed only once for each forecast year, on the first iteration of 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:

1. First Iteration:
    a. The PTS determines the revenue requirements associated with interregional / interstate pipeline company transportation and storage services, using a cost based approach, and uses this 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.
    b. The ITS establishes supply curves for production and liquefied natural gas imports.

2. Each Iteration:
    a. The DTS sets markups for intrastate transmission and for distribution services based on historical data and changes in consumption levels.
    b. 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.

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[9]Parameters are provided by OGSM for the construction of supply curves for domestic non-associated and conventional Western Canadian natural gas production. The use of demand curves in the NGTDM is an option; the model can also respond to fixed consumption levels.

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

c. 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.

3. Last Iteration:
   a. 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.
   b. Other outputs from NGTDM are passed to report writing routines.

For the historical years (1990 through 2005), 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 wellhead prices). The primary unknowns are pipeline and storage tariffs and market hub prices. When prices are translated from the supply nodes, through the network to the end-user (or citygate) in the historical years, the resulting prices are compared against published values for citygate prices. These differentials (benchmark factors) are carried through and applied during the forecast years as a calibration mechanism. In the most recent historical year (2006) 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, wellhead and border crossing prices, non-associated natural gas production, and Canadian and liquefied natural gas import levels. In addition, the NGTDM provides a forecast of lease and plant fuel consumption, 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. 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 a historically observed percentage of dry gas production.[11] Pipeline fuel use depends on the amount of gas flowing through each region, as

[11] The regional factors used in calculating lease and plant fuel consumption (PCTLP) are initially based on historical averages (1996 through 2006) 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

as described in Chapter 4. The level of natural gas exports are currently set exogenously to NEMS and are distinguished by seven Canadian (Appendix E, CANEXP) and three Mexican (set by OGSM) border crossing points, as well as for exports of liquefied natural gas to Japan from Alaska (set exogenously by OGSM). Peak and off-peak period export levels to the lower 48 States are generated by applying average (1991 or 1992 to 2006) historical shares (PKSHR_EMEX, PKSHR_ECAN, respectively) to the annual forecast levels. The representation in the NGTDM of gas delivered to consumers is described below.

Classification of Natural Gas Consumers

Natural gas that is delivered to consumers is represented within the NEMS at the Census Division level and by five primary end-use sectors: residential, commercial, industrial, transportation, and electric generation.[12] 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 predominately 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.[13] Within the industrial sector the non-core segment includes the industrial boiler market and refineries; the core makes up the rest. The electric generating units defining each of the two customer classes modeled are as follows: (1) core − gas steam 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).[14]

For any given NEMS iteration and forecast year, the individual 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 the NEMS converges, the difference between the actual

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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 *AEO2008* these factors were not carried beyond the first STEO year of 2007. A similar adjustment is performed on the factors used in calculating pipeline fuel consumption using STEO values from STQGPTR (Appendix E).

[12]Natural gas burned in the transportation sector is defined as compressed natural gas that is burned in natural gas vehicles; and the electric generation sector includes all electric power generators except combined heat and power generators.

[13]The 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.

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

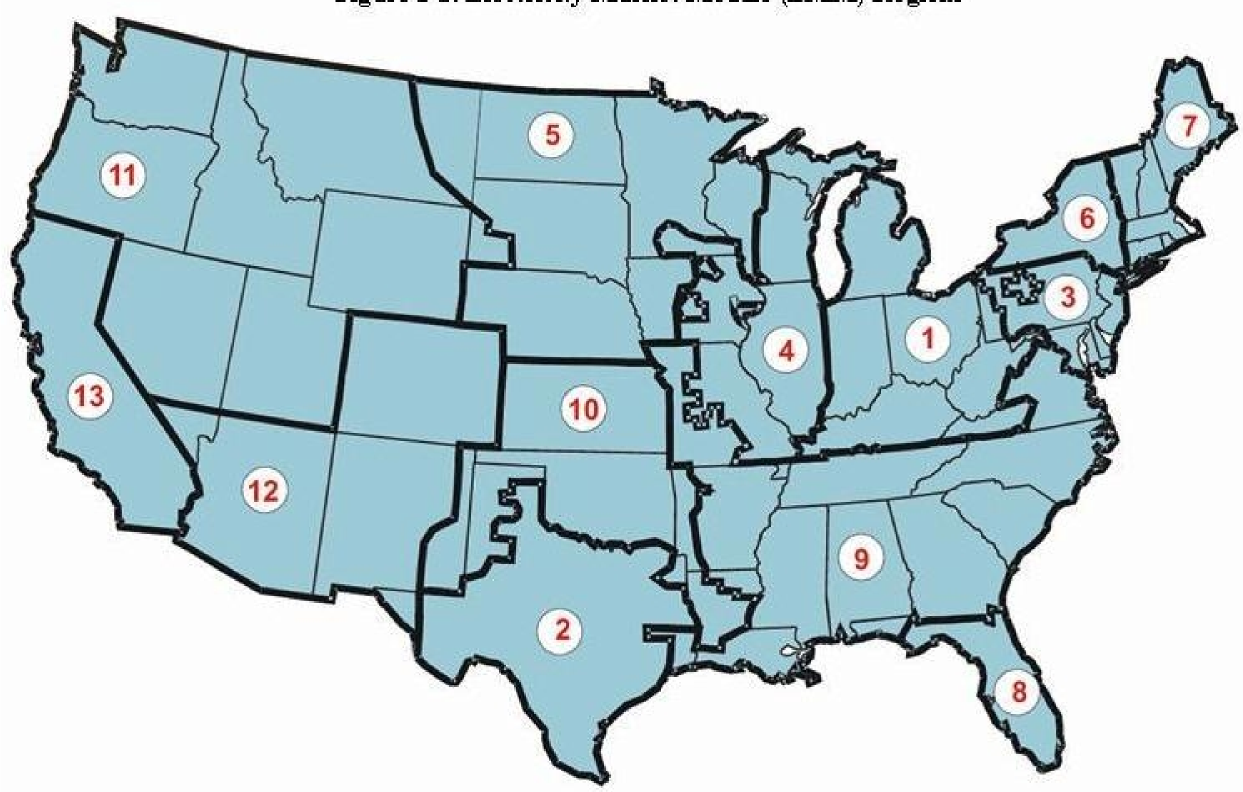
the actual consumption, as determined by the NEMS demand modules, and the approximated consumption levels in the NGTDM are insignificant.

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[15] sectors are provided by the NEMS demand modules for the nine Census divisions, the primary integrating regions represented in the NEMS. Alaska and Hawaii are included within the Pacific Census Division. The EMM represents the electricity generation process for 13 electricity supply regions, the nine North American Electric Reliability Council (NERC) Regions and four selected NERC Subregions (**Figure 2-2**).

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



1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New York (NY)
7. New England (NE)
8 Florida Reliability Coordinating Council (FL)
9 Southeastern Electric Reliability Council (SERC)
10 Southwest Power Pool (SPP)
11 Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13 California (CA)

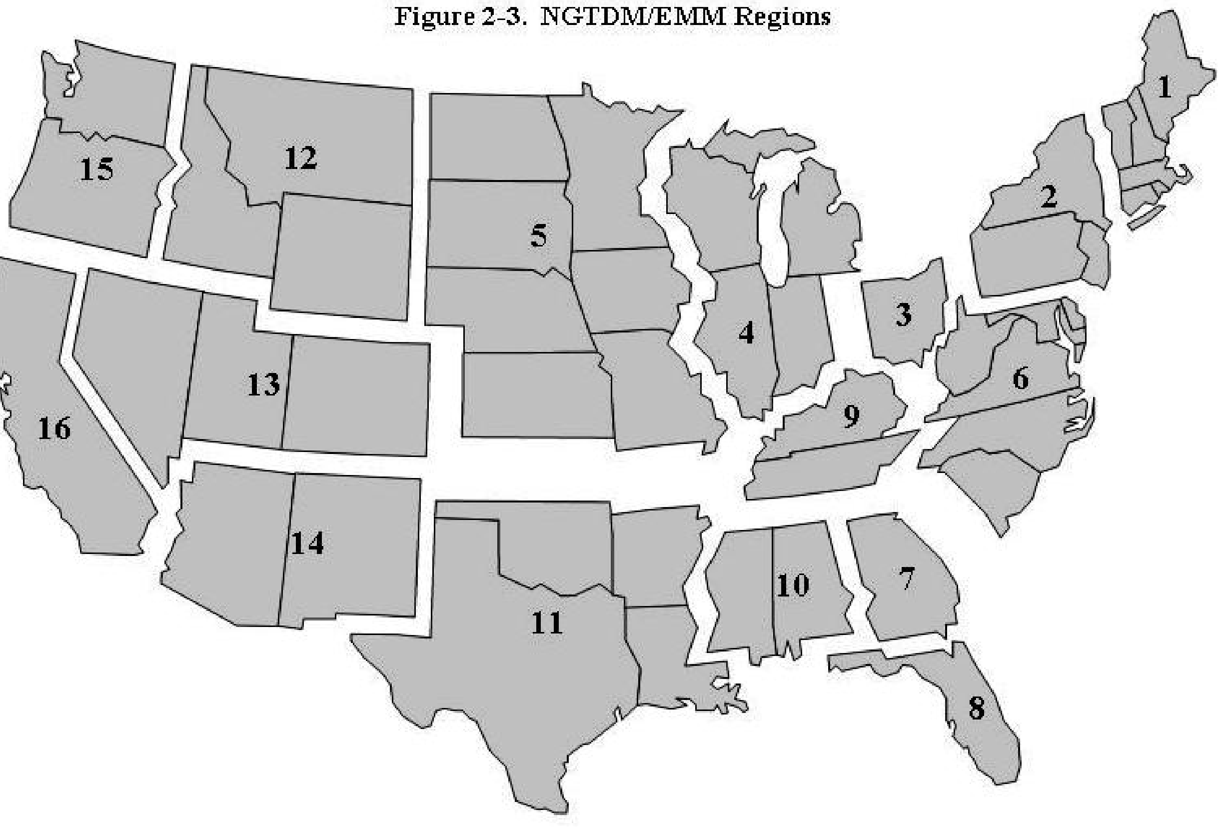
[15]The “non-electric” sectors refer to sectors (other than commercial and industrial combined heat and power generators) that do not produce electricity using natural gas (i.e., the residential, commercial, industrial, and transportation demand sectors).

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 few following 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 from 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" (as shown in **Figure 1-2**).

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 seventeen 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.

Figure 2-3. NGTDM/EMM Regions



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 2006) 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 2006, except for New England − 1997 to 2005) are established as base level shares (core − BASN_PKSHR_UF, non-core − BASN_PKSHR_UI). These are increased each year of the forecast by 0.5 percent, not to exceed 32 percent of the year.[16]

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 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:

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

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 *AEO2008*)
PR	=	delivered price at which demand is to be evaluated (1987 dollars per Mcf)

[16]The peak period covers 33 percent of the year.

$NGDMD\_CRVF_{s,r}$ = 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)

Note: Demand curves can be represented with fixed consumption levels by setting elasticities equal to zero.

The form of the demand curve 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 *AEO2008*). 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 the *AEO2008* all of the electric generator demand curve elasticities were set to zero.

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 (conventional and unconventional), and Arctic Canada production; liquefied natural gas imports; natural gas production in Alaska (including that which is transported through Canada via pipeline[17]); 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 which 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, conventional gas from the Western Canada region, and liquefied natural gas imports.[18] 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) that varies with a change in the oil production in the current forecast year.[19] 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

[17]With the recent high natural gas prices several different options have been proposed for bringing stranded natural gas in Alaska to market (i.e., by pipeline, as LNG, and as liquids). The LNG option was deemed the least likely and is not considered in the model. The Petroleum Market Module forecasts the potential conversion of Alaska natural gas into liquids. The NGTDM allows for the building of a generic pipeline from Alaska into Alberta, although not at the same time as a MacKenzie Valley pipeline. The pipeline is assumed to have first access to the currently proved reserves in Alaska which are assumed to be lower cost given their association with previous oil production.

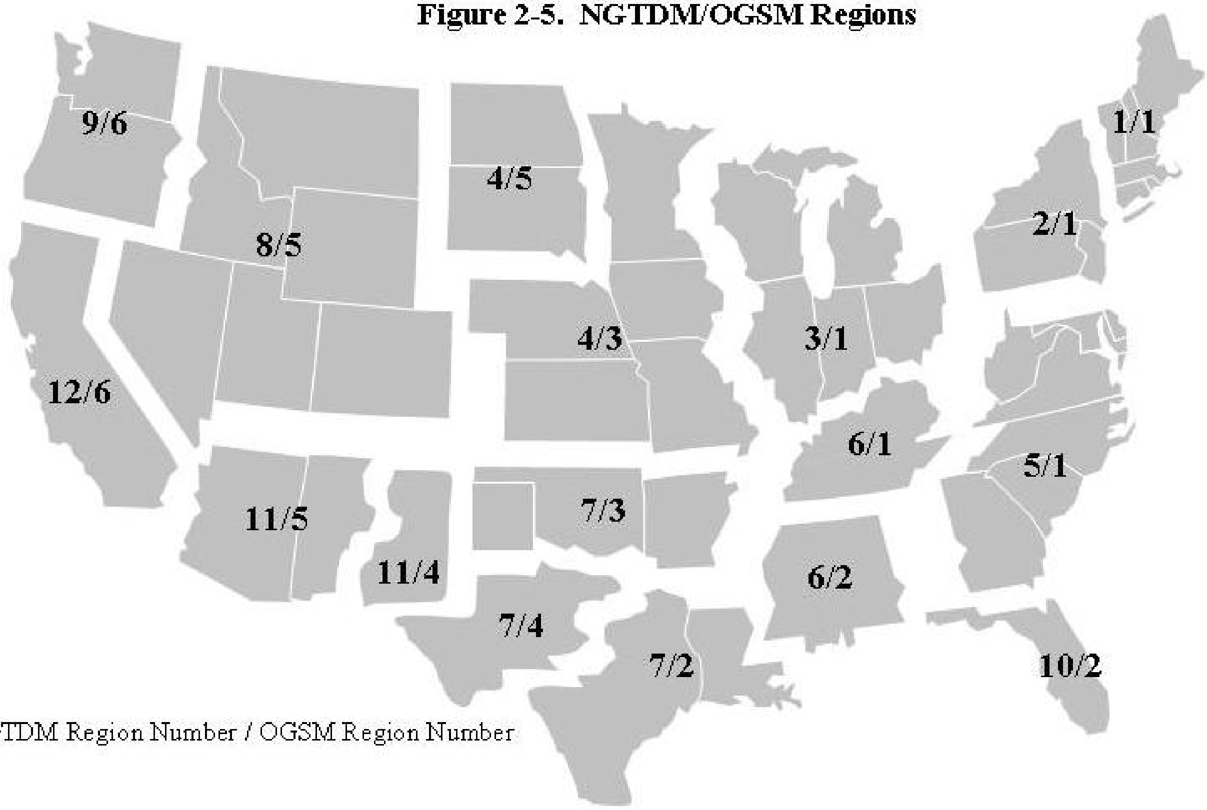
[18]Liquefied natural gas imports are set based on the price in the previous NEMS iteration and are effectively "fixed" when the NGTDM determines a natural gas market equilibrium solution; whereas the other two categories are determined as a part of the market equilibrium process in the NGTDM.

[19]The annual oil production level is determined in the OGSM and can vary between each iteration of NEMS. For programming convenience natural gas produced with oil shales (OGSHALENG) is also added to this category.

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 OGSM models the foreign

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

Figure 2-5. NGTDM/OGSM Regions



NGTDM Region Number / OGSM Region Number sources of gas that are transported via pipeline from Canada[20] and Mexico. Seven Canadian and three Mexican border crossings demarcate the foreign pipeline interface in the NGTDM. Supplies from the four existing onshore domestic liquefied natural gas regasification terminals are represented as specific supply sources in the NGTDM. In addition the model allows for potential new LNG facilities in each of the coastal NGTDM regions.[21]

Supplemental Gas Sources

Sources for synthetically produced natural gas are geographically specified in the NGTDM based on current plant locations. Annual production of synthetic natural gas from coal is exogenously specified (Appendix E, SNGCOAL), independent of the price of natural gas in the current forecast year. The *AEO2008* 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 2005) 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 2005). 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.[22] Regional peak and off-peak supply levels for the three supplemental gas supplies are generated by applying the same average (1990-2006) historical share (PKSHR_SUPLM) of national supplemental supplies in the peak period.

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. Statistically estimated equations for forecasting this category of gas for the lower 48 regions are incorporated within the OGSM; and the results are passed to the NGTDM for each iteration and forecast year of the 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 (1994-2006) historical shares of total (including non-associated) peak production in the year (PKSHR_PROD).

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[20] Conventional gas from Western Canada is modeled in the OGSM. The rest of the Canadian supplies are modeled in the NGTDM.

[21] 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 are considered for Alaska or Hawaii.

[22] For *AEO2008*, the effect of the factors was negated immediately after the first projected STEO year of 2007.

Natural Gas Imports

The NGTDM sets the parameters for projecting gas imported through liquefied natural gas facilities and most of the parameters and forecast values associated with the Canada gas market; while the OGSM sets the forecast values for imports from Mexico, as well as some of the parameters for establishing a supply curve for conventional natural gas in Western Canada. Mexican imports into the U.S. are set within the OGSM to be passed to the NGTDM. Liquefied natural gas imports are set at the beginning of each NEMS iteration within the NGTDM by evaluating supply curves, generated by the NGTDM at the beginning of the forecast year, at prices set in the previous NEMS iteration. Peak and off-peak values from both of these sources are based on average (1994 or 1990 to 2006) historical shares (PKSHR_IMEX and PKSHR_ILNG, respectively).

Canada

A few of the forecast elements used in representing the Canada gas market are set exogenously in the NGTDM. 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. While most 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)[23] and split into peak and off-peak periods using PKSHR_PROD (Appendix E). Similarly, 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,[24] and split into seasonal periods using PKSHR_CDMD (Appendix E).

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). 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 predominately 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, PKUTZ and OPUTZ). "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.[25] 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

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[23]Eastern Canada is expected to continue to provide only a small share of the total production in Canada and is almost exclusively offshore. The exogenously defined levels are largely based on projections generated by the National Energy Board of Canada.

[24]These values are taken from the projections in the *International Energy Outlook 2007* and can be adjusted for side case runs.

[25]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, FLOW_THRU_IN) and split into peak and off-peak levels based on average (1990-2006 historically based shares for general Canadian imports (PKSHR_ICAN).

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[26] gas to the United States. This total volume is apportioned to the western import crossings according to their relative size at the time.

The vast majority of natural gas produced in Canada is from the Western Canadian Sedimentary Basin (WCSB). Therefore, a more detailed approach was used in modeling supplies from this region. The OGSM contains a series of estimated and accounting equations for forecasting conventional (including from tight formations)[27] wells drilled, reserves added, reserve levels, and expected production-to-reserve ratios in the WCSB. These beginning-of-year reserves and the expected production-to-reserve ratios are used within the NGTDM to build a supply curve for conventional 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 the lower 48 region. 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 conventional natural gas production inclusive of lease and plant fuel consumption.

Natural gas produced from unconventional sources (coal beds) in Western Canada is based on an assumed production profile, with the area under the curve equal to the assumed ultimate recovery (CUR_ULTRES). The production level is initially specified in terms of the forecast year and uses one form before reaching its peak production level and a second 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 (PARMB) in the peak year (PKIYR). 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 (PARMB). The actual production volumes are adjusted to reflect an 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:

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

$$0 = \mathrm{PARMA} * (\mathrm{LSTYR0} - \mathrm{PKIYR})^2 + \mathrm{PARMB} \qquad (3)$$

[26]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."

[27]Since current data tend to combine statistics for conventional drilling and production and that from tight gas formations, the OGSM module does not distinguish the two at present. The conventional resource estimate was increased by 20 percent as a rough estimate of the future contribution from tight formations until more reliable estimates can be generated. For the rest of the discussion, the use of the term "conventional" should be assumed to include gas from tight formations.

Results:

$$PRD2 = PARMA*(PRDIYR - PKIYR)^2 + PARMB \quad (4)$$

where,

$$PARMA = \frac{-3}{2} * \frac{CUR\_ULTRES*PERRES}{(PKIYR - LSTYR0)^3} \quad (5)$$

$$PARMB = -PARMA*(PKIYR - LSTYR0)^2 \quad (6)$$

After Peak Production

Assumptions:

$$CUR\_ULTRES*(1 - PERRES) = \int_{PKIYR}^{LSTYR} [(PARMC*PRDIYR) + PARMD]\, dPRDIYR \quad (7)$$

$$PARMB = (PARMC*PKIYR) + PARMD \quad (8)$$

$$0 = (PARMC*LSTYR) + PARMD \quad (9)$$

Results:

$$PRD2 = (PARMC*PRDIYR) + PARMD \quad (10)$$

where,

$$PARMC = \frac{-PARMB^2}{2*CUR\_ULTRES*(1 - PERRES)} \quad (11)$$

$$PARMD = -PARMC*LSTYR \quad (12)$$

given,

$$CUR\_ULTRES = ULTRES*(1 + RESTECH)^{(MODYR - RESBASE)}*(1 + RESADJ) \quad (13)$$

and,

PRD2	=	Unadjusted Canada unconventional gas production (Bcf)
CUR_ULTRES	=	Estimate of ultimate recovery of natural gas from unconventional Canada sources in the current forecast year (Bcf)
ULTRES	=	Estimate of ultimate recovery of natural gas from unconventional Canada sources in the year RESBASE (70,000 Bcf), based on National Energy Board, 2003.
RESBASE	=	Year associated with CUR_ULTRES (2002)
RESTECH	=	Factor to increase resource estimate over time due to technology (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 (0.50, fraction)
PKIYR	=	Assumed peak year of production (2040)

LSTYR0	=	Last year of zero production (2004)
PRDIYR	=	Implied year of production along cumulative production path after price adjustment

The actual production is set by taking the unadjusted unconventional 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 preestablished expected price path (exprc), represented by the functional form: exprc = (3.2 + [0.03*(MODYR-2004)]. The price adjustment factor is set to the price in the previous forecast year, times a royalty adjustment factor (ROY_ADJ=0.95),[28] divided by the expected price, all raised to the 0.3 power. Technology is assumed to progressively increase production by 1 percent per year (TECHGRW) more than it would have been otherwise (e.g., in the fifth forecast year production is increased by 5 percent above what it would have been otherwise). [29] 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.

A simple trigger mechanism is used to project the potential levels of liquefied natural gas (LNG) imports into Canada. The model allows for four terminals and/or stages of LNG imports, each triggering when the regional market price, minus a transportation cost, exceeds an assumed trigger price. For *AEO2008*, the earliest start year for an LNG terminal was assumed to be 2008 for the east coast and 2010 for the west coast. In both regions, the volume for the first stage was assumed at 85 percent of 1 Bcf per day, while each subsequent stage was set at 85 percent of 0.5 Bcf per day. The cost based trigger prices for the east coast range from $1.00 (used to force in a facility under construction like Canaport in eastern Canada) to $3.52 in 1987 dollars/Mcf and for the west coast range from $3.66 to $4.86 in 1987 dollars/Mcf. The final trigger price includes a market price adjustment factor that is described in the next section. These trigger prices are compared against either the citygate price in New England (for the east coast) or in the Pacific Northwest (for the west coast) minus a 75-cent (1987 dollars/Mcf) transmission cost. Capacity expansion is restricted to occur no more than once every 3 years, while import volumes are assumed to phase up to their maximum level over a 3-year period.

Liquefied Natural Gas

For the *AEO2003* and previously, the expansion of regasification capacity to import LNG into the U.S. was projected within the OGSM by comparing the regional market price in the United States in the previous forecast year to estimates of the least cost supply option for bringing gas into a U.S. region from a slate of likely international sources. If the market price exceeded the indicated cost of bringing the gas to market (sum of production, liquefaction, shipping, and regasification costs), a terminal would be built or expanded accordingly, within the limitations imposed on the model. Utilization of the capacity was progressively increased over the forecast horizon based on exogenously specified values. The decision for each terminal was made independently, with no accounting for the limits on supply availability. For *AEO2004*, a new algorithm was implemented in the model, this time

[28] Soon before the AEO2008 was finalized, Alberta increased their royalty rates as of 2009. This factor was added to approximate an expected general decline in incentive to produce gas in Western Canada as a result. Since some activity is expected to shift to other provinces in the region, the full impact of the average royalty change was not imposed.

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

the model, this time in the NGTDM, which would allow an endogenous setting of LNG capacity utilization, would impose fewer exogenously specified controls on the decision to expand capacity, and would include some accounting of the competition for supplies between U.S. terminals and other areas in the world. As of *AEO2006*, the decision to add regasification capacity was set at the beginning of each forecast year based on a net present value (NPV) calculation using expected future domestic gas prices, current cost estimates, future world gas price estimates, and estimates of risks associated with the siting of a terminal. The specifics of the capacity expansion decision process will be explained later. The primary output of this decision is the current regasification capacity level (RCURCAP) that is used to set the LNG import levels in the current forecast year.

Determination of LNG Import Levels. Within a given iteration of NEMS, LNG import levels are established based on the market prices from the previous iteration before the NGTDM equilibrates supply and demand internally. This is done by evaluating region specific LNG import supply curves (NGLNG_SUPCRV) at market prices. These supply curves are set at the beginning of each NEMS forecast year based in part on assumptions and by running a least cost, transportation algorithm (in the form of a linear program) to establish a base point on each curve. The linear program, which is described below, is used to determine the least cost for supplying a given slate of regional imports for the year (as indicated by the shadow price on the regasification balancing row). The LP results are used to establish a base price corresponding to an expected utilization rate (PERAVGRG, Appendix E) of the existing beginning of year capacity (RCURCAP) or effective capacity (EFFCAP) on each supply curve. Other quantity points are set on the supply curve as an assumed percentage of the capacity. In the first three years of operation the effective capacity is set at 25 percent, then 50 percent, then 75 percent of the full regasification capacity to reflect a phase in of operations. The prices corresponding to most of these quantities are set using an assumed price elasticity (LNGELAS, Appendix E). The LNG supply curve in each region is formed by connecting the established price/quantity pairs. The specifications for the seven price/quantity pairs follow:

Step (s)	**Quantity ($CRVQ_{n=s,r}$)**	**Price ($CRVP_{n=s,r}$)**
0	$EFFCAP_{r,yr}$ * $PERMINRG_r$	0.0
1	$EFFCAP_{r,yr}$ * $PERMINRG_r$	$MINPRCRG_r$
2	$EFFCAP_{r,yr}$ * average($PERMINRG_r$, $PERAVGRG_r$)	Minimum{LP [$CRVQ_{n=2,r}$], $CRVP_{n=3,r}$ * $(CRVQ_{n=2,r}/CRVQ_{n=3,r})^{LNGELAS}$}
3	$EFFCAP_{r,yr}$ * $PERAVGRG_r$	LP [$CRVQ_{n=3,r}$]
4	$EFFCAP_{r,yr}$ * average($PERAVGRG_r$, 1.0)	Maximum{ LP [$CRVQ_{n=4,r}$], $CRVP_{n=3,r}$ * $(CRVQ_{n=4,r}/CRVQ_{n=3,r})^{LNGELAS}$}
5	$EFFCAP_{r,yr}$	$CRVP_{n=4,r}$ * $(CRVQ_{n=5,r}/CRVQ_{n=4,r})^{LNGELAS}$}
6	$EFFCAP_{r,yr}$	100.0

where,

$CRVQ_{n,r}$	=	Quantity level at supply curve point n for region r (Bcf)
$CRVP_{n,r}$	=	Price level at supply curve point n for region r (1987$/Mcf)
EFFCAP	=	Effective beginning of year LNG sendout capacity (Bcf), in first available year equals 25 percent of RCURCAP, in second available year equals 50 percent of RCURCAP, in third year available year equals 75 percent of RCURCAP, thereafter equal to RCURCAP.
RCURCAP	=	Beginning of year LNG sendout capacity[30] (Bcf)
PERMINRG	=	Minimum LNG capacity utilization level (Appendix E, fraction)
PERAVGRG	=	Expected LNG capacity utilization level (Appendix E, fraction)
LP(x)	=	Cost exiting the regasification terminal, determined by evaluating the shadow price on the regasification balancing row in the LP when the right-hand-side (RHS) or the LNG import levels are set to "x" (1987$/Mcf).
MINPRCRG	=	Minimum price allowed (1987$/Mcf).
RISKPREM	=	Risk premium to reflect market and investment uncertainties of constructing an LNG regasification terminal (Appendix E, 87$/Mcf)
LNGELAS	=	Assumed elasticity (Appendix E)
100.0	=	A maximum price at which the supply curve can be evaluated (1987$/Mcf)
n	=	Supply curve point number (0 through 6)
r	=	Region identifier (1 to 16)
yr	=	Current forecast year

The specifics of the linear program structure are described below. The objective function for the LP minimizes the total cost of producing, liquefying, shipping, and regasifying natural gas as it exits the regasification facilities in the United States. The total cost equals the sum, across these four stages in the process, of the product of the quantity of gas involved and its associated per-unit cost or charge. The constraints on the system simply balance the flow of gas as it moves from one stage to another, accounting for potential losses along the way. The primary input to the LP problem is the amount of gas to be regasified, which is represented below with "RHS" or right-hand side.

Within the LP structure (shown below and in **Figure 2-6**) the column variables represent the cost curves for the production, liquefaction, shipping, and regasification processing used to price LNG imports entering the United States. The number of steps on each curve varies. The corresponding costs are included in the objective function or cost row (LNGOBJ). The other rows represent either balance constraints at each point of transfer (BL-rows), or summation rows for accounting purposes (SUM-rows). The step sizes for the cost curves are reflected in the bound rows (BND).

LNGOBJ: min $\sum_{rg} \sum_{s} cr_{rg,s} * QRGS(rg)S(s) + \sum_{lq} \sum_{rg} \sum_{s} cs_{lq,rg,s} * QS(lq)(rg)S(s) + \sum_{lq} \sum_{s} cl_{lq,s} * QLIQ(lq)S(s) + \sum_{lq} \sum_{s} cp_{lq,s} * QPRD(lq)S(s)$

subject to:

BLDMRG(rg): $\sum_{s} QRGS(rg)S(s) \geq RHS$

BLSHRG(rg): $\sum_{s} (-1/lr)\, QRGS(rg)S(s) + \sum_{lq} \sum_{s} ls * QS(lq)(rg)S(s) = 0.0$

[30]Sendout capacity is the maximum annual volume of gas that can be delivered by a regasification facility into the pipeline system.

BLSHLQ(lq):	$\sum_{rg} \sum_{s}$ - QS(lq)(rg)S(s) + $\sum_{s}$ QLIQ(lq)S(s)	= 0.0
BLPRLQ(lq):	$\sum_{s}$ (-1/ll) QLIQ(lq)S(s) + $\sum_{s}$ lp * QPRD(lq)S(s)	= 0.0
SUMRGS(rg):	$\sum_{s}$ QRGS(rg)S(s)	(unconstrained)
SUMS(lq)(rg):	$\sum_{s}$ QS(lq)(rg)S(s)	(unconstrained)
SUMLIQ(lq):	$\sum_{s}$ QLIQ(lq)S(s)	(unconstrained)
SUMPRD(lq):	$\sum_{s}$ QPRD(lq)S(s)	(unconstrained)
BND	QRGS(rg)S(s)	≤ qr(rg)(s)
	QS(lq)(rg)S(s)	≤ qs(lq)(rg)(s)
	QLIQ(lq)S(s)	≤ ql(lq)(s)
	QPRD(lq)S(s)	≤ qp(lq)(s)

where,

QXXX(yy)S(z) = Quantity associated with either regasification (XXX=RGS), liquefaction (XXX=LIQ), or production (XXX=PRD), in region yy, on step z (Bcf)

QS(xx)(yy)S(z) = Quantity associated with shipping from region xx to region yy on step z (Bcf)

(rg) = regasification regions (1-16)

(lq) = liquefaction and production regions (1-14)

(s) = step on corresponding curve (maximum number for production=2, liquefaction=4, shipping=2, regasification=7)

cr,cs,cl,cp = per-unit cost or charge for regasification, shipping, liquefaction, and production (1987$/Mcf)

lr,ls,ll,lp = net flow resulting from regasification, shipping, liquefaction, and production losses (Bcf)

qr,qs,ql,qp = upper bound on regasification, shipping, liquefaction, and production steps (Bcf)

RHS = Right-hand side of LP, representing LNG import levels to United States that correspond to the following variables used in the code:

cr = SCRV_PRG8(rg,s) (SCRV_PRG in Appendix G)
cs = SCRV_PSH8(lq,rg,s) (SCRV_PSH in Appendix G)
cl = SCRV_PLQ8(lq,s) (SCRV_PLQ in Table F10, Appendix F)
cp = SCRV_PPR8(lq,s) (SCRV_PPR in Table F9, Appendix F)
qr = SCRV_QRG8(rg,s) (Appendix E as SCRV_QRG)[31]
qs = SCRV_QSH8(lq,rg,s) (Appendix E as SCRV_QSH)
ql = SCRV_QLQ8(lq,s) (Appendix E as SCRV_QLQ)
qp = SCRV_QPR8(lq,s) (Appendix E as SCRV_QPR)
lr = RLOSS8 (Appendix E as RLOSS)
ls = SLOSS8 (Appendix E as SLOSS)
ll = LLOSS8 (Appendix E as LLOSS)
lp = PLOSS8 (Appendix E as PLOSS)
RHS = oOGQNGIMP(10+rg,curiyr)

[31]This is adjusted in the code by an assumed maximum utilization rate (PERMAXRG, Appendix E), used to define the maximum annual sustained throughput.

Figure 2-6. LNG Linear Program Schematic

Columns / Rows	**QRGS(rg)S(s)** where s=1,7	**QS(lq)(rg)S(s)** where s=1,2	**QLIQ(lq)S(s)** where s=1,4	**QPRD(lq)S(s)** where s=1,2	**Type**	**RHS**
LNGOBJ	+cr	+cs	+cl	+cp	N	
BLDMRG(rg)	+1				≥	RHS
BLSHRG(rg)	-1 / lr	+1 * ls			=	0
BLSHLQ(lq)		-1	+1		=	0
BLPRLQ(lq)			-1 / ll	+1 * lp	=	0
SUMRGS(rg)	+1				N	
SUMS(lq)(rg)		+1			N	
SUMLIQ(lq)			+1		N	
SUMPRD(lq)				+1	N	
BND	+qr(s)	+qs(s)	+ql(s)	+qp(s)		

N = Nonconstraining

Columns

QRGS(rg)S(s) = Regasification curve: Quantity of LNG regasified in each regasification region, by step
QS(lq)(rg)S(s) = LNG shipment curve: Quantity of LNG shipped from liquefaction region to regasification region, by step
QLIQ(lq)S(s) = Liquefaction curve: Quantity of LNG produced from NG in each liquefaction region, by step
QPRD(lq)S(s) = Production curve: Quantity of NG produced for liquefaction in each production region, by step

Rows

LNGOBJ = LNG objective function
BLDMRG(rg) = For each regasification region, balance between regasification and US imports of LNG.
BLSHRG(rg) = For each regasification region, balance between regasification to meet US imports and LNG shipped from liquefaction locations.
BLSHLQ(lq) = For each liquefaction region, balance between LNG produced and LNG shipped to regasification regions.
BLPRLQ(lq) = For each liquefaction region, balance between foreign NG production sent to liquefaction facilities and LNG produced.
SUMRGS(rg) = For each regasification region, total regasification of LNG.
SUMS(lq)(rg) = For each shipment link between liquefaction region and regasification region, total LNG shipment
SUMLIQ(lq) = For each liquefaction region, total NG liquefied.
SUMPRD(lq) = For each production region, total NG produced for liquefaction.
BND = Upper bound on column variables.

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

The costs of production, liquefaction, shipping, and regasification are incorporated in the LP through the use of step curves (SCRV_PXX, SCRV_QXX), one for each element (XX=RG, SH, LQ, or PR) in each region represented (see **Table 2-1**). For production and shipping only a single step or value is used, providing a mechanism for setting a per-unit cost, with no explicit limit on the quantity. For regasification and liquefaction the first step typically represents the existing capacity, if any, followed by potential incremental expansion (either at existing facilities or at a greenfield facility). In some limited cases, the quantities reflect specific facilities where construction has already begun, or is highly likely to commence. Each step is limited by an earliest allowed start year (SCRV_YRG, SCRV_YSH, SCRV_YLQ, SCRV_YPR). Each liquefaction step is identified as representing either existing capacity, an expansion at an existing facility or a greenfield facility (LIQTYP, Appendix E).

Liquefaction costs are reevaluated each year for the next available step on the liquefaction supply curve based on an estimation of how capital costs for new liquefaction capacity are expected to change across time. If an expansion at an existing or greenfield facility occurs in the previous year, the per-unit cost of what is now the existing capacity is set equal to a quantity-weighted average of the per-unit cost for the existing capacity the previous year and the per-unit cost of the expansion. Both regasification and liquefaction levels are limited by a maximum utilization rate (PERMAXRG and L_UTILRATE, Appendix E). Liquefaction is also limited by an assumed maximum utilization available to the United States (PERMAXLQ, Appendix E). This factor is used to reflect the fact that all of the liquefaction capacity in the world will not be available for the United States. The limits on liquefaction effectively limit production (as represented in the model) in a region as well.

With the LNG market evolving rapidly, it is difficult to determine with much certainty how costs, including taxes, will change in the future, let alone how prices will be set. After reviewing the limited information available on the subject a number of assumptions were made to represent future costs in the model, as well as the price implications of an evolving market. The per unit costs on the production curves are set exogenously (Table F9, Appendix F) and held constant throughout the forecast period, while the costs for liquefaction, shipping, and regasification are allowed to change across time, primarily in response to changes in costs of debt and equity across time. Specifics as to how per-unit liquefaction, shipping, and regasification costs are set in the model for a particular year and step are provided in Appendix G. For regasification, the per-unit charge is only set for the first step using the algorithm described in Appendix G. The assumed relationship between the per-unit charge on the first step versus the per-unit charges on subsequent steps is set exogenously and applied in the model to set the charge on the subsequent steps. Regasification costs are assumed to increase as additional capacity is added (i.e., at higher steps on the step curve), to reflect the assumption that the less costly facilities will be built first.

As described above, the supply curves provide an estimate of the minimum expected cost of bringing natural gas to the U.S., with some accounting of the fact that U.S. is not the only consumer of LNG in the world (i.e., by limiting the liquefaction capacity available to the U.S.). While costs are an important factor, a more fundamental question is what price might suppliers require to ship gas to the U.S. For example, if Europeans are willing to pay $10 per Mcf for LNG, then suppliers will first want to ship their cargoes to Europe, unless the U.S. is willing to pay more, accounting for transportation differences. Since the NEMS is not an international model, a “market price adjustment” factor was added to the expected cost of shipping gas to the U.S. in attempt to reflect world markets. This factor was set as a function of the projected world growth in natural gas

Table 2-1. LNG Regasification and Liquefaction Regions

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

Number	Liquefaction Regions
1	Algeria
2	Nigeria
3	Norway
4	Venezuela
5	Trinidad
6	Qatar
7	Australia
8	Malaysia
9	Indonesia
10	Sakhalin
11	Egypt
12	Peru
13	Oman
14	Angola
15	Equatorial Guinea
16	Northwest Russia

* In the *AEO2008* version of the NEMS, LNG imports in Mexico and Canada are not handled within the LP framework. LNG imports in Mexico are handled within the OGSM modeling framework and Canada LNG was described previously. The LP structure was established to allow for the eventual inclusion of Canada and Mexico.
Source: Office of Integrated Analysis and Forecast, Energy Information Administration

consumption from EIA's *International Energy Outlook 2006* and the projected international refinery acquisition cost, as follows:

$$\text{MKTPRC\_ADD}_t = \text{MKTPRC\_ADD}_{t-1} + [\text{PAR\_CON} * (\frac{\text{IEOCONS}_t}{\text{IEOCONS}_{t-1}} - 1)] + [\text{PAR\_WOP} * \frac{\text{IT\_WOP}_t - \text{IT\_WOP}_{t-1}}{5.7}] \quad (14)$$

where,

MKTPRC_ADD = market price adjustment (1987\$/Mcf), (initialized to 1.2 in 2005)
IT_WOP = international refinery acquisition cost (1987\$/bbl)
IEOCONS = world natural gas consumption from a preliminary version of the *International Energy Outlook 2007* (Tcf)
5.7 = factor to convert barrels into thousand cubic feet equivalent

PAR_CON = assumed parameter on world gas consumption (0.6)
PAR_WOP = assumed parameter on oil price (0.55)

The market price adjustment factor is meant to capture the impact of the competition for LNG in the world as other consumers bid up the price for gas above the basic cost of delivery. This competition is expected to occur in response to increasing demand for natural gas in the world. The world oil price is expected to influence the price through potential fuel switching on the demand side, through contracts that are tied to the world oil price, and through the potential of converting natural gas to liquids.

LNG Regasification Expansion Decision

The decision to expand LNG regasification capacity is made at the beginning of each forecast year, before the model equilibrates or LNG import supply curves are generated. The LP is used to derive the expected regional specific costs for bringing LNG into the U.S. if the next available regasification capacity step were brought online. The LP is solved for import levels equivalent to the current capacity (RCURCAP) plus an assumed utilization (PERAVGRG) of the next available step. To reflect market and investment uncertainties, as well as the added cost of dealing with siting opposition, an exogenously specified regional specific risk premium (RISKPREM, Appendix E) is added to the resulting costs. The risk premium attempts to capture regional differences in siting obstacles by looking at such things as number of current proposed projects, number of canceled projects, number of oil import facilities, and other demographic indicators. The final cost estimates are used in the following net present value calculation to estimate the potential profitability of adding regasification capacity in a region:

$$NPV_r = \sum_{k=CURIYR}^{LOOKYR} \{IMPPRC_{r,k} - [CRVP4_r + (MKTPRC\_ADD_k - MKTPRC\_ADD_{CURIYR})]\} * \left(\frac{1}{1+INT}\right)^{(k-CURIYR)} \quad (15)$$

where,

NPV = net present value (1987 dollars)
MKTPRC_ADD = market price adjustment, as specified previously (1987$/Mcf)
IMPPRC = expected market price for LNG at the U.S. regasification terminal from a previous model cycle of NEMS, as netbacked from the citygate.

CRVP4 = Least cost to deliver LNG sufficient to fill expanded capacity in region r (as derived by solving the linear program) plus a region specific risk premium (RISKPREM) (1987$/Mcf)
RISKPREM = Risk premium to reflect market and investment uncertainties of constructing an LNG regasification terminal (Appendix E, 87$/Mcf)
CURIYR = current forecast year
LOOKYR = last year to look ahead (CURIYR +10)
INT = assumed discount rate (0.05)

If the net present value is positive, capacity will be added to RCURCAP equivalent to the next available step on the associated regasification curve.

"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 total production from the 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 price is the "expected" wellhead price (XPBASE, presented below) and 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). The basic assumption behind the curve is that the 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,32 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 2-7**. 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:

$$\text{NGSUP\_PR} = \text{PBASE} * (((\frac{1}{\text{ELAS}}) * (\frac{\text{QVAR - QBASE}}{\text{QBASE}})) + 1) \qquad (16)$$

A more familiar form of this equation is the definition of the elasticity (ξ) as: $\xi = (\Delta Q/Qo) / (\Delta P/Po)$, where Δ symbolizes "the change in" and Qo and Po represent a base level price/quantity pair.

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

32 For *AEO2008* the middle segment was not activated.

Lowest segment:

PBASE = CPBASE = APBASE * (1. - (PARM_SUPCRV5 / $PARM\_SUPELAS_2$))
QBASE = CQBASE = AQBASE * (1. - PARM_SUPCRV5)
ELAS = $PARM\_SUPELAS_1$ = 0.75

Lower segment:

PBASE = APBASE = XPBASE * (1. - (PARM_SUPCRV3 / $PARM\_SUPELAS_3$))
QBASE = AQBASE = XQBASE * (1. - PARM_SUPCRV3)
ELAS = $PARM\_SUPELAS_2$ = 0.50

Middle segment:

(in historical years)
PBASE = XPBASE = historical wellhead price
QBASE = XQBASE = $QSUP_s$ / (1. - $PERCNT_n$)

(in forecast years)

PBASE = XPBASE

$$XPBASE = e^{-8.45472} * UGRRESSHR^{0.961499} * oEXSPEND_{t-1}^{0.066877} * HDD^{0.524556} *$$
$$ZOGRESNG_s^{-0.02052} * oIT\_WOP_t^{0.367606} * ZWPRLAG_s^{0.239954} * e^{-8.4572*-0.321886} *$$
$$UGRRESSHRLAG^{-0.321886*0.961499} * oEXSPEND_{t-2}^{-0.321886*0.066877} *$$
$$HDD^{-0.321886*0.524556} * ZOGRESNGLAG1_s^{-0.321886*-0.02052} * oIT\_WOP_{t-1}^{-0.321886*0.367606}$$

QBASE = XQBASE = $ZOGRESNG_s$ * $ZOGPRRNG_s$
ELAS = $PARM\_SUPELAS_3$ = 4.00

Upper segment:

PBASE = BPBASE = XPBASE * (1. + (PARM_SUPCRV3 / $PARM\_SUPELAS_3$))
QBASE = BQBASE = XQBASE * (1. + PARM_SUPCRV3)
ELAS = $PARM\_SUPELAS_4$ = 0.5

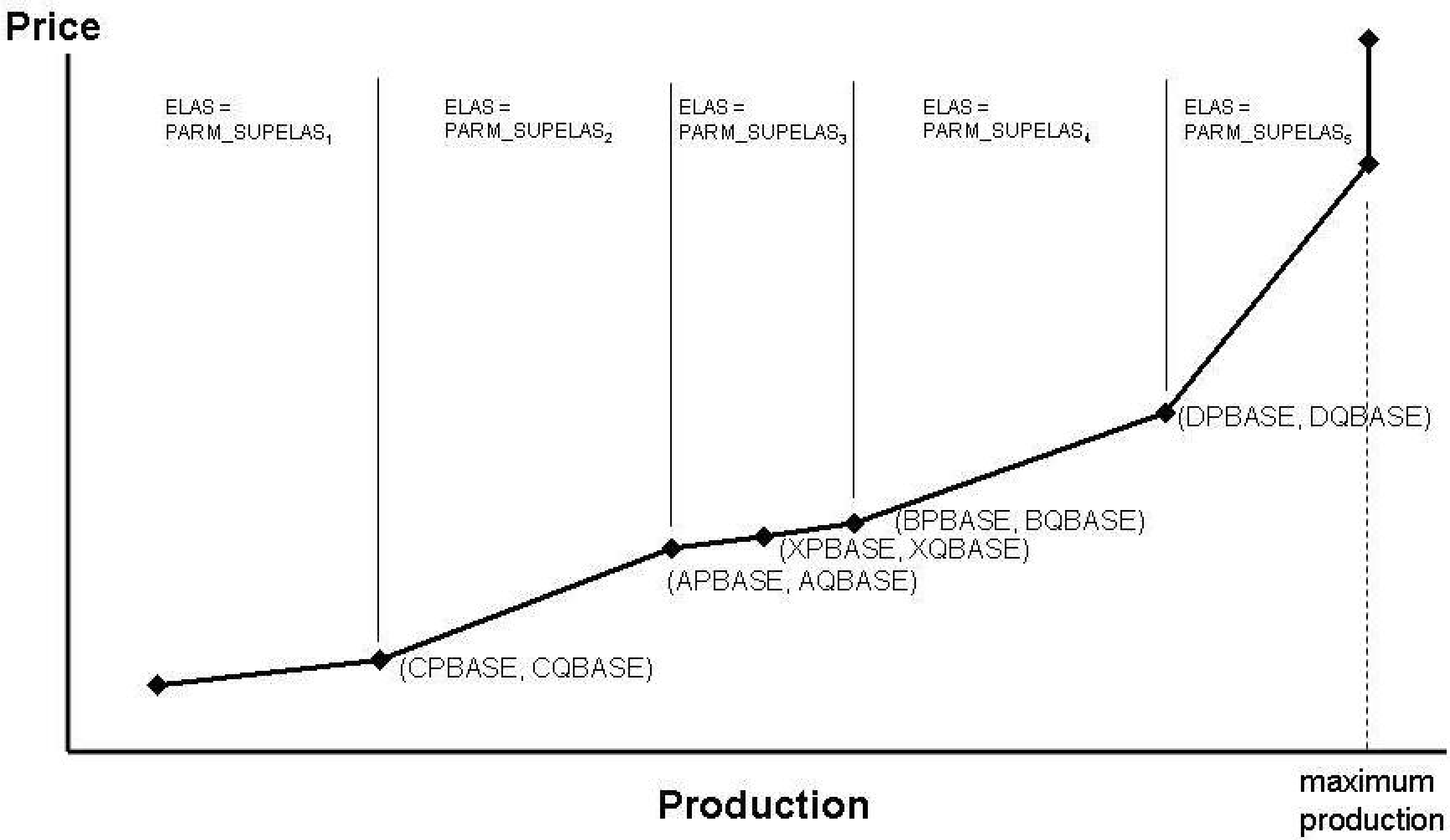
Uppermost segment:

PBASE = DPBASE = BPBASE * (1. + (PARM_SUPCRV5 / $PARM\_SUPELAS_4$))
QBASE = DQBASE = BQBASE * (1. + PARM_SUPCRV5)
ELAS = $PARM\_SUPELAS_5$ = 0.25

where,

NGSUP_PR	=	Wellhead price (1987$/Mcf)
QVAR	=	Production, including lease & plant (Bcf)
XPBASE	=	Base wellhead price on the supply curve (Table F11, Appendix F) (1987$/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)

Figure 2-7. Generic Supply Curve



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)
$ZWPRLAG_s$	=	Lagged wellhead price for supply source s (1987/Mcf)
$ZOGTAXPREM_s$	=	Tax stimulation variable provided by OGSM (currently set to zero)
$ZOGRESNG_s$	=	Natural gas proved reserves for supply source s (Bcf)
$ZOGRESNGLAG1_s$	=	Natural gas proved reserves in previous forecast year (Bcf)
$ZOGPRRNG_s$	=	Natural gas production to reserves ratio for supply sources (fraction)
UGGRESSHR	=	Share of gas reserves from unconventional sources (fraction)
UGGRESSHRLAG	=	Previous year's share of gas reserves from unconventional sources (fraction)
oEXSPEND	=	National average drilling cost per well (1987 dollars)
HDD	=	Historical average heating degree days
ZOGRESNG	=	Beginning-of-year reserves (Bcf)
OGRESNGLAG	=	Previous year's beginning-of-year reserves (Bcf)
oIT_WOP	=	International refinery acquisition cost (1987$/bbl)
$PERCNT_n$	=	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 that 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:

$$QVAR = (VALUE - FIXSUP) / (1. - PERCNT_n)$$
$$[\ FIXSUP = ZOGCCAPPRD_s * (1. - PERCNT_n)\ ]$$

where,

QVAR	=	Production, including lease & plant consumption
VALUE	=	Production, net of lease & 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 (from OGSM)[33]
FIXSUP	=	ZOGCCAPPRD net of lease and plant consumption
s	=	NGTDM/OGSM supply region
n	=	region/node

[33]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.

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:

$$AK\_HDD_y = \exp(6.917) * YEAR^{-0.002} * AK\_HDD_{y-1}^{0.255} \tag{17}$$

$$AK\_RN_y = \exp(-2.677) * AK\_RN_{y-1}^{0.888} * AK\_RN_{y-2}^{0.185} * AK\_POP_y^{0.626} \tag{18}$$

$$AK\_CN_y = \exp(-6.081) * AK\_CN_{y-1}^{0.422} * AK\_POP_y^{1.182} \tag{19}$$

$$\begin{aligned}(res):\ AKQTY\_F_{s=1,y} &= \exp(8.874) * AKQTY\_F_{s=1,y=1}^{0.257} * AKQTY\_F_{s=1,y-2}^{=0.356} \\ &* AKQTY\_F_{y-4}^{-0.240} * AK\_RN_y^{0.902} * AKPR\_F_{s=1,y}^{-0.664}\end{aligned} \tag{20}$$

$$(com):AKQTY\_F_{s=2.y} = YEAR^{-0.014} * AKQTY\_F_{s=2,y-1}^{0.483} AK\_CN_y^{0.430} * AK\_HDD_y^{0.483} \tag{21}$$

where,

$AKQTY\_F_{s=1}$	=	consumption of natural gas by residential (s=1) customers in Alaska in year y (MMcf, converted to Bcf)
$AKQTY\_F_{s=2}$	=	consumption of natural gas by commercial (s=2) customers in Alaska in the current forecast year y (MMcf, converted to Bcf)
AK_RN	=	number of residential customers in year y (thousands, Appendix F, Table F1)
AK_CN	=	number of commercial customers in year y (thousands, Appendix F, Table F2)
AK_HDD	=	average annual heating degree days in Anchorage, indicator for Alaska (Appendix F, Table F2.1)
AK_POP	=	exogenously specified projection of the population in Alaska (thousands, Appendix E)
YEAR	=	4 digit year indicator (1967=0, 1968=1, etc.)

Gas consumption by Alaska industrial customers is set exogenously, as follows:

$$(ind):\ AKQTY\_F_{s=3,y} = AK\_QIND\_S_y \tag{22}$$

where,

$AKQTY\_F_{s=3}$ = consumption of natural gas by industrial customers in year y (s=3), (Bcf)

AK_QIND_S = consumption of natural gas by industrial customers in southern Alaska, the sum of consumption at the Agrium fertilizer plant (assumed to close in 2007, Appendix E) and at the LNG liquefaction facility (assumed to close in 2011, Appendix E)

s = sector

y = year

The production of gas in Alaska depends on 1) whether a pipeline is constructed from Alaska to Alberta, 2) whether a gas-to-liquids plant is built in Alaska, and 3) consumption in and exports from Alaska. The production of gas related to the Alaska pipeline equals the volumes delivered to Alberta (which depend on assumptions about the pipeline capacity) plus what is consumed for lease, plant, and pipeline operations. If the Petroleum Market Module (PMM) determines that a gas-to-liquids facility will be built in Alaska, then the natural gas consumed in the process (AKGTL_NGCNS, set in the PMM) is added to production in the north, along with the associated lease and plant fuel consumed. Other production in North Alaska that is not related to the pipeline, is largely lease and plant fuel associated with the crude oil extraction processes; whereas gas is produced in the south to satisfy consumption and export requirements. For simplicity the quantity of lease and plant fuel not related to the pipeline or GTL in Alaska is modeled in total and is assigned to North Alaska production. The details follow:

$$(S.AK): \; AK\_PROD_{r=1} = AK\_CONS\_S + EXPJAP + QALK\_LAP\_S + QALK\_PIP\_S - AK\_DISCR \tag{23}$$

$$(N.AK_1): \; AK\_PROD_{r=2} = QALK\_LAP\_N = 197.94 + 35.189 * \ln(year - 1989) \tag{24}$$

$$(N.AK_2): \; AK\_PROD_{r=3} = \frac{QAK\_ALB_t}{1 - AK\_PCTLSE_3 - AK\_PCTPLT_3 - AK\_PCTPIP_3} + AKGTL\_NGCNS_t + AKGTL\_LAP \tag{25}$$

where,

$$AK\_CONS\_S = \sum_{s=1}^{4} (AKQTY\_F_s + AKQTY\_I_s) \tag{26}$$

$$QALK\_LAP\_S = 0.0 \qquad \text{(total is assigned to the North)} \tag{27}$$

$$QALK\_PIP\_S = (AK\_CONS\_S + EXPJAP) * AK\_PCTPIP_2 \tag{28}$$

$$AKGTL\_LAP = oAKGTL\_NGCNS_t * (AK\_PCTLSE_3 + AK\_PCTPLT_3) \tag{29}$$

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 to Japan (from OGSM in Bcf)

QALK_LAP_N = quantity of gas consumed for lease and plant operations, excluding that

that related to the pipeline and GTL, where the projection is set to a logarithmic trend line fitted through historical data from 1990 to 2005 in Excel with R^2=0.7866 (Bcf)

$QALK\_PIP_r$ = quantity of gas consumed as pipeline fuel (Bcf)

AK_DISCR = discrepancy, the average (1995-2003) historically based difference in reported supply levels and consumption levels in Alaska (Bcf)

QAK_ALB_t = gas entering Alberta via pipeline that was produced on the North Slope (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_PCTPLTr = (for r=1 and r=2) not used, (for r=3) plant fuel as a percent of gas production (fraction, Appendix E)

AK_PCTPIPr = (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)

$AKGTL\_NGCNS_t$ = natural gas consumed in a gas-to-liquids plant in the North Slope (from PMM in Bcf)

AKGTL_LAP = lease and plant consumption associated with the gas for a gas-to-liquids plant (Bcf)

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 gas-to-liquids process, 3 = north associated with a pipeline to Alberta and/or a gas-to-liquids plant

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 the 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 gas-to-liquids process, lease and plant fuel (AKGTL_LAP) is calculated as shown above and pipeline fuel is considered negligible. For the rest of north Alaska, pipeline fuel consumption is assumed to be negligible, while lease and plant fuel not associated with the pipeline or GTL (QALK_LAP_N) is set based on the trend line provided above.

Estimates for natural gas wellhead and delivered prices in Alaska are roughly 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 should a pipeline be connected to Alberta) is set using the following estimated equation:

$$\begin{aligned} AK\_WPRC_t = {} & AK\_F_1 + (AK\_F_2 * T) - \\ & AK\_F_3 * \{ WPRLAG - [AK\_F_1 + (AK\_F_2 * (T-1))] \} \end{aligned} \qquad (30)$$

where,

AK_WPRC = natural gas wellhead price in Alaska, presuming no pipeline to Alberta ($/Mcf)

$WPRLAG$ = AK_WPRC in the previous forecast year ($/Mcf)
AL_F = estimated parameters for wellhead price (Appendix F, Table F1)
T = time parameter, where T=1 for 1970 (the first historical data point).

The price for natural gas associated with a pipeline to Alberta 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. 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[34] 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,[35] 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 reflect the uncertainties in the necessary capital outlays and in the ultimate selling price (FR_PRISK, Appendix E).[36] 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.

[34]For the MacKenzie pipeline a straight average is taken. For the Alaska pipeline the prices are weighted, with a greater emphasis on the prices in the recent past. For the Alaska pipeline 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.

[35]The required wellhead price in Alaska and for the MacKenzie Delta is progressively adjusted across the forecast horizon in a higher or lower technology case, such that by the last year (2030) the price is higher or lower than the price in the reference case by a fraction equal to 0.25 times the technology factor adjustment rate (e.g., 0.50 for *AEO2008*)

[36]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 the 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 one direction and other pipelines flowing in the opposite direction.[37] 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[38] represent imports or exports. The arcs which are designated as "secondary" in **Figure 3-1** generally represent relatively low flow volumes and are handled somewhat differently and separately from those designated as "primary."

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

[37]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 15, 5 to 10, 15 to E. Canada, 20 to 7, 21 to 11, 22 to 12, and Alaska to W. Canada. The flows along these arcs are initially set at the last historical level and are only increased (proportionately) when a known (or likely) planned capacity expansion occurs.

[38]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.

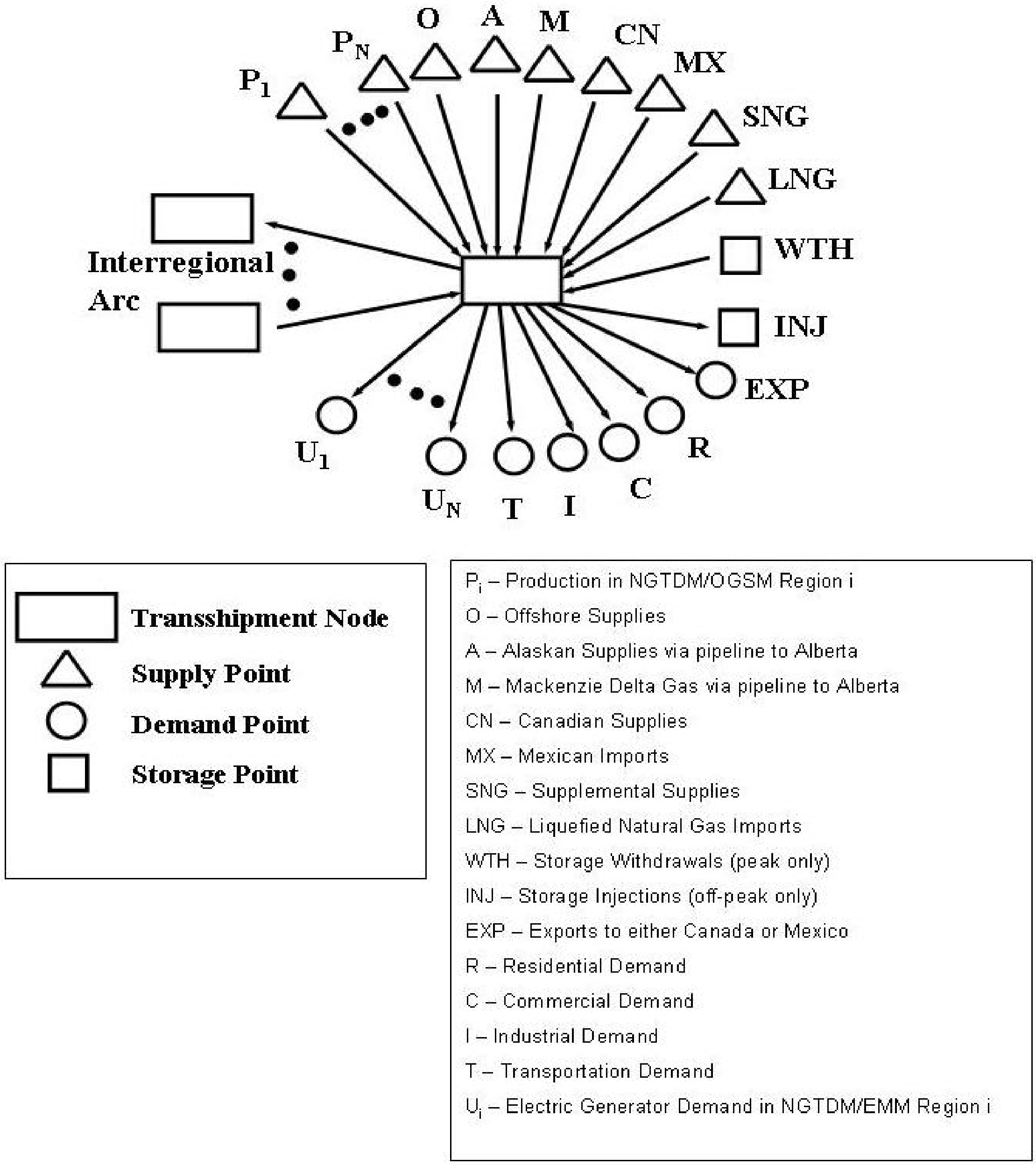
Figure 3-1. Natural Gas Transmission and Distribution Module Network

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.[39] Exports and (in the off-peak period) net storage injections are also 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, supplemental gas production, gas produced in Alaska and transported via pipeline, Mexican imports, or (in the peak period) net storage withdrawals in the region.

[39]Conceptually within the model, the flow of gas to each end-use sector passes through a common citygate point before reaching the end-user.

Figure 3-2. Transshipment Node



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.[40]

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

[40]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.

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.

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 US 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.

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)	P(1/1), LNG Everett Mass., LNG generic
2	R, C, I, T, U(2), INJ	P(2/1), WTH, LNG generic
3	R, C, I, T, U(3), U(4), INJ	P(3/1), WTH
4	R, C, I, T, U(5), INJ	P(4/3), P(4/5), Synthetic natural gas from coal, WTH, LNG generic
5	R, C, I, T, U(6), U(7), INJ	P(5/1), LNG Cove Pt Maryland, LNG Elba Island Georgia, Atlantic Offshore, WTH, LNG generic
6	R, C, I, T, U(9), U(10), INJ	P(6/1), P(6/2), WTH, LNG generic
7	R, C, I, T, U(11), INJ	P(7/2), P(7/3), P(7/4), LNG Lake Charles Louisiana, Offshore Louisiana, Gulf of Mexico, WTH, LNG generic
8	R, C, I, T, U(12), U(13), INJ	P(8/5), WTH
9	R, C, I, T, U(15), INJ	P(9/6), WTH, LNG generic
10	R, C, I, T, U(6), U(8), INJ	P(10/2), WTH
11	R, C, I, T, U(14), INJ	P(11/4), P(11/5), WTH
12	R, C, I, T, U(16), INJ	P(12/6), Pacific Offshore, WTH, LNG generic
13 – 19	--	--
20	Mexican Exports (TX)	Mexican Imports (TX)
21	Mexican Exports (AZ/NM)	Mexican Imports (AZ/NM)
22	Mexican Exports (CA)	Mexican Imports (CA)
23	Eastern Canadian consumption, INJ	Eastern Canadian supply, WTH
24	Western Canadian consumption, INJ	Western Canadian supply, WTH, Alaskan Supply via a pipeline, MacKenzie Valley gas via a pipeline

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 Interstate Transmission Submodule. 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.

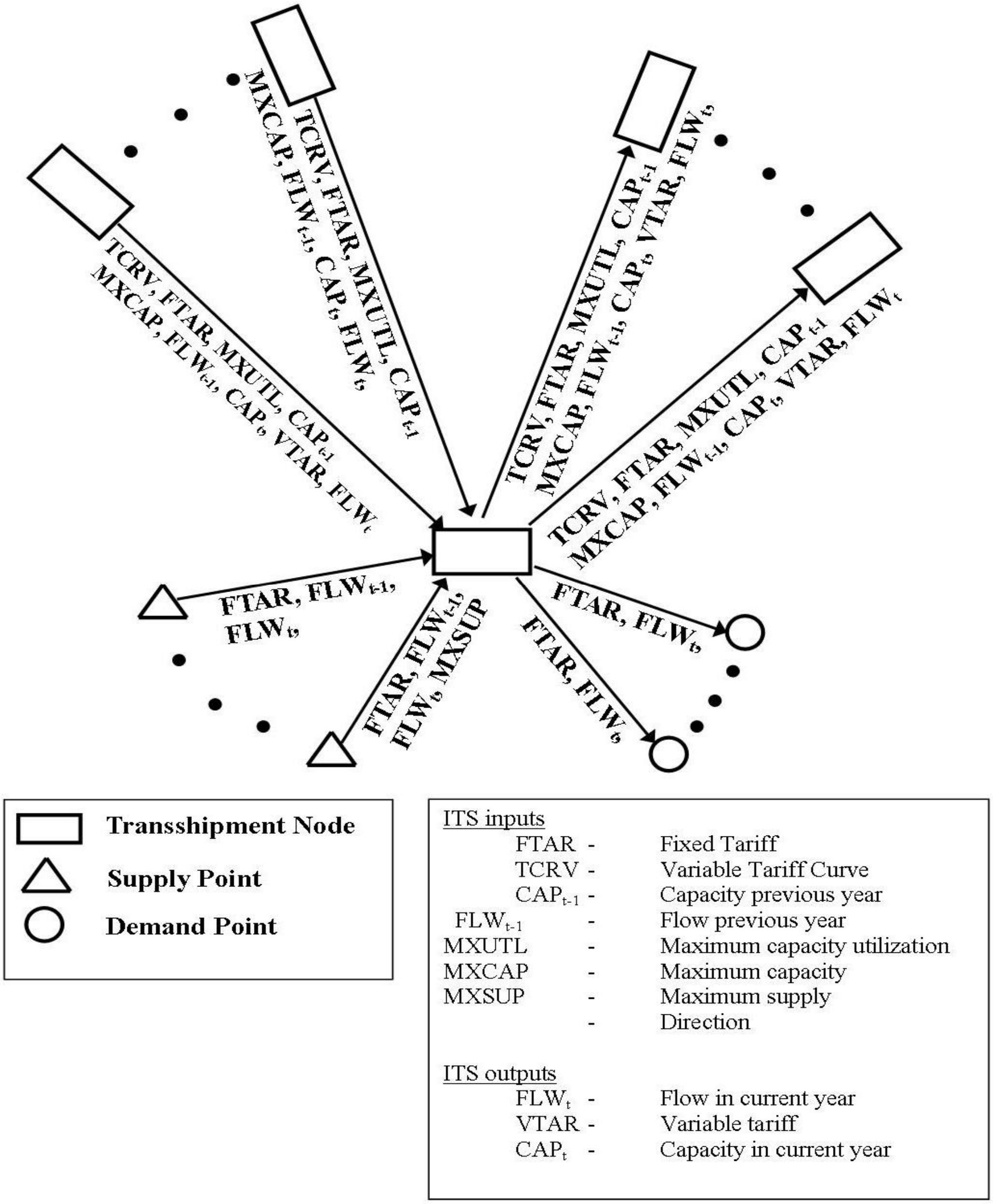
Specifications of a Network Arc

Each arc of the network has associated variables inputs and model variable outputs. The variables that define an interregional arc 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.

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 progress and announcements). Any additional capacity beyond the planned level is determined during the 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 variable tariff is established by applying the flow level along the arc to the associated tariff supply curve, established by the Pipeline Tariff

Figure 3-3. Variables Defined and Determined for Network Arc



Submodule. During the solution process in the Interstate Transmission Submodule, the resulting tariff 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,

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.[41]

For the arcs from the transshipment nodes to the end-use sectors, 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 end-use 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 theoretically represent gathering charges, but are currently assumed to be zero.[42] 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 and supply points, respectively, the current version of the module does not impose such limits on the flows along these arcs.

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 has 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

The NEMS generates an annual forecast of the outlook for U.S. energy markets for the years 1990 through 2030. During 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 during 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. In doing so, 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).

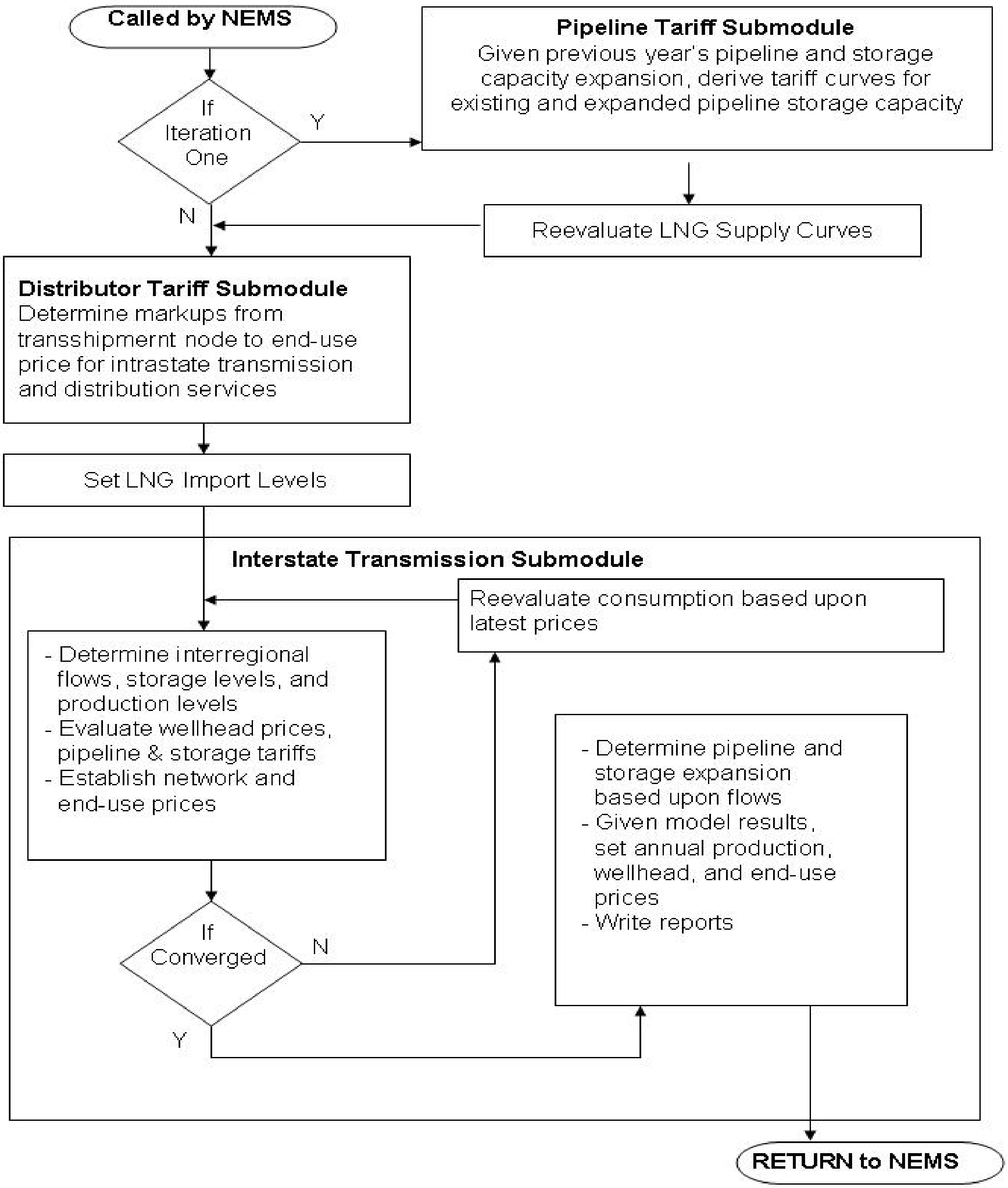
Although the NGTDM is executed for each iteration of each forecast year solved by the NEMS, it is not necessary that all of the individual components of the module be executed for all iterations. Of the NGTDM's three components or submodules, the Pipeline Tariff Submodule is executed only once per forecast year since the submodule's input values do not change from one iteration of NEMS to the next. However, the Interstate Transmission Submodule and the Distributor Tariff Submodule are executed every iteration of each forecast year because their input values can change by iteration. Within the Interstate Transmission Submodule an iterative process is used. The basic solution

[41]During the off-peak period in a previous version of the module, only the usage fee was used as a basis for determining the relative flow along the arcs entering a node. However, the total tariff was ultimately used when setting delivered prices.

[42]Ultimately the gathering charges are reflected in the delivered prices when the model is benchmarked to historically reported citygate prices.

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**, showing the general calling sequence.

Figure 3-4. NGTDM Process Diagram



The Interstate Transmission Submodule 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 Pipeline Tariff Submodule 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 Interstate Transmission Submodule. These curves extend beyond the level of the current year's capacity and provide estimates of the tariffs should capacity be expanded. The Distributor Tariff Submodule provides distributor tariffs for use in the Interstate Transmission Submodule. The Distributor Tariff Submodule must be called at 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 Interstate Transmission Submodule solves for natural gas prices and quantities which reflect a market equilibrium for the current forecast year. A brief summary of each of the NGTDM submodules follows.

Interstate Transmission Module

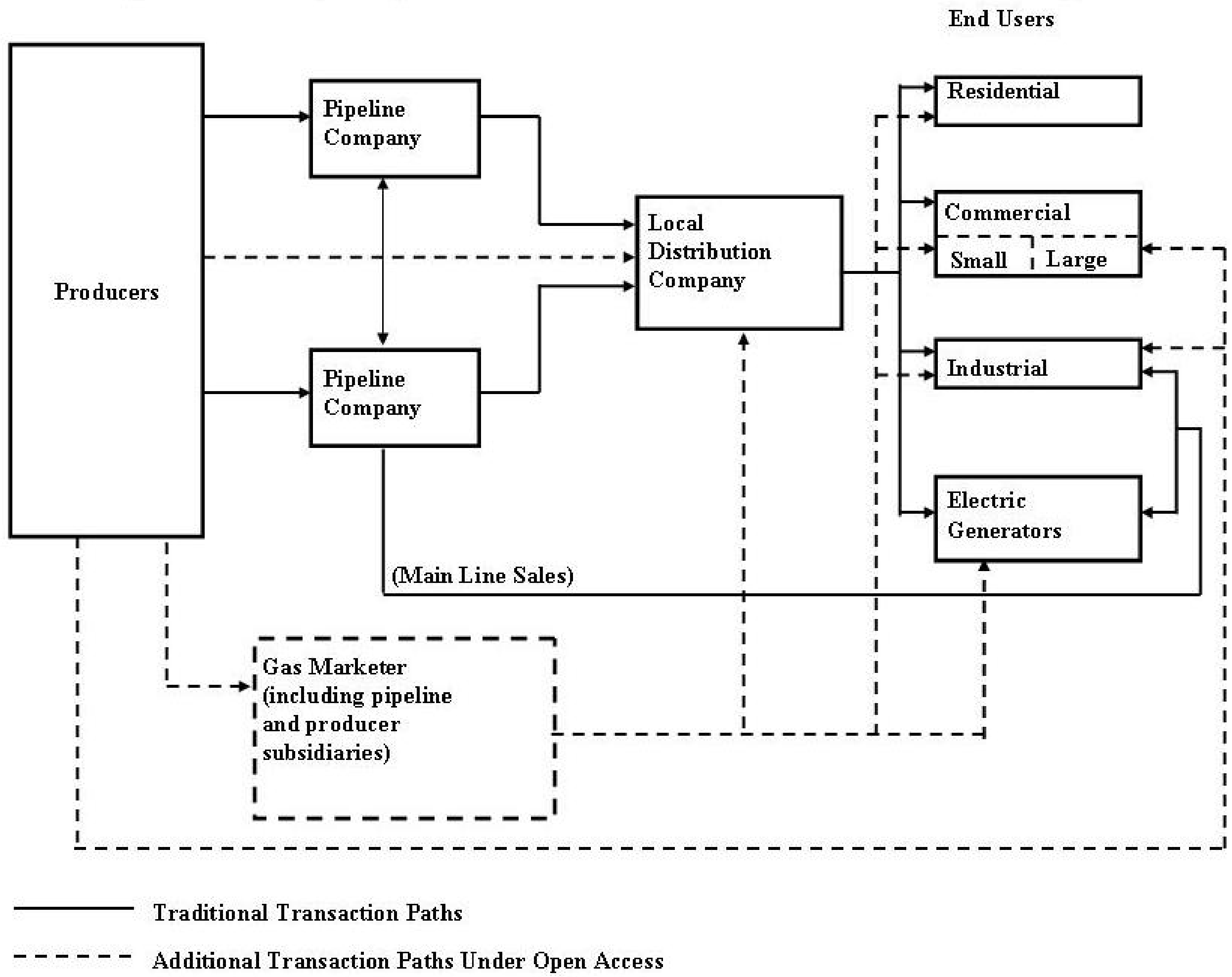
The Interstate Transmission Submodule (ITS) is the main integrating module of the NGTDM. One of its major functions is to simulate the natural gas price determination process. The ITS brings together the major economic factors that influence regional natural gas trade on a seasonal basis in the United 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 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, 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 Pipeline Tariff Submodule, 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 citygate 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 Distributor Tariff Submodule. At this point consumption levels can be reevaluated given the resulting set of delivered 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, city gate, and delivered), 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 next forecast year, the Pipeline Tariff Submodule 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

Figure 3-5. Principal Buyer/Seller Transaction Paths for Natural Gas Marketing



service plus some regulator-specified rate of return. Although this approach is still used as a basis for setting pipeline tariffs, more pricing flexibility has been introduced, particularly in the interstate pipeline industry and more recently by local distributors. Pipeline companies are also offering a range

range of services under competitive and market-based pricing arrangements. Additionally, newer players—for example marketers of spot gas and brokers for pipeline capacity—have entered the market, creating new links connecting suppliers with end-users. The marketing links are expected to become increasingly complex in the future.

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) is currently driving 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.[43] 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 Rocky Mountain region and the Gulf of Mexico. As capacity changes take place, prices of services should adjust accordingly to reflect new market conditions.

Federal and State initiatives are reducing barriers to market entry and are encouraging the development of more competitive markets for pipeline and distribution services. Mechanisms used to make the transmission sector more competitive include the widespread capacity releasing programs, market-based rates, and the formation of market centers with deregulated upstream pipeline services. The ITS is not designed to model any specific type of program, but to simulate the overall impact of the movement towards market based pricing of transmission services.

Pipeline Tariff Submodule

The primary purpose of the Pipeline Tariff Submodule (PTS) is to provide volume dependent curves for computing tariffs for interstate transportation and storage services within the Interstate Transmission Submodule. 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. 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

[43]Further information can be found on the Energy Information Administration web page on "Natural Gas Pipeline Capacity & Utilization" www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/usuage.html.

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 accounted for within the Distributor Tariff Submodule.

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 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 Distributor Tariff Submodule. 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-percent 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. Ultimately, the NGTDM is trying to project market prices and uses cost-of-service rates as a means in the process of establishing market prices.

Distributor Tariff Submodule

The primary purpose of the Distributor Tariff Submodule (DTS) is to determine the price markup from the regional market hub to the end-user. For most customers, this consists of (1) distributor markups charged by local distribution companies for the distribution of natural gas from the citygate to the end user and (2) 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 most industrial and electric generator customers, gas is not purchased through a local distribution company, so they are not specifically charged a distributor tariff. In this case, the “distributor tariff” represents the difference between the average price obtained by local distribution companies at the citygate and the price obtained by the average industrial or electric generator 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. In most cases, projected distributor tariffs in the model depend initially on base year values, which are established by subtracting historical citygate prices from historical delivered prices, and generally reflect an average over a number of historical years.

Distributor tariffs for all but the transportation sector are set using econometrically estimated equations. Transportation sector markups, representing sales for natural gas vehicles, are set separately for fleet and personal vehicles and account for distribution to delivery stations, retail markups, federal and state motor fuels taxes, and the potential impact of retail competition with gasoline. Many of these modeling choices are the result of data limitations.[44]

[44]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. EIA is considering purchasing some of these data from a private vendor to support potential future analysis.

4. Interstate Transmission Submodule Solution Methodology

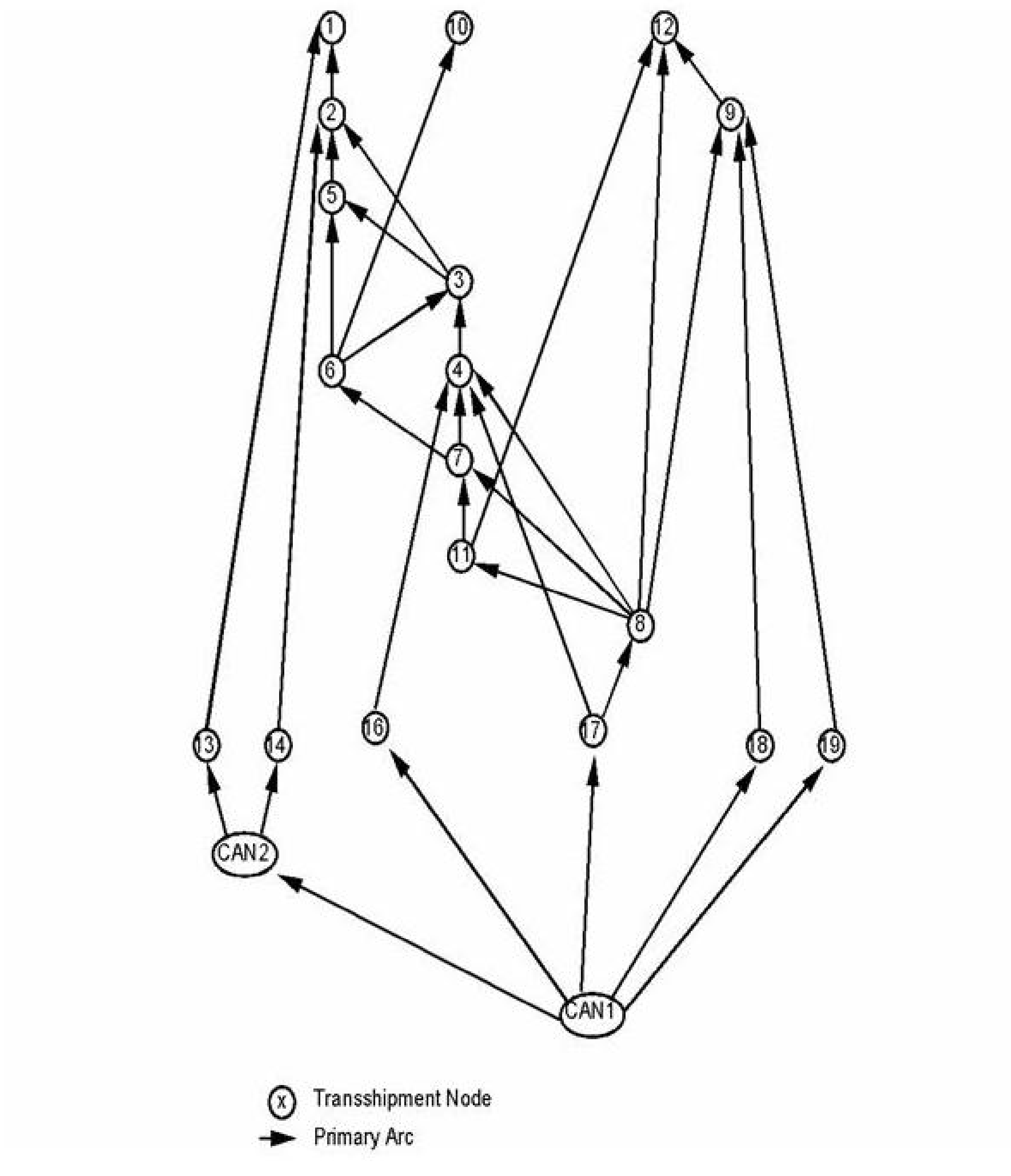
As a key component of the NGTDM, the Interstate Transmission Submodule (ITS) determines the market equilibrium between supply and demand of natural gas within the North American pipeline system. This translates into finding the price such that the quantity of gas that consumers would desire to purchase 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 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,[45] supply prices, and 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, import, and delivered prices, supply quantities, and resulting flow patterns are obtained from the ITS and sent to other NGTDM submodules or other NEMS modules after some processing. Network characteristics, input requirements, and the heuristic 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. 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 (historically about 3 percent of the total flow) or relatively low flow volumes that are exogenously set or set by other NEMS modules (e.g. Mexican imports and exports). In the 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 Solution Process section below. A hierarchical, acyclic network structure allows for the systematic representation of the flow of natural gas (and its associated

[45]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, that planning and construction for the pipeline actually started before the pipeline came online.

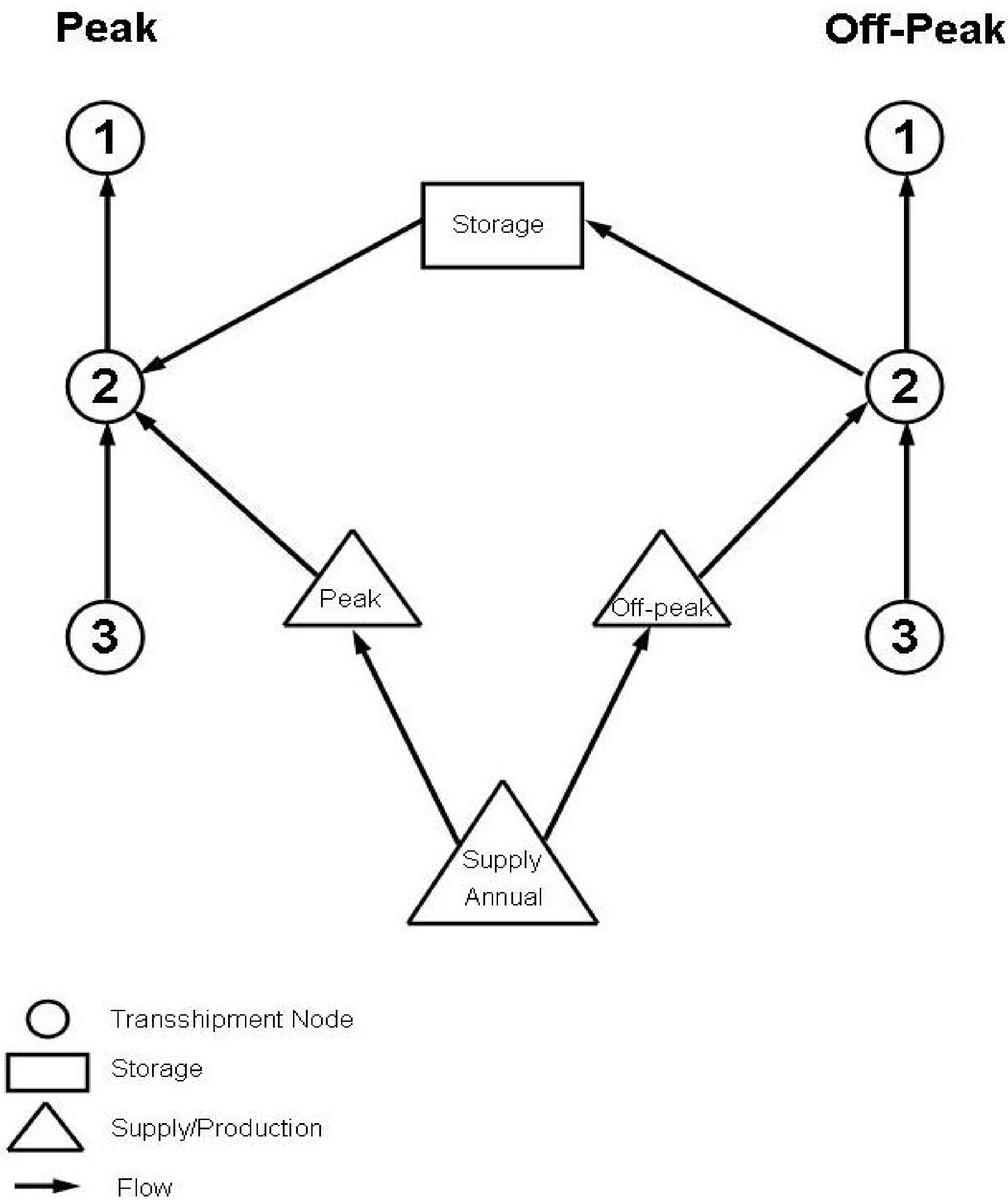
Figure 4-1. Network "Tree" or Hierarchical, Acyclic Network of Primary Arcs



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.

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

Figure 4-2. Simplified Example of Supply and Storage Links Across Networks



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.

Input Requirements of the ITS

The following is a list of the key inputs required during ITS processing:

- 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
- Natural gas production in eastern Canada and unconventional production in western Canada, by season.
- Natural gas flow by pipeline from Alaska to Alberta.
- Natural gas flow by pipeline from the MacKenzie Delta to Alberta.
- Regional supply curve parameters for U.S. nonassociated and western Canadian conventional natural gas supply[46]
- 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 U.S. nonassociated onshore and offshore and western Canadian natural gas supplies, U.S. associated-dissolved gas supplies, and Mexican imports and exports are provided by the Oil and Gas Supply Module (OGSM). In contrast, Canadian data, with the exclusion of western Canadian supply curves, are set 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. In previous versions of the module, maximum seasonal pipeline utilizations were used to simulate the impact of varying demand load patterns within a season on the need to maintain pipeline capacity sufficient for peak day flows, not just average seasonal flows. This characteristic is now being represented differently in the module.

[46]These supply sources are referred to as the "variable" supplies because they are allowed to change in response to price changes during the ITS solution process.

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 import/export levels (excluding Canadian imports) 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, 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 verify that sufficient sustained[47] capacity is available for the peak day in each period; and 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[48] and propane injection can be used to accommodate a peak day in this month.

Heuristic 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 established 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[49] 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 conventional gas from Western Canada), secondary flows into the region, and the regions 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**), a sharing algorithm is used to determine the percent 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

[47]"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.

[48]Line packing is a means of storing gas within a pipeline for a short period of time by compressing the gas.

[49]Fixed supplies are those supply sources that are not allowed to vary in response to changes in the natural gas price during the ITS solution process.

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[50] 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 up each network tree, regional wellhead prices are used with pipeline tariffs, while adjusting for price impacts from pipeline fuel consumption, to calculate regional node prices for each season. Next, intraregional and intrastate markups are added to the regional/seasonal node prices, followed by the addition of corresponding seasonal, sectoral distributor tariffs, to generate delivered prices. Seasonal prices are then converted to annual delivered prices using quantity-weighted averaging. To speed overall NEMS convergence,[51] 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.[52] 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 pseudo supply, called 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

[50]For the peak period networks only.

[51]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, the NEMS will theoretically converge to an equilibrium solution in less iterations.

[52]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.

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 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.[53]

The following subsections describe many of these procedures in greater detail, including: net node demands, pipeline fuel consumption, sharing algorithm, 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 demands, 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:

$$NODE\_DMD_{PK,r} = PFUEL_{PK,r} + FLOW_{PK,a} + NODE\_CDMD_{PK,r}$$

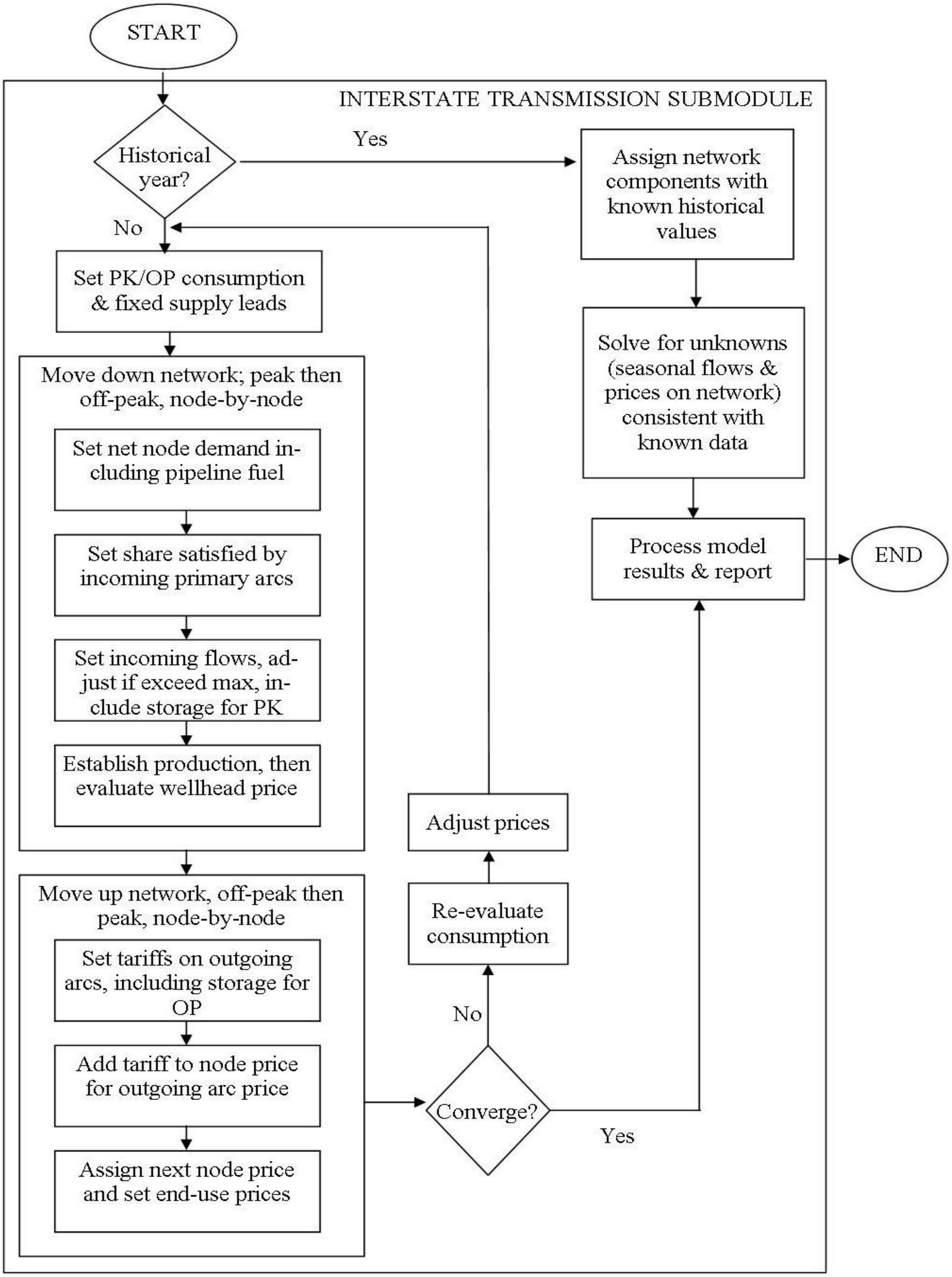
$$\sum_{nonu} (PKSHR\_DMD_{nonu,r} * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \tag{31}$$

$$\sum_{jutil \subset r} (PKSHR\_UDMD_{jutil} * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil})$$

$$NODE\_CDMD_{PK,r} = YEAR\_CDMD_{PK,r} - (PKSHR\_PROD_{s} * ZADGPRD_{s}) \tag{32}$$

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

Figure 4-3. Interstate Transmission Submodule System Diagram



$$YEAR\_CDMD_{PK,r} = DISCR_{PK,r,t} + CN\_DISCR_{PK,cn} \\ ((PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\ (PK1 * SAFLOW_{a,t}) - (PK2 * SAFLOW_{a',t}) - \\ (PKSHR\_YR * QAK\_ALB_t) - (PKSHR\_SUPLM * ZTOTSUP_r) - \\ (PKSHR\_ILNG * OGQNGIMP_{L,t}) - (PKSHR\_PROD_s * CN\_FIXSUP_{cn,t}) \tag{33}$$

Off-Peak:

$$NODE\_DMD_{OP,r} = PFUEL_{OP,r} + FLOW_{OP,a} + FLOW_{PK,st} + NODE\_CDMD_{OP,r} + \\ \sum_{nonu} ((1 - PKSHR\_DMD_{nonu,r}) * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \\ \sum_{jutil \subset r} ((1 - PKSHR\_UDMD_{jutil}) * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil})) + \tag{34}$$

$$NODE\_CDMD_{OP,r} = YEAR\_CDMD_{OP,r} - ((1 - PKSHR\_PROD_s) * ZADGPRD_s) \tag{35}$$

$$YEAR\_CDMD_{OP,r} = DISCR_{OP,r,t} + CN\_DISCR_{OP,cn} + \\ ((1 - PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\ ((1 - PK1) * SAFLOW_{a,t}) - ((1 - PK2) * SAFLOW_{a',t}) - \\ ((1 - PKSHR\_YR) * QAK\_ALB_t) - ((1 - PKSHR\_SUPLM) * ZTOTSUP_r) - \\ ((1 - PKSHR\_ILNG) * OGQNGIMP_{L,t}) - ((1 - PKSHR\_PROD_s) * CN\_FIXSUP_{cn,t}) \tag{36}$$

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 nonelectric sectors nonu (Bcf)
$ZNGQTY\_I_{nonu,r}$	=	Noncore demands in region r, by nonelectric 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)
$ZADGPRD_s$	=	On- and off-shore associated-dissolved gas production in supply subregion s (Bcf)
$DISCR_{n,r,t}$	=	Lower 48 discrepancy in region r, for network n, in forecast year t (Bcf)[54]

[54]Projected lower 48 discrepancies are primarily based on the average historical level from 1999 to 2004. Discrepancies are adjusted

$CN\_DISCR_{n,cn}$	=	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)
$SAFLOW_{a,t}$	=	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)
$PKSHR\_DMD_{nonu,r}$	=	Average (2001-2006) fraction of annual consumption in each nonelectric sector in region r corresponding to the peak season
$PKSHR\_UDMD_{jutil}$	=	Average (1994-2006, except New England 1997-2006) fraction of annual consumption in the electric generator sector in region r corresponding to the peak season
$PKSHR\_PROD_{s}$	=	Average (1994-2006) fraction of annual production in supply region s corresponding to the peak season (Appendix E)
PKSHR_CDMD	=	Fraction of annual Canadian demand corresponding to the peak season (Appendix E)
PKSHR_YR	=	Fraction of the year represented by the peak season
PKSHR_SUPLM	=	Average (1990-2006) fraction of supplemental supply corresponding to the peak season
PKSHR_ILNG	=	Average (1990-2006) fraction of LNG supply corresponding to the peak season
PK1, PK2	=	Fraction of flow corresponding to peak season (composed of PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, or PKSHR_YR)
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	=	Nonelectric 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) region r
s	=	Supply subregion ID into region r (1-21)

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adjusted in the STEO years to account for STEO discrepancy (Appendix E, STDISCR) and annual net storage withdrawal (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).

cn = Canadian supply subregion ID in region r (1-2)
L = LNG import region ID into region r (1-12)
st = Arc ID corresponding to storage supply into region r

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 an 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[55] 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:

$$PFUEL_{n,r} = PFUEL\_FAC_{n,r} * NODE\_DMD_{n,r} * SCALE\_PF \tag{37}$$

where,

$PFUEL_{n,r}$ = Pipeline fuel consumption in region r, for network n (Bcf)
$PFUEL\_FAC_{n,r}$ = Average (2001-2006) 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 at 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) [56] 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:

$$ARC\_PFUEL_{n,a} = (PFUEL_{n,r} - INTRA\_PFUEL_{n,r}) * \frac{FLOW_{n,a}}{TFLOW} \tag{38}$$

where,

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[55] EIA produces a separate quarterly forecast for primary national energy statistics over the next several years. For certain forecast items, the NEMS is calibrated to produce an equivalent (within 2 to 5 percent) result for these years. For *AEO2008*, the year calibrated to *STEO* results was 2007.

[56] 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.

$ARC\_PFUEL_{n,a}$ = 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)
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 intraregional flow factor in an historical year:

$$FLO\_FAC_{n,r} = INTRA\_FLO_{n,r} \;/\; (NODE\_DMD_{n,r} - PFUEL_{n,r}) \tag{39}$$

Forecast of intraregional flow:

$$INTRA\_FLO_{n,r} = FLO\_FAC_{n,r} * (NODE\_DMD_{n,r} - PFUEL_{n,r}) \tag{40}$$

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 - 2006) 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

While moving systematically downward from node to node through the acyclic network, a sharing algorithm is used to allocate 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,[57] then the 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 dictates that the share ($SHR_{n,a,t}$) of demand for one arc into a node is proportional to the share defined in the previous model year.[58] This proportion is a multiplicative value represented as the ratio of the inverse price (defined the previous cycle up the network tree) along the arc, to the average of all inverse prices along all arcs going into that node. The price term ($ARC\_SHRPR_{n,a}$) represents the unit cost associated with an arc going into a node, and is 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:

$$SHR_{n,a,t} = \frac{ARC\_SHRPR_{n,a}^{-\gamma}}{\frac{\sum_{b} ARC\_SHRPR_{n,b}^{-\gamma}}{N}} * SHR_{n,a,t-1} \tag{41}$$

where,

$SHR_{n,a,t}$, $SHR_{n,a,t-1}$	=	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] (87$/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

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

[58]When planned pipeline capacity is added at the beginning of a forecast year, the value of SHR_{t-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.

[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:

$$FLOW_{n,a} = SHR_{n,a,t} * NODE\_DMD_{n,r} \tag{42}$$

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):

$$MAXFLO_{PK,a} = MAXPCAP_{PK,a} * (PKSHR\_YR * PKUTZ_{a}) \tag{43}$$

such that $MAXPCAP_{PK,a}$

for Supply[59]*:*

$$MAXPCAP_{PK,a} = ZOGRESNG_{s} * \mathit{ZOGPRRNG}_{s} * MAXPRRFAC * (1 - (PCTLP_{r} * SCALE\_LP_{t})) \tag{44}$$

for Pipeline:

$$MAXPCAP_{PK,a} = PTMAXPCAP_{i,j} \tag{45}$$

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

for Storage:

$$MAXPCAP_{PK,a} = PTMAXPSTR_{st} \qquad (46)$$

for Canadian imports

$$MAXPCAP_{PK,a} = CURPCAP_{a,t} \qquad (47)$$

Maximum off-peak pipeline flows:

$$MAXFLO_{OP,a} = MAXPCAP_{OP,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \qquad (48)$$

such that $MAXPCAP_{OP,a}$ is

either current capacity

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} \qquad (49)$$

or current capacity plus capacity additions,

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} + ((1 + XBLD) * \left(\frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} - CURPCAP_{a,t}\right)) \qquad (50)$$

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

$$MAXPCAP_{OP,a} = MAXPCAP_{PK,a} \qquad (51)$$

Maximum off-peak flows from supply sources:,

$$MAXFLO_{OP,a} = MAXPCAP_{PK,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \qquad (52)$$

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 (1996-2006) 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)
$FLOW_{PK,a}$	=	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 (Appendix E, fraction)
$OPUTZ_a$	=	Pipeline utilization along arc a for the off-peak season (Appendix E, fraction)
XBLD	=	Percent increase over capacity builds to account for weather (Appendix E, fraction)
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 and, if 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,[60] 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:

[60]For AEO2008 capacity expansion on Canadian import arcs were set exogenously (PLANPCAP, Appendix E).

Storage:

$$ACTPCAP_a = \frac{FLOW_{PK,a}}{PKUTZ_a} \tag{53}$$

Pipeline:

$$ACTPCAP_a = MAXPCAP_{OP,a} \tag{54}$$

Pipeline arc entering region 10 (Florida)

$$ACTPCAP_a = \text{MAX between } \frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} \text{ and } \frac{FLOW_{OP,a}}{(1 - PKSHR\_YR) * OPUTZ_a} \tag{55}$$

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.[61] 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.[62] 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

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

[62]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).

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:

$$MTHFLW_{n,a} = MTH\_NETNOD_{n,r} * \frac{SHR_{n,a,t}}{\sum_{c} SHR_{n,c,t}} \tag{56}$$

where,

$MTHFLW_{n,a}$	=	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:

$$MTH\_CAPADD_{n,a} = MTH\_TCAPADD_{n} * \frac{INIT\_CAPADD_{n,a}}{\sum_{c} INIT\_CAPADD_{n,c}} \tag{57}$$

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
$INIT\_CAPADD_{n,a}$	=	$MTHFLW_{a}$ - MTH_CAP_{a}, 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.

Wellhead 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 wellhead 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 wellhead price equals the price obtained from the annual supply curve when evaluated using total annual production. To obtain seasonal wellhead prices, the following methodology is used. Taking one supply region at a time, equivalent annual production levels (ANNSUP) are determined for each seasonal model result, as follows:

Peak:

$$ANNSUP = \frac{NODE\_QSUP_{PK,s}}{PKSHR\_YR} \tag{58}$$

Off-peak:

$$ANNSUP = \frac{NODE\_QSUP_{OP,s}}{(1 - PKSHR\_YR)} \tag{59}$$

where,

ANNSUP	=	Equivalent annual production level (Bcf)
$NODE\_QSUP_{n,s}$	=	Seasonal (n=PK-peak or OP-off-peak) 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,

$$FSF = \frac{PSUP_s}{SPAVG_s} \quad (60)$$

and,

$$NODE\_PSUP_{n,s} = SPSUP_n * FSF \quad (61)$$

where,

FSF	=	Scaling factor for seasonal prices
$PSUP_s$	=	Annual supply price from the annual supply curve for supply region s (87$/Mcf)
$SPAVG_s$	=	Quantity-weighted average annual supply price using peak and off-peak prices and production levels for supply region s (87$/Mcf)
$NODE\_PSUP_{n,s}$	=	Adjusted seasonal supply prices for supply region s (87$/Mcf)
$SPSUP_n$	=	Estimated seasonal supply prices [for supply region s] (87$/Mcf)
n	=	network (peak or off-peak)
s	=	supply source

During the STEO years (2007 for *AEO2008*), national average wellhead prices (lower 48 only) generated by the model are compared to the national STEO wellhead price forecast to generate a benchmark factor ($SCALE\_WPR_t$). This factor is used to adjust the regional (annual and seasonal) lower 48 wellhead prices to equal STEO results. This benchmark factor is only applied during the STEO years. The benchmark factor is applied as follows:

Annual:

$$PSUP_s = PSUP_s * SCALE\_WPR_t \quad (62)$$

Seasonal:

$$NODE\_PSUP_{n,s} = NODE\_PSUP_{n,s} * SCALE\_WPR_t \quad (63)$$

where,

$PSUP_s$	=	Annual supply price from the annual supply curve for supply region s (87$/Mcf)
$NODE\_PSUP_{n,s}$	=	Adjusted seasonal supply prices for supply region s (87$/Mcf)
$SCALE\_WPR_t$	=	STEO benchmark factor for wellhead price in year t
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 (SCALE_CAN, for AEO2007 set to 1.0 in 2006 and 2007) which is set to align Canadian import levels with STEO results.

While the NGTDM does not explicitly represent the Henry Hub within its modeling structure, the module reports a projected value for reporting purposes. The price at the Henry Hub is set using an econometrically estimated equation as a function of the lower 48 average natural gas wellhead price, as follows:

$$oOGHHPRNG_{t} = 1.00082 * e^{0.115718} * oOGWPRNG_{s=13,t}^{0.977713} \quad (64)$$

where,

$oOGHHPRNG_t$ = Natural gas price at the Henry Hub (87$/MMBtu)
$oOGWPRNG_{s,t}$ = Average natural gas wellhead price for supply region 13, representing the lower 48 average (87$/Mcf)
s = supply source/region
t = forecast year

Details about the generation of this estimated equation and associated parameters are provided in Table F12, Appendix F.

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, and reflect the average rate charged over all of the pipelines represented along an arc. 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 storage, the fixed term establishes a minimum and is set to $0.001 per Mcf. The variable term is obtained from tariff/capacity curves provided by two PTS functions and represents reservation fees for pipelines and all charges for storage. These two functions are NGPIPE_VARTAR and X1NGSTR_VARTAR. When determining network flows a different set of tariffs ($ARC_SHRFEE_{n,a}$) are used than are used when setting delivered prices ($ARC_ENDFEE_{n,a}$).

In the peak period ARC_SHRFEE equals ARC_ENDFEE and the total tariff (reservation plus usage fee). In the off-peak period, ARC_ENDFEE represents the total tariff as well, but ARC_SHRFEE represents the fee that drives the flow decision. In previous AEOs this was set to just the usage fee. The assumption behind this structure was that delivered prices will ultimately reflect reservation charges; but that during the off-peak period in particular, decisions regarding the purchase and transport of gas are made largely independently of where pipeline is reserved and the associated fees. For *AEO2008* the ARC_SHRFEE was set similarly to ARC_ENDFEE because the usage fees seemed to be underestimating off-peak market prices. (This decision will be reexamined in the future.) During the peak period, the gas is more likely to flow along routes where pipeline is reserved; and reserved; and therefore the flow decision is more greatly influenced by the relative reservation fees.[63] The following arc tariff equations apply:

Pipeline:

$$ARC\_ENDFEE_{n,a} = ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n, a, i, j, FLOW_{n,a})$$
$$ARC\_SHRFEE_{n,a} = ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n, a, i, j, FLOW_{n,a}) \quad (65)$$

Storage:

$$ARC\_SHRFEE_{n,a} = ARC\_FIXTAR_{n,a,t} + X1NGSTR\_VARTAR(st, FLOW_{n,a})$$
$$ARC\_ENDFEE_{n,a} = ARC\_FIXTAR_{n,a,t} + X1NGSTR\_VARTAR(st, FLOW_{n,a}) \quad (66)$$

where,

$ARC\_SHRFEE_{n,a}$	=	Total arc fees along arc a for network n [used with sharing algorithm] (87$/Mcf)
$ARC\_ENDFEE_{n,a}$	=	Total arc fees along arc a for network n [used with delivered pricing] (87$/Mcf)
$ARC\_FIXTAR_{n,a,t}$	=	Fixed (or usage) fees along an arc a for a network n in time t (87$/Mcf)
NGPIPE_VARTAR	=	PTS function to define pipeline tariffs representing reservation fees for specified arc at given flow level
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	=	regional source (i) and destination (j) link on arc a
st	=	storage source ID

A methodology for defining gathering charges has not been developed but may be developed in a separate effort at a later date.[64] In order to accommodate this, the supply arc indices in the variable $ARC\_FIXTAR_{n,a}$ have been reserved for this information (currently set to 0).

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[63]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.

[64]In a previous version of the NGTDM, "gathering" charges were used to benchmark the regional wellhead prices to historical values. It is possible that they may be used (at least in part) to fulfill the same purpose in the ITS. In the past an effort was made, with little success, to derive representative gathering charges. Currently, the gathering charge portion of the tariff along the supply arcs is assumed to be zero.

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 as 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:

$$ARC\_SHRPR_{n,a} = NODE\_SHRPR_{n,rs} + ARC\_SHRFEE_{n,a}$$

$$ARC\_ENDPR_{n,a} = NODE\_ENDPR_{n,rs} + ARC\_ENDFEE_{n,a} \tag{67}$$

with adjustment:

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

$$ARC\_ENDPR_{n,a} = \frac{(ARC\_ENDPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})} \tag{68}$$

where,

$ARC\_SHRPR_{n,a}$	=	Price calculated for natural gas along inflow arc a for network n [used with sharing algorithm] (87$/Mcf)
$ARC\_ENDPR_{n,a}$	=	Price calculated for natural gas along inflow arc a for network n [used with delivered pricing] (87$/Mcf)
$NODE\_SHRPR_{n,r}$	=	Node price for region i on network n [used with sharing algorithm] (87$/Mcf)
$NODE\_ENDPR_{n,r}$	=	Node price for region i on network n [used with delivered pricing] (87$/Mcf
$ARC\_SHRFEE_{n,a}$	=	Tariff along inflow arc a for network n [used with sharing algorithm] (87$/Mcf)
$ARC\_ENDFEE_{n,a}$	=	Tariff along inflow arc a for network n [used with delivered pricing] (87$/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 delivered 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 delivered pricing and flow sharing algorithm pricing. 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:

$$NODE\_SHRPR_{n,r2} = \frac{\Sigma_a (ARC\_SHRPR_{n,a} * FLOW_{n,a})}{\Sigma_a FLOW_{n,a}}$$

$$NODE\_ENDPR_{n,r2} = \frac{\Sigma_a (ARC\_ENDPR_{n,a} * FLOW_{n,a})}{\Sigma_a FLOW_{n,a}} \tag{69}$$

and,

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

$$NODE\_ENDPR_{n,rd} = \frac{(NODE\_ENDPR_{n,rd} * NODE\_DMD_{n,rd})}{(NODE\_DMD_{n,rd} - INTRA\_PFUEL_{n,rd})} \tag{70}$$

where,

$NODE\_SHRPR_{n,r}$	=	Node price for region r on network n [used with flow sharing algorithm] (87$/Mcf)
$NODE\_ENDPR_{n,r}$	=	Node price for region r on network n [used with delivered pricing] (87$/Mcf)
$ARC\_SHRPR_{n,a}$	=	Price calculated for natural gas along inflow arc a for network n [used with flow sharing algorithm] (87$/Mcf)
$ARC\_ENDPR_{n,a}$	=	Price calculated for natural gas along inflow arc a for network n [used with delivered pricing] (87$/Mcf)
$FLOW_{n,a}$	=	Network n flow along arc a (Bcf)
$INTRA\_PFUEL_{n,r}$	=	Intraregional pipeline fuel consumption in region r, for network n (Bcf)
$NODE\_DMD_{n,r}$	=	Net node demands (w/ pipeline fuel) in region r, for 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 defined. Thus, for every region where storage is available, the storage node price is set equal to the to the off-peak regional node price. This applies for both the delivered pricing and the flow sharing algorithm pricing:

$$NODE\_SHRPR_{PK,i} = NODE\_SHRPR_{OP,r}$$
$$NODE\_ENDPR_{PK,i} = NODE\_ENDPR_{OP,r} \qquad (71)$$

where,

$NODE\_SHRPR_{PK,i}$	=	Price at node i [used with flow sharing algorithm] (87$/Mcf)
$NODE\_SHRPR_{OP,r}$	=	Price at node r in off-peak network [used with flow sharing algorithm] (87$/Mcf)
$NODE\_ENDPR_{PK,i}$	=	Price at node i [used with delivered pricing] (87$/Mcf)
$NODE\_ENDPR_{OP,r}$	=	Price at node r in off-peak network [used with delivered pricing] (87$/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[65] 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 adjustment variable, with the process continuing as described above. The objective is to eliminate the need for backstop supply while keeping the associated price at a minimum. The equations for adjusting the node price are:

$$NODE\_SHRPR_{n,r} = NODE\_SHRPR_{n,r} + RBKSTOP\_PADJ_{n,r} \qquad (72)$$

$$RBKSTOP\_PADJ_{n,r} = RBKSTOP\_PADJ_{n,r} + BKSTOP\_PADJ_{n,r} \qquad (73)$$

where,

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[65]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.

$NODE\_SHRPR_{n,r}$ = Node price for region r on network n [used with flow sharing algorithm] (87$/Mcf)
$RBKSTOP\_PADJ_{n,r}$ = Cumulative price adjustment due to backstop (87$/Mcf)
$BKSTOP\_PADJ_{n,r}$ = Incremental backstop price adjustment (87$/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 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 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 equations used to define the new production levels are:

$$\begin{aligned} NODE\_QSUP_{n,s} = {} & (QSUP\_WT * NODE\_QSUP_{n,s}) + \\ & ((1 - QSUP\_WT) * NODE\_QSUPPREV_{n,s}) \end{aligned} \tag{74}$$

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 ($NODE\_PSUP_{n,s}$) for these quantities are then determined using the same methodology defined above for obtaining 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 (nonelectric sectors). For the nonelectric sectors (residential, commercial, industrial, and transportation), prices are established at the NGTDM the NGTDM region 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 and are determined 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 during the historical years of the model. These equations are defined below:

$$CGPR_{n,r} = NODE\_ENDPR_{n,r} + INTRAREG\_TAR_{n,r} + INTRAST\_TAR_{r} + CGBENCH_{n,r} \tag{75}$$

such that:

$$CGBENCH_{n,r} = avg(HCG\_BENCH_{n,r,HISYR}) = avg(HCGPR_{n,r,HISYR} - CGPR_{n,r}) \tag{76}$$

where,

$CGPR_{n,r}$	=	City gate price in region r on network n in each HISYR (87$/Mcf)
$NODE\_ENDPR_{n,r}$	=	Node price for region r on network n (87$/Mcf)
$INTRAREG\_TAR_{n,r}$	=	Intraregional tariff for region r on network n (87$/Mcf)
$INTRAST\_TAR_{r}$	=	Intrastate tariff in region r (87$/Mcf)
$CGBENCH_{n,r}$	=	City gate benchmark factor for region r on network n (87$/Mcf)
$HCGPR_{n,r,EHISYR}$	=	Historical city gate price in region r on network n in historical year EHISYR (87$/Mcf)
n	=	network (peak and off-peak)
r	=	region (lower 48 only)
HISYR	=	historical year, over which average is taken (1990-2005, excluding the outlier year of 2001)
avg	=	straight average of indicated value over all 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 nonelectric sectors and 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 ($SCALE\_FPR_{sec,t}$, $SCALE\_IPR_{sec,t}$)[66]

$SCALE\_IPR_{sec,t}$)[66] 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.

Nonelectric Sectors (except core transportation):

$$NGPR\_SF_{n,sec,r} = CGPR_{n,r} + DTAR\_SF_{n,sec,r} + SCALE\_FPR_{sec,t}$$
$$NGPR\_SI_{n,sec,r} = CGPR_{n,r} + DTAR\_SI_{n,sec,r} + SCALE\_IPR_{sec,t} \tag{77}$$

$$NGPR\_F_{sec,r} = NGPR\_SF_{PK,sec,r} * PKSHR\_DMD_{sec,r} + NGPR\_SF_{OP,sec,r} * (1. - PKSHR\_DMD_{sec,r})$$
$$NGPR\_I_{sec,r} = NGPR\_SI_{PK,sec,r} * PKSHR\_DMD_{sec,r} + NGPR\_SI_{OP,sec,r} * (1. - PKSHR\_DMD_{sec,r}) \tag{78}$$

where,

$NGPR\_SF_{n,sec,r}$	=	Seasonal (n) core nonelectric sector (sec) price in region r (87$/Mcf)
$NGPR\_SI_{n,sec,r}$	=	Seasonal (n) noncore nonelectric sector (sec) price in region r (87$/Mcf)
$NGPR\_F_{sec,r}$	=	Annual core nonelectric sector (sec) price in region r (87$/Mcf)
$NGPR\_I_{sec,r}$	=	Annual noncore nonelectric sector (sec) price in region r (87$/Mcf)
$CGPR_{n,r}$	=	City gate price in region r on network n (87$/Mcf)
$DTAR\_SF_{n.sec,r}$	=	Seasonal (n) distributor tariff to core nonelectric sector (sec) in region r (87$/Mcf)
$DTAR\_SI_{n.sec,r}$	=	Seasonal (n) distributor tariff to noncore nonelectric sector (sec) in region r (87$/Mcf)
$PKSHR\_DMD_{sec,r}$	=	Average (2001-2005) fraction of annual consumption for nonelectric sector in peak season for region r
$SCALE\_FPR_{sec,t}$	=	STEO benchmark factor for core delivered prices for sector sec, in year t (87$/Mcf)
$SCALE\_IPR_{sec,t}$	=	STEO benchmark factor for noncore delivered prices for sector sec, in year t (87$/Mcf)
n	=	network (peak or off-peak)
sec	=	nonelectric sector
r	=	region (lower 48 only)

Electric Generation Sector:

[66]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 industrial price, because of differences in the definition of the price in the STEO versus the price in the AEO, nor for the transportation sector since the STEO does not include a comparable value.

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

$$NGUPR\_SI_{n,j} = CGPR_{n,r} + UDTAR\_SI_{n,j} + SCALE\_IPR_{sec,t} \tag{79}$$

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

$$NGUPR\_I_j = NGUPR\_SI_{PK,j} * PKSHR\_UDMD_j + NGUPR\_SI_{OP,j} * (1. - PKSHR\_UDMD_j) \tag{80}$$

where,

$NGUPR\_SF_{n,j}$	=	Seasonal (n) core utility sector price in region j (87$/Mcf)
$NGUPR\_SI_{n,j}$	=	Seasonal (n) noncore utility sector price in region j (87$/Mcf)
$NGUPR\_F_j$	=	Annual core utility sector price in region j (87$/Mcf)
$NGUPR\_I_j$	=	Annual noncore utility sector price in region j (87$/Mcf)
$CGPR_{n,r}$	=	City gate price in region r on network n (87$/Mcf)
$UDTAR\_SF_{n,j}$	=	Seasonal (n) distributor tariff to core utility sector in region j (87$/Mcf)
$UDTAR\_SI_{n,j}$	=	Seasonal (n) distributor tariff to noncore utility sector in region j (87$/Mcf)
$PKSHR\_UDMD_j$	=	Average (1994-2006, except for New England 1997-2006) 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 (87$/Mcf)
$SCALE\_IPR_{sec,t}$	=	STEO benchmark factor for noncore delivered prices for sector sec, in year t (87$/Mcf)
n	=	network (peak or off-peak)
sec	=	utility sector (electric generation only)
r	=	region (lower 48 only)
j	=	NGTDM/EMM subregion

For *AEO2008*, 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.

Core Transportation Sector:

A somewhat different methodology is used to determine natural gas delivered prices for the core (F) transportation sector. The core transportation sector consists of a personal vehicles component and a fleet vehicles component. Like the other nonelectric sectors, seasonal distributor tariffs are added to the regional city gate prices to determine seasonal delivered prices for both components. Annual core

core prices are then established for each component in a region by averaging the corresponding seasonal prices, as follows:

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

$$NGPR\_TRFV\_SF_{n,r} = CGPR_{n,r} + DTAR\_TRFV\_SF_{n,r} + SCALE\_FPR_{sec,t} \tag{81}$$

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

$$NGPR\_TRFV\_F_{r} = NGPR\_TRFV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + NGPR\_TRFV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r}) \tag{82}$$

where,

$NGPR\_TRPV\_SF_{n,r}$	=	Seasonal (n) price of natural gas used by personal vehicles (core) in region r (87$/Mcf)
$NGPR\_TRFV\_SF_{n,r}$	=	Seasonal (n) price of natural gas used by fleet vehicles (core) in region r (87$/Mcf)
$DTAR\_TRPV\_SF_{n,r}$	=	Seasonal (n) distributor tariff to core transportation (personal vehicles) sector in region r (87$/Mcf)
$DTAR\_TRFV\_SF_{n,r}$	=	Seasonal (n) distributor tariff to core transportation (fleet vehicles) sector in region r (87$/Mcf)
$CGPR_{n,r}$	=	City gate price in region r on network n (87$/Mcf)
$NGPR\_TRPV\_F_{r}$	=	Annual price of natural gas used by personal vehicles (core) in region r (87$/Mcf)
$NGPR\_TRFV\_F_{r}$	=	Annual price of natural gas used by fleet vehicles (core) in region r (87$/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), (87$/Mcf)
n	=	network (peak or off-peak)
sec	=	transportation sector =4
r	=	region (lower 48 only)

Before the personal vehicle and fleet vehicle components can be averaged to determine a single annual price for the core transportation sector, the price of CNG for personal vehicles is compared against a unit-equivalent motor gasoline price. The model assumes that retail CNG prices will be set at a discount off of the motor gasoline price (based on historical relationships), as long as costs are covered. Therefore, the price of CNG for personal vehicles is set as follows:

$$\begin{aligned} NGPR\_TRPV\_F_{r} = \text{maximum of } \{&\text{init } NGPR\_TRPV\_F_{r} + (oJNGTR_{t} * oCFNGN_{t}) \\ &\text{and } (oPMGCM_{c,t} + oJMGCM_{t}) * oCFNGN_{t} * PERMG\} \\ &- (oJNGTR_{t} * oCFNGN_{t}) \end{aligned} \tag{83}$$

where,

$NGPR\_TRPV\_F_r$	=	Price of natural gas used for personal vehicles (core) in region r (87$/Mcf)
$initNGPR\_TRPV\_F_r$	=	Initial price of natural gas used for personal vehicles (core) in region r, set by adding distribution tariff to city gate price (87$/Mcf)
$JNGTR_t$	=	NEMS emissions price adjustment for natural gas in transportation sector in model year t (87$/MMBTU)
oCFNGN	=	Natural gas conversion factor (MMBTU per Mcf)
oPMGCM	=	Motor gasoline price in the Census Division associated with region r (87$/MMBtu)
$oJMGCM_t$	=	NEMS emission price adjustment for motor gasoline in model year t (87$/MMBTU)
PERMG	=	Fraction of motor gasoline price to set CNG price, (i.e., 1 minus the discount rate) (Appendix E)
r	=	region (lower 48 only)
t	=	forecast year
c	=	Census division

Once the personal vehicles price for natural gas is established, the two core component prices are averaged (using quantity weights) to produce an annual core price for each region ($NGPR\_F_{sec=4,r}$). Seasonal core prices are also determined by quantity-weighted averaging of the two seasonal components ($NGPR\_SF_{n,sec=4,r}$).

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 into Census Division prices and 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 wellhead price in the nearest NGTDM region plus a markup (or markdown) that is based on the difference between similar import and wellhead 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 wellhead 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). 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 industrial and electric generator customers do not purchase their gas through local distribution companies, their "distributor tariff" represents the difference between the average price paid by local distribution companies at the city gate and the average price paid by the industrial or electric generator customer.[67] 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 core transportation sector is composed of two categories of compressed natural gas (CNG) consumers (fleet vehicles and personal vehicles); and therefore, separate distributor tariffs are developed for each of these two categories.

For the residential, commercial, industrial, and electric generation sectors distributor tariffs are based on econometrically estimated equations and are driven in part by sectoral consumption levels.[68] This general approach was taken since in the past data were 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. Such an approach is currently being reexamined and is only expected to be applied to the residential and commercial sectors. Distribution charges for CNG into vehicles are set to the sum of historical tariffs for delivering CNG to refueling stations, federal and state motor fuels taxes and credits, and estimates of dispensing charges. The specific methodologies used to calculate each sectors 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 commercial natural gas consumption for the commercial tariff and natural gas consumption per household for the residential sector tariff. In both cases lagged values influence the results significantly, as follows:

$$\begin{aligned}DTAR\_SF_{s=1,r,n} = {} & e^{PRSREG3_r + PRSREGPK3_{r,n}} * \left(\frac{BASQTY\_SF_{s=1,r,n}}{NUMRS_{r,t}}\right)^{-0.640736} * e^{0.00359432*t} \\ & DTAR\_SFPREV_{s=1,r,n}^{0.253685} * e^{-0.253685*(PRSREG3_r + PRSREGPK3_{r,n})} \\ & \left(\frac{BASQTY\_SFPREV_{s=1,r,n}}{NUMRS_{r,t-1}}\right)^{(-0.253685*-0.640736)} \quad e^{-0.253685*0.00359432*(t-1)}\end{aligned} \tag{84}$$

[67]It is not unusual for these "markups" to be negative.

[68]Historical distributor tariffs for a sector in a particular region/season can be estimated by taking the difference between the average sectoral end-use price and the average city gate price in the region/season (Appendix E, HCGPR).

$$DTAR\_SF_{s=2,r,n} = e^{PCMREG1_r + PCMREGPK1_{r,n}} * (BASQTY\_SF_{s=2.r.n})^{-0.334438*1.05} * e^{0.015522*t}$$

$$DTAR\_SFPREV_{s=2,r,n}^{0.224301} * e^{-0.224301*(PCMREG1_r + PCMREGPK1_{r,n})} \quad (85)$$

$$(BASQTY\_SFPREV_{s=2,r,n})^{(-0.2224301*-0.334438*1.05)} \; e^{-0.224301*0.01522*(t-1)}$$

where,

$$NUMRS_{r,t-1} = oRSGASCUST_{t-1,cd} * RECS\_ALIGN_r * NUM\_REGSHR_r \quad (86)$$

where,

$DTAR\_SF_{s,r,n}$	=	core distributor tariff in current forecast year for sector s, region r, and network n (1987$/Mcf)
$DTAR\_SFPREV_{s,r,n}$	=	core distributor tariff in previous forecast year (1987$/Mcf). [For first forecast year set at the 2005 historical value.]
$BASQTY\_SF_{s,r,n}$	=	sector (s) level gas consumption for region r, and network n (Bcf)
$BASQTY\_SFPREV_{s,r,n}$	=	sector (s) level gas consumption for region r, and network n in previous year (Bcf)
NUMRS	=	number of residential customers in year t
$PRSREG3_r$, $PCMREG1_r$	=	residential and commercial regional constant terms (Tables F6 and F7, Appendix F)
$PRSREGPK3_{r,n}$	=	residential, regional, peak period, constant term (Table F6, Appendix F)
$PCMREGPK1_{r,n}$	=	commercial, regional, peak period, constant term (Table F7, Appendix F)
$oRSGASCUST_{cd,t-1}$	=	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 2005 Residential Consumption Survey (RECS), the data on which oRSGASCUST is based, with similar data from the EIA's Natural Gas Annual, the data on which the DTAR_SF estimation is based.
NUM_REGSHR_r	=	share of residential customers in NGTDM region r relative to the number in the larger or equal sized associated census division, set to values in last historical year, 2005. (Appendix E)
s	=	sector (=1 for residential, =2 for commercial)
cd	=	census division
r	=	region (12 NGTDM regions)
n	=	network (peak or off-peak)
t	=	forecast year (e.g., 2010)

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

Industrial Sector

For the industrial sector, a single distributor tariff (i.e., no distinction between core and noncore) is estimated for each season and region as a function of the industrial consumption level in that season and region. Next, core seasonal tariffs are set by assuming a differential between the core price and the estimated distributor tariff for the season and region, based on historical estimates.[69] The noncore price is set to insure that the quantity-weighted average of the core and noncore price in a season and region will equal the originally estimated tariff for that season and region. Historical prices for the industrial sector are estimated based on the data that are available from the Manufacturing Energy Consumption Survey (MECS) (Table F5, Appendix F). The industrial prices within EIA's Natural Gas Annual only represent industrial customers who purchase gas through their local distribution company, a small percentage of the total; whereas the prices in the MECS represent a much larger percentage of the total industrial sector. The equation for the single seasonal/regional industrial distributor tariff follows:

$$\begin{aligned} TAR = {} & 0.096182 + PIN\_REG1_r + PIN\_REGPK1_{r,n} + \\ & (-0.000251581 * QCUR_n) + (0.490900 * TARLAG_n) + \\ & -0.490900 * [0.096182 + PIN\_REG1_r + PIN\_REGPK1_{r,n} + \\ & (-0.000251581 * QLAG_n)] \end{aligned} \tag{87}$$

The core and noncore distributor tariffs are set using:

$$DTAR\_SF_{s=3,r,n} = TAR + (DTAR\_SFPREV_{s=3,r,n} - TARLAG_n) \tag{88}$$

$$DTAR\_SI_{s=3.r,.n} = \frac{(TAR * QCUR_n) - (DTAR\_SF_{s=3,r,n} * BASQTY\_SF_{s=3,r,n})}{BASQTY\_SI_{s=3,r,n}} \tag{89}$$

where,

TAR	=	seasonal distributor tariff for the industrial sector (s=3) in region r (87$/Mcf)
TARLAGn	=	seasonal distributor tariff for the industrial sector (s=3) in region r in the previous forecast year (87$/Mcf)
PIN_REG1_r	=	estimated constant term (Table F4, Appendix F)
$PIN\_REGPK1_{r,n}$	=	estimated coefficient, set to zero for the off-peak period and for any region where the coefficient is not statistically significant
$DTAR\_SF_{n,s,r}$	=	seasonal distributor tariff for the core industrial sector (s=3) in region r (87$/Mcf)
$DTAR\_SI_{n,s,r}$	=	seasonal distributor tariff for the noncore industrial sector (s=3) in region r (87$/Mcf)
$DTAR\_SFPREV_{n,s,r}$	=	seasonal distributor tariff for the core industrial sector (s=3) in region r (87$/Mcf) in the previous forecast year [In the first forecast year set to the estimated 2005 historical value [Appendix F, Table F5] (87$/Mcf)]
$BASQTY\_SF_{n,s=3,r}$	=	seasonal core natural gas consumption for industrial sector(s=3) in the current forecast year (Bcf)
$BASQTY\_SI_{n,s=3,r}$	=	seasonal noncore natural gas consumption for industrial sector (s=3) in the current forecast year (Bcf)

[69]Historical core and noncore prices from the Manufacturing Energy Consumption Survey were used as a basis for setting this differential in the last historical year.

$QCUR_n$ = sum of BASQTY_SF and BASQTY_SI for industrial in a particular season and region
$QLAG_n$ = sum of BASQTY_SFPREV and BASQTY_SIPREV for industrial in a particular season and region, the value of QCUR in the last forecast year
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 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 city gate price in each NGTDM region and the natural gas price paid on average by electric generators in each NGTDM/EMM region, and are often negative. A single markup or tariff (i.e., no distinction between core and noncore) is projected for each season and region using econometrically estimated equations, as was done for the industrial sector. However, the current version of the model (as used for *AEO2008*) assigns this same value to both the core and noncore segments.[69] The estimated equations for the distributor tariffs for electric generators are a function of natural gas consumption by the sector relative to that consumed by the other sectors. The greater the electric consumption share, the greater the price difference between the electric sector and the average, as they will need to reserve more space on the pipeline system. The specific equations follow:

$$\begin{aligned} UDTAR\_SF_{n=1,j} = {} & (-0.201039 + 0.023) + PELREG6_j + (0.248175 * 0.70) * \\ & (BASUQTY\_SF_{n=1,j} + BASUQTY\_SI_{n=1,j}) / OTHR_{ngt}) + \\ & (0.141027 * UDTAR\_SFPREV_{n=1,j}) - 0.141027 * \\ & [(-0.201039 + 0.023) + PELREG6_j + (0.248175 * 0.70) * \\ & (BASUQTY\_SFPREV_{n=1,j} + BASUQTY\_SIPREV_{n=1,j}) / \\ & OTHRLAG_{ngt})] \end{aligned} \qquad (90)$$

$$\begin{aligned} UDTAR\_SF_{n=2,j} = {} & (0.051338 + 0.047) + PELREG5_j + (0.143507 * 0.70) * \\ & (BASUQTY\_SF_{n=2,j} + BASUQTY\_SI_{n=2,j}) / OTHR_{ngt} + \\ & (0.262643 * UDTAR\_SFPREV_{n=2,j}) - 0.262643 * \\ & [(0.051338 + 0.047) + PELREG5_j + (0.143507 * 0.70) * \\ & (BASUQTY\_SFPREV_{n=2,j} + BASUQTY\_SIPREV_{n=2,j}) / \\ & OTHRLAG_{ngt}] \end{aligned} \qquad (91)$$

[69]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.

and

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

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 in current forecast year (Bcf)
$BASUQTY\_SI_{n,j}$	=	noncore electric generator gas consumption in 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)
$PELREG6_j$	=	regional constant terms for peak period (Table F8, Appendix F)
$PELREG5_j$	=	regional constant terms for off-peak period (Table F8, Appendix F)
n	=	network (peak or off-peak)
j	=	NGTDM/EMM region (see chapter 2)
ngt	=	NGTDM region of which NGTDM/EMM region is contained

Parameter values and details about the estimation of these two equations can be found in Table F8, Appendix F.

Transportation Sector

Consumers of compressed natural gas (CNG) have been classified into two end-use categories within the core transportation sector: fleet vehicles and personal vehicles. A distributor tariff is set for both categories to capture 1) the cost of the natural gas delivered to the dispensing station above the city gate price, 2) the per-unit cost or charge for dispensing the gas, and 3) federal and state motor fuels taxes and credits. For both categories, the distribution charge for the CNG delivered to the 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. Similarly federal and state motor fuels taxes are assumed to be the same for both categories and held constant in nominal dollars.[70] The Highway Bill of 2005 raised the motor fuels tax for CNG.[71] The model adjusts the distribution costs accordingly. A primary difference in the pricing for the two categories is the assumed per-unit dispensing charge. The necessary data for a proper determination of the average historical dispensing charge is not available. In reality the costs are expected to vary widely, largely

[70]Motor vehicle fuel taxes are assumed constant in current year dollars throughout the forecast, but are converted into 1987 dollars for use in the model.

[71]The Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU), Section 1113. The bill also allowed for an excise tax credit of $0.50 per gasoline gallon equivalent to be paid to the seller of the CNG through September of 2009. Since it can not be determined how much of any of this credit might be passed through to the consumer, an assumption was made that it would not impact the retail price.

largely because of wide variations in throughput volumes. The assumed values were based on an estimate provided by an industry analyst and verified as possible. The distributor tariffs for CNG vehicles are set as follows:

$$DTAR\_TRFV\_SF_{n,r} = HDTAR\_SF_{n,s=4,r,EHISYR} * (1 - TRN\_DECL)^{YR\_DECL} + RETAIL\_COST_2 + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_t} \quad (92)$$

$$DTAR\_TRPV\_SF_{n,r} = HDTAR\_SF_{n,s=4,r,EHISYR} * (1 - TRN\_DECL)^{YR\_DECL} + RETAIL\_COST_1 + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_t} \quad (93)$$

where,

$DTAR\_TRFV\_SF_{n,r}$	=	distributor tariff for the fleet vehicle transportation sector (87$/Mcf)
$DTAR\_TRPV\_SF_{n,r}$	=	distributor tariff for the personal vehicle transportation sector (87$/Mcf)
$HDTAR\_SF_{n,s,r,EHISYR}$	=	historical (2004) distributor tariff for the transportation sector to deliver the CNG to the station[72] (87$/ Mcf)
TRN_DECL	=	fleet vehicle distributor decline rate, set to zero for *AEO2008* [Appendix E, (fraction)]
YR_DECL	=	difference between the current year and the last historical year over which the decline rate is applied
$STAX_r$	=	State motor vehicle fuel tax for CNG [Appendix E, (current yr $/Mcf)]
FTAX	=	Federal motor vehicle fuel tax minus federal excise motor fuel credit for CNG [Appendix E, (current yr $/Mcf)]
MC_PCWGDP_t	=	GDP conversion from current year dollars to $87 [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

While the delivered price or cost for the CNG going into fleet vehicles is set in the model by adding the "distributor tariff" to the city gate price, the price for personal vehicles is only initially set this way. As described in Chapter 4, the model assumes that the retail sales price for CNG (i.e., for personal vehicles) will be set at a discount off of the competing motor gasoline price, as long as the costs are covered.

[72]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.

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 2000, 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 (1994-2003) of 28 major interstate natural gas pipelines developed by Foster Associates,[73] (2) "a competitive profile of natural gas services" database developed by Foster Associates,[74] and (3) a pipeline capacity database developed by the Office of Oil and Gas, EIA.[75] 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 for individual plants (production

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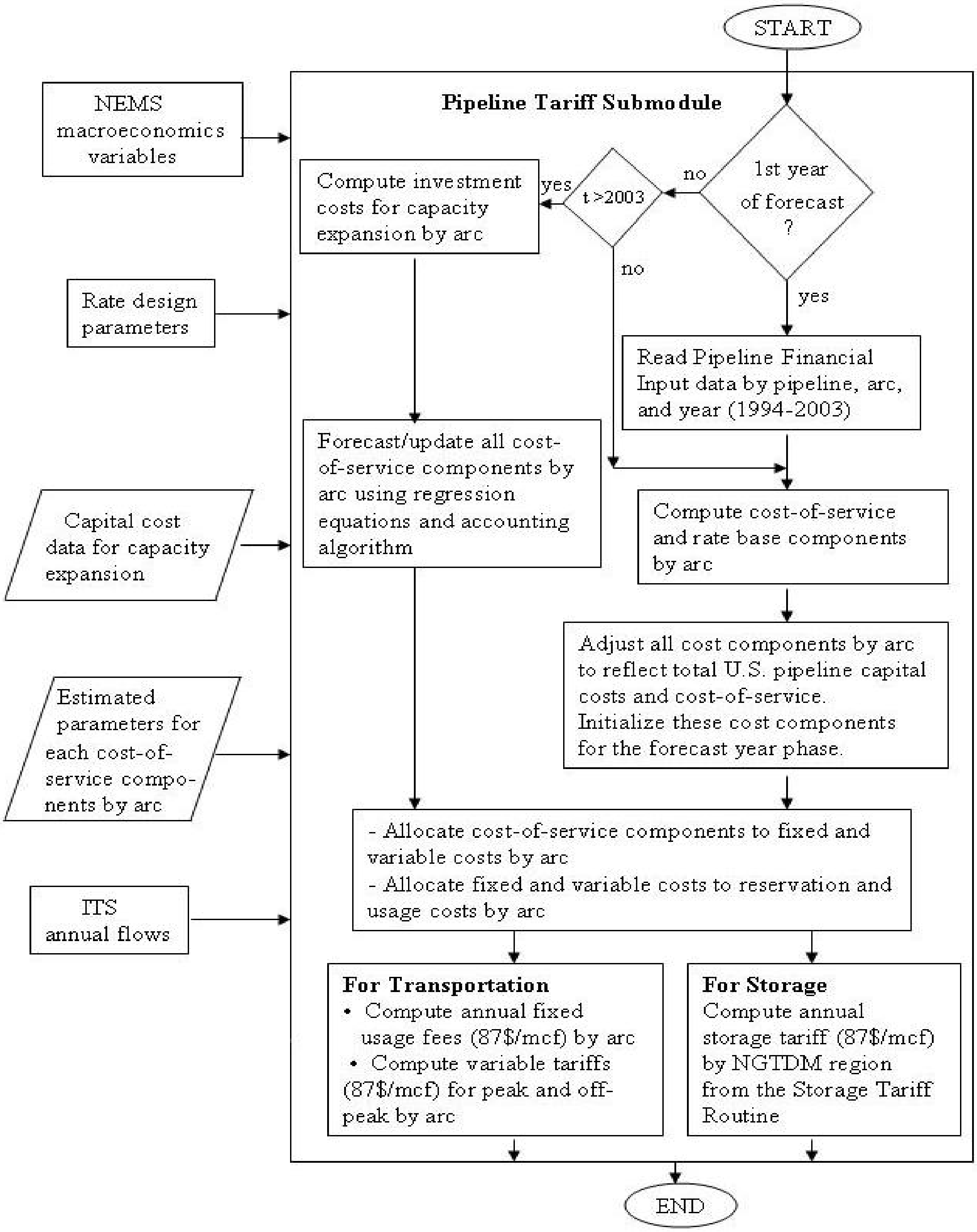
[73]Foster Financial Reports, 28 Major Interstate Natural Gas Pipelines, 2004 Edition, Foster Associates, Inc., Bethesda, Maryland. The primary sources of data for this report are FERC Form 2 and the monthly FERC Form 11 pipeline company filings. This report can be purchased from Foster Associates.

[74]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.

[75]A spreadsheet compiled by James Tobin of the Office of Oil and Gas (James.Tobin@eia.doe.gov) 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 August 16, 2007).

Figure 6-1. Pipeline Tariff Submodule System Diagram



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. The third database contains 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

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 (1994-2003).

- 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

databases are pre-processed offline to generate the pipeline transmission financial data by pipeline company, NGTDM interstate arc, and historical year (1994-2003) used as input into the PTS.

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 four-step 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:

$$TCOS_{a,t} = TRRB_{a,t} + TNOE_{a,t} \tag{94}$$

where,

TCOS	=	total cost-of-service (dollars)
TRRB	=	total return on rate base (dollars)
TNOE	=	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:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \tag{95}$$

where,

TRRB	=	total return on rate base after taxes (dollars)
WAROR	=	weighted-average after-tax return on capital (fraction)
APRB	=	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.

$$PFEN_{a,t} = \sum_{p} [(PFES_{a,p,t} / TOTCAP_{a,p,t}) * PFER_{a,p,t} * APRB_{a,p,t}] \tag{96}$$

$$CMEN_{a,t} = \sum_{p} [(CMES_{a,p,t} / TOTCAP_{a,p,t}) * CMER_{a,p,t} * APRB_{a,p,t}] \tag{97}$$

$$LTDN_{a,t} = \sum_{p} [(LTDS_{a,p,t} / TOTCAP_{a,p,t}) * LTDR_{a,p,t} * APRB_{a,p,t}] \tag{98}$$

such that,

$$TRRB_{a,t} = (PFEN_{a,t} + CMEN_{a,t} + LTDN_{a,t}) \tag{99}$$

where,

PFEN	=	total return on preferred stock (dollars)
PFES	=	value of preferred stock (dollars)
TOTCAP	=	total capitalization (dollars)
PFER	=	coupon rate for preferred stock (fraction) [read as D_PFER]
APRB	=	adjusted pipeline rate base (dollars) [read as D_APRB]
CMEN	=	total return on common stock equity (dollars)
CMES	=	value of common stock equity (dollars)
CMER	=	common equity rate of return (fraction) [read as D_CMER]
LTDN	=	total return on long-term debt (dollars)
LTDS	=	value of long-term debt (dollars)
LTDR	=	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 96 to 98 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:

$$GPFESTR_{a,p,t} = PFES_{a,p,t} / TOTCAP_{a,p,t} \tag{100}$$

$$GCMESTR_{a,p,t} = CMES_{a,p,t} / TOTCAP_{a,p,t} \tag{101}$$

$$GLTDSTR_{a,p,t} = LTDS_{a,p,t} / TOTCAP_{a,p,t} \tag{102}$$

where,

GPFESTR	=	capital structure ratio for preferred stock for existing pipeline (fraction) [read as D_GPFES]
GCMESTR	=	capital structure ratio for common equity for existing pipeline (fraction) [read as D_GCMES]
GLTDSTR	=	capital structure ratio for long-term debt for existing pipeline (fraction) [read as D_GLTDS]
PFES	=	value of preferred stock (dollars)
CMES	=	value of common stock (dollars)
LTDS	=	value of long-term debt (dollars)
TOTCAP	=	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 $APRB_{a,p,t}$..

$$TOTCAP_{a,p,t} = APRB_{a,p,t} \tag{103}$$

where,

TOTCAP	=	total capitalization (dollars)
APRB	=	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 100 to 102, 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:

$$\begin{aligned} PFES_{a,p,t} &= GPFESTR_{a,p,t} * APRB_{a,p,t} \\ CMES_{a,p,t} &= GCMESTR_{a,p,t} * APRB_{a,p,t} \\ LTDS_{a,p,t} &= GLTDSTR_{a,p,t} * APRB_{a,p,t} \\ GPFESTR_{a,p,t} &+ GCMESTR_{a,p,t} + GLTDSTR_{a,p,t} = 1.0 \end{aligned} \tag{104}$$

where,

PFES	=	value of preferred stock in nominal dollars
CMES	=	value of common equity in nominal dollars
LTDS	=	long-term debt in nominal dollars
GPFESTR	=	capital structure ratio for preferred stock for existing pipeline (fraction)
GCMESTR	=	capital structure ratio of common stock for existing pipeline (fraction)
GLTDSTR	=	capital structure ratio of long term debt for existing pipeline (fraction)
APRB	=	adjusted rate base (dollars)
p	=	pipeline
a	=	arc
t	=	forecast year

The cost of capital at the arc level ($WAROR_{a,t}$) 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:

$$\begin{aligned} WAROR_{a,t} = \sum_p [(&PFES_{a,p,t} * PFER_{a,p,t} + CMES_{a,p,t} * CMER_{a,p,t} + \\ &LTDS_{a,p,t} * LTDR_{a,p,t})] / APRB_{a,t} \end{aligned} \tag{105}$$

$$APRB_{a,t} = PFES_{a,t} + CMES_{a,t} + LTDS_{a,t} \tag{106}$$

where,

WAROR	=	weighted-average after-tax return on capital (fraction)
PFES	=	value of preferred stock (dollars)

PFER = preferred stock rate (fraction)
CMES = value of common stock equity (dollars)
CMER = common equity rate of return (fraction)
LTDS = value of long-term debt (dollars)
LTDR = long-term debt rate (fraction)
APRB = 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:

$$APRB_{a,p,t} = NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t} \tag{107}$$

where,

APRB = adjusted rate base (dollars)
NPIS = net capital cost of plant in service (dollars) [read as D_NPIS]
CWC = total cash working capital (dollars) [read as D_CWC]
ADIT = 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:

$$NPIS_{a,p,t} = GPIS_{a,p,t} - ADDA_{a,p,t} \tag{108}$$

where,

NPIS = net capital cost of plant in service (dollars)
GPIS = original capital cost of plant in service (dollars) [read as D_GPIS]
ADDA = accumulated depreciation, depletion, and amortization (dollars) [read as D_ADDA]

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

$$\begin{aligned} APRB_{a,,t} &= \sum_{p} APRB_{a,p,t} = \sum_{p} (NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t}) \\ &= (NPIS_{a,t} + CWC_{a,t} - ADIT_{a,t}) \end{aligned} \tag{109}$$

with,

$$NPIS_{a,,t} = \sum_{p} (GPIS_{a,p,t} - ADDA_{a,p,t}) \qquad (110)$$
$$= (GPIS_{a,t} - ADDA_{a,t})$$

where,

$APRB_{a,t}$	=	adjusted rate base (dollars) at the arc level
$NPIS_{a,t}$	=	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
$GPIS_{a,t}$	=	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:

$$TNOE_{a,t} = \sum_{p} (DDA_{a,p,t} + TOTAX_{a,p,t} + TOM_{a,p,t}) \qquad (111)$$

where,

TNOE	=	total normal operating expenses (dollars)
DDA	=	depreciation, depletion, and amortization costs (dollars) [read as D_DDA]
TOTAX	=	total Federal and State income tax liability (dollars)
TOM	=	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:

$$DDA_{a,t} = \sum_{p} DDA_{a,p,t} \qquad (112)$$

$$TOM_{a,t} = \sum_{p} TOM_{a,p,t} \qquad (113)$$

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:

$$TOTAX_{a,t} = \sum_{p} (FSIT_{a,p,t} + OTTAX_{a,p,t} + DIT_{a,p,t}) \tag{114}$$

$$FSIT_{a,t} = \sum_{p} FSIT_{a,p,t} = \sum_{p} (FIT_{a,p,t} + SIT_{a,p,t}) \tag{115}$$

where,

TOTAX	=	total Federal and State income tax liability (dollars)
FSIT	=	Federal and State income tax (dollars)
OTTAX	=	all other taxes assessed by Federal, State, or local governments except income taxes and deferred income tax (dollars) [read as D_OTTAX]
DIT	=	deferred income taxes (dollars) [read as D_DIT]
FIT	=	Federal income tax (dollars)
SIT	=	State income tax (dollars)

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:

$$ATP_{a,t} = \sum_{p} (PFER_{a,p,t} * PFES_{a,p,t} + CMER_{a,p,t} * CMES_{a,p,t}) \tag{116}$$

where,

ATP	=	after-tax profit (dollars) at the arc level
PFER	=	preferred stock rate (fraction)
PFES	=	value of preferred stock (dollars)
CMER	=	common equity rate of return (fraction)
CMES	=	value of common stock equity (dollars)
a	=	arc
t	=	historical year

and the Federal income taxes at the arc level are

$$FIT_{a,t} = \frac{FRATE * ATP_{a,t}}{(1. - FRATE)} \tag{117}$$

where,

FIT	=	Federal income tax (dollars) at the arc level
FRATE	=	Federal income tax rate (fraction) (Appendix E)
ATP	=	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:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{118}$$

where,

SIT	=	State income tax (dollars) at the arc level
SRATE	=	average State income tax rate (fraction) (Appendix E)
FIT	=	Federal income tax (dollars) at the arc level
ATP	=	after-tax profits (dollars) at the arc level

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

$$TOTAX_{a,t} = (FSIT_{a,t} + OTTAX_{a,t} + DIT_{a,t}) \tag{119}$$

where,

TOTAX	=	total Federal and State income tax liability (dollars) at the arc level
FSIT	=	Federal and State income tax (dollars) at the arc level
OTTAX	=	all other taxes assessed by Federal, State, or local governments except income taxes and deferred income taxes (dollars), at the arc level
DIT	=	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:

$$OTTAX_{a,t} = \sum_{p} OTTAX_{a,p,t} \tag{120}$$

$$DIT_{a,t} = \sum_{p} DIT_{a,p,t} \tag{121}$$

Adjustment from 28 major pipelines to total U.S. 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 the FERC and published in the Oil and Gas Journal,[76] there were more than 120 interstate natural gas pipelines operating in the United States in 2000. The total annual capitalization and operating revenues for all these pipelines are much higher than those for the 28 major interstate pipelines in the financial database. The total annual gross plant in service for all interstate natural gas pipelines in the U.S. increases from 117 percent of total annual gross plant in service for the 28 major interstate pipelines in 1994 to about 127 percent in 2003, while the total annual operating revenues for all the interstate natural gas pipelines in the United States fall from 167 percent of total annual operating revenues for the 28 major natural gas pipelines in 1994 to 146 percent in 2003. All the cost-of-service and rate base components at the arc level computed in the above sections are scaled up as follows:

[76] *Pipeline Economics*, Oil and Gas Journal, 1994, 1995, 1997, 1999, 2001, 2002, 2003.

For the capital costs and adjusted rate base components,

$$
\begin{aligned}
&GPIS_{a,t} = GPIS_{a,t} * HFAC\_GPIS_t * (1.0 + PCNT\_R) \\
&ADDA_{a,t} = ADDA_{a,t} * HFAC\_GPIS_t \\
&NPIS_{a,t} = NPIS_{a,t} * HFAC\_GPIS_t \\
&CWC_{a,t} = CWC_{a,t} * HFAC\_GPIS_t \\
&ADIT_{a,t} = ADIT_{a,t} * HFAC\_GPIS_t \\
&APRB_{a,t} = APRB_{a,t} * HFAC\_GPIS_t
\end{aligned}
\tag{122}
$$

For the cost-of-service components,

$$
\begin{aligned}
&PFEN_{a,t} = PFEN_{a,t} * HFAC\_REV_t \\
&CMEN_{a,t} = CMEN_{a,t} * HFAC\_REV_t \\
&LTDN_{a,t} = LTDN_{a,t} * HFAC\_REV_t \\
&DDA_{a,t} = DDA_{a,t} * HFAC\_REV_t \\
&FSIT_{a,t} = FSIT_{a,t} * HFAC\_REV_t \\
&OTTAX_{a,t} = OTTAX_{a,t} * HFAC\_REV_t \\
&DIT_{a,t} = DIT_{a,t} * HFAC\_REV_t \\
&TOM_{a,t} = TOM_{a,t} * HFAC\_REV_t
\end{aligned}
\tag{123}
$$

where,

GPIS	=	original capital cost of plant in service (dollars)
HFAC_GPIS	=	adjustment factor for capital costs to total U.S. (Appendix E)
PCNT_R	=	assumed average percentage (fraction) for pipeline replacement costs (Appendix E)
ADDA	=	accumulated depreciation, depletion, and amortization (dollars)
NPIS	=	net capital cost of plant in service (dollars)
CWC	=	total cash working capital (dollars)
ADIT	=	accumulated deferred income taxes (dollars)
APRB	=	adjusted pipeline rate base (dollars)
PFEN	=	total return on preferred stock (dollars)
HFAC_REV	=	adjustment factor for operation revenues to total U.S. (Appendix E)
CMEN	=	total return on common stock equity (dollars)
LTDN	=	total return on long-term debt (dollars)
DDA	=	depreciation, depletion, and amortization costs (dollars)
FSIT	=	Federal and State income tax (dollars)
OTTAX	=	all other taxes assessed by Federal, State, or local governments except income taxes and deferred income taxes (dollars)
DIT	=	deferred income taxes (dollars)
TOM	=	total operations and maintenance expense (dollars)
a	=	arc
t	=	historical year

To account for additional costs on pipeline replacements, the PTS increases the capital costs of existing gross plants in service, after adjusting for all interstate natural gas pipelines in the U.S., by a small percentage (PCNT_R).

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 2004.

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 R_i to fixed and variable cost is determined as follows:

$$R_{i,f} = ALL_f * R_i / 100 \tag{124}$$

$$R_{i,v} = ALL_v * R_i / 100 \tag{125}$$

where,

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

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

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:

$$FC_a = \sum_i R_{i,f} \tag{126}$$

$$VC_a = \sum_i R_{i,v} \tag{127}$$

where,

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

Table 6-1. Illustration of Fixed and Variable Cost Classification

Cost of Service Line Item	Total (dollars)	Cost Allocation Factors (percent) Fixed	Variable	Cost Component (dollars) 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 Operations & Maintenance	105,000	60	40	63,000	42,000
Total Cost-of-Service	227,000			185,000	42,000

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 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

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 percent are recovered from a peak day reservation fee and 50 percent 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.

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:

$$R_{i,f,r} = ALL_{f,r} * R_{i,f} / 100 \tag{128}$$

$$R_{i,f,u} = ALL_{f,u} * R_{i,f} / 100 \tag{129}$$

$$R_{i,v,r} = ALL_{v,r} * R_{i,v} / 100 \tag{130}$$

$$R_{i,v,u} = ALL_{v,u} * R_{i,v} / 100 \tag{131}$$

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, AVU)
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

Table 6-3a. Illustration of Allocation of Fixed Costs to Rate Components

Cost of Service Line Item	Total (dollars)	Allocation Factors (percent)		Cost Assigned to Rate Component (dollars)	
		Reservation	Usage	Reservation	Usage
Total Return					
Preferred Stock	1,000	0	100	0	1,000
Common Stock	30,000	0	100	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)		Cost Assigned to Rate Component (dollars)	
		Reservation	Usage	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 Operations & Maintenance	42,000	0	100	0	42,000
Total Cost-of-Service	42,000			0	42,000

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.

$$RCOST_a = \sum_i (R_{i,f,r} + R_{i,v,r}) \tag{132}$$

$$UCOST_a = \sum_i (R_{i,f,u} + R_{i,v,u}) \quad (133)$$

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*.

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:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA\_PIPE} \quad (134)$$

such that,

For peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR\_YR}{(QNOD_{a,t} * MC\_PCWGDP_t)} \quad (135)$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \quad (136)$$

For off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_t)} \quad (137)$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \quad (138)$$

where,

NGPIPE_VARTAR	=	function to define pipeline tariffs (87$/Mcf)
PNOD	=	base point, price (87$/Mcf)
QNOD	=	base point, quantity (Bcf)
Q	=	flow along pipeline arc (Bcf), dependent variable for the function
ALPHA_PIPE	=	price elasticity for pipeline tariff curve for current capacity
RCOST	=	reservation cost-of-service (dollars)
PTNETFLOW	=	natural gas network flow (throughput, Bcf)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
MC_PCWGDP	=	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) are derived directly from the usage costs, utilization rates for peak and off-peak time periods, and annual arc capacity. These fees are computed as the average fees over each historical year, as follows:

$$\begin{aligned}FIXTAR_{a,t} = UCOST_{a,t} / [(PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} +\\ (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_{t}]\end{aligned} \quad (139)$$

where,

FIXTAR	=	annual fixed usage fees for existing and new capacity (87$/Mcf)
UCOST	=	annual usage cost of service for existing and new capacity (dollars)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
PTPKUTZ	=	peak pipeline utilization (fraction)
PTCURPCAP	=	current pipeline capacity (Bcf)
PTOPUTZ	=	off-peak pipeline utilization (fraction)
MC_PCWGDP	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	historical year

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:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA\_STR} \quad (140)$$

such that,

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC\_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP\_ADJ_{r,t} * ADJ\_STR \quad (141)$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \quad (142)$$

where,

X1NGSTR_VARTAR	=	function to define storage tariffs (87$/Mcf)
Q	=	peak period net storage withdrawals (Bcf)
PNOD	=	base point, price (87$/Mcf)
QNOD	=	base point, quantity (Bcf)
ALPHA_STR	=	price elasticity for storage tariff curve (ratio, Appendix E)
STCOS	=	existing storage capacity cost of service, computed from historical cost-of-service components
MC_PCWGDP	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
STRATIO	=	portion of revenue requirement obtained by moving gas from the off-peak to the peak period (fraction, Appendix E)
STCAP_ADJ	=	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	=	storage utilization (fraction)
PTCURPSTR	=	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)

(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 (2000 dollars per Mcf) were computed based on a pipeline construction project cost database[78] compiled by the Office of Oil and Gas. These costs are adjusted for inflation from 2004 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:

$$CCOST_{a,t} = AVG\_CAPCOST_a * MC\_PCWGDP_t / MC\_PCWGDP_{2000} \qquad (143)$$

where,

CCOST	=	average pipeline capital cost per unit of expanded capacity (nominal dollars per Mcf)
AVG_CAPCOST	=	average pipeline capital cost per unit of expanded capacity in 2000 dollars per Mcf (Appendix E)
MC_PCWGDP	=	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:

$$NCAE_{a,t} = CCOST_{a,t} * CAPADD_{a,t} * 1{,}000{,}000 \qquad (144)$$

where,

[78] A spreadsheet compiled by James Tobin of EIA's Office of Oil and Gas (James.Tobin@eia.doe.gov) 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	=	capital cost to expand capacity on a network arc (dollars)
CCOST	=	average capital cost per unit of expansion (dollars per Mcf)
CAPADD	=	capacity additions for an arc as determined in the ITS (Bcf/yr)
a	=	arc
t	=	forecast year

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 [79]

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 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.

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

- 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.

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.

$$APRB_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} + CWC_{a,t} - ADIT_{a,t} \qquad (145)$$

where,

APRB	=	adjusted rate base in dollars
GPIS	=	total capital cost of plant in service (gross plant in service) in dollars
ADDA	=	accumulated depreciation, depletion, and amortization in dollars
CWC	=	total cash working capital including other cash working capital in dollars
ADIT	=	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:

$$GPIS_{a,t} = GPIS\_E_{a,t} + GPIS\_N_{a,t} \qquad (146)$$

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 (2003)
II. Capacity expansion costs for new capacity	Accounting algorithm [equation 147]
b. Accumulated Depreciation, Depletion & Amortization	Accounting algorithm [equations 153, 154, 156] and empirically estimated for existing capacity [equation 155]
c. Cash and other working capital	User defined option for the combined existing and new capacity [equation 157]
d. Accumulated deferred income taxes	Empirically estimated for the combined existing and new capacity [equation 158]
f. Depreciation, depletion, and amortization	Existing Capacity: empirically estimated [equation 155] New Capacity: accounting algorithm [equation 156]
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

where,

GPIS = total capital cost of plant in service (gross plant in service) in dollars
GPIS_E = gross plant in service in the last historical year (2003)
GPIS_N = 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 ($GPIS\_E_{a,t}$) reflects the amount of gross plant in service in the last historical year (2003). The capital cost of new plant in service ($GPIS\_N_{a,t}$) in year t is computed as the accumulated new capacity expansion expenditures from 2004 to year t and is determined by the following equation:

$$GPIS\_N_{a,t} = \sum_{s=2004}^{t} NCAE_{a,s} \tag{147}$$

where,

GPIS_N = gross plant in service for new capacity expansion in dollars
NCAE = new capacity expansion expenditures occurring in year s after 2003 (in dollars) [equation 144]
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.

$$NPIS_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} \tag{148}$$

where,

NPIS = total net plant in service in dollars
GPIS = total capital cost of plant in service (gross plant in service) in dollars
ADDA = 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:

$$ADDA_{a,t} = ADDA\_E_{a,t} + ADDA\_N_{a,t} \tag{149}$$

where,

ADDA = accumulated depreciation, depletion, and amortization in dollars
ADDA_E = accumulated depreciation, depletion, and amortization for existing capacity in dollars
ADDA_N = accumulated depreciation, depletion, and amortization for new capacity in dollars
a = arc
t = forecast year

With this equation and the relationship between the capital costs of existing and new plants in service from equation 146, total net plant in service ($NPIS_{a,t}$) is set equal to the sum of net plant in service for existing pipelines and new capacity expansions, as follows:

$$NPIS_{a,t} = NPIS\_E_{a,t} + NPIS\_N_{a,t} \tag{150}$$

$$NPIS\_E_{a,t} = GPIS\_E_{a,t} - ADDA\_E_{a,t-1} \tag{151}$$

$$NPIS\_N_{a,t} = GPIS\_N_{a,t} - ADDA\_N_{a,t-1} \tag{152}$$

where,

NPIS = total net plant in service in dollars
NPIS_E = net plant in service for existing capacity in dollars
NPIS_N = net plant in service for new capacity in dollars
GPIS_E = gross plant in service in the last historical year (2003)
ADDA_E = accumulated depreciation, depletion, and amortization for existing capacity in dollars
ADDA_N = 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.

$$ADDA_{a,t} = ADDA_{a,t-1} + DDA_{a,t} \tag{153}$$

where,

ADDA = accumulated depreciation, depletion, and amortization in dollars
DDA = 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 is the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with the arc.

$$DDA_{a,t} = DDA\_E_{a,t} + DDA\_N_{a,t} \tag{154}$$

where,

DDA = annual depreciation, depletion, and amortization in dollars
DDA_E = depreciation, depletion, and amortization costs for existing capacity in dollars
DDA_N = 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:

$$\begin{aligned} DDA\_E_{a,t} = {} & \beta_{0,a} * (1-\rho) + \beta_1 * NPIS\_E_{a,t-1} + \\ & \beta_2 * NEWCAP\_E_{a,t} + \rho * DDA\_E_{a,t-1} - \\ & \rho * (\beta_1 * NPIS\_E_{a,t-2} + \beta_2 * NEWCAP\_E_{a,t-1}) \end{aligned} \tag{155}$$

where,

DDA_E = annual depreciation, depletion, and amortization costs for existing capacity in nominal dollars
$\beta_{0,a}$ = DDA_C_a, constant term estimated by arc (Appendix F, Table F3.2, $\beta_{0,a}$ = $B\_ARC_{xx\_yy}$)
β_1 = DDA_NPIS, estimated coefficient for net plant in service for existing capacity (Appendix F, Table F3.2)
β_2 = DDA_NEWCAP, estimated coefficient for the change in gross plant in service for existing capacity (Appendix F, Table F3.2)

ρ	=	autocorrelation coefficient from estimation (Appendix F, Table F3.2 , DDA_RHO)
NPIS_E	=	net plant in service for existing capacity (dollars)
NEWCAP_E	=	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:

$$DDA\_N_{a,t} = GPIS\_N_{a,t} / 30 \tag{156}$$

where,

DDA_N	=	annual depreciation, depletion, and amortization for new capacity in dollars
GPIS_N	=	gross plant in service for new capacity in dollars [equation 147]
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 2000 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 gross plant in service, as defined below:

$$R\_CWC_{a,t} = CWC\_K * e^{(CWC\_C*(1-\rho)+CWC\_GPIS*\log(GPIS_{a,t})+\rho*\log(R\_CWC_{a,t-1})-\rho*CWC\_GPIS*\log(GPIS_{a,t-1}))} \tag{157}$$

where,

R_CWC	=	total pipeline transmission cash working capital for existing and new capacity (2000 real dollars)
CWC_K	=	correction factor estimated in stage 2 of the regression equation estimation process (Appendix F, Table F3)
CWC_C	=	estimated arc specific constant for gas transported from node to node (Appendix F, Table F3)
CWC_GPIS	=	estimated GPIS coefficient (Appendix F, Table F3)
ρ	=	autocorrelation coefficient from estimation (Appendix F, Table F3 -- CWC_RHO)
GPIS	=	capital cost of plant in service for existing and new capacity in dollars (not deflated)
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:

$$ADIT_{a,t} = \beta_{0,a} + \beta_1 * NEWCAP_{a,t} + \beta_2 * POLICY\_CHG + ADIT_{a,t-1} \qquad (158)$$

where,

ADIT	=	accumulated deferred income taxes in dollars
$\beta_{0,a}$	=	$ADIT\_C_a$, constant term estimated by arc (Appendix F, Table F3.4, $\beta_{0,a} = B\_ARC_{xx\_yy}$)
β_1	=	ADIT_NEWCAP, estimated coefficient on the change in gross plant in service (Appendix F, Table F3.4)
β_2	=	BPOLICY_CHG, estimated coefficient for the binary variable POLICY_CHG (Appendix F, Table F3.4)
POLICY_CHG	=	binary variable representing a change in tax policy in 2004 known as the Jobs and Growth Tax Relief and Reconciliation Act of 2003 (POLICY_CHG = 1 if MODYEAR is equal to 2004 and POLICY_CHG = 0 if MODYEAR is not equal to 2004)
NEWCAP	=	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:

$$PFER_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_PFER_a \qquad (159)$$

$$CMER_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_CMER_a \qquad (160)$$

$$LTDR_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_LTDR_a \qquad (161)$$

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 (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:

$$WAROR_{a,t} = \frac{(PFER_{a,t} * PFES_{a,t}) + (CMER_{a,t} * CMES_{a,t}) + (LTDR_{a,t} * LTDS_{a,t})}{TOTCAP_{a,t}} \quad (162)$$

$$TOTCAP_{a,t} = (PFES_{a,t} + CMES_{a,t} + LTDS_{a,t}) \quad (163)$$

where,

WAROR	=	weighted-average after-tax rate of return on capital (fraction)
PFER	=	rate or return for preferred stock (fraction)
PFES	=	value of preferred stock (dollars)
CMER	=	common equity rate of return (fraction)
CMES	=	value of common stock (dollars)
LTDR	=	long-term debt rate (fraction)
LTDS	=	value of long-term debt (dollars)
TOTCAP	=	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 as follows:

$$WAROR_{a,t} = (PFER_{a,t} * GPFESTR_{a,t}) + (CMER_{a,t} * GCMESTR_{a,t}) + (LTDR_{a,t} * GLTDSTR_{a,t}) \quad (164)$$

where,

$$GPFESTR_{a,t} = PFES_{a,t} / TOTCAP_{a,t} \quad (165)$$

$$GCMESTR_{a,t} = CMES_{a,t} / TOTCAP_{a,t} \quad (166)$$

$$GLTDSTR_{a,t} = LTDS_{a,t} / TOTCAP_{a,t} \quad (167)$$

and,

WAROR	=	weighted-average after-tax rate of return on capital (fraction)
PFER	=	coupon rate for preferred stock (fraction)
CMER	=	common equity rate of return (fraction)
LTDR	=	long-term debt rate (fraction)

GPFESTR = ratio of preferred stock to estimated capital for existing and new capacity (fraction) [referred to as capital structure for preferred stock]
GCMESTR = ratio of common stock to estimated capital for existing and new capacity (fraction)[referred to as capital structure for common stock]
GLTDSTR = ratio of long term debt to estimated capital for existing and new capacity (fraction)[referred to as capital structure for long term debt]
PFES = value of preferred stock (dollars)
CMES = value of common stock (dollars)
LTDS = value of long-term debt (dollars)
TOTCAP = 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 163 is equal to the adjusted rate base ($APRB_{a,t}$) defined in equation 145:

$$TOTCAP_{a,t} = APRB_{a,t} \tag{168}$$

where,

TOTCAP = estimated capital in dollars
APRB = 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 165 to 167, 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:

$$\begin{aligned} PFES_{a,t} &= GPFESTR_a * APRB_{a,t} \\ CMES_{a,t} &= GCMESTR_a * APRB_{a,t} \\ LTDS_{a,t} &= GLTDSTR_a * APRB_{a,t} \end{aligned} \tag{169}$$

where,

PFES = value of preferred stock in nominal dollars
CMES = value of common equity in nominal dollars
LTDS = long-term debt in nominal dollars
GPFESTR = ratio of preferred stock to adjusted rate base for existing and new capacity (fraction) [referred to as capital structure for preferred stock]

GCMESTR = ratio of common stock to adjusted rate base for existing and new capacity (fraction)[referred to as capital structure for common stock]

GLTDSTR = 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 = 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 (1994-2003).

$$GPFESTR_a = \frac{\sum_{t=1994}^{2003} \sum_{p} (GPFESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1994}^{2003} \sum_{p} APRB_{a,p,t}} \tag{170}$$

$$GCMESTR_a = \frac{\sum_{t=1994}^{2003} \sum_{p} (GCMESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1994}^{2003} \sum_{p} APRB_{a,p,t}} \tag{171}$$

$$GLTDSTR_a = \frac{\sum_{t=1994}^{2003} \sum_{p} (GLTDSTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1994}^{2003} \sum_{p} APRB_{a,p,t}} \tag{172}$$

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 (1994-2003) (Appendix E)

$GCMESTR_{a,p,t}$ = capital structure for common stock (fraction) by pipeline company in the historical years (1994-2003)(Appendix E)

$GLTDSTR_{a,p,t}$ = capital structure for long term debt (fraction) by pipeline company in the historical years (1994-2003) (Appendix E)

$APRB_{a,p,t}$ = adjusted rate base (capitalization) by pipeline company in the historical years (1994-2003) (Appendix E)

p = pipeline company

a = arc
t = historical year (1994-2003)

The weighted average cost of capital in the forecast year in equation 164 is forecast as follows:

$$WAROR_{a,t} = (PFER_{a,t} * GPFESTR_{a}) + (CMER_{a,t} * GCMESTR_{a}) + (LTDR_{a,t} * GLTDSTR_{a}) \quad (173)$$

where,

WAROR = weighted-average after-tax rate of return on capital (fraction)
PFER = coupon rate for preferred stock (fraction), function of AA utility bond rate [equation 159]
CMER = common equity rate of return (fraction), function of AA utility bond rate [equation 160]
LTDR = long-term debt rate (fraction), function of AA utility bond rate [equation 161]
$GPFESTR_a$ = 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 ($WAROR_{a,t}$) is applied to the adjusted rate base ($APRB_{a,t}$) 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:

$$TCOS_{a,t} = TRRB_{a,t} + DDA_{a,t} + TOTAX_{a,t} + TOM_{a,t} \quad (174)$$

where,

TCOS = total cost-of-service or revenue requirement for existing and new capacity (dollars)
TRRB = total return on rate base for existing and new capacity after taxes (dollars)

DDA	=	depreciation, depletion, and amortization for existing and new capacity (dollars)
TOTAX	=	total Federal and State income tax liability for existing and new capacity (dollars)
TOM	=	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:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \tag{175}$$

where,

TRRB	=	total return on rate base (after taxes) for existing and new capacity in dollars
WAROR	=	weighted-average after-tax rate of return on capital for existing and new capacity (fraction)
APRB	=	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:

$$PFEN_{a,t} = GPFESTR_{a} * PFER_{a,t} * APRB_{a,t} \tag{176}$$

$$CMEN_{a,t} = GCMESTR_{a} * CMER_{a,t} * APRB_{a,t} \tag{177}$$

$$LTDN_{a,t} = GLTDSTR_{a} * LTDR_{a,t} * APRB_{a,t} \tag{178}$$

where,

PFEN = total return on preferred stock for existing and new capacity (dollars)

GPFESTR = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
PFER = coupon rate for preferred stock for existing and new capacity (fraction)
APRB = adjusted rate base for existing and new capacity (dollars)
CMEN = total return on common stock equity for existing and new capacity (dollars)
GCMESTR = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
CMER = common equity rate of return for existing and new capacity (fraction)
LTDN = total return on long-term debt for existing and new capacity (dollars)
GLTDSTR = historical average capital structure ratio for long term debt for existing and new capacity (fraction), held constant over the forecast period
LTDR = 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 154.

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:

$$TOTAX_{a,t} = FSIT_{a,t} + DIT_{a,t} + OTTAX_{a,t} \tag{179}$$

$$FSIT_{a,t} = FIT_{a,t} + SIT_{a,t} \tag{180}$$

where,

TOTAX = total Federal and State income tax liability for existing and new capacity (dollars)
FSIT = Federal and State income tax for existing and new capacity (dollars)
FIT = Federal income tax for existing and new capacity (dollars)
SIT = State income tax for existing and new capacity (dollars)
DIT = deferred income taxes for existing and new capacity (dollars)
OTTAX = 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:

$$ATP_{a,t} = APRB_{a,t} * (PFER_{a,t} * GPFESTR_{a} + CMER_{a,t} * GCMESTR_{a}) \tag{181}$$

where,

ATP = after-tax profit for existing and new capacity (dollars)
APRB = adjusted pipeline rate base for existing and new capacity (dollars)

PFER = coupon rate for preferred stock for existing and new capacity (fraction)

GPFESTR = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
CMER = common equity rate of return for existing and new capacity (fraction)
GCMESTR = 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:

$$FIT_{a,t} = (FRATE * ATP_{a,t} / 1. - FRATE) \tag{182}$$

where,

FIT = Federal income tax for existing and new capacity (dollars)
FRATE = Federal income tax rate (fraction, Appendix E)
ATP = 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:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{183}$$

where,

SIT = State income tax for existing and new capacity (dollars)
SRATE = average State income tax rate (fraction, Appendix E)
FIT = Federal income tax for existing and new capacity (dollars)
ATP = 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.

$$DIT_{a,t} = ADIT_{a,t} - ADIT_{a,t-1} \tag{184}$$

where,

DIT = deferred income taxes for existing and new capacity (dollars)
ADIT = 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.

$$OTTAX_{a,t} = OTTAX_{a,t-1} * EXPFAC_{a,t} * (MC\_PCWGDP_{t} / MC\_PCWGDP_{t-1}) \tag{185}$$

where,

OTTAX = all other taxes assessed by Federal, State, or local governments except income taxes for existing and new capacity (dollars)
EXPFAC = capacity expansion factor (growth in capacity) from previous year's capacity

MC_PCWGDP = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

The capacity expansion factor is expressed as follows:

$$EXPFAC_{a,t} = PTCURPCAP_{a,t} / PTCURPCAP_{a,t-1} \tag{186}$$

where,

EXPFAC = capacity expansion factor (growth in capacity)
PTCURPCAP = 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, $GPIS_a$, and a time trend, TECHYEAR, that proxies the state of technology, as defined below:

$$R\_TOM_{a,t} = TOM\_K * e^{(\beta_{0,a} * (1-\rho) + G2 + G3 + G4 - \rho * (G5 + G6))} \tag{187}$$

where,

R_TOM = total operating and maintenance cost for existing and new capacity (1996 real 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 F3.5, $\beta_{0,a} = B\_ARC_{xx\_yy}$)
G2 = $\beta_1 * \log(GPIS_{a,t-1})$
G3 = $\beta_2 * TECHYEAR$
G4 = $\rho * \log(R\_TOM_{a,t-1})$
G5 = $\beta_1 * \log(GPIS_{a,t-2})$
G6 = $\beta_2 * (TECHYEAR - 1.0)$
log = natural logarithm operator

ρ = estimated autocorrelation coefficient (Appendix F, Table F3.5 -- TOM_RHO)
β_1 = TOM_GPIS1, estimated coefficient on the change in gross plant in service (Appendix F, Table F3.5)
β_2 = TOM_BYEAR, estimated coefficient for the time trend variable TECHYEAR (Appendix F, Table F3.5)
GPIS = capital cost of plant in service for existing and new capacity in dollars (not deflated)
TECHYEAR = MODYEAR (time trend in Julian units, the minimum value of this variable in the sample being 1994, otherwise TECHYEAR=0 if less than 1994)
a = arc
t = forecast year

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

$$TOM_{a,t} = R\_TOM_{a,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{2000}} \tag{188}$$

where,
TOM = total operating and maintenance costs for existing and new capacity (nominal dollars)
R_TOM = total operating and maintenance costs for existing and new capacity (2000 real dollars)
MC_PCWGDP = 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 174 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**.[80] Note that the return on rate base ($TRRB_{a,t}$) has three components ($PFEN_{a,t}$, $CMEN_{a,t}$, and $LTDN_{a,t}$ [equations 176, 177, and 178]).

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:

$$FC_{a,t} = \sum_i (\xi_i * Item_{i,a,t}) \tag{189}$$

[80] 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.

$$VC_{a,t} = \sum_{i}[(1.0 - \xi_i) * Item_{i,a,t}] \quad (190)$$

$$TCOS_{a,t} = FC_{a,t} + VC_{a,t} \quad (191)$$

where,

TCOS	=	total cost-of-service for existing and new capacity (dollars)
FC	=	fixed cost for existing and new capacity (dollars)
VC	=	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 - ξ_i**	**λ_i**	**100 - λ_i**	**μ_i**	**100-μ_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 λ_i and μ_i (**Table 6-6**), as follows:

$$RFC_{a,t} = \sum_{i}(\lambda_i * \xi_i * Item_{i,a,t}) \quad (192)$$

$$UFC_{a,t} = \sum_{i}[(1.0 - \lambda_i) * \xi_i * Item_{i,a,t}] \quad (193)$$

$$RVC_{a,t} = \sum_{i} [\mu_i * (1.0 - \xi_i) * Item_{i,a,t}] \qquad (194)$$

$$UVC_{a,t} = \sum_{i} [(1.0 - \mu_i) * (1.0 - \xi_i) * Item_{i,a,t}] \qquad (195)$$

$$TCOS_{a,t} = RFC_{a,t} + UFC_{a,t} + RVC_{a,t} + UVC_{a,t} \qquad (196)$$

where,

TCOS = total cost-of-service for existing and new capacity (dollars)
RFC = fixed reservation cost for existing and new capacity (dollars)
UFC = fixed usage cost for existing and new capacity (dollars)
RVC = variable reservation cost for existing and new capacity (dollars)
UVC = 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 costs into 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:

$$RCOST_{a,t} = (RFC_{a,t} + RVC_{a,t}) \qquad (197)$$

$$UCOST_{a,t} = (UFC_{a,t} + UVC_{a,t}) \qquad (198)$$

where,

RCOST = reservation cost for existing and new capacity (dollars)
UCOST = annual usage cost for existing and new capacity (dollars)
RFC = fixed reservation cost for existing and new capacity (dollars)
UFC = fixed usage cost for existing and new capacity (dollars)
RVC = variable reservation cost for existing and new capacity (dollars)
UVC = 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:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA\_PIPE} \tag{199}$$

capacity expansion segment:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA2\_PIPE} \tag{200}$$

such that,

for peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR\_YR}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{201}$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \tag{202}$$

for off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_t)} \quad (203)$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \quad (204)$$

where,

NGPIPE_VARTAR	=	function to define pipeline tariffs (87$/Mcf)
PNOD	=	base point, price (87$/Mcf)
QNOD	=	base point, quantity (Bcf)
Q	=	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	=	reservation cost-of-service (million dollars)
PTNETFLOW	=	natural gas network flow (throughput, Bcf)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
MC_PCWGDP	=	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:

$$FIXTAR_{a,t} = UCOST_{a,t} / [(PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_t] \quad (205)$$

where,

FIXTAR	=	annual fixed usage fees for existing and new capacity (87$/Mcf)
UCOST	=	annual usage cost for existing and new capacity (million dollars)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
PTPKUTZ	=	peak pipeline utilization (fraction)
PTCURPCAP	=	current pipeline capacity (Bcf)
PTOPUTZ	=	off-peak pipeline utilization (fraction)
MC_PCWGDP	=	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 percent of reservation costs (RCOST). Therefore, annual fixed usage fees which are proportional to usage costs are expected to be less than 10 percent of the variable tariffs. In general, these fixed fees are

are within the range of 5 percent of the variable tariffs which are charged to firm customers.

Canadian Fixed and Variable Tariffs

Fixed and variables 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 variables 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 percent, then the pipeline tariff is set to a low level (70 percent of CNMAXTAR). If the Canadian pipeline utilization is between 50 and 90 percent, then the pipeline tariff is set to a level between 70 and 80 percent of CNMAXTAR. The sliding scale is determined using the corresponding utilization factor, as follows:

$$\begin{aligned} NGPIPE\_VARTAR_{a,t} = {} & CNMAXTAR - [CNMAXTAR * (1.0 - 0.9) * 2.0] - \\ & [CNMAXTAR * (0.9 - CANUTIL_{a,t}) * 0.25] \end{aligned} \tag{206}$$

If the Canadian pipeline utilization is greater than 90 percent, then the pipeline tariff is set to between 80 and 100 percent of CNMAXTAR. This is accomplished again using Canadian pipeline utilization, as follows:

$$NGPIPE\_VARTAR_{a,t} = CNMAXTAR - [CNMAXTAR * (1.0 - CANUTIL_{a,t}) * 2.0] \tag{207}$$

where,

$$CANUTIL_{a,t} = \frac{Q_{a,t}}{QNOD_{a,t}} \tag{208}$$

for peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * PKSHR\_YR * PTPKUTZ_{a,t} \tag{209}$$

for off-peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} \tag{210}$$

and,

NGPIPE_VARTAR	=	function to define pipeline tariffs (87$/Mcf)
CNMAXTAR	=	maximum effective tariff (87$/Mcf, ARC_VARTAR, Appendix E)
CANUTIL	=	pipeline utilization (fraction)
QNOD	=	base point, quantity (Bcf)
Q	=	flow along pipeline arc (Bcf)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
PTPKUTZ	=	peak pipeline utilization (fraction)
PTCURPCAP	=	current pipeline capacity (Bcf)

PTOPUTZ = 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 that replaces a placeholder function which was used to assign a storage tariff for each region in the *Annual Energy Outlook 2000* version of the Pipeline Tariff Submodule. All variables and equations presented below are used for the forecast time period (1999-2030). 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[81] 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[82] 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:

$$STCOS_{r,t} = STBTOI_{r,t} + STDDA_{r,t} + STTOTAX_{r,t} + STTOM_{r,t} \qquad (211)$$

where,

STCOS = total cost-of-service or revenue requirement for existing and new capacity (dollars)
STBTOI = total return on rate base for existing and new capacity (after-tax operating income) (dollars)
STDDA = depreciation, depletion, and amortization for existing and new capacity (dollars)

[81] 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.
[82] 'After-tax' in this section refers to 'after taxes have been taken out.'

STTOTAX = total Federal and State income tax liability for existing and new capacity (dollars)
STTOM = total operating and maintenance expenses for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

The storage cost-of-service by region is first computed in nominal dollars and subsequently converted to 1987$ for use in the computation of a base for regional storage tariff, PNOD (87$/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
4. Other Taxes	Previous year's other taxes adjusted to inflation rate and growth in capacity

Computation of total return on rate base (after-tax operating income), $STBTOI_{r,t}$

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:

$$STBTOI_{r,t} = STWAROR_{r,t} * STAPRB_{r,t} \tag{212}$$

where,

STBTOI = total return on rate base (after-tax operating income) for existing and new capacity in dollars
STWAROR = weighted-average after-tax rate of return on capital for existing and new capacity (fraction)
STAPRB = 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.

$$STPFEN_{r,t} = STGPFESTR_r * STPFER_{r,t} * STAPRB_{r,t} \tag{213}$$

$$STCMEN_{r,t} = STGCMESTR_r * STCMER_{r,t} * STAPRB_{r,t} \tag{214}$$

$$STLTDN_{r,t} = STGLTDSTR_r * STLTDR_{r,t} * STAPRB_{r,t} \tag{215}$$

where,

STPFEN	=	total return on preferred stock for existing and new capacity (dollars)
STPFER	=	coupon rate for preferred stock for existing and new capacity (fraction)
STGPFESTR	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
STAPRB	=	adjusted rate base for existing and new capacity (dollars)
STCMEN	=	total return on common stock equity for existing and new capacity (dollars)
STGCMESTR	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
STCMER	=	common equity rate of return for existing and new capacity (fraction)
STLTDN	=	total return on long-term debt for existing and new capacity (dollars)
STGLTDSTR	=	historical average capital structure ratio for long term debt for existing and new capacity (fraction), held constant over the forecast period
STLTDR	=	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:

$$STBTOI_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t} + STLTDN_{r,t}) \tag{216}$$

It can be seen from the above equations that the weighted average rate of return on capital for existing and new storage capacity, $STWAROR_{r,t}$, can be determined as follows:

$$\begin{aligned} STWAROR_{r,t} = {} & STPFER_{r,t} * STGPFESTR_r + STCMER_{r,t} * STGCMESTR_r + \\ & STLTDR_{r,t} * STGLTDSTR_r \end{aligned} \tag{217}$$

The historical average capital structure ratios $STGPFESTR_r$, $STGCMESTR_r$, and $STGLTDSTR_r$ in the above equation are computed as follows:

$$STGPFESTR_r = \frac{\sum_{t=1990}^{1998} STPFES_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \tag{218}$$

$$STGCMESTR_{r} = \frac{\sum_{t=1990}^{1998} STCMES_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \quad (219)$$

$$STGLTDSTR_{r} = \frac{\sum_{t=1990}^{1998} STLTDS_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \quad (220)$$

where,

STGPFESTR	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
STGCMESTR	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
STGLTDSTR	=	historical average capital structure ratio for long term debt for existing and new capacity (fraction), held constant over the forecast period
STPFES	=	value of preferred stock for existing capacity (dollars) [read in as D_PFES]
STCMES	=	value of common stock equity for existing capacity (dollars) [read in as D_CMES]
STLTDS	=	value of long-term debt for existing capacity (dollars) [read in as D_LTDS]
STAPRB	=	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:

$$STPFER_{r,t} = MC\_RMPUAANS_{t} / 100.0 + ADJ\_STPFER_{r} \quad (221)$$

$$STCMER_{r,t} = MC\_RMPUAANS_{t} / 100.0 + ADJ\_STCMER_{r} \quad (222)$$

$$STLTDR_{r,t} = MC\_RMPUAANS_{t} / 100.0 + ADJ\_STLTDR_{r} \quad (223)$$

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 (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 common 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:

$$ADJ\_STLTDR_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STLTDN_{r,t}}{STLTDS_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \tag{224}$$

$$ADJ\_STPFER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STPFEN_{r,t}}{STPFES_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \tag{225}$$

$$ADJ\_STCMER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STCMEN_{r,t}}{STCMES_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \tag{226}$$

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 = total return on preferred stock for existing capacity (dollars) [read in as D_PFEN]
STCMEN = total return on common stock equity for existing capacity (dollars) [read in as D_CMEN]
STLTDN = total return on long-term debt for existing capacity (dollars) [read in as D_LTDN]
STPFES = value of preferred stock for existing capacity (dollars) [read in as D_PFES]
STCMES = value of common stock equity for existing capacity (dollars) [read in as D_CMES]
STLTDS = 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 (percentage)
STGPIS = original capital cost of plant in service (dollars) [read in as D_GPIS]
r = NGTDM region
t = forecast year

Computation of adjusted rate base, $STAPRB_{r,t}$[83]

The adjusted rate base for existing and new storage facilities in an NGTDM region has three components and can be written as follows:

$$STAPRB_{r,t} = STNPIS_{r,t} + STCWC_{r,t} - STADIT_{r,t} \quad (227)$$

where,

STAPRB	=	adjusted storage rate base for existing and new capacity (dollars)
STNPIS	=	net plant in service for existing and new capacity (dollars)
STCWC	=	total cash working capital for existing and new capacity (dollars)
STADIT	=	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:

$$STNPIS_{r,t} = STGPIS_{r,t} - STADDA_{r,t-1} \quad (228)$$

where,

STNPIS	=	net plant in service for existing and new capacity (dollars)
STGPIS	=	gross plant in service for existing and new capacity (dollars)
STADDA	=	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:

$$STGPIS_{r,t} = STGPIS\_E_{r,t} + STGPIS\_N_{r,t} \quad (229)$$

$$STNPIS_{r,t} = STNPIS\_E_{r,t} + STNPIS\_N_{r,t} \quad (230)$$

where,

STGPIS	=	gross plant in service for existing and new capacity (dollars)
STNPIS	=	net plant in service for existing and new capacity (dollars)
STGPIS_E	=	gross plant in service for existing capacity (dollars)
STGPIS_N	=	gross plant in service for new capacity (dollars)
STNPIS_E	=	net plant in service for existing capacity (dollars)
STNPIS_N	=	net plant in service for new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

[83] 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.

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:

$$STADDA_{r,t-1} = STADDA\_E_{r,t-1} + STADDA\_N_{r,t-1} \tag{231}$$

where,

STADDA	=	accumulated depreciation, depletion, and amortization for existing and new capacity (dollars)
STADDA_E	=	accumulated depreciation, depletion, and amortization for existing capacity (dollars)
STADDA_N	=	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:

$$STADDA\_E_{r,t} = STADDA\_E_{r,t-1} + STDDA\_E_{r,t} \tag{232}$$

$$STADDA\_N_{r,t} = STADDA\_N_{r,t-1} + STDDA\_N_{r,t} \tag{233}$$

where,

STADDA_E	=	accumulated depreciation, depletion, and amortization for existing capacity (dollars)
STADDA_N	=	accumulated depreciation, depletion, and amortization for new capacity (dollars)
STDDA_E	=	depreciation, depletion, and amortization for existing capacity (dollars)
STDDA_N	=	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.

$$STADDA_{r,t} = STADDA_{r,t-1} + STDDA_{r,t} \tag{234}$$

where,

STADDA	=	accumulated depreciation, depletion, and amortization for existing and new capacity in dollars
STDDA	=	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.

$$STDDA_{r,t} = STDDA\_E_{r,t} + STDDA\_N_{r,t} \tag{235}$$

where,

STDDA = annual depreciation, depletion, and amortization for existing and new capacity in dollars
STDDA_E = depreciation, depletion, and amortization costs for existing capacity in dollars
STDDA_N = 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:

$$\begin{aligned} STDDA\_E_{r,t} = {} & STDDA\_CREG_r + STDDA\_NPIS * STNPIS\_E_{r,t-1} \\ & + STDDA\_NEWCAP * STNEWCAP_{r,t} \end{aligned} \tag{236}$$

where,

STDDA_E = annual depreciation, depletion, and amortization costs for existing capacity in dollars
STDDA_CREG = 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 = net plant in service for existing capacity (dollars)
STNEWCAP = 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:

$$STDDA\_N_{r,t} = STGPIS\_N_{r,t} / 30 \tag{237}$$

where,

STDDA_N = annual depreciation, depletion, and amortization for new capacity in dollars
STGPIS_N = 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 ($STGPIS\_N_{r,t}$) in year t is computed as the accumulated new capacity expansion expenditures from 1999 to year t and is determined by the following equation:

$$STGPIS\_N_{r,t} = \sum_{s=1999}^{t} STNCAE_{r,s} \qquad (238)$$

where,

STGPIS_N	=	gross plant in service for new capacity expansion in dollars
STNCAE	=	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:

$$STNCAE_{r,t} = STCCOST_{r,t} * STCAPADD_{r,t} * 1{,}000{,}000. \qquad (239)$$

where,

STNCAE	=	total capital cost to expand capacity for an NGTDM region (dollars)
STCCOST	=	capital cost per unit of natural gas storage expansion (dollars per Mcf)
STCAPADD	=	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 ($STCCOST_{r,t}$) 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 ($STCCOST_{r,t}$) is computed by the following equations:

$$STCOST_{r,t} = STCCOST\_CREG_r * e^{(BETAREG_r * STEXPFAC98_r)} * (1.0 + STCSTFAC) \qquad (240)$$

where,

STCCOST	=	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	=	expansion factor parameter (set to STCCOST_BETAREG, Appendix E)
STEXPFAC98	=	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:

$$STEXPFAC98_r = \frac{PTCURPSTR_{r,t}}{PTCURPSTR_{r,1998}} - 1.0 \tag{241}$$

where,

PTCURPSTR = 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:

$$\begin{aligned} R\_STCWC_{r,t} = {} & e^{(STCWC\_CREG_r * (1-\rho))} * DSTTCAP_{r,t-1}^{STCWC\_TOTCAP} * \\ & R\_STCWC_{r,t-1}^{\rho} * DSTTCAP_{r,t-2}^{-\rho * STCWC\_TOTCAP} \end{aligned} \tag{242}$$

where,

R_STCWC = total cash working capital at the beginning of year t for existing and new capacity (1996 real dollars)
$STCWC\_CREG_r$ = constant term, estimated by region (Appendix F, Table F3)
ρ = autocorrelation coefficient from estimation (Appendix F, Table F3 — STCWC_RHO)
DSTTCAP = 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 real dollars is converted to nominal dollars to be consistent with the convention used in this submodule.

$$STCWC_{r,t} = R\_STCWC_{r,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{1996}} \tag{243}$$

where,

STCWC = total cash working capital at the beginning of year t for existing and new capacity (nominal dollars)
R_STCWC = total cash working capital at the beginning of year t for existing and new capacity (1996 real dollars)
MC_PCWGDP = 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:

$$STADIT_{r,t} = STADIT\_C + (STADIT\_ADIT * STADIT_{r,t-1}) + (STADIT\_NEWCAP * NEWCAP_{r,t}) \tag{244}$$

where,

STADIT = 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 = 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, STTOTAXr,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:

$$STTOTAX_{r,t} = STFSIT_{r,t} + STDIT_{r,t} + STOTTAX_{r,t} \tag{245}$$

$$STFSIT_{r,t} = STFIT_{r,t} + STSIT_{r,t} \tag{246}$$

where,

STTOTAX = total Federal and State income tax liability for existing and new capacity (dollars)
STFSIT = Federal and State income tax for existing and new capacity (dollars)
STFIT = Federal income tax for existing and new capacity (dollars)
STSIT = State income tax for existing and new capacity (dollars)
STDIT = deferred income taxes for existing and new capacity (dollars)
STOTTAX = all other taxes assessed by Federal, State, or local governments for 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:

$$STATP_{r,t} = STAPRB_{r,t} * (STPFER_{r,t} * STGPFESTR_r + STCMER_{r,t} * STGCMESTR_r) \quad (247)$$

$$STATP_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t}) \quad (248)$$

where,

STATP	=	after-tax profit for existing and new capacity (dollars)
STAPRB	=	adjusted pipeline rate base for existing and new capacity (dollars)
STPFER	=	coupon rate for preferred stock for existing and new capacity (fraction)
STGPFESTR	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
STCMER	=	common equity rate of return for existing and new capacity (fraction)
STGCMESTR	=	historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
STPFEN	=	total return on preferred stock for existing and new capacity (dollars)
STCMEN	=	total return on common stock equity for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

and the Federal income taxes are

$$STFIT_{r,t} = (FRATE * STATP_{r,t}) / (1. - FRATE) \quad (249)$$

where,

STFIT	=	Federal income tax for existing and new capacity (dollars)
FRATE	=	Federal income tax rate (fraction, Appendix E)
STATP	=	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:

$$STSIT_{r,t} = SRATE * (STFIT_{r,t} + STATP_{r,t}) \quad (250)$$

where,

STSIT	=	State income tax for existing and new capacity (dollars)
SRATE	=	average State income tax rate (fraction, Appendix E)
STFIT	=	Federal income tax for existing and new capacity (dollars)
STATP	=	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.

$$STDIT_{r,t} = STADIT_{r,t} - STADIT_{r,t-1} \qquad (251)$$

where,

STDIT = deferred income taxes for existing and new capacity (dollars)
STADIT = 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.

$$STOTTAX_{r,t} = STOTTAX_{r,t-1} * (MC\_PCWGDP_t / MC\_PCWGDP_{t-1}) \qquad (252)$$

where,

STOTTAX = all other taxes assessed by Federal, State, or local governments except income taxes for existing and new capacity (dollars) [read in as $D\_OTTAX_{r,t}$, t=1990-1998]
MC_PCWGDP = 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.[84] Because their impacts were not supported by the data, they were not accounted for in the estimations. The final estimating equation is:

$$\begin{aligned} R\_STTOM_{r,t} = {} & e^{(STTOM\_C*(1-\rho))} * DSTWCAP_{r,t-1}^{STTOM\_WORKCAP} * \\ & * R\_STTOM_{r,t-1}^{\rho} * DSTWCAP_{r,t-2}^{-\rho*STTOM\_WORKCAP} \end{aligned} \qquad (253)$$

where,

R_STTOM = total operating and maintenance cost for existing and new capacity (1996 real dollars)
STTOM_C = constant term from estimation (Appendix F, Table F3)
ρ = autocorrelation coefficient from estimation (Appendix F, Table F3 -- STTOM_RHO)

[84]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.

DSTWCAP = 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.

$$STTOM_{r,t} = R\_STTOM_{r,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{1996}} \quad (254)$$

where,

STTOM = total operating and maintenance costs for existing and new capacity (nominal dollars)
R_STTOM = total operating and maintenance costs for existing and new capacity (1996 real dollars)
MC_PCWGDP = 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 211)) 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 U.S. 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 adjustment factor to obtain the "actual" cost of service across all regions in the U.S. is 165 percent. This adjustment factor, $STCAP\_ADJ_{r,t}$, 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:

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC\_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP\_ADJ_{r,t} * ADJ\_STR * (1.0 - STR\_EFF/100.)^t \quad (255)$$

where,

$$STCAP\_ADJ_{r,t} = \frac{PTCURPSTR_{r,t}}{FS\_PTCURPSTR_{r,t}} \quad (256)$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \quad (257)$$

and,

PNOD	=	base point, price (87$/Mcf)
STCOS	=	storage cost of service for existing and new capacity (dollars)
QNOD	=	base point, quantity (Bcf)
MC_PCWGDP	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
STRATIO	=	portion of revenue requirement obtained by moving gas from the off-peak to the peak period (fraction, Appendix E)
STCAP_ADJ	=	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	=	storage utilization (fraction)
PTCURPSTR	=	current storage capacity (Bcf)
FS_PTCURPSTR	=	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:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA\_STR} \quad (258)$$

capacity expansion segment:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA2\_STR} \quad (259)$$

where,

X1NGSTR_VARTAR	=	function to define storage tariffs (87$/Mcf)
PNOD	=	base point, price (87$/Mcf)
QNOD	=	base point, quantity (Bcf)
Q	=	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

Alaskan 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 (FRPCNSYR, Appendix E), the associated discount rate for the project (FR_DISCRT, Appendix E), the initial capacity (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:

$$FR\_DDA_t = FR\_CAPITL1 / INVEST\_YR \quad (260)$$

where,

FR_DDA	=	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)

The structure of the final cost of capitalization, FR_CAPITL1, is computed as follows:

$$FR\_CAPITL1 = FR\_CAPIT0 / FR\_PCNSYR * [(1+r) + (1+r)^2 + ... + (1+r)^{FR\_PCNSYR}] \quad (261)$$

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 AA utility bond rate (MC_RMPAANS, 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:

$$\begin{aligned} FR\_NPIS_t &= FR\_GPIS_t - FR\_ADDA_t \\ FR\_ADDA_t &= FR\_ADDA_{t-1} + FR\_DDA_t \end{aligned} \quad (262)$$

where,

FR_GPIS = original capital cost of plant in service (gross plant in service) in thousand nominal dollars, set to FR_CAPITL1.
FR_NPIS = net plant in service (thousand nominal dollars)
FR_ADDA = accumulated depreciation, depletion, and amortization in thousand nominal dollars

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, gets 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:

$$FR\_TRRB_t = WACC_t * FR\_NPIS_t \quad (263)$$

where,

$$\begin{aligned} WACC_t = {} & FR\_DEBTRATIO * COST\_OF\_DEBT_t + (1.0 - FR\_DEBTRATIO) * \\ & COST\_OF\_EQUITY_t \end{aligned} \quad (264)$$

and

$$COST\_OF\_DEBT_t = (AABOND_t + FR\_DISCRT) / 100. \quad (265)$$

$$COST\_OF\_EQUITY_t = (AABOND_t + FR\_ROR\_PREM) / 100. \quad (266)$$

where,

FR_TRRB = after-tax operating income or return on rate base (thousand nominal dollars)
WACC = weighted average cost of capital (fraction), nominal
FR_NPIS = net plant in service (thousand nominal dollars)
COST_OF_DEBT = cost of debt (fraction)
COST_OF_EQUITY = cost of equity (fraction)
AABOND = nominal AA utility bond rate, $MC\_RMPUAAS_t$, (in 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)

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:

$$FR\_TAXES_t = (FR\_TXR + FR\_OTXR) * FR\_NETPFT_t \quad (267)$$

where,

FR_TAXE = total taxes (thousand nominal dollars)
FR_NETPFT = net profit (thousand nominal dollars)
FR_TXR = 5-year average Lower 48 pipeline income tax rate, as a proxy (Appendix E)
FR_OTXR = 5-year average Lower 48 pipeline other income tax rate, as a proxy (Appendix E)

Net profit, FR_NETPFT, is computed as the return on rate base (FR_TRRB_t) minus the long-term debt (FR_LTD_t), 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:

$$FR\_NETPFT_t = (FR\_TRRB_t - FR\_LTD_t) \quad (268)$$

$$FR\_LTD_t = FR\_DEBTRATIO * (AABOND_t + FR\_DISCRT) / 100.0 * FR\_NPIS_t \quad (269)$$

where,

FR_LTD = long-term debt (thousand nominal dollars)
FR_NPIS = net plant in service (thousand nominal dollars)
FR_DEBTRATIO = 5-year average Lower 48 pipeline debt structure ratio (Appendix E)
FR_NETPFT = net profit (thousand nominal dollars)

FR_TRRB	=	return on rate base (thousand nominal dollars)
AABOND	=	nominal AA utility bond rate, $MC\_RMPUAAS_t$, (in percent) provided by the Macroeconomic Activity Module
FR_DISCRT	=	user-set debt premium, percent (Appendix E)

In the above equations, the long-term debt rate is assumed equal to the AA utility bond rate plus a 1 percent, which represents a risk premium generally charged by financial institutions. When AA utility bond rates are needed for years beyond the last forecast year (LASTYR), the variable $AABOND_t$ becomes the average over a number of years (FR_ESTNYR, Appendix E) of the AA utility bond 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:

$$FR\_COS_t = (FR\_TRRB_t + FR\_DDA_t + FR\_TAXES_t + FR\_TOM_{FR\_CAPYR} * (MC\_PCWGDP_t / MC\_PCWGDP_{FR\_CAPYR}) * FR\_PVOL * 1000.0) \tag{270}$$

where,

FR_COS	=	cost of service (thousand nominal dollars)
FR_TRRB	=	return on rate base (thousand nominal dollars)
FR_DDA	=	depreciation (thousand nominal dollars)
FR_TAXES	=	total taxes (thousand nominal dollars)
FR_TOM	=	total operating and maintenance expenses (in nominal dollars per Mcf, set constant in real terms) (Appendix E)
MC_PCWGDP	=	GDP price deflator (from Macroeconomic Activity Module)
FR_PVOL	=	initial pipeline capacity (Bcf/year)
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:

$$COS_t = FR\_COS_t / (FR\_PVOL * 1000.0) \tag{271}$$

where,

COS	=	per-unit cost of service or annual pipeline tariff (nominal dollars/Mcf)

To convert this nominal tariff to real 1987$/Mcf, the GDP implicit price deflator variable provided by the Macroeconomic Activity Module is needed. The real tariff equation is written as follows:

$$COSR_t = COS_t / MC\_PCWGDP_t \tag{272}$$

where,

COSR	=	annual real pipeline tariff (1987 dollars/Mcf)
MC_PCWGDP	=	GDP price deflator (from Macroeconomic Activity Module)

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

Nonelectric 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 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. Industrial and electric generator end users fall into both categories, with industrial boilers 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 or a gas-to-liquids facility are 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, any gas needed to support the production of gas-to-liquids, associated lease, plant, and pipeline fuel for these two applications, 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 nonelectric 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. Historically based shares *(PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, PKSHR_ILNG)* are also applied to exogenous forecasts/historical values for natural gas exports and imports *(SEXP, SIMP, CANEXP, Q23TO3, FLO_THRU_IN,OGQNGEXP)*. These historical based shares are generated from monthly historical data *(QRS, QCM, QIN, QEU, MON_QEXP, MON_QIMP)*

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. 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)*.

Pricing of Distribution Services

End-use prices for residential, commercial, industrial, transportation, and electric generation customers are derived by adding markups to the regional hub price of natural gas. Each regional end-use markup consists of an intraregional 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 sectors as the difference between historical city gate and end-use prices *(SPRS, SPCM, SPIN, SPEU, SPTR, PRS, PCM PIN, PEU)*.[85] Historical industrial end-use prices are derived in the module using an econometrically estimated equation *(Table F5)*.[86] The residential, commercial, industrial, and electric generator distributor tariffs are also based on econometrically estimated equations *(Tables F4, F6, F7, and F8)*. The distributor tariff for the personal (PV) and fleet vehicle (FV) components of the transportation sector are set using historical data, a decline rate *(TRN_DECL)*, state and federal taxes *(STAX, FTAX)*, and assumed dispensing costs/charges *(RETAIL_COST).* The final price for compressed gas is set at the maximum of the cost based price and a fraction *(PERMG)* of the equivalent motor gasoline price.

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 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
- Capacity reservation shares used to allocate cost of service components to portions of the pipeline network
- Average pipeline capital cost per unit of expanded capacity *(AVGCOST)* 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)*

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[85] All historical prices are converted from nominal to real 1987 dollars using a price deflator *(GDP_B87)*.

[86] Traditionally industrial prices have been derived by collecting sales data from local distribution companies. More recently, industrial customers have not relied on LDCs to purchase their gas. As a result, annually published industrial natural gas prices only represent a rather small portion of the total population. In the module, these published prices are adjusted using an econometrically estimated equation based on EIA's survey of manufacturers to derive a more representative set of industrial prices.

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 AA bond 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 wellhead 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 *(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)*, although these are currently not active for pipelines. They were originally intended to reflect an expected variant in the load throughout a season. Adjustments are now being 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 regions 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 conventional and tight gas production from the Canadian Sedimentary Basin are based on an expected production level as set in the Oil and Gas Supply Module. 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 Canadian Western Canadian Sedimentary Basin is set exogenously *(CN_FIXSUP)*. Unconventional gas production in Canada from coal beds is based on an assumed production withdrawal profile from a total resource base 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 and/or a gas-to-liquids facility.

Imports from Mexico and Canada at each border crossing point are represented as follows: (1) Mexican imports are assumed constant and provided by the Oil and Gas Supply Module; (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 a set of supply curves generated by establishing supply costs for various import quantities related to current capacity levels (*PERMAXRG, PERMINRG, PERAVGRG*), using a least-cost transportation algorithm specified as a linear program. Step functions representing the cost of production (*SCRV_PPR, SCRVQPR, SCRV_YPR*), liquefaction (*SCRV_PLQ, SCRVQLQ, SCRV_YLQ, PERLIQUS*), shipping (*SCRV_PSH, SCRVQSH, SCRV_YSH*), and regasification (*SCRV_PRG SCRVQRG, SCRV_YRG*) are used within the linear program. Costs for regasification, liquefaction, and shipping are endogenously set based on numerous assumptions (the specific variables are listed in the Model Inputs section below). A risk premium (*RISKPREM*) is added to these costs to reflect market and cost uncertainties when assessing potential regasification capacity additions. All supply levels that are held constant (i.e., are not responsive to current year prices) are converted into peak and off-peak levels using historically *(MON_QIMP)* based shares *(HPKSHR_ICAN, HPKSHR_IMEX, HPKSHR_ILNG)*.

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. Synthetic production from coal 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. Throughout the forecast, these production levels are split into seasonal periods using an historically *(NSUPLM_TOT)* based share (PKSHR_SUPLM).

The module 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 nonvarient 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/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 supply prices
  (SPIM, SPWH)
- 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)
- 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 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)
- Unconventional western Canadian production parameters
  (ULTRES, RESBASE, PKIYR, LSTYR0, PERRES, RESTECH, TECHGRW)

Supply Inputs

- Liquefied natural gas import projection
  (LNGBLDT, LNGELAS, QNGIMP, PERMAXRG, PERMINRG, PERAVGRG, MINPRCRG, RISKPREM, PLOSS, LLOSS, RLOSS, SLOSS, PERMAXLQ, PCURCAP, LCURCAP, SCURCAP, RCURCAP, SCRV_Pxx, SCRV_Qxx, SCRV_Yxx, with "xx" PR, LQ, SH,and RG)
- Liquefied natural gas pricing
  (MBAJA, LNGDIFF, PAR_WOP, PAR_CON, IEOCONS, STRT_YR, IEOCYRS, IEOCYRN)
- Regasification cost parameters
  (RG_ENDOG, RG_DOLS, RG_CST_TANK, RG_CST_5VAP, RG_CST_ACRE, RG_CONT_FRAC, RF_DEBT_EQTY, RG_CORP_TAXRAT, RG_RISK_DEBT, RG_RISK_FAC, RG_RISK_SCAL, RG_LIFE_YRS, RG_OM_FRAC, RG_TAX_FRAC, RG_INSUR_FRAC, RG_FUEL_MMBTU, RG_FUEL_FRAC, RG_TANK_CAP, RG_VAP_CAP, RG_ACRE_MIN, RG_ACRE_CAP, RG_CST_MARINE, RG_CST_2MARINE, RG_CST_SITE, RG_CST_BLDS, RG_CST_MISC, RG_CST_INSTALL, RG_CST_ENGR, RG_UTIL_FIN, RG_INT_CONST, RG_COST_WAGES, RG_OM_CAPCST, RG_TAX_CAPCST, RG_INSUR_CAPCST, R G_PER_FUEL, RG_KW_MMTONS, RG_BCF_MMTONS, RG_COST_KWH, RG_COST_ESCAL)
- Liquefaction cost parameters
  (L_CONV_FAC, L_AVGTAX, L_DEBTRATIO, L_COST_EQUITY, L_CORPTAX, L_DEPREYR, L_MAINT_PCT, L_COSTRUNUP, L_PARM_A, L_PARM_B, L_FUEL_PCT, L_STAFF_NUM, L_CEO_FACLT, L_AVG_SALARY, L_EXPFAC, L_EXPYRS, L_INTPREMIUM, L_UTILRATE)
- Shipping cost parameters
  (SH_DOLS, SH_NUMBLD_YR, SH_AVAIL_DAY, SH_LOAD_DAY, SH_UTL_RATE, SH_DEBT_EQTY, SH_CORP_TAXRAT, SH_LIFE_YRS, SH_BOIL_RATE, SH_LNG_COST, SH_BUNKER_DAY, SH_BUNKER_COST, SH_CAP_CM, SH_UNIT_COST, CM_TO_BCF, SH_SPEED, SH_OPC_PER, SH_PORT_COST, SH_RISK_FAC, SH_RISK_SCAL, SH_MILES)
- Supply curve parameters
  (SUPCRV, PARM_MINPR, PARM_SUPCRV3, PARM_SUPCRV5, PARM_SUPELAS, MAXPRRFAC, MAXPRRNG, PARM_MINPR)
- Synthetic natural gas projection
  (SNGCOAL, SNGLIQ)

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, cost, and volume 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, cost, and volume parameters
  (D_TOM, D_DDA, D_OTTAX, D_FSIT, D_DIT, D_LTDN, D_PFEN, D_CMEN, D_GPIS, D_ADDA, D_NPIS, D_CWC, D_ADIT, D_APRB, D_LTDS, D_PFES, D_CMES, D_TCAP, D_WCAP)
- Revenue requirement forecasting equation parameters for pipeline and storage rates
  (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
  (AVGCOST)
- 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)
- 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)
- State and Federal taxes, costs to dispense, and other compressed natural gas pricing parameters
  (STAX, FTAX, RETAIL_COST, TRN_DECL, PERMG)
- Historical city gate prices
  (HCGPR)

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,)
- 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 Petroleum Market Module)
- 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)
- Dry natural gas production by PADD region (to Petroleum Market Module)
- Nonassociated dry natural gas production by NGTDM/Oil and Gas Supply Module region (to NEMS REPORTS and Oil and Gas Supply Module)
- Canadian natural gas wellhead price and production (to Oil and Gas Supply Module)
- Natural gas imports and prices by border crossing (to NEMS REPORTS and Oil and Gas Supply Module)

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)
- Historical and forecast values historically based factors applied in the module (NGOBENCH)
- Intermediate results from the Distributor Tariff Submodule (NGODTM)
- 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 used to in a gas-to-liquids conversion process in Alaska
- Natural gas wellhead 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[88]

[88]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

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: Integrated Analysis and Forecasting
- Division: Oil and Gas Division, EI-83
- Model Contact: Joe Benneche
- Telephone: (202) 586-6132

Documentation: 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, November 2008).

Previous Documentation: 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, October 2007).

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, August 2006).

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 2005).

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)

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)

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 2002).

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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).

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 1994).

Reviews Conducted: Paul R. Carpenter, PhD, The Brattle Group. "Draft Review of Final Design Proposal Seasonal/North American Natural Gas Transmission Model." Cambridge, MA, August 15, 1996.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Natural Gas Annual Flow Module (AFM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, Aug 25, 1992.

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, Apr 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, Apr 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, Apr 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, Jan 4, 1995.

Archive Tapes: The NGTDM is archived as a component of the 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 2008, DOE/EIA-0383(2008). The archive package can be downloaded from ftp://ftp.eia.doe.gov/pub/oiaf/aeo.

Energy System Covered: 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 liquefied natural gas import terminals. In a separate component, potential liquefied natural gas production and liquefaction for U.S. import is represented for 14 international ports. A simplified Canadian representation is subdivided into an eastern and western region, with potential LNG import facilities on both shores.

Time Unit/Frequency: Annually through 2030, 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
- Mineral Management Service, Federal Offshore Statistics 1995.
  — Alabama and Louisiana state and federal offshore production before 1990
- Mineral Management Service.
  — Revenues and volumes for offshore production in Texas, California, and Louisiana
- Foster Pipeline and Storage Financial Cost Data
  — pipeline and storage financial data
- State of Alaska Historical and Projected Oil and Gas Consumption, Alaska Department of Natural Resources
  — North slope end-use consumption by sector
- 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
- National Energy Board, “Canada’s Energy Future: Scenarios for Supply and Demand to 2025,” 2003.
  — Partial basis for setting offshore production projections for Canada and for resource assumptions
- Internal Gas Technology Institute report produced for EIA, March 31, 2003
  — LNG supply, liquefaction, and shipping, costs
- Internal Project Technical Liaison, Inc report produced for EIA,
  — LNG regasification costs
- *Fundamentals of the Global LNG Industry 2001*,
  — Natural gas liquefaction costs
- www.dataloy.com
  — LNG shipping distances
- Hart Energy Network’s Motor Fuels Information Center at www.hartenergynetowrk.com/motorfuels/state/doc/glance/glnctax.htm
  — compressed natural gas vehicle taxes by state
- National Oceanic and Atmospheric Association
  — 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

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 wellhead, 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, wellhead prices, lease and plant consumption, pipeline consumption, supplemental supplies

- 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, *Alternate Fuel Price Report*, Office of Energy Efficiency and Renewable Energy
  - — Sample of retail prices paid for compressed natural gas for vehicles.
- 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 the world.

Models and other:

- National Energy Modeling System (NEMS)
  - — Domestic supply, imports, and demand representations are provided as inputs to the NGTDM from other NEMS models

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 volumes and prices by region
- Pipeline fuel consumption by region
- Lease and plant fuel consumption by region
- Lease and plant fuel consumption by region
- The 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)

Part of Another Model: Yes, the National Energy Modeling System (NEMS).

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 and prices, pipeline capacity expansion and utilization, 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 LDC's 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
  - — Liquefied natural gas module uses a linear program to assess the minimum cost for delivering gas to the U.S.

Model Interfaces: NEMS

Computing Environment:

- Hardware Used: Personal Computer
- Operating System: UNIX simulation
- Language/Software Used: FORTRAN
- Storage Requirement: 2,300K bytes for input data storage; 1,000K bytes for source code storage; and 17,100K 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: November 2006.

Appendix B

References

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Decision Focus Incorporate, *Generalized Equilibrium Modeling: The Methodology of the SRI-GULF Energy Model* (Palo Alto, CA, May 1977).

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Appendix C

NEMS Model Documentation Reports

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, *National Energy Modeling System Integrating Module Documentation Report*, DOE/EIA-M057.

Energy Information Administration, *Model Documentation Report: Macroeconomic Activity Module of the National Energy Modeling System*.

Energy Information Administration, *Documentation of the D.R.I. Model of the U.S. Economy*.

Energy Information Administration, *National Energy Modeling System International Energy Model Documentation Report*.

Energy Information Administration, *World Oil Refining, Logistics, and Demand Model Documentation Report*.

Energy Information Administration, *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation Report: Transportation Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Documentation of the Electricity Market Module*.

Energy Information Administration, *Documentation of the Oil and Gas Supply Module*.

Energy Information Administration, *EIA Model Documentation: Petroleum Market Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation: Coal Market Module*.

Energy Information Administration, *Model Documentation Report: Renewable Fuels Module*.

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.

Chapter 2 Equations

EQ. #	**SUBROUTINE** (or FUNCTION [*])
1	NGDMD_CRVF[*] (core), NGDMD_CRVI[*] (noncore)
2- 13	NGCAN_FXADJ
14	NGLNG_MKTPRC
15	NGLNG_SETCRV
16	NGSUP_PR[*]
17-30	NGTDM_DMDALK

Chapter 4 Equations

EQ. #	**SUBROUTINE** (or FUNCTION [*])
31,34	NGSET_NODEDMD, NGDOWN_TREE
32,35	NGSET_NODECDMD
33,36	NGSET_YEARCDMD
37,38	NGDOWN_TREE
39	NGSET_INTRAFLO
40	NGSET_INTRAFLO
41	NGSHR_CALC
42	NGDOWN_TREE
43	NGSET_MAXFLO[*]
44-47	NGSET_MAXPCAP
48-52	NGSET_MAXFLO[*]
53-55	NGSET_ACTPCAP
56-57	NGSHR_MTHCHK
58-61	NGSET_SUPPR
62-63	NGSTEO_BENCHWPR
64	NGSTEO_BENCHWPR
65-66	NGSET_ARCFEE
67-70	NGUP_TREE

71	NGSET_STORPR
72-73	NGUP_TREE
74	NGCHK_CONVNG
75	NGSET_SECPR
76	NGSET_BENCH, HNGSET_CGPR
77-83	NGSET_SECPR

Chapter 5 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
84-91	NGDTM_FORECAST_DTARF
92-93	NGDTM_FORECAST_TRNF

Chapter 6 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
94-99, 103-121, 170-172	NGPREAD
100-102, 122-123	NGPIPREAD
143-161, 173, 175-188	NGPSET_PLCOS_COMPONENTS
124-133, 139, 174, 189-198, 205	NGPSET_PLINE_COSTS
134-138, 199-204, 205-210	NGPIPE_VARTAR*
218-220	NGSTREAD
211-217, 221-223, 227-254	NGPSET_STCOS_COMPONENTS
224-226	NGPST_DEVCONST
140-142, 255-259	X1NGSTR_VARTAR*
162-169	(accounting relationships, not part of code)
260-272	NGFRPIPE_TAR*

Appendix E

Model Input Variable 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 the *AEO2008* 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 NEMS2008 archive package. The archive package can be downloaded from ftp://ftp.eia.doe.gov/pub/oiaf/aeo. In addition, the files are available upon request from Joe Benneche at (202) 586-6132 or Joseph.Benneche@eia.doe.gov.

ngcan.txt	V1.52	nghismn.txt	V1.22	ngptar.txt	V1.22
ngcap.txt	V1.26	nglngdat.txt	V1.57	nguser.txt	V1.120
ngdtar.txt	V1.27	ngmap.txt	V1.5		
nghisan.txt	V1.30	ngmisc.txt	V1.120		

Variable	File	Variable	File
ACTPCAP	NGCAN	AL_OFST2	NGHISAN
ACTPCAP	NGCAP	AL_ONSH	NGHISAN
ADDYR	NGCAP	AL_ONSH2	NGHISAN
ADIT_C	NGPTAR	ALB_TO_L48	NGMISC
ADIT_BNEWCAP	NGPTAR	ALPHAFAC	NGUSER
ADJ_PIP	NGPTAR	ALPHA2_PIPE	NGPTAR
ADJ_STR	NGPTAR	ALPHA2_STR	NGPTAR
ADW	NGHISAN	ALPHA_PIPE	NGPTAR
AFR_CMEN	NGPTAR	ALPHA_STR	NGPTAR
AFR_DDA	NGPTAR	AMAP	NGMAP
AFR_DIT	NGPTAR	ARC_2NODE	NGMAP
AFR_FSIT	NGPTAR	ARC_FIXTAR	NGCAN
AFR_LTDN	NGPTAR	ARC_LOOP	NGMAP
AFR_OTTAX	NGPTAR	ARC_VARTAR	NGCAN
AFR_PFEN	NGPTAR	AVG_CAPCOST	NGPTAR
AFR_TOM	NGPTAR	AVR_CMEN	NGPTAR
AFX_CMEN	NGPTAR	AVR_DDA	NGPTAR
AFX_DDA	NGPTAR	AVR_DIT	NGPTAR
AFX_DIT	NGPTAR	AVR_FSIT	NGPTAR
AFX_FSIT	NGPTAR	AVR_LTDN	NGPTAR
AFX_LTDN	NGPTAR	AVR_OTTAX	NGPTAR
AFX_OTTAX	NGPTAR	AVR_PFEN	NGPTAR
AFX_PFEN	NGPTAR	AVR_TOM	NGPTAR
AFX_TOM	NGPTAR	BPOLICY_CHG	NGPTAR
AK_C	NGMISC	CANEXP	NGCAN
AK_CM	NGMISC	CAN_XMAPCN	NGMAP
AK_CN	NGMISC	CAN_XMAPUS	NGMAP
AK_D	NGMISC	CM_ADJ	NGDTAR
AK_E	NGMISC	CM_ALP	NGDTAR
AK_EM	NGMISC	CM_LNQ	NGDTAR
AK_ENDCONS_N	NGMISC	CM_PKALP	NGDTAR
AK_F	NGMISC	CM_RHO	NGDTAR
AK_G	NGMISC	CM_TO_BCF	NGLNGDAT
AK_IN	NGMISC	CNCAPSW	NGUSER
AK_HDD	NGMISC	CNPER_YROPEN	NGCAP
AK_PCTLSE	NGMISC	CN_DMD	NGCAN
AK_PCTPIP	NGMISC	CN_FIXSHR	NGCAN
AK_PCTPLT	NGMISC	CN_FIXSUP	NGCAN
AK_POP	NGMISC	CN_UNPRC	NGCAN
AK_QIND_S	NGMISC	CNPLANYR	NGCAN
AK_RM	NGMISC	CON	NGHISMN
AK_RN	NGMISC	CON_ELCD	NGHISMN
AKPIP1	NGMISC	CON_EPMGR	NGHISMN
AKPIP2	NGMISC	CWC_C	NGPTAR
AL_ADJ	NGHISAN	CWC_DISC	NGPTAR
AL_FYR	NGHISAN	CWC_GPIS	NGPTAR
AL_LYR	NGHISAN	CWC_K	NGPTAR
AL_OFFD	NGHISAN	CWC_RHO	NGPTAR
AL_OFST	NGHISAN	D_ADDA	NGPTAR

Variable	File
D_ADIT	NGPTAR
D_APRB	NGPTAR
D_CMEN	NGPTAR
D_CMER	NGPTAR
D_CMES	NGPTAR
D_CWC	NGPTAR
D_CONST	NGPTAR
D_DDA	NGPTAR
D_DIT	NGPTAR
D_FLO	NGPTAR
D_FSIT	NGPTAR
D_GCMES	NGPTAR
D_GLTDS	NGPTAR
D_GPFES	NGPTAR
D_GPIS	NGPTAR
D_LTDN	NGPTAR
D_LTDR	NGPTAR
D_LTDS	NGPTAR
D_MXPKFLO	NGPTAR
D_NPIS	NGPTAR
D_OTTAX	NGPTAR
D_PFEN	NGPTAR
D_PFER	NGPTAR
D_PFES	NGPTAR
D_TOM	NGPTAR
DDA_C	NGPTAR
DDA_NEWCAP	NGPTAR
DDA_NPIS	NGPTAR
DDA_RHO	NGPTAR
DUM_CAPCOST	NGPTAR
DUM_CAP	NGPTAR
DUM_CAPYR	NGPTAR
EL_ALP	NGDTAR
EL_CNST	NGDTAR
EL_PARM	NGDTAR
EL_RESID	NGDTAR
EL_RHO	NGDTAR
EMMSUB_EL	NGMAP
EMMSUB_NG	NGMAP
EPMYR1	NGHISMN
EPMYR2	NGHISMN
EXP_A	NGPTAR
EXP_B	NGPTAR
EXP_C	NGPTAR
FAC1	NGLNGDAT
FAC2	NGLNGDAT
FDGOM	NGHISMN
FDIFF	NGDTAR
FE_CCOST	NGMISC
FE_EXPFAC	NGMISC
FE_FR_TOM	NGMISC
FE_PFUEL_FAC	NGMISC
FE_R_STTOM	NGMISC
FE_R_TOM	NGMISC
FE_STCCOST	NGMISC
FE_STEXPFAC	NGMISC
FID_WA	NGMISC
FLO_THRU_IN	NGCAN
FMT_ND	NGMISC
FR_AVGTARYR	NGMISC
FR_CAPITL0	NGMISC
FR_CAPYR	NGMISC
FR_DEBTRATIO	NGMISC
FR_DISCRT	NGMISC
FR_ESTNYR	NGMISC
FR_OTXR	NGMISC
FR_PADDTAR	NGMISC
FR_PCNSYR	NGMISC
FR_PDRPFAC	NGMISC
FR_PEXPFAC	NGMISC
FR_PFUEL	NGMISC
FR_PMINWPR	NGMISC
FR_PMINYR	NGMISC
FR_PPLNYR	NGMISC
FR_PRISK	NGMISC
FR_PTREAT	NGMISC
FR_PVOL	NGMISC
FR_ROR_PREM	NGMISC
FR_TOM0	NGMISC
FR_TXR	NGMISC
FRATE	NGPTAR
FUTWTS	NGMISC
GAMMAFAC	NGUSER
GOF_AL	NGHISTAN
GOF_CA	NGHISTAN
GOF_LA	NGHISTAN
GOF_TX	NGHISTAN
GDP_B87	NGMISC
HAFLOW	NGMISC
HCGPR	NGHISAN
HDYWHTLAG	NGDTAR
HFAC_GPIS	NGPTAR
HFAC_REV	NGPTAR
HHDD	NGDTAR
HI_RN	NGMISC
HNETINJ	NGCAN
HNETINJ	NGHISMN
HNETWTH	NGCAN
HNETWTH	NGHISMN
HOPUTZ	NGCAP

Variable	File	Variable	File
HPIMP	NGHISAN	LNGFIX	NGLNGDAT
HPKSHR_FLOW	NGMISC	LNGHYR	NGLNGDAT
HPKUTZ	NGCAP	LSTEP	NGLNGDAT
HPSUP	NGCAN	LSTYR_MMS	NGHISAN
HQIMP	NGHISAN	MAPLNG_NG	NGMAP
HQSUP	NGCAN	MAP_NRG_CRG	NGDTAR
HW_ADJ	NGDTAR	MAP_PRDST	NGHISMN
HW_BETA0	NGDTAR	MAP_STSUB	NGHISAN
HW_BETA1	NGDTAR	MAXCYCLE	NGUSER
HW_RHO	NGDTAR	MAXPRRFAC	NGMISC
HYEAR	NGHIST	MAXPRRNG	NGMISC
IEOCYRN	NGLNGDAT	MAXUTZ	NGCAP
IEOCYRS	NGLNGDAT	MBAJA	NGMISC
IEOCONS	NGLNGDAT	MDPIP1	NGMISC
INTRAREG_TAR	NGDTAR	MDPIP2	NGMISC
INTRAST_TAR	NGDTAR	MEX_XMAP	NGMAP
IN_ALP	NGDTAR	MINPRCRG	NGLNGDAT
IN_CNST	NGDTAR	MINYR	NGPTAR
IN_DIST	NGDTAR	MISC_GAS	NGHISAN
IN_LNQ	NGDTAR	MISC_OIL	NGHISAN
IN_PKALP	NGDTAR	MISC_ST	NGHISAN
IN_RHO	NGDTAR	MONMKT_PRD	NGHISMN
L_AVG_SALARY	NGLNGDAT	MON_PEXP	NGHISMN
L_AVGTAX	NGLNGDAT	MON_PIMP	NGHISMN
L_CEO_FACTY	NGLNGDAT	MON_QEXP	NGHISMN
L_CONV_FAC	NGLNGDAT	MON_QIMP	NGHISMN
L_CORPTAX	NGLNGDAT	MUFAC	NGUSER
L_COST_EQUTY	NGLNGDAT	NAW	NGHISAN
L_COSTRUNUP	NGLNGDAT	NG_CCAP	NGMISC
L_DEBTRATIO	NGLNGDAT	NG_CENMAP	NGMAP
L_DEPREYR	NGLNGDAT	NGCFEL	NGHISMN
L_EXPFAC	NGLNGDAT	NGDBGCNTL	NGUSER
L_EXPYRS	NGLNGDAT	NGDBGRPT	NGUSER
L_FUEL_PCT	NGLNGDAT	NINJ_TOT	NGHISMN
L_INTPREMIUM	NGLNGDAT	NNETWITH	NGUSER
L_MAINT_PCT	NGLNGDAT	NOBLDYR	NGUSER
L_PARM_A	NGLNGDAT	NODE_2ARC	NGMAP
L_PARM_B	NGLNGDAT	NODE_ANGTS	NGMAP
L_STAFF_NUM	NGLNGDAT	NODE_SNGCOAL	NGMAP
L_UTILRATE	NGLNGDAT	NPROC	NGMAP
LA_OFFD	NGHISAN	NQPF_TOT	NGHISMN
LA_OFST	NGHISAN	NSUPLM_TOT	NGHISMN
LA_ONSH	NGHISAN	NUMPLNADD	NGLNGDAT
LCURCAP	NGMISC	NUM_REGSHR	NGDTAR
LEVELYRS	NGPTAR	NUMRS	NGDTAR
LIQTYP	NGLNGDAT	NWTH_TOT	NGHISMN
LLOSS	NGLNGDAT	NYR_MISS	NGHISAN
LNGBLDT	NGLNGDAT	OCSMAP	NGMAP
LNGDIFF	NGMISC	oEL_MRKUP_BETA	NGDTAR
LNGELAS	NGLNGDAT	oOGHHPRNG	NGMISC

Variable	File	Variable	File
OPTIND	NGDTAR	Q23TO3	NGCAN
OPTCOM	NGDTAR	QAK_ALB	NGMISC
OPTRES	NGDTAR	QLP_LHIS	NGHISMN
OPTELP	NGDTAR	QMD_ALB	NGMISC
OPTELO	NGDTAR	QNGIMP	NGLNGDAT
OPUTZ	NGCAP	QOF_AL	NGHISAN
PAR_CON	NGLNGDAT	QOF_ALFD	NGHISAN
PAR_WOP	NGLNGDAT	QOF_ALST	NGHISAN
PARM_MINPR	NGUSER	QOF_CA	NGHISAN
PARM_SUPCRV3	NGUSER	QOF_GM	NGHISAN
PARM_SUPCRV5	NGUSER	QOF_LA	NGHISAN
PARM_SUPELAS	NGUSER	QOF_LAFD	NGHISAN
PCTADJSHR	NGUSER	QOF_LAST	NGHISAN
PCNT_R	NGPTAR	QOF_TX	NGHISAN
PCTFLO	NGUSER	QOF_MS	NGHISAN
PCURCAP	NGMISC	QSUP_DELTA	NGUSER
PERAVGRG	NGLNGDAT	QSUP_SMALL	NGUSER
PERMAXLQ	NGLNGDAT	QSUP_WT	NGUSER
PERMAXRG	NGLNGDAT	RCURCAP	NGMISC
PERMG	NGDTAR	RECS_ALIGN	NGDTAR
PERMINRG	NGLNGDAT	RETAIL_COST	NGDTAR
PER_YROPEN	NGCAP	REV	NGHISMN
PIPE_FACTOR	NGPTAR	RGELAS	NGLNGDAT
PKOPMON	NGMISC	RG_ACRE_MIN	NGLNGDAT
PKSHR_CDMD	NGCAN	RG_ACRE_CAP	NGLNGDAT
PKSHR_PROD	NGCAN	RG_BCF_MMTONS	NGLNGDAT
PKUTZ	NGCAP	RG_CST_2MARINE	NGLNGDAT
PLANPCAP	NGCAN	RG_CST_5VAP	NGLNGDAT
PLANPCAP	NGCAP	RG_CST_ACRE	NGLNGDAT
PLOSS	NGLNGDAT	RG_CST_BLDS	NGLNGDAT
PMMMAP_NG	NGMAP	RG_CST_ENGR	NGLNGDAT
PRC_EPMCD	NGHISMN	RG_CST_INSTALL	NGLNGDAT
PRC_EPMGR	NGHISMN	RG_CST_MARINE	NGLNGDAT
PRCWTS	NGMISC	RG_CST_MISC	NGLNGDAT
PRCWTS2	NGMISC	RG_CST_SITE	NGLNGDAT
PRD_MLHIS	NGHISMN	RG_CST_TANK	NGLNGDAT
PRICE_AL	NGHISAN	RG_CONT_FRAC	NGLNGDAT
PRICE_CA	NGHISAN	RG_CORP_TAXRAT	NGLNGDAT
PRICE_LA	NGHISAN	RG_COST_KWH	NGLNGDAT
PRICE_TX	NGHISAN	RG_COST_WAGES	NGLNGDAT
PROC_ORD	NGMAP	RG_DEBT_EQTY	NGLNGDAT
PSTEP	NGLNGDAT	RG_DOLS	NGLNGDAT
PSUP_DELTA	NGUSER	RG_ENDOG	NGLNGDAT
PTCURPCAP	NGCAP	RG_FUEL_MMBTU	NGLNGDAT
PTMAXPCAP	NGCAN	RG_FUEL_FRAC	NGLNGDAT
PTMBYR	NGPTAR	RG_INSUR_CAPCST	NGLNGDAT
PTMSTBYR	NGPTAR	RG_INSUR_FRAC	NGLNGDAT
PUTL_POW	NGHISAN	RG_INT_CONST	NGLNGDAT
PUTLFYR	NGHISAN	RG_KW_MMTONS	NGLNGDAT
PUTLLYR	NGHISAN	RG_LIFE_YRS	NGLNGDAT

Variable	File	Variable	File
RG_OM_CAPCST	NGLNGDAT	SH_BUNKER_COST	NGLNGDAT
RG_OM_FRAC	NGLNGDAT	SH_BUNKER_DAY	NGLNGDAT
RG_PER_FUEL	NGLNGDAT	SH_CAP_CM	NGLNGDAT
RG_REG_ADJ	NGLNGDAT	SH_CORP_TAXRAT	NGLNGDAT
RG_RISK_DEBT	NGLNGDAT	SH_DEBT_EQTY	NGLNGDAT
RG_RISK_FAC	NGLNGDAT	SH_DOLS	NGLNGDAT
RG_RISK_SCAL	NGLNGDAT	SH_ENDOG	NGLNGDAT
RG_TANK_CAP	NGLNGDAT	SH_LIFE_YRS	NGLNGDAT
RG_TAX_CAPCST	NGLNGDAT	SH_LNG_COST	NGLNGDAT
RG_TAX_FRAC	NGLNGDAT	SH_LOAD_DAY	NGLNGDAT
RG_UTIL_FIN	NGLNGDAT	SH_MILES	NGLNGDAT
RG_VAP_CAP	NGLNGDAT	SH_NUMBLD_YR	NGLNGDAT
RISKPREM	NGLNGDAT	SH_OPC_PER	NGLNGDAT
RLOSS	NGLNGDAT	SH_PORT_COST	NGLNGDAT
ROF_AL	NGHISAN	SH_RISK_FAC	NGLNGDAT
ROF_CA	NGHISAN	SH_RISK_SCAL	NGLNGDAT
ROF_GM	NGHISAN	SH_SPEED	NGLNGDAT
ROF_LA	NGHISAN	SH_UNIT_COST	NGLNGDAT
ROF_MS	NGHISAN	SH_UTL_RATE	NGLNGDAT
ROF_TX	NGHISAN	SHR_OPT	NGUSER
RS_ADJ	NGDTAR	SIMP	NGHISAN
RS_ALP	NGDTAR	SIM_EX	NGHISAN
RS_COST	NGDTAR	SITM_RG	NGHISAN
RS_LNQ	NGDTAR	SLOSS	NGLNGDAT
RS_PARM	NGDTAR	SMKT_PRD	NGHISAN
RS_PKALP	NGDTAR	SNET_WTH	NGHISAN
RS_RHO	NGDTAR	SNGCOAL	NGMISC
RSTEP	NGLNGDAT	SNGCOAL	NGHISAN
SAFLOW	NGMISC	SNGLIQ	NGHISAN
SARC_2NODE	NGMAP	SNG_EM	NGHISAN
SBAL_ITM	NGHISAN	SNG_OG	NGHISAN
SCEN_DIV	NGHISAN	SNODE_2ARC	NGMAP
SCH_ID	NGHISAN	SNUM_ID	NGHISAN
SCRV_PLQ	NGLNGDAT	SPCM	NGHISAN
SCRV_PPR	NGLNGDAT	SPCNEWFAC	NGPTAR
SCRV_PRG	NGLNGDAT	SPCNODID	NGPTAR
SCRV_PSH	NGLNGDAT	SPCNODN	NGPTAR
SCRV_QLQ	NGLNGDAT	SPCPNODBAS	NGPTAR
SCRV_QPR	NGLNGDAT	SPEU	NGHISAN
SCRV_QRG	NGLNGDAT	SPEX	NGHISAN
SCRV_QSH	NGLNGDAT	SPIM	NGHISAN
SCRV_YLQ	NGLNGDAT	SPIN	NGHISAN
SCRV_YPR	NGLNGDAT	SPIN_PER	NGHISAN
SCRV_YRG	NGLNGDAT	SPLANPCAP	NGCAP
SCRV_YSH	NGLNGDAT	SPRS	NGHISAN
SCURCAP	NGMISC	SPTR	NGHISAN
SDRY_PRD	NGHISAN	SPWH	NGHISAN
SEXP	NGHISAN	SQCM	NGHISAN
SH_AVAIL_DAY	NGLNGDAT	SQEU	NGHISAN
SH_BOIL_RATE	NGLNGDAT	SQIN	NGHISAN

Variable	File
SQLP	NGHISAN
SQPF	NGHISAN
SQRS	NGHISAN
SQTR	NGHISAN
SRATE	NGPTAR
SSTEP	NGLNGDAT
SSUPLM	NGHISAN
STADIT_ADIT	NGPTAR
STADIT_C	NGPTAR
STADIT_NEWCAP	NGPTAR
STCCOST_BETAREG	NGPTAR
STCCOST_CREG	NGPTAR
STCSTFAC	NGPTAR
STCWC_CREG	NGPTAR
STCWC_RHO	NGPTAR
STCWC_TOTCAP	NGPTAR
STDDA_CREG	NGPTAR
STDDA_NEWCAP	NGPTAR
STDDA_NPIS	NGPTAR
STDISCR	NGUSER
STENDCON	NGUSER
STEOYRS	NGUSER
STEPLQ	NGLNGDAT
STEPPR	NGLNGDAT
STEPRG	NGLNGDAT
STEPSH	NGLNGDAT
STLNGIMP	NGUSER
STLNGRG	NGUSER
STLNGRGN	NGUSER
STLNGYR	NGUSER
STLNGYRN	NGUSER
STOGPRSUP	NGUSER
STOGWPRNG	NGUSER
STPHAS_YR	NGUSER
STPNGCM	NGUSER
STPNGEL	NGUSER
STPNGRS	NGUSER
STQGPTR	NGUSER
STQLPIN	NGUSER
STR_2NODE	NGMAP
STR_EFF	NGPTAR
STRATIO	NGPTAR
STR_FACTOR	NGPTAR
STRT_YR	NGLNGDAT
STSCAL_CAN	NGUSER
STSCAL_DISCR	NGUSER
STSCAL_FPR	NGUSER
STSCAL_IPR	NGUSER
STSCAL_LPLT	NGUSER
STSCAL_NETSTR	NGUSER
STSCAL_PFUEL	NGUSER
STSCAL_SUPLM	NGUSER
STSCAL_WPR	NGUSER
STTOM_C	NGPTAR
STTOM_RHO	NGPTAR
STTOM_WORKCAP	NGPTAR
STTOM_YR	NGPTAR
SUPCRV	NGUSER
SUPSUB_NG	NGMAP
SUPSUB_OG	NGMAP
SUTZ	NGCAP
SYR	NGLNGDAT
TFD	NGDTAR
TFDYR	NGDTAR
TMPGDP	NGLNGDAT
TOM_BYEAR	NGPTAR
TOM_C	NGPTAR
TOM_GPIS1	NGPTAR
TOM_K	NGPTAR
TOM_RHO	NGPTAR
TOM_YR	NGPTAR
TRN_DECL	NGDTAR
TST1,TST2	NGDTAR
TST2YR	NGDTAR
TTRNCAN	NGCAN
TYP	NGLNGDAT
UTIL_ELAS_F	NGDTAR
UTIL_ELAS_I	NGDTAR
NONU_ELAS_F	NGDTAR
NONU_ELAS_I	NGDTAR
VOL	NGLNGDAT
WHP_LHIS	NGHISMN
WPR4CAST_FLG	NGUSER
XBLD	NGCAP

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: Tony Radich, EIA, June 2007

Source: *Natural Gas Annual*, DOE/EIA-0131.

Derivation: Annual data from 1967 through 2005 were transformed into logarithmic form, tested for unit roots, and examined for simple correlations. The effect of heating degree days on residential quantity was statistically insignificant and dropped from the final estimation. Lags of dependent variables were added as needed to remove serial correlation from residuals. Heteroskedasticity-consistent standard error estimators were also used as needed.

Residential Natural Gas Consumption

The forecast equation for residential natural gas consumption is estimated below:

$$QRS = 8.874 + 0.257 * QRS(-1) – 0.356 * QRS(-2) – 0.240 * QRS(-4) + 0.902 * NRS -0.664 * D(PRS)$$

where,

QRS	=	natural log of Alaska residential natural gas consumption in MMcf
NRS	=	natural log of thousands of Alaska residential gas customers. See the forecast equation for Alaska residential gas customers in Table F2.
PRS	=	natural log of Alaska residential natural gas price in 1987 $ per Mcf.
(-1)	=	first lag
(-2)	=	second lag
(-3)	=	third lag
(-4)	=	fourth lag
D( )	=	first difference, i.e., difference between current and previous year’s value

All variables are annual from 1967 through 2005.

Regression Diagnostics and Parameters Estimates:

Dependent Variable: QRS
Method: Least Squares
Date: 07/03/07
Sample (adjusted): 1971- 2005
Included observations: 35 after adjustments
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficien	Std. Erro	t-Statisti	Prob.
C	8.87425	2.55361	3.47516	0.001
QRS(-1)	0.25683	0.29447	0.87216	0.390
QRS(-2)	-0.35580	0.19394	-1.83461	0.076
QRS(-4)	-0.23958	0.11005	-2.17697	0.037
NRS	0.90231	0.25961	3.47560	0.001
D(PRS)	-0.66417	0.28666	-2.31693	0.027

R-squared	0.82276	Mean dependent var	9.38952
Adjusted R-squared	0.79220	S.D. dependent var	0.35579
S.E. of regression	0.16219	Akaike info criterion	-0.64529
Sum squared resid	0.76285	Schwarz criterion	-0.37866
Log likelihood	17.2927	F-statistic	26.9239
Durbin-Watson stat	1.68409	Prob(F-statistic)	0.00000

The equation for the Alaska residential natural gas consumption translates into the following forecast equation in the code:

AKQTY_F(1) = *EXP*[8.874 + (0.257**LOG*(PREV_AKQTY(1,t-1)*1000.)) -
(0.356**LOG*(PREV_AKQTY(1,t-2)*1000.)) -
(0.240**LOG*(PREV_AKQTY(1,t-4)*1000.)) + (0.902*log(AK_RNt))) -
(0.664*(log(AKPR_F(1)) - log(PREV_AKPR(1,t-1))))]/1000.

where,

AKQTY_F(1)	=	residential Alaskan natural gas consumption, (Bcf)
PREV_AKQTY(1,t-1)	=	previous year's residential Alaskan natural gas consumption, (Bcf)
PREV_AKQTY(1,t-2)	=	two-year lag's residential Alaskan natural gas consumption, (Bcf)
PREV_AKQTY(1,t-4)	=	four-year lag's residential Alaskan natural gas consumption, (Bcf)
AK_RNt	=	residential consumers (thousands) at current year. See Table F2
AKPR_F(1)	=	Alaska residential natural gas prices in 1987$ per Mcf
PREV_AKPR(1,t-1)	=	previous year's Alaska residential natural gas price in 1987$ per Mcf

Commercial Natural Gas Consumption

The forecast equation for commercial natural gas consumption is estimated below:

QCM = -0.014 * YEAR + 0.483 * QCM(-1) + 0.430 * NCM + 0.483 * HDD

where,

QCM	=	natural log of Alaska commercial natural gas consumption in MMcf
NCM	=	natural log of thousands of Alaska commercial gas customers. See the forecast equation in Table F2.
HDD	=	natural log of Anchorage heating degree days
(-1)	=	first lag
YEAR	=	time trend (1967 = 0)

Anchorage heating degree days are estimated by the following equation:

HDD = 6.917 – 0.002 * YEAR + 0.255 * HDD(-1)

Regression Diagnostics and Parameters Estimates:

Dependent Variable: QCM
Method: Least Squares
Date: 07/03/07
Sample (adjusted): 1968 2005
Included observations: 38 after adjustments

Variable	Coefficien	Std. Erro	t-Statisti	Prob.
YEAR	-0.01379	0.00524	-2.63212	0.012
QCM(-1)	0.48299	0.07432	6.49828	0.000
NCM	0.43020	0.11702	3.67623	0.000
HDD	0.48347	0.06725	7.18828	0.000

R-squared	0.86915	Mean dependent var	9.79848
Adjusted R-squared	0.85761	S.D. dependent var	0.33661
S.E. of regression	0.12702	Akaike info criterion	-1.18964
Sum squared resid	0.54855	Schwarz criterion	-1.01726
Log likelihood	26.6032	Durbin-Watson stat	1.63469

Dependent Variable: HDD
Method: Least Squares
Date: 07/03/07
Sample (adjusted): 1968-2005
Included observations: 38 after adjustments
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficien	Std. Erro	t-Statisti	Prob.
C	6.91680(	1.53418(	4.50844(	0.000:
YEAR	-0.00197:	0.00106:	-1.85412	0.072:
HDD(-1)	0.25472	0.16497(	1.54406(	0.131(

R-squared	0.20846(	Mean dependent var	9.23033
Adjusted R-squared	0.16323(	S.D. dependent var	0.07244(
S.E. of regression	0.06626(	Akaike info criterion	-2.51451
Sum squared resid	0.15370	Schwarz criterion	-2.38523:
Log likelihood	50.7758:	F-statistic	4.60906
Durbin-Watson stat	2.04070(	Prob(F-statistic)	0.01671

The equation for the Alaska commercial natural gas consumption translates into the following forecast equation in the code:

AKQTY_F(2) = exp[(-0.014*YEAR) + (0.483*log(PREV_AKQTY(2,MODYR-1)*1000.)) + (0.430*log(AK_CN(MODYR))) + (0.483*log(AK_HDD(MODYR)))]/1000.

where,

AKQTY_F(2) = commercial Alaskan natural gas consumption, (Bcf)
YEAR = time trend (1967=0)
PREV_AKQTY(2,t-1) = previous year's commercial Alaskan natural gas consumption, (Bcf)
AK_CN_t = commercial consumers (thousands) at current year. See Table F2
AK_HDD_t = Anchorage heating degree days

Natural Gas Wellhead Price

The forecast equation for natural gas wellhead price is determined below:

$AK\_WPRC_t = AK\_F_1 + (AK\_F_2 * T2)$

Variables:	AK_F(1)	AK_F(2)
Estimated Value:	0.4540	0.0279
t-statistic:	(7.08)	(7.97)

R Squared: 0.69
rho = 0.4466 (t-2.64), Durbin-Watson = 1.07
Strong serial correlation exists between the disturbance terms. After correcting the model using the first-order autocorrelation coefficient (rho), the equation parameters become:

Parameters:	AK_F(1)	AK_F(2)
Estimated Value:	0.4746	0.0268
t-statistic	(4.82)	(5.06)

R-Squared = 0.75
Durbin-Watson = 1.77
Autoregressive parameter, ρ = -0.44665 (t= 2.64)

The forecast equation becomes:

$$AK\_WPRC_t = AK\_F_1 + (AK\_F_2 * T2) - \rho * (AK\_WPRC_{t-1} - (AK\_F_1 + (AK\_F_2 * (T2-1))))$$

where,

t	=	year index
T2	=	time trend variable having value 1, 2, 3,..., 32 starting from 1970 to 2001. In 2030, the T2 variable will take on the value of 61.
AK_WPRC_t	=	average natural gas wellhead price (1987$/Mcf) in current year.
AK_F	=	Parameters for Alaskan natural gas wellhead price (Appendix E).

Data used in estimating parameters in Tables F1 and F2

Year	Residential Consumption	Commercial Consumption	Residential Price	Commercial Price	Wellhead Price	Historical Population	HDD, Anchorage	Residential Customers	Commercial Customers	gdp defl
	(mmcf)	(mmcf)	(1987 $/Mcf)	(1987 $/Mcf)	(1987 $/Mcf)	(thousands)		(thousands)	(thousands)	
1967	1,958	2,722	4.63	3.03	0.77	278.00	10,521	9.00	2.00	0.2389
1968	2,293	4,713	4.47	2.23	0.73	285.00	10,637	11.00	2.00	0.2491
1969	4,573	11,018	4.25	1.82	0.70	296.00	9,881	14.00	4.00	0.2615
1970	6,211	12,519	4.04	1.81	0.66	302.58	10,137	15.00	4.00	0.2753
1971	6,893	14,256	3.87	1.85	0.61	315.51	11,879	18.00	3.00	0.2891
1972	8,394	16,011	3.76	1.99	0.36	324.46	12,016	21.00	3.00	0.3017
1973	5,024	12,277	3.61	1.79	0.34	330.54	11,665	23.00	3.00	0.3185
1974	4,163	13,106	3.33	1.83	0.36	341.06	10,683	22.00	4.00	0.3473
1975	10,393	14,415	3.14	1.87	0.58	376.17	11,308	25.00	4.00	0.3800
1976	10,917	14,191	3.00	1.89	0.71	400.97	10,361	28.00	4.00	0.4020
1977	11,282	14,564	2.93	2.29	0.68	403.44	9,394	30.00	5.00	0.4275
1978	12,166	15,208	2.82	2.11	0.83	404.77	9,131	33.00	5.00	0.4576
1979	7,313	15,862	2.53	1.52	0.77	402.75	9,450	36.00	6.00	0.4955
1980	7,917	16,513	2.34	1.44	0.99	401.85	10,583	37.00	6.00	0.5404
1981	7,904	16,149	2.41	1.73	0.77	418.49	9,470	40.00	6.00	0.5912
1982	10,554	24,232	2.09	1.86	0.74	449.61	11,251	48.00	7.00	0.6273
1983	10,434	24,693	2.62	2.18	0.82	488.42	10,106	55.00	8.00	0.6521
1984	11,833	24,654	2.69	2.24	0.79	513.70	9,578	63.00	10.00	0.6766
1985	13,256	20,344	2.95	2.48	0.78	532.50	10,528	65.00	10.00	0.6971
1986	12,091	20,874	3.34	2.60	0.51	544.27	9,718	66.00	11.00	0.7125
1987	12,256	20,224	3.21	2.41	0.94	539.31	9,679	68.00	11.00	0.7320
1988	12,529	20,842	3.35	2.51	1.23	541.98	9,916	69.00	12.00	0.7569
1989	13,589	21,738	3.38	2.39	1.27	547.16	10,547	70.00	12.00	0.7856
1990	14,165	21,622	3.40	2.36	1.24	550.04	10,893	70.81	11.92	0.8159
1991	13,562	20,897	3.62	2.51	1.28	569.27	10,186	72.57	12.07	0.8444
1992	14,350	21,299	3.21	2.24	1.19	587.07	10,691	74.27	12.20	0.8639
1993	13,858	20,003	3.28	2.30	1.18	596.99	9,374	75.84	12.36	0.8838
1994	14,895	20,698	2.92	2.01	1.03	600.62	10,294	77.67	12.48	0.9026
1995	15,231	24,979	2.88	1.80	1.30	601.35	9,979	79.47	12.58	0.9211
1996	16,179	27,315	2.67	1.81	1.26	604.92	10,984	81.35	12.73	0.9385
1997	15,146	26,908	2.89	1.87	1.40	608.85	9,729	83.60	12.95	0.9541
1998	15,617	27,079	2.78	1.83	1.00	615.21	10,025	86.24	13.18	0.9647
1999	17,634	27,667	2.72	1.63	1.02	619.50	11,088	88.92	13.41	0.9787
2000	15,987	26,485	2.62	1.51	1.29	627.53	9,761	91.25	13.71	1.0000
2001	16,818	15,849	3.02	2.26	1.42	632.24	10,056	93.90	14.00	1.0240
2002	16,191	15,691	3.10	2.40	1.50	640.54	9,405	97.08	14.34	1.0419
2003	16,853	17,270	3.02	2.46	1.66	647.75	9,347	100.40	14.00	1.0631
2004	18,200	18,373	3.27	2.78	2.29	656.85	9,610	104.30	14.36	1.0910
2005	18,029	16,903	3.74	3.22	3.10	663.25	9,340	108.40	14.12	1.1213

Table F2

Data: Equations for the number of residential and commercial customers in Alaska

Author: Tony Radich, EIA, June, 2007.

Source: *Natural Gas Annual* (1985-2000), DOE/EIA-0131, see Table F1.

Derivation: **a. Residential customers**

Since 1967, the number of residential households has increased steadily, mirroring the population growth in Alaska. Because the current year's population is highly dependent on the previous year's value, the number of residential consumers was estimated based on its lag values. The forecast equation is determined as follows:

$$NRS = -2.677 + 0.888 * NRS(-1) – 0.185 * NRS(-2) + 0.626 * POP$$

where,

NRS = natural log of thousands of Alaska residential gas customers (AK_RN in the code, Appendix E)
POP = natural log of Alaska population in thousands (AK_POP in the code, Appendix E)
(-1) = first lag
(-2) = second lag

Regression Diagnostics and Parameters Estimates:

Dependent Variable: NRS
Method: Least Squares
Date: 07/03/07
Sample (adjusted): 1969-2005
Included observations: 37 after adjustments

Variable	Coefficien	Std. Erro	t-Statisti	Prob.
C	-2.67733	0.94605	-2.82999	0.007
NRS(-1)	0.88772	0.16640	5.33465	0.000
NRS(-2)	-0.18450	0.14121	-1.30656	0.200
POP	0.62643	0.20168	3.10599	0.003

R-squared	0.99580	Mean dependent var	3.95082
Adjusted R-squared	0.99542	S.D. dependent var	0.60233
S.E. of regression	0.04076	Akaike info criterion	-3.46040
Sum squared resid	0.05482	Schwarz criterion	-3.28624
Log likelihood	68.0174	F-statistic	2609.42
Durbin-Watson stat	1.65615	Prob(F-statistic)	0.00000

This translates into the following forecast equation in the code:

$$AK\_RN_t = \exp[-2.677 + (0.888*\log(AK\_RN_{t-1})) - (0.185*\log(AK\_RN_{t-2})) + (0.626*\log(AK\_POPt))]$$

b. Commercial customers

The number of commercial consumers, based on billing units, also showed a strong relationship to its lag value. The forecast equation was determined as follows:

NCM = -6.081 + 0.422 * NCM(-1) + 1.182 * POP

where,

NCM	=	natural log of thousands of Alaska commercial gas customers (AK_CM in the code, Appendix E)
POP	=	natural log of Alaska population in thousands (AK_POP in the code, Appendix E)
(-1)	=	first lag

Regression Diagnostics and Parameters Estimates:

Dependent Variable: NCM
Method: Least Squares
Date: 07/03/07
Sample (adjusted): 1968-2005
Included observations: 38 after adjustments
White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficien	Std. Erro	t-Statisti	Prob.
C	-6.08090	2.52285	-2.41033	0.021
NCM(-1)	0.42225	0.23203	1.81979	0.077
POP	1.18184	0.48303	2.44671	0.019

R-squared	0.96170	Mean dependent var	2.08164
Adjusted R-squared	0.95952	S.D. dependent var	0.58200
S.E. of regression	0.11709	Akaike info criterion	-1.37597
Sum squared resid	0.47990	Schwarz criterion	-1.24669
Log likelihood	29.1435	F-statistic	439.515
Durbin-Watson stat	1.92678	Prob(F-statistic)	0.00000

This translates into the following forecast equation in the code:

$$AK\_CN_t = \exp[-6.081 + (0.422*\log(AK\_CN_{t-1})) + (1.182*\log(AK\_POP_t))]$$

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, 1994-2003
Foster Storage Financial Data, 1990-1998

Variables:

For Transportation:

R_CWC = total pipeline transmission cash working capital for existing and new capacity (2000 real 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 >= 2004)
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 (1996 real dollars)
GPIS = capital cost of plant in service for existing and new capacity (nominal dollars)

POLICY_CHG = binary variable representing a change in tax policy in 2004 known as the Jobs and Growth Tax Relief and Reconciliation Act of 2003 (POLICY_CHG = 1 if MODYEAR is equal to 2004 and POLICY_CHG = 0 if MODYEAR is not equal to 2004)
TECHYEAR = MODYEAR (time trend in Julian units, the minimum value of this variable in the sample being 1994, otherwise TECHYEAR=0 if less than 1994)
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 real 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 real 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, March 29-31, 2006.
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 1994 through 2003. 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 GPIS and the level of cash working capital R_CWC_a was assumed. A preliminary analysis was tested for unobserved arc specific effects using binary variables for each arc. No evidence of arc specific effects was found.

The forecasting equation is presented in two stages.

Stage 1:

$$\begin{aligned} Ln(R\_CWC_{a,t}) &= CWC\_C*(1-\rho) + CWC\_GPIS*Ln(GPIS_{a,t}) + \\ &\rho*Ln(R\_CWC_{a,t-1}) - \rho*CWC\_GPIS*Ln(GPIS_{a,t-1}) \end{aligned}$$

Stage 2:

$$R\_CWC_{a,t} = CWC\_K * \exp(Ln(R\_CWC_{a,t}))$$

where 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: 395

Mean of dep. var.	= 19248.9	LM het. test	=81.0123 [.000]
Std. dev. of dep. var.	= 30831.0	Durbin-Watson	= 2.58513 [<1.00]
Sum of squared residuals	= .106006E+11	Jarque-Bera test	= 8803.11 [.000]
Variance of residuals	= .269051E+08	Ramsey's RESET2	= .442761 [.506]
Std. error of regression	= 5187.02	Schwarz B.I.C.	= 3941.77
R-squared	= .971719	Log likelihood	= -3938.78
Adjusted R-squared	= .971719		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
CWC_K	1.00749	.731571E-02	137.716	[.000]

Parameter	Estimate	Standard Error	t-statistic	P-value
CWC_C	-1.86043	2.46851	-.753668	[.451]
CWC_GPIS	.747776	.196809	3.79950	[.000]
RHO (= ρ)	.952451	.017352	54.8913	[.000]

__For Storage:__

$$\begin{aligned} R\_STCWC_{r,t} &= e^{(\beta_{0,r}*(1-\rho))} * DSTTCAP_{r,t-1}^{\beta_1} * \\ &R\_STCWC_{r,t-1}^{\rho} * DSTTCAP_{r,t-2}^{-\rho*\beta_1} \end{aligned}$$

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 1994 through 2003. 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.

$$\begin{aligned} DDA\_E_{a,t} = {} & DDA\_C_a * ARC_a * (1-\rho) + DDA\_NPIS * NPIS_{a,t-1} + \\ & DDA\_NEWCAP * NEWCAP\_E_{a,t} + \rho * DDA\_E_{a,t-1} \\ & - \rho * (DDA\_NPIS * NPIS_{a,t-2} + DDA\_NEWCAP * NEWCAP\_E_{a,t-1}) \end{aligned}$$

where,

DDA_C_a = constant term estimated by arc for the binary variable ARC_a (see Table F3.2, $DDA\_C_a = B\_ARC_{xx\_yy}$)
ARC_a = binary variable created for each arc to control for arc specific effects
DDA_NPIS = estimated coefficient (see Table F3.2)
DDA_NEWCAP = estimated coefficient (see Table F3.2)
ρ = first-order autocorrelation, DDA_RHO (see Table F3.2)

The results of this regression are reported below:

Dependent variable: DDA_E

Mean of dep. var.	= 23989.0	R-squared	= .992291
Std. dev. of dep. var.	= 32138.3	Adjusted R-squared	= .991119
Sum of squared residuals	= .313701E+10	LM het. Test	= 86.8138 [.000]
Variance of residuals	= .917255E+07	Durbin-Watson	= 2.52311 [<1.00]
Std. error of regression	= 3028.62		

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 F3.3, $\beta_{0,r}$ = REG_r)
	= STDDA_CREG (Appendix E)
β_1, $\beta 2$	= (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 1994 through 2003. 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 was:

$$delta\ ADIT_{a,t} = ADIT\_C_a * ARC_a + ADIT\_NEWCAP * NEWCAP_{a,t} + BPOLICY\_CHG * POLICY\_CHG$$

where,

$ADIT\_C_a$	= constant term estimated by arc for the binary variable ARC_a (see Table F3.4, $ADIT\_C_a = B\_ARC_{xx\_yy}$)
ADIT_NEWCAP	= estimated coefficient (see Table F3.4)
BPOLICY_CHG	= estimated coefficient (see Table F3.4)

For Storage:

$$STADIT_{r,t} = \beta_0 + \beta_1 * STADIT_{r,t-1} + \beta_2 * NEWCAP_{r,t}$$

where,

β_0 = -212.535
= STADIT_C (Appendix E)
$\beta_{1,}\ \beta 2$ = (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 1994 through 2003. 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:

$$
\begin{aligned}
&Ln(R\_TOM_{a,t}) = TOM\_C_a * ARC_a * (1-\rho) + TOM\_GPIS1 * Ln(GPIS_{a,t-1}) \\
&+ TOM\_BYEAR * TECHYEAR + \rho * Ln(R\_TOM_{a,t-1}) \\
&- \rho * (TOM\_GPIS1 * Ln(GPIS_{a,t-2} + TOM\_BYEAR * (TECHYEAR-1))
\end{aligned}
$$

Stage 2:

$$R\_TOM_{a,t} = TOM\_K * \exp(Ln(R\_TOM_{a,t}))$$

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 ARC_a (see Table F3.5, $TOM\_C_a = B\_ARC_{xx\_yy}$)
ARC_a = binary variable created for each arc to control for arc specific effects

TOM_GPIS1 = estimated coefficient (see Table F3.5)
TOM_BYEAR = estimated coefficient (see Table F3.5)
ρ = first-order autocorrelation, TOM_RHO (see Table F3.5)

The results of this regression are reported below:

Dependent variable: R_TOM
Number of observations: 395

Mean of dep. var.	= 53631.8	LM het. Test	= 5.12601 [.024]
Std. dev. of dep. var.	= 77048.6	Durbin-Watson	= 2.43022 [<1.00]
Sum of squared residuals	= .500261E+11	Jarque-Bera test	= 30569.1 [.000]
Variance of residuals	= .126970E+09	Ramsey's RESET2	= .453221 [.501]
Std. error of regression	= 11268.1	Schwarz B.I.C.	= 4248.21
R-squared	= .978629	Log likelihood	= -4245.22
Adjusted R-squared	= .978629		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
TOM_K	1.00477	.611758E-02	164.243	[.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_WORCAP (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 Depreciation, Depletion, and Amortization Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
DDA_NEWCAP	6.19E-03	3.19E-03	1.94459	[.052]
DDA_NPIS	0.024735	5.05E-03	4.89433	[.000]
B_ARC01_01	5085.04	1254.95	4.05198	[.000]
B_ARC02_01	5114.78	1334.17	3.83369	[.000]
B_ARC02_02	42015.2	7763.21	5.41209	[.000]
B_ARC02_03	2061.97	434.862	4.74165	[.000]
B_ARC02_05	7601.76	1539.74	4.93705	[.000]
B_ARC03_02	5458.63	1414.26	3.85972	[.000]
B_ARC03_03	30722.7	5486.09	5.60011	[.000]
B_ARC03_04	1135.57	273.249	4.15581	[.000]
B_ARC03_05	3635.29	1629.26	2.23126	[.026]
B_ARC03_15	6797.03	1469.8	4.62446	[.000]
B_ARC04_03	18296	3508.46	5.21483	[.000]
B_ARC04_04	29936.7	10794	2.77344	[.006]
B_ARC04_07	1911.26	316.274	6.04306	[.000]
B_ARC04_08	-1571.57	1293.61	-1.21487	[.224]
B_ARC05_02	16465.1	3712.78	4.4347	[.000]
B_ARC05_03	6368.64	1302.42	4.88984	[.000]
B_ARC05_05	40334.8	6760.3	5.96642	[.000]
B_ARC05_06	450.49	99.4	4.53209	[.000]
B_ARC06_03	12359.3	2535.92	4.87368	[.000]
B_ARC06_05	21073.8	3809.49	5.53191	[.000]
B_ARC06_06	66017	12786	5.16322	[.000]
B_ARC06_07	1180.34	139.593	8.45559	[.000]
B_ARC06_10	14367.1	2618.9	5.48591	[.000]
B_ARC07_04	15023.9	2700.87	5.5626	[.000]

Variable	**Coefficient**	**Standard-Error**	**t-statistic**	**P-value**
B_ARC07_06	47154.3	8167.31	5.77354	[.000]
B_ARC07_07	75047.5	16028.1	4.68223	[.000]
B_ARC07_08	921.397	172.749	5.33373	[.000]
B_ARC07_11	3664.43	1947.22	1.88188	[.060]
B_ARC07_21	1180.36	327	3.60965	[.000]
B_ARC08_04	-1449.2	4175.47	-0.34708	[.729]
B_ARC08_07	1440.64	304.401	4.73269	[.000]
B_ARC08_08	33599.8	5975.05	5.62336	[.000]
B_ARC08_09	4912.65	1585.23	3.09902	[.002]
B_ARC08_11	776.144	649.022	1.19587	[.232]
B_ARC08_12	7392.99	1486.09	4.97479	[.000]
B_ARC09_08	2637.87	433.549	6.08437	[.000]
B_ARC09_09	13226.4	2899.51	4.56158	[.000]
B_ARC09_12	2568.74	1008.16	2.54795	[.011]
B_ARC09_20	283.833	39.2326	7.23462	[.000]
B_ARC11_07	3473.7	1457.89	2.38269	[.017]
B_ARC11_08	978.325	374.445	2.61274	[.009]
B_ARC11_11	4248.57	2676.64	1.58728	[.112]
B_ARC11_12	2943.12	2029.66	1.45005	[.147]
B_ARC11_22	180.633	86.2674	2.09387	[.036]
B_ARC15_02	1762.2	625.512	2.8172	[.005]
B_ARC16_04	7144.35	1577.54	4.52879	[.000]
B_ARC17_04	2965.74	1448.98	2.04678	[.041]
B_ARC19_09	3498.46	1370.66	2.5524	[.011]
B_ARC20_09	5768.88	944.742	6.1063	[.000]
B_ARC21_07	709.327	216.933	3.26979	[.001]
DDA_RHO(=ρ)	0.210326	0.159839	1.31586	[.188]

Table F3.3. Summary Statistics for Storage Depreciation, Depletion, and Amortization Equation

Variable	**Coefficient**	**St-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 F3.4. Summary Statistics for Pipeline Accumulated Deferred Income Tax Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
BPOLICY_CH	0.098683	0.028051	3.51799	[.000]
ADIT_NEWCAP	0.041124	0.019618	2.09624	[.036]
B_ARC01_01	2669.77	1005.56	2.655	[.008]
B_ARC02_01	2180.33	840.357	2.59453	[.009]
B_ARC02_02	15558.8	3826.1	4.06648	[.000]
B_ARC02_03	675.908	170.2	3.97125	[.000]
B_ARC02_05	2892.77	722.223	4.00537	[.000]
B_ARC03_02	1636.8	485.076	3.37432	[.001]
B_ARC03_03	4805.04	6627.6	0.725004	[.468]
B_ARC03_04	-104.457	201.979	-0.51717	[.605]
B_ARC03_05	3272.05	978.859	3.34272	[.001]
B_ARC03_15	2185.52	560.889	3.89653	[.000]
B_ARC04_03	3168.08	2967.23	1.06769	[.286]
B_ARC04_04	-6395.59	15384.8	-0.41571	[.678]
B_ARC04_07	-815.874	1140	-0.71568	[.474]
B_ARC04_08	2982.58	1117.94	2.66792	[.008]
B_ARC05_02	6443.12	1609.67	4.00276	[.000]
B_ARC05_03	1368.74	587.12	2.33128	[.020]
B_ARC05_05	8948.74	3382.05	2.64595	[.008]
B_ARC05_06	121.863	77.1132	1.58031	[.114]
B_ARC06_03	2902.52	1853.55	1.56593	[.117]
B_ARC06_05	4831.94	2183.93	2.2125	[.027]
B_ARC06_06	17985.4	7797.5	2.30655	[.021]
B_ARC06_07	-44.6155	237.371	-0.18796	[.851]
B_ARC06_10	3271.28	2650.75	1.23409	[.217]
B_ARC07_04	-3284.93	5079.66	-0.64668	[.518]
B_ARC07_06	9877.2	5136.52	1.92293	[.054]
B_ARC07_07	13105.7	4967.72	2.63817	[.008]
B_ARC07_08	363.518	215.812	1.68442	[.092]
B_ARC07_11	3362.14	1724.54	1.94958	[.051]
B_ARC07_21	872.192	537.273	1.62337	[.105]
B_ARC08_04	5416.81	3254.14	1.66459	[.096]
B_ARC08_07	863.036	345.563	2.49748	[.013]
B_ARC08_08	-692.817	8460.34	-0.08189	[.935]
B_ARC08_09	3616.5	381.921	9.46922	[.000]
B_ARC08_11	1750.89	490.608	3.56881	[.000]
B_ARC08_12	-2334.07	3535.82	-0.66012	[.509]
B_ARC09_08	603.562	213.818	2.82279	[.005]
B_ARC09_09	5556.78	960.084	5.78781	[.000]
B_ARC09_12	2681.59	268.431	9.98986	[.000]
B_ARC09_20	93.4085	41.4262	2.25481	[.024]

Variable	**Coefficient**	**Standard-Error**	**t-statistic**	**P-value**
B_ARC11_07	1659.88	1468.61	1.13023	[.258]
B_ARC11_08	601.913	509.649	1.18103	[.238]
B_ARC11_11	5389.55	2709.13	1.9894	[.047]
B_ARC11_12	3985.64	1622.98	2.45576	[.014]
B_ARC11_22	368.244	246.485	1.49398	[.135]
B_ARC15_02	622.065	270.005	2.3039	[.021]
B_ARC16_04	2131.13	625.495	3.4071	[.001]
B_ARC17_04	-574.601	1098.96	-0.52286	[.601]
B_ARC19_09	3601.3	361.969	9.94921	[.000]
B_ARC20_09	1427.68	475.28	3.00386	[.003]
B_ARC21_07	695.681	285.354	2.43796	[.015]

Table F3.5. Summary Statistics for Pipeline Total Operating and Maintenance Expense Equation

Variable	**Coefficient**	**Standard-Error**	**t-statistic**	**P-value**
TOM_GPIS1	0.583387	0.204955	2.84641	[.004]
TOM_BYEAR	-0.03531	9.93E-03	-3.55395	[.000]
B_ARC01_01	72.9152	17.8781	4.07847	[.000]
B_ARC02_01	72.9055	17.869	4.08	[.000]
B_ARC02_02	73.9683	17.5836	4.20666	[.000]
B_ARC02_03	72.7817	18.0305	4.03659	[.000]
B_ARC02_05	73.4421	17.8352	4.11781	[.000]
B_ARC03_02	73.0351	17.8642	4.08836	[.000]
B_ARC03_03	73.9723	17.5761	4.20869	[.000]
B_ARC03_04	72.3595	18.0903	3.9999	[.000]
B_ARC03_05	73.1401	17.8453	4.09858	[.000]
B_ARC03_15	72.2482	17.8586	4.04558	[.000]
B_ARC04_03	73.3898	17.6876	4.14921	[.000]
B_ARC04_04	73.8435	17.5528	4.20695	[.000]
B_ARC04_07	72.7243	18.0393	4.03144	[.000]
B_ARC04_08	72.5212	17.9032	4.05075	[.000]
B_ARC05_02	73.6639	17.6969	4.16254	[.000]
B_ARC05_03	73.3384	17.8643	4.10529	[.000]
B_ARC05_05	73.8606	17.5985	4.19697	[.000]
B_ARC05_06	72.2234	18.2318	3.9614	[.000]
B_ARC06_03	73.4898	17.7204	4.14718	[.000]
B_ARC06_05	73.6665	17.6807	4.16649	[.000]
B_ARC06_06	74.043	17.4957	4.23207	[.000]
B_ARC06_07	72.5004	18.1156	4.00209	[.000]
B_ARC06_10	72.8397	17.7943	4.09343	[.000]
B_ARC07_04	73.6862	17.7071	4.1614	[.000]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC07_06	73.8563	17.5615	4.20558	[.000]
B_ARC07_07	74.2294	17.4629	4.25069	[.000]
B_ARC07_08	72.4417	18.1493	3.99144	[.000]
B_ARC07_11	73.7026	17.7704	4.14749	[.000]
B_ARC07_21	72.866	18.0641	4.03375	[.000]
B_ARC08_04	72.6851	17.7421	4.09676	[.000]
B_ARC08_07	72.6408	18.0852	4.01659	[.000]
B_ARC08_08	73.3112	17.6703	4.14885	[.000]
B_ARC08_09	72.5807	17.8618	4.06346	[.000]
B_ARC08_11	73.1593	17.9584	4.07383	[.000]
B_ARC08_12	71.9772	17.9074	4.01941	[.000]
B_ARC09_08	72.3579	18.0437	4.01016	[.000]
B_ARC09_09	73.0025	17.7673	4.10881	[.000]
B_ARC09_12	72.3087	17.9291	4.03303	[.000]
B_ARC09_20	71.3061	18.4092	3.87339	[.000]
B_ARC11_07	73.5172	17.816	4.12647	[.000]
B_ARC11_08	73.1014	18.0429	4.05153	[.000]
B_ARC11_11	73.889	17.7311	4.16719	[.000]
B_ARC11_12	73.7343	17.7704	4.14927	[.000]
B_ARC11_22	72.538	18.3479	3.95348	[.000]
B_ARC15_02	72.4572	18.011	4.02294	[.000]
B_ARC16_04	72.0823	17.8504	4.03812	[.000]
B_ARC17_04	71.6735	17.8871	4.007	[.000]
B_ARC19_09	72.4381	17.8828	4.05071	[.000]
B_ARC20_09	72.6902	17.9294	4.05424	[.000]
B_ARC21_07	72.372	18.1164	3.99483	[.000]
TOM_RHO	0.384029	0.062427	6.15169	[.000]

Table F4

Data: Equation for industrial distribution tariffs

Author: Ernest Zampelli, SAIC, 2007.

Source: The source for the peak and off-peak consumption data used in this estimation was the Natural Gas Monthly (1990-2006), DOE/EIA-0130. 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. Prices for the estimations were derived as described in Table F5.

Variables:

$TIN_{r,n,t}$	industrial distributor tariff in region r, network n (1987 dollars per Mcf) [$DTAR\_SF_3$]
$PREG_{r,n}$	=1, if observation is in region r during peak period (n=1), =0 otherwise
$QIN_{r,t}$	industrial gas consumption in region r in year t (MMcf) [$BASQTY\_SF_3+BASQTY\_SI_3$]
r	NGTDM region
t	year
α_0, α_r, $\alpha_{r,n}$	estimated parameters for regional dummy variables [$PINREGPK1_r$]
β	estimated parameter for consumption
ρ	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 industrial distributor tariff equation was estimated using panel data for the 12 NGTDM regions over the 1990 to 2006time period. The equation was estimated in linear form with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5. The form of the estimating equation follows:

$$\ln TIN_{r,n,t} = \alpha_0 + \sum_r \alpha_{r,pk} * REG_{r,pk} + \beta * QIN_{r,t} + \rho * TIN_{r,t-1}$$
$$- \rho * (\alpha_0 + \sum_r \alpha_{r,pk} * REG_{r,pk} + \beta * QIN_{r,t-1})$$

Regression Diagnostics and Parameter Estimates:

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

Objective function: Exact ML (keep first obs.)
Balanced data: N = 24, T_I = 17, NOB = 408
CONVERGENCE ACHIEVED AFTER 7 ITERATIONS

Dependent variable: $TIN_{r,t}$
Number of observations: 408

Mean of dep. var . =	.108629	R-squared =	.594768
Std. dev. of dep. var . =	1.38260	Adjusted R-squared =	.589728
Sum of squared residuals =	315.337	Durbin-Watson =	1.97575
Variance of residuals =	.784420	Schwarz B.I.C. =	544.740
Std. error of regression =	.885675	Log likelihood =	-526.707

Parameter	Estimate	Standard Error	t-statistic	P-value	Variables
α_0	.096182	.032375	2.97090	[.003]	[IN_CONST]
$\alpha_{1,pk}$	.778030	.139153	5.59118	[.000]	[IN_PKALP]
$\alpha_{2,pk}$	.474943	.098595	4.81710	[.000]	[IN_PKALP]
$\alpha_{7,pk}$	-.351311	.082328	-4.26723	[.000]	[IN_PKALP]
β	-.000251581	.0000511346	-4.91990	[.000]	[IN_LNQ]
ρ	.490900	.044680	10.9870	[.000]	[IN_RHO]

Data used for estimation

			New Engl	Mid Atlantic	E.N. Central	W.N. Central	S Atl - Fl	E.S. Central	W.S. Central	Mtn - AZ/NM	WA/OR	Florida	AZ/NM	Calif
			1	2	3	4	5	6	7	8	9	10	11	12
1990	QIN	peak	25.2	156.2	454.0	140.9	185.2	152.2	948.6	56.6	46.2	30.1	13.2	177.1
1990	QIN	off-peak	56.1	270.9	730.7	245.0	351.3	272.4	1987.3	93.8	81.2	55.9	24.5	388.1
1991	QIN	peak	39.3	168.9	481.7	149.9	171.2	158.5	979.3	66.4	47.3	30.2	14.3	201.5
1991	QIN	off-peak	82.4	282.2	729.3	255.0	330.7	288.3	2003.6	109.2	87.5	53.2	24.3	401.1
1992	QIN	peak	54.2	204.1	498.6	156.0	185.1	166.5	1018.4	74.3	49.7	29.9	13.8	217.1
1992	QIN	off-peak	108.8	354.7	777.8	263.9	353.2	305.0	1942.1	128.7	88.6	54.9	23.1	377.4
1993	QIN	peak	61.8	224.1	529.3	167.0	185.5	176.4	1045.5	83.6	54.2	34.3	13.2	214.7
1993	QIN	off-peak	123.3	366.7	786.4	283.2	328.2	305.8	2109.3	148.5	98.7	66.1	25.0	445.0
1994	QIN	peak	60.9	243.6	553.3	190.7	182.9	170.2	1088.7	91.1	58.1	42.8	13.7	210.1
1994	QIN	off-peak	111.8	398.1	795.9	320.4	380.7	299.5	2069.7	149.8	112.1	84.0	30.9	446.7
1995	QIN	peak	67.6	274.8	564.1	177.9	198.2	181.2	1094.9	92.3	63.0	49.5	18.4	216.0
1995	QIN	off-peak	117.1	462.7	842.0	303.0	408.7	324.0	2205.9	154.1	115.9	84.0	30.3	471.9
1996	QIN	peak	54.4	285.5	579.0	166.3	193.9	178.9	1197.0	93.3	66.6	46.1	17.9	231.7
1996	QIN	off-peak	113.0	481.6	876.2	282.2	386.0	324.4	2331.9	168.1	135.4	90.7	31.9	461.8
1997	QIN	peak	48.4	233.8	528.0	180.9	213.7	185.7	1158.8	77.5	70.7	41.9	18.4	232.7
1997	QIN	off-peak	86.1	402.4	813.5	291.9	398.9	334.1	2246.5	136.5	130.9	83.2	35.3	487.2
1998	QIN	peak	53.9	226.1	508.1	165.8	200.6	186.8	1119.2	93.1	83.2	40.7	18.1	232.5
1998	QIN	off-peak	95.1	375.2	770.4	298.6	370.2	328.9	2141.0	155.4	152.7	81.2	35.1	513.6
1999	QIN	peak	54.7	194.3	523.0	160.9	221.3	201.0	1023.0	77.4	81.6	43.8	18.7	203.6
1999	QIN	off-peak	101.3	336.3	804.8	274.7	340.8	366.7	2032.5	146.7	150.6	90.4	34.2	522.8
2000	QIN	peak	55.3	148.4	539.9	163.0	194.9	200.2	1080.4	84.8	57.1	35.1	17.3	218.3
2000	QIN	off-peak	85.2	266.5	787.7	285.6	364.3	347.3	2230.7	142.6	102.9	69.6	33.8	558.5
2001	QIN	peak	49.6	139.4	481.0	150.1	155.2	168.5	1051.6	104.2	50.9	30.8	19.0	211.1
2001	QIN	off-peak	85.6	228.8	699.4	258.2	303.5	299.3	1974.5	167.1	94.0	63.9	35.4	455.9

			New Engl	Mid Atlantic	E.N. Central	W.N. Central	S Atl - Fl	E.S. Central	W.S. Central	Mtn - AZ/NM	WA/OR	Florida	AZ/NM	Calif
			1	2	3	4	5	6	7	8	9	10	11	12
2002	QIN	peak	52.5	144.3	470.4	153.7	173.2	176.8	1011.8	91.6	51.5	28.7	14.5	241.2
2002	QIN	off-peak	81.7	234.4	758.8	279.7	328.8	305.4	2005.8	169.3	86.7	54.8	26.0	499.4
2003	QIN	peak	39.7	139.8	481.4	158.5	175.7	176.3	982.8	89.8	47.0	25.3	13.9	252.4
2003	QIN	off-peak	46.1	215.8	678.9	260.2	298.4	286.7	1907.0	146.3	86.4	48.0	25.8	527.1
2004	QIN	peak	37.2	136.4	491.5	156.6	176.4	173.9	974.1	91.3	49.6	23.4	16.2	271.5
2004	QIN	off-peak	45.2	214.2	688.5	265.9	305.7	303.3	1906.9	146.7	89.9	40.2	26.6	564.8
2005	QIN	peak	40.7	133.0	478.5	158.1	171.4	168.2	861.3	93.8	48.3	23.0	14.0	267.7
2005	QIN	off-peak	45.6	202.6	681.3	260.6	289.6	282.8	1642.4	159.8	88.2	40.1	27.8	514.1
2006	QIN	peak	34.9	124.5	428.5	157.2	159.8	156.9	830.1	98.3	50.7	24.7	13.1	244.4
2006	QIN	off-peak	47.2	207.9	673.6	282.9	303.7	292.9	1655.9	155.5	90.1	46.1	22.4	488.0
1990	TIN	peak	1.62	1.23	0.59	0.36	0.58	0.26	-0.54	0.36	0.84	0.74	0.82	1.11
1990	TIN	off-peak	0.62	0.78	0.58	0.15	0.22	0.10	-0.76	-0.31	0.61	0.82	0.95	0.81
1991	TIN	peak	1.58	1.26	0.59	0.32	0.48	0.25	-0.67	0.02	0.82	0.49	0.97	1.30
1991	TIN	off-peak	0.51	0.56	0.44	0.05	-0.02	0.03	-0.66	-0.50	0.74	0.56	0.83	0.86
1992	TIN	peak	1.73	1.07	0.54	0.41	0.49	0.27	-0.63	0.05	0.82	0.58	2.00	1.34
1992	TIN	off-peak	0.21	0.16	0.24	0.14	-0.07	-0.03	-0.59	-0.79	0.87	0.49	1.73	0.48
1993	TIN	peak	1.83	0.87	0.58	0.36	0.48	0.34	-0.55	-0.09	0.75	0.83	1.26	0.29
1993	TIN	off-peak	0.01	.017	0.43	0.01	-0.16	0.04	-0.46	-0.49	0.68	0.98	1.15	-0.20
1994	TIN	peak	1.84	1.06	0.87	0.49	0.49	0.53	-0.51	-0.40	0.59	0.51	1.39	0.77
1994	TIN	off-peak	-0.29	0.36	0.66	-0.05	-0.17	0.11	-0.40	-0.64	0.35	0.65	0.83	0.46
1995	TIN	peak	1.46	0.81	0.48	0.38	0.59	0.55	-0.62	0.11	0.57	0.33	1.60	1.79
1995	TIN	off-peak	-0.34	0.39	0.23	-0.11	0.07	0.07	-0.56	0.11	0.54	0.50	1.32	1.11
1996	TIN	peak	1.66	0.76	0.23	0.53	0.49	0.10	-0.23	0.16	0.50	0.27	1.07	1.12
1996	TIN	off-peak	-0.17	0.14	0.25	-0.15	0.10	0.15	-0.29	0.19	0.20	0.49	1.00	0.86
1997	TIN	peak	1.63	0.89	0.62	-0.30	0.51	0.36	-0.48	0.05	0.69	0.12	0.56	1.42
1997	TIN	off-peak	0.04	-0.70	0.27	-0.37	-0.03	0.12	-0.22	0.33	0.23	0.50	0.43	0.73
1998	TIN	peak	1.42	0.26	0.63	0.33	0.32	0.44	-0.18	0.15	0.46	0.44	0.91	1.59
1998	TIN	off-peak	-0.39	-0.37	0.56	-0.17	-0.26	0.04	-0.10	0.39	0.36	0.41	0.50	0.83
1999	TIN	peak	0.92	0.32	0.63	0.28	0.12	0.40	-0.35	0.78	0.35	1.06	0.72	0.85
1999	TIN	off-peak	-0.30	-0.55	0.25	-0.17	-0.31	0.07	-0.14	0.50	0.24	0.20	0.29	0.42
2000	TIN	peak	1.14	0.90	0.32	0.29	0.42	0.05	-0.33	0.63	0.58	0.38	0.11	0.82
2000	TIN	off-peak	0.34	-0.35	0.31	-0.27	-0.16	-0.08	-0.12	0.68	0.22	0.76	0.18	0.69
2001	TIN	peak	1.10	1.24	0.76	.023	0.64	0.33	-0.31	1.17	0.04	0.44	-0.53	-0.40
2001	TIN	off-peak	1.32	0.92	1.01	0.15	-0.04	0.37	0.08	1.10	0.72	1.57	0.57	0.85
2002	TIN	peak	2.02	1.19	0.88	0.51	0.41	0.56	-0.15	1.50	1.56	1.30	1.42	1.45
2002	TIN	off-peak	0.132	0.68	0.57	0.14	-0.11	0.34	-0.12	0.97	0.77	0.86	0.71	1.07
2003	TIN	peak	1.69	1.64	0.69	0.11	0.42	0.66	0.05	0.67	0.55	-0.07	0.37	1.55
2003	TIN	off-peak	1.40	1.26	1.02	-0.07	-0.15	0.00	0.16	0.14	0.42	1.07	0.90	1.34
2004	TIN	peak	2.74	1.53	1.05	0.39	0.46	0.54	0.09	0.97	0.93	0.93	0.82	1.76
2004	TIN	off-peak	1.71	0.93	0.59	-0.07	0.01	0.21	0.27	0.47	0.52	1.19	0.84	0.97
2005	TIN	peak	2.52	1.76	0.88	0.71	0.92	0.59	0.02	0.97	1.28	0.54	1.27	1.98
2005	TIN	off-peak	1.08	0.97	0.44	-0.52	-0.21	0.22	0.25	0.76	0.79	-0.07	0.76	0.87
2006	TIN	peak	2.44	1.56	0.84	0.92	0.41	0.52	0.05	2.10	1.09	1.81	1.37	1.86
2006	TIN	off-peak	1.56	0.70	0.86	-0.18	0.14	-0.03	0.06	1.99	0.79	2.31	1.63	1.37

Table F5

Data: Historical industrial sector natural gas prices by type of service, NGTDM region.

Derivation: The historical industrial natural gas prices published in the *Natural Gas Annual (NGA)* only reflect gas purchased through local distribution companies. In order to approximate the average price to all industrial customers by service type and NGTDM region (HPGFINGR, HPGIINGR), data available at the Census Division from the 1994 Manufacturing Energy Consumption Survey (MECS)[1] were used to estimate an equation for the regional MECS price as a function of the regional NGA industrial price and the regional supply price (quantity-weighted average of the gas wellhead price and import price). Core and noncore distinctions were assumed based on MECS data for 1988, 1991, and 1994 at the four Census Region level.[2] The procedure is outlined below.

1) Assign average Census Division industrial price using econometrically derived equation:

$$PIN\_NG_{cd} = 1.00501 * \exp(-0.015505) * PW\_CDV_{cd}^{0.195949} * PI\_CDV_{cd}^{.773725}$$

2) Assign prices to the NGTDM regions that represent subregions of Census Divisions by multiplying the Census Division price from step 1 by the subregion price (as published in the NGA), divided by the Census Division price (as published in the NGA). For the Pacific Division, the industrial price in Alaska from the NGA, with quantity weights, is used to approximate a Pacific Division price for the lower-48 (i.e., CA, WA, and OR), before this step is performed.

3) Core industrial prices are derived by applying an historical, regional, average average-to-firm price markup (FDIFF, in 1987$/Mcf, Northeast 0.11, North Central 0.14, South 0.67, West 0.39) to the established average regional industrial price (from step 2). Noncore prices are calculated so that the quantity-weighted average of the core and noncore prices equal the original regional estimate. The data used to generate the average-to-firm markups are presented below.

4) Finally, the peak and off-peak prices from the NGA are scaled to align with the core and noncore prices generated from step 3 on an average annual basis, to arrive at peak/off-peak, core/noncore industrial prices for the NGTDM regions.

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[1]A request was issued to the Census Bureau to obtain similar data from other MECS surveys to improve this estimation.

[2]Through a special request, the Census Bureau generated MECS data by Census Region and by service type (core versus noncore) based on an assumption of which industrial classifications are more likely to consume most of their purchased natural gas in boilers (core) or non-boiler applications (noncore).

	Prices (87$/mcf)			Consumption (Bcf)		
	1988	**1991**	**1994**	**1988**	**1991**	**1994**
Core						
Northeast	3.39	3.05	3.04	335	299	310
North Central	3.04	2.37	2.42	864	759	935
South	2.91	2.40	2.53	643	625	699
West	3.21	2.70	2.55	217	204	227
Noncore						
Northeast	3.05	2.78	2.67	148	146	187
North Central	2.60	2.01	2.17	537	648	747
South	1.96	1.57	1.75	2517	2592	2970
West	2.54	2.19	1.91	347	440	528

Variables:

PIN_NG Industrial natural gas prices by NGTDM region (1987$/Mcf)
PW_CDV Average supply price by Census Division (1987$/Mcf)
PI_CDV Industrial natural gas price from the NGA by Census Division (1987$/Mcf)
FDIFF Average (1988, 1991, 1994) difference between the firm industrial price and the average industrial price by Census Region (1987$/Mcf)
PIN_FNG Industrial core natural gas prices by NGTDM region (1987$/Mcf)
PIN_ING Industrial noncore natural gas prices by NGTDM region (1987$/Mcf)
HPGFINGR Industrial core natural gas prices by period and NGTDM region (1987$/Mcf)
HPGIINGR Industrial noncore natural gas prices by period and NGTDM region (1987$/Mcf)

Estimation: The industrial price equation was estimated using data pooled across the nine Census Divisions for the year 1994. The equation was estimated in log-linear form by ordinary least squares using TSP version 4.5.

$$\ln(PIN\_NG_{cd}) = \beta_0 + \beta_1 * \ln(PW\_CDV_{cd}) + \beta_2 * \ln(PI\_CDV_{cd})$$

Method of estimation = Ordinary Least Squares

Dependent variable: LNPIN_NG
Current sample: 1 to 9
Number of observations: 9

Mean of dep. var. =	.860873	LM het. test =	3.31885 [.068]
Std. dev. of dep. var. =	.207370	Durbin-Watson =	1.22195 [<.255]
Sum of squared residuals =	.032783	Jarque-Bera test =	.128884 [.938]
Variance of residuals =	.546378E-02	Ramsey's RESET2 =	2.97276 [.145]
Std. error of regression =	.073917	F (zero slopes) =	28.4818 [.001]
R-squared =	.904707	Schwarz B.I.C. =	-9.20157
Adjusted R-squared =	.872942	Log likelihood =	12.4974

	Estimated	Standard		
Variable	Coefficient	Error	t-statistic	P-value
C	-.015504	.128982	-.120203	[.908]
LNPW_CDV	.195949	.095673	2.04811	[.086]
LNPI_CDV	.773725	.153329	5.04619	[.002]

Note: Multiplication by 1.00501 is a required adjustment since a variable y is being predicted from an equation where the dependent variable is the natural log of y.

Table F6

Data: Equation for residential distribution tariffs

Author: Ernest Zampelli, SAIC, 2007.

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 region r, network n (1987 dollars per Mcf) [$DTAR\_SF_1$]
REG_r	=1, if observation is in region r, =0 otherwise
$PREG_{r,n}$	=1, if observation is in region r during peak period (n=1), =0 otherwise
$QRS_{r,t}$_NUMR	residential gas consumption for region r in year t (MMcf per thousand customers) [($BASQTY\_SF_1$+$BASQTY\_SI_1$)/NUMRS]
r	NGTDM region
n	network (1=peak, 2=off-peak)
t	year
$\alpha_r,\alpha_{r,n}$	estimated parameters for regional dummy variables [PRSREG3, PRSREGPK3]
β_1, β_2	estimated parameters
ρ	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 residential distributor tariff equation was estimated using panel data for the 12 NGTDM regions over the 1990 to 2005 time period. The equation was estimated in log-linear form with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5. The form of the estimating equation follows:

$$\begin{aligned}\ln TRS_{r,n,t} = {} & \sum_r (\alpha_r * REG_r + \alpha_{r,n} * PREG_{r,n}) + \beta_1 * \ln QRS\_NUMR_{r,t} \\ & + \beta_2 * YEAR_t + \rho * \ln TRS_{r,t-1} \\ & - \rho * (\sum_r (\alpha_r * REG_r + \alpha_{r,pk} * REG_{r,pk}) + \beta_1 * \ln QRS_{r,t-1} + \beta_2 * YEAR_t)\end{aligned}$$

Regression Diagnostics and Parameter Estimates:

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

Objective function: Exact ML (keep first obs.)
Balanced data: NI = 24, T = 16, NOB = 384

CONVERGENCE ACHIEVED AFTER 4 ITERATIONS

Dependent variable: $\ln TRS_{r,t}$
Number of observations: 384

Mean of dep. var . =	10.9599	R-squared =	.973970
Std. dev. of dep. var . =	5.98732	Adjusted R-squared =	.972761
Sum of squared residuals =	357.430	Durbin-Watson =	1.91401
Variance of residuals =	.976585	Schwarz B.I.C. =	584.940
Std. error of regression =	.988223	Log likelihood =	-531.384

Parameter	Estimate	Standard Error	t-statistic	P-value	Variables
α_1	-12.3856	2.62063	-4.72619	[.000]	[RS_ALP]
α_2	-12.3246	2.62141	-4.70151	[.000]	[RS_ALP]
α_3	-12.8268	2.62260	-4.89088	[.000]	[RS_ALP]
α_4	-12.8782	2.62187	-4.91183	[.000]	[RS_ALP]
α_5	-12.5316	2.61980	-4.78342	[.000]	[RS_ALP]
α_6	-12.8081	2.61882	-4.89077	[.000]	[RS_ALP]
α_7	-12.7830	2.61707	-4.88447	[.000]	[RS_ALP]
α_8	-13.0346	2.62206	-4.97111	[.000]	[RS_ALP]
α_9	-12.6091	2.62116	-4.81052	[.000]	[RS_ALP]
α_{10}	-12.4263	2.61350	-4.75464	[.000]	[RS_ALP]
α_{11}	-12.7189	2.61803	-4.85820	[.000]	[RS_ALP]
α_{12}	-12.8488	2.61868	-4.90660	[.000]	[RS_ALP]
$\alpha_{1,pk}$	.279017	.059710	4.67290	[.000]	[RS_PKALP]
$\alpha_{4,pk}$	-.245880	.035723	-6.88289	[.000]	[RS_PKALP]
$\alpha_{10,pk}$	-.269254	.036097	-7.45915	[.000]	[RS_PKALP]
β_1	-.640736	.026258	-24.4011	[.000]	[RS_LNQ]
β_2	.00359432	.00135191	2.65869	[.008]	[RS_LNQ]
ρ	.253685	.050231	5.05040	[.000]	[RS_RHO]

Data used for estimation

			New Engl	Mid Atl	E.N. Central	W.N. Central	S. Atl - FL	E.S. Central	W.S. Central	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA
			1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1990	QRS_NUMR	peak	0.054	0.054	0.071	0.062	0.046	0.046	0.040	0.053	0.048	0.015	0.039	0.0341
1990	QRS_NUMR	off-peak	0.038	0.037	0.048	0.038	0.029	0.028	0.026	0.037	0.032	0.013	0.021	0.0265
1991	QRS_NUMR	peak	0.052	0.051	0.075	0.068	0.048	0.048	0.043	0.057	0.048	0.014	0.037	0.0304
1991	QRS_NUMR	off-peak	0.036	0.034	0.048	0.039	0.029	0.027	0.026	0.038	0.035	0.013	0.022	0.0286
1992	QRS_NUMR	peak	0.058	0.055	0.074	0.061	0.050	0.049	0.041	0.053	0.045	0.016	0.039	0.0302
1992	QRS_NUMR	off-peak	0.044	0.039	0.052	0.039	0.032	0.028	0.026	0.033	0.029	0.014	0.021	0.0251
1993	QRS_NUMR	peak	0.060	0.061	0.080	0.069	0.055	0.051	0.043	0.059	0.054	0.014	0.037	0.0315
1993	QRS_NUMR	off-peak	0.042	0.039	0.050	0.042	0.031	0.029	0.029	0.038	0.034	0.014	0.022	0.0260
1994	QRS_NUMR	peak	0.062	0.065	0.081	0.069	0.054	0.052	0.042	0.052	0.049	0.015	0.035	0.0306
1994	QRS_NUMR	off-peak	0.036	0.036	0.043	0.034	0.026	0.023	0.024	0.036	0.033	0.012	0.022	0.0287
1995	QRS_NUMR	peak	0.054	0.060	0.078	0.065	0.053	0.050	0.039	0.047	0.044	0.015	0.030	0.0270
1995	QRS_NUMR	off-peak	0.035	0.037	0.050	0.039	0.029	0.025	0.024	0.040	0.032	0.012	0.021	0.0269
1996	QRS_NUMR	peak	0.058	0.063	0.083	0.073	0.058	0.055	0.044	0.052	0.051	0.017	0.033	0.0268
1996	QRS_NUMR	off-peak	0.038	0.041	0.052	0.041	0.031	0.028	0.025	0.037	0.035	0.013	0.021	0.0261
1997	QRS_NUMR	peak	0.054	0.058	0.075	0.064	0.049	0.047	0.042	0.054	0.046	0.012	0.038	0.0282
1997	QRS_NUMR	off-peak	0.037	0.039	0.049	0.037	0.031	0.026	0.025	0.036	0.034	0.011	0.019	0.0247
1998	QRS_NUMR	peak	0.049	0.050	0.064	0.056	0.045	0.043	0.038	0.051	0.048	0.013	0.038	0.0315
1998	QRS_NUMR	off-peak	0.033	0.034	0.039	0.030	0.024	0.021	0.020	0.035	0.030	0.012	0.020	0.0284
1999	QRS_NUMR	peak	0.048	0.057	0.071	0.058	0.045	0.043	0.033	0.047	0.049	0.012	0.032	0.0321
1999	QRS_NUMR	off-peak	0.036	0.034	0.038	0.031	0.023	0.021	0.019	0.035	0.036	0.012	0.021	0.0289
2000	QRS_NUMR	peak	0.055	0.060	0.073	0.060	0.054	0.048	0.036	0.048	0.048	0.014	0.031	0.0281
2000	QRS_NUMR	off-peak	0.033	0.037	0.041	0.032	0.028	0.022	0.021	0.033	0.033	0.012	0.021	0.0271
2001	QRS_NUMR	peak	0.052	0.056	0.068	0.061	0.046	0.047	0.039	0.051	0.050	0.014	0.034	0.0293
2001	QRS_NUMR	off-peak	0.031	0.033	0.036	0.029	0.023	0.020	0.018	0.031	0.038	0.011	0.017	0.0242
2002	QRS_NUMR	peak	0.050	0.053	0.065	0.056	0.047	0.046	0.039	0.050	0.045	0.013	0.031	0.0274
2002	QRS_NUMR	off-peak	0.034	0.035	0.043	0.035	0.026	0.020	0.020	0.033	0.033	0.011	0.016	0.0250
2003	QRS_NUMR	peak	0.059	0.062	0.073	0.061	0.053	0.048	0.040	0.046	0.040	0.014	0.029	0.0254
2003	QRS_NUMR	off-peak	0.035	0.035	0.039	0.030	0.024	0.018	0.017	0.031	0.030	0.011	0.016	0.0253
2004	QRS_NUMR	peak	0.055	0.059	0.070	0.057	0.051	0.044	0.035	0.046	0.043	0.013	0.031	0.0273
2004	QRS_NUMR	off-peak	0.032	0.033	0.035	0.027	0.023	0.017	0.017	0.031	0.028	0.011	0.016	0.0240
2005	QRS_NUMR	peak	0.058	0.059	0.067	0.055	0.049	0.042	0.033	0.044	0.042	0.012	0.027	0.0247
2005	QRS_NUMR	off-peak	0.032	0.032	0.034	0.026	0.023	0.019	0.016	0.029	0.029	0.011	0.016	0.0230
1990	TRS	peak	3.67	2.92	1.49	1.48	2.76	1.83	1.84	1.49	2.74	4.27	2.75	2.591
1990	TRS	off-peak	4.29	3.90	2.16	2.04	3.59	2.76	3.18	1.67	3.39	6.09	4.09	2.590
1991	TRS	peak	3.85	3.07	1.54	1.50	2.68	2.04	1.92	1.52	2.41	4.76	2.77	2.912
1991	TRS	off-peak	4.34	3.92	2.13	2.13	3.51	2.94	3.15	1.68	3.12	6.47	4.02	3.094
1992	TRS	peak	3.99	3.23	1.52	1.61	2.88	2.09	1.90	1.57	2.57	4.62	2.67	2.785
1992	TRS	off-peak	3.66	3.64	1.97	2.09	3.07	2.58	3.09	1.44	3.28	6.52	3.93	2.753
1993	TRS	peak	3.98	3.15	1.60	1.51	2.79	1.95	1.80	1.53	2.56	5.13	2.68	2.771
1993	TRS	off-peak	3.46	3.79	2.22	2.17	3.31	2.55	2.80	1.67	2.93	6.90	3.85	2.869
1994	TRS	peak	4.31	3.35	1.75	1.71	2.83	2.17	1.86	1.37	2.72	4.80	3.00	2.897
1994	TRS	off-peak	4.04	4.59	2.46	2.11	3.72	3.22	3.49	1.72	3.12	6.93	4.00	3.227
1995	TRS	peak	4.38	3.45	1.51	1.71	2.81	2.16	1.95	1.63	2.87	4.71	3.20	3.482
1995	TRS	off-peak	3.92	4.50	1.89	2.21	3.47	2.82	3.35	2.01	3.40	6.84	4.19	3.556
1996	TRS	peak	3.84	2.95	1.19	1.67	2.30	1.47	1.69	1.39	2.58	4.37	2.23	2.824
1996	TRS	off-peak	3.38	4.09	2.06	2.23	3.65	2.83	3.15	1.80	2.85	6.74	3.45	3.203

			New Eng.	Mid Aatl.	E.N. Central	W.N. Central	S Atl. - FL	E.S. Central	W.S. Central	Mtn- AZ/NM	WA/OR	Florida	AZ/ NM	CA
			1	2	3	4	5	6	7	8	9	10	11	12
1997	TRS	peak	4.16	3.54	1.68	1.68	2.91	2.17	1.72	1.30	2.40	4.90	2.28	2.624
1997	TRS	off-peak	3.95	3.66	1.99	2.01	3.69	3.18	3.20	2.08	2.62	7.26	4.47	3.257
1998	TRS	peak	4.20	3.64	1.63	1.85	2.71	2.36	2.22	1.75	2.71	4.98	2.58	3.400
1998	TRS	off-peak	3.85	4.41	2.43	2.58	4.21	3.34	3.73	2.66	2.95	7.00	5.02	3.523
1999	TRS	peak	4.55	3.58	1.60	1.82	2.17	2.33	2.03	2.06	2.51	5.14	2.93	3.204
1999	TRS	off-peak	2.95	3.97	2.16	2.51	4.02	3.25	3.56	2.45	2.84	7.01	4.12	2.951
2000	TRS	peak	3.57	2.64	1.33	1.76	2.82	1.93	1.62	1.58	2.42	4.84	2.32	2.782
2000	TRS	off-peak	3.43	3.18	2.15	2.55	3.61	3.34	3.47	2.14	2.81	7.02	2.86	3.127
2001	TRS	peak	3.21	2.30	1.52	1.66	2.69	2.10	1.86	1.66	2.51	5.45	2.22	2.148
2001	TRS	off-peak	4.94	4.63	2.42	3.16	4.44	4.27	3.87	3.58	4.19	8.98	4.70	3.056
2002	TRS	peak	3.76	2.73	1.68	1.73	3.22	2.48	2.20	1.82	3.84	5.88	3.60	2.753
2002	TRS	off-peak	3.24	3.73	2.22	2.49	4.16	3.77	3.45	2.65	3.71	8.09	5.16	2.806
2003	TRS	peak	2.89	2.64	1.26	1.36	2.59	2.07	1.63	1.28	2.40	5.47	2.64	2.630
2003	TRS	off-peak	5.04	4.54	2.48	2.92	4.94	4.22	4.51	2.65	2.81	9.09	5.03	2.862
2004	TRS	peak	4.24	3.01	1.57	1.79	3.15	2.55	2.08	1.61	2.70	6.20	2.86	2.685
2004	TRS	off-peak	4.33	4.30	2.41	3.07	5.14	4.41	4.63	2.60	3.21	8.97	5.15	2.472
2005	TRS	peak	3.91	3.29	1.69	1.82	3.32	3.03	2.31	1.91	3.00	6.40	2.95	2.900
2005	TRS	off-peak	3.52	4.23	2.44	2.88	4.60	4.09	4.52	2.66	3.17	8.06	4.47	2.552

QRS_NUMR (MMcf/thousand customers), TRS (nom$/Mcf)

Table F7

Data: Equation for commercial distribution tariffs

Author: Ernest Zampelli, SAIC, 2007.

Source: The source for the peak and off-peak data used in this estimation was the *Natural Gas Monthly* (1990-2006), 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.

Variables:

$TCM_{r,n,t}$	commercial distributor tariff in region r, network n (1987 dollars per Mcf) [$DTAR\_SF_2$]
REG_r	=1, if observation is in region r, =0 otherwise
$PREG_{r,n}$	=1, if observation is in region r during peak period (n=1), =0 otherwise
YEAR	calendar year (e.g., 2010) [MODYR]
QCM_t	commercial gas consumption for region r in year t (MMcf) [$BASQTY\_SF_2$+$BASQTY\_SI_2$]
r	NGTDM region
n	network (1=peak, 2=off-peak)
t	year
$\alpha_r, \alpha_{r,n}$	estimated parameters for regional dummy variables [PCMREG1, PCMREGPK1]
β_1, β_2	estimated parameters
ρ	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 2002 time period. The equation was estimated in log-linear form with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5. The form of the estimated equation follows:

$$\ln TCM_{r,n,t} = \sum_r (\alpha_r * REG_r + \alpha_{r,n} * PREG_{r,n}) + \beta_1 * \ln QCM_{r,t} + \beta_2 * YEAR_t + \rho * \ln TCM_{r,t-1}$$
$$- \rho * (\sum_r (\alpha_r * REG_r + \alpha_{r,pk} * REG_{r,pk}) + \beta_1 * \ln QCM_{r,t-1} + \beta_2 * YEAR_{t-1})$$

Regression Diagnostics and Parameter Estimates

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

Objective function: Exact ML (keep first obs.)

Balanced data: NI = 24, T = 17, NOB = 408

CONVERGENCE ACHIEVED AFTER 4 ITERATIONS

Dependent variable: ln$TCM_{r,t}$
Number of observations: 408

Mean of dep. var.	= 3.43984		R-squared	=	.803874
Std. dev. of dep. var.	= 2.19975		Adjusted R-squared	=	.794799
Sum of squared residuals	= 386.287		Durbin-Watson	=	1.91704
Variance of residuals	= .993026		Schwarz B.I.C.	=	625.266
Std. error of regression	= .996507		Log likelihood	=	-568.159

Parameter	Estimate	Standard Error	t-statistic	P-value
α_1	-29.1058	3.77911	-7.70175	[.000]
α_2	-28.6198	3.75929	-7.61310	[.000]
α_3	-28.7396	3.75471	-7.65427	[.000]
α_4	-29.2867	3.76815	-7.77216	[.000]
α_5	-28.6876	3.76643	-7.61665	[.000]
α_6	-28.9823	3.77761	-7.67215	[.000]
α_7	-28.9907	3.76598	-7.69803	[.000]
α_8	-29.3766	3.77458	-7.78274	[.000]
α_9	-29.1245	3.78601	-7.69266	[.000]
α_{10}	-29.0861	3.79441	-7.66551	[.000]
α_{11}	-29.2976	3.79012	-7.72999	[.000]
α_{12}	-28.4892	3.76837	-7.56008	[.000]
$\alpha_{1,pk}$	.522577	.094216	5.54660	[.000]
$\alpha_{2,pk}$	.351341	.130028	2.70204	[.007]
α_{3pk}	.223029	.057253	3.89551	[.000]
α_{7pk}	-.135934	.062581	-2.17213	[.030]
β_1	-.334438*	.063487	-5.26780	[.000]
β_2	.015522	.00192569	8.06059	[.000]
ρ	.224301	.049337	4.54634	[.000]

* Because the reported estimate of the parameter yielded projections of the commercial distributor tariff that were considered inconsistent with analyst's expectations (particularly given the lack of a term showing efficiency improvements, similar to consumption per household for the residential distributor tariff), it was increased by 5 percent, within the 95% confidence interval limit.

Data used for estimation

			New Engl	Mid Atlantic	E.N. Central	W.N. Central	S Atl - Flor	E.S. Central	W.S. Central	Mtn - AZ/NM	WA/OR	Florida	AZ/NM	Calif
			1	2	3	4	5	6	7	8	9	10	11	12
1990	QCM	peak	50698	225718	363973	158779	104800	64210	123080	70939	31659	14377	27131	124493
1990	QCM	off-peak	46201	210536	272788	133901	95352	52983	136527	55783	27461	21929	24964	162820
1991	QCM	peak	52432	240780	389784	174622	119222	69140	135102	77306	33212	15380	27089	109933
1991	QCM	off-peak	44809	205604	259856	140126	104963	51967	136897	59397	30854	23884	25501	179823
1992	QCM	peak	58796	258737	389732	160471	1308712	69570	129533	73589	30756	16541	27585	115952
1992	QCM	off-peak	54864	223622	285713	136312	114759	55556	144089	54014	26614	25186	27388	171200
1993	QCM	peak	62960	263785	417389	183554	139673	74956	127869	83273	37860	15876	26668	109418
1993	QCM	off-peak	53936	217662	285168	135178	114556	58537	143040	63334	29807	25275	28798	142988
1994	QCM	peak	81641	277036	435569	183888	1409112	78312	131158	79295	35081	15982	25835	106204
1994	QCM	off-peak	65486	216701	266283	126419	112209	53950	137169	64070	30861	23953	28316	157985
1995	QCM	peak	76213	276406	435727	182295	145801	79207	138755	74179	33618	16416	23872	107861
1995	QCM	off-peak	67612	237646	304927	139269	119437	56770	161710	71670	31369	23967	28272	173099
1996	QCM	peak	83821	313791	472037	200774	151001	87207	137631	84529	39154	17000	26290	94074
1996	QCM	off-peak	76940	244358	318645	146946	127341	63487	143822	70399	34582	24810	29163	143126
1997	QCM	peak	87466	310643	430921	177173	145469	80710	150578	87897	36256	14768	29734	104085
1997	QCM	off-peak	86527	323063	318507	131706	131562	67464	165895	70362	35895	21932	27801	151589
1998	QCM	peak	81024	315507	377202	166752	145488	73849	130102	82487	39036	14951	30175	103765
1998	QCM	off-peak	75121	297485	271916	110660	129277	58072	135412	69956	32511	22708	28819	180135
1999	QCM	peak	67353	338072	418196	169421	149026	75432	131552	77404	42336	15044	28343	107403
1999	QCM	off-peak	69210	329131	272580	112760	124016	60727	132184	69557	36809	21225	30061	139047
2000	QCM	peak	73828	325896	442727	176855	162463	82263	143006	83228	41699	18965	28657	100873
2000	QCM	off-peak	65103	343845	295275	117168	132335	57024	149439	71213	37352	28939	30490	147337
2001	QCM	peak	71521	302094	425951	180607	149417	80914	142134	89824	43636	19507	29762	101543
2001	QCM	off-peak	59806	313044	264072	109572	130128	55327	126906	65419	41408	29779	28492	146001
2002	QCM	Peak	68690	312901	396492	169092	156638	79207	159788	90579	39302	21953	29563	95771
2002	QCM	off-peak	64481	331724	315599	132535	130456	56677	165182	71256	34867	33850	27618	144257
2003	QCM	peak	71876	356402	463864	183619	167751	86376	160603	84059	38294	21442	27867	103956
2003	QCM	off-peak	58076	292074	287942	114900	135926	56701	152341	70774	35661	32841	28170	130707
2004	QCM	peak	68898	363181	440958	179726	173118	81783	145990	87070	40590	22461	30498	99592
2004	QCM	off-peak	512259	307265	275581	111706	135306	57993	138535	69222	34079	33860	28119	133808
2005	QCM	peak	70217	381077	437697	171144	172688	78073	130076	86611	41087	22603	28284	95282
2005	QCM	off-peak	50493	311539	267470	107049	136678	60354	125677	72017	36289	35087	27790	139345
2006	QCM	peak	60461	285652	369152	150022	151616	69802	130510	86161	42125	19324	28662	99415
2006	QCM	off-peak	48106	264102	282715	112483	138391	57295	154634	71124	36997	30301	28128	161653
1990	TCM	peak	2.813	2.189	1.156	1.044	2.002	1.538	1.230	1.025	1.973	2.081	1.720	2.472
1990	TCM	off-peak	2.267	2.039	1.464	0.841	1.879	1.700	1.206	0.835	2.096	2.091	1.754	1.708
1991	TCM	peak	2.744	2.232	1.218	1.097	1.903	1.676	1.251	1.060	1.853	2.140	1.786	2.901
1991	TCM	off-peak	2.263	2.020	1.508	0.924	1.789	1.751	1.248	0.837	2.022	2.073	1.952	2.075
1992	TCM	peak	2.927	2.366	1.214	1.187	2.033	1.760	1.381	1.088	1.934	2.034	1.735	2.921
1992	TCM	off-peak	1.669	2.016	1.302	0.887	1.539	1.541	1.089	0.576	2.184	2.004	1.636	1.552
1993	TCM	peak	2.766	2.275	1.301	1.139	1.974	1.675	1.337	1.139	1.873	2.509	1.788	3.114
1993	TCM	off-peak	1.158	1.962	1.552	1.065	1.656	1.554	1.140	0.885	1.970	2.577	1.768	2.342
1994	TCM	peak	3.245	2.583	1.461	1.361	2.037	1.911	1.303	0.965	2.053	2.072	2.022	4.215
1994	TCM	off-peak	1.438	2.479	1.741	0.863	1.753	1.862	1.447	0.982	2.021	2.331	2.081	3.367
1995	TCM	peak	3.098	2.591	1.257	1.280	2.032	1.871	1.318	1.215	2.188	2.072	2.182	3.984
1995	TCM	off-peak	1.548	2.409	1.307	1.058	1.745	1.692	1.186	1.343	2.258	2.066	2.137	2.984
1996	TCM	peak	2.677	2.397	0.955	1.308	1.731	1.145	1.147	0.979	1.915	1.895	1.382	3.030

			New Engl	Mid Atlantic	E.N. Central	W.N. Central	S Atl - Flor	E.S. Central	W.S. Central	Mtn - AZ/NM	WA/OR	Florida	AZ/NM	Calif
			1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1996	TCM	off-peak	1.285	2.119	1.437	1.076	1.817	1.912	1.172	1.022	1.802	2.303	1.504	2.486
1997	TCM	peak	3.038	2.528	1.400	1.246	2.094	1.746	1.216	0.867	1.6109	1.946	1.438	2.990
1997	TCM	off-peak	1.698	1.016	1.397	0.823	2.008	1.993	1.435	1.197	1.620	2.398	1.687	2.480
1998	TCM	peak	2.910	1.998	1.350	1.323	2.052	1.965	1.565	1.314	1.854	2.281	1.838	3.432
1998	TCM	off-peak	1.452	1.514	1.689	1.189	2.103	1.832	1.667	1.771	1.858	2.246	2.288	2.867
1999	TCM	peak	2.796	1.839	1.340	1.342	1.751	1.904	1.321	1.593	1.789	2.280	1.988	2.987
1999	TCM	off-peak	1.408	0.763	1.462	1.041	1.891	1.827	1.523	1.645	1.781	2.274	1.818	2.564
2000	TCM	peak	2.354	2.761	1.002	1.279	1.989	1.494	0.892	1.117	1.819	1.995	1.153	2.630
2000	TCM	off-peak	0.915	0.583	1.454	1.193	1.791	1.870	1.266	1.261	1.382	1.936	1.162	2.353
2001	TCM	peak	2.098	2.475	1.139	1.210	2.161	1.771	0.929	1.275	1.711	3.091	1.250	2.069
2001	TCM	off-peak	2.078	2.587	1.780	1.632	2.477	2.622	1.572	2.727	2.982	3.910	2.108	2.264
2002	TCM	Peak	2.706	1.560	1.612	1.182	2.145	2.075	1.422	1.432	2.871	3.061	2.485	2.427
2002	TCM	off-peak	1.314	1.334	1.817	1.305	1.942	2.278	1.359	1.718	2.310	3.008	2.350	1.830
2003	TCM	peak	2.088	2.276	0.955	0.993	1.678	1.659	1.024	0.864	1.678	2.797	1.556	2.200
2003	TCM	off-peak	3.082	2.185	1.659	1.504	2.214	2.148	1.982	1.721	1.593	3.326	2.067	2.056
2004	TCM	peak	3.194	2.493	1.199	1.325	2.126	1.947	1.420	1.100	2.306	3.215	1.682	2.227
2004	TCM	off-peak	2.287	2.095	1.474	1.439	2.033	2.261	1.918	1.636	2.201	3.258	2.141	1.481
2005	TCM	peak	2.910	2.851	1.226	1.378	2.086	2.532	1.633	1.452	2.102	2.758	1.747	2.499
2005	TCM	off-peak	1.814	2.473	1.298	1.204	1.596	2.150	1.731	1.568	1.684	2.571	1.580	1.545
2006	TCM	peak	2.889	2.351	1.403	1.708	2.243	2.464	1.469	1.643	2.421	3.646	2.132	2.463
2006	TCM	off-peak	2.568	1.320	1.518	1.457	2.480	2.542	1.867	2.223	2.661	3.205	3.069	2.095

QCM (mmcf), TCM (1987$/Mcf)

Table F8

Data: Equation for electric generator distribution tariffs or markups.

Author: Ernest Zampelli, SAIC, 2007.

Source: The original source for the natural gas prices to electric generators used with city gate prices to calculate markups was the *Electric Power Monthly*, DOE/EIA-0226. The original source for the rest of the data used was the *Natural Gas Monthly*, DOE/EIA-0130. State level city gate and electric generator prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM and 16 NGTDM/EMM regions, respectively) 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 consumption data were generated within the historical routines in the NEMS system based on state level data from the original source and may differ from the original source.

Variables:

$MARKUP_{r,t}$	electric generator distributor tariff (or markup) in region r, year t (1987 dollars per Mcf) [UDTAR_SF]
$ELEC\_RATIO_{r,t}$	electric generator consumption of natural gas [sum of BASUQTY_SF and BASUQTY_SI] divided by nonelectric consumption of natural gas (residential, commercial, industrial, and transportation) [OTHR]
REG_r	=1, if observation is in region r, =0 otherwise
β_{0r}	coefficient on REG_r [PELREG5 or PELREG6 equivalent to the product of REG_r and β_{0r}]
β_0, $\beta 1$	Estimated parameters
ρ	autocorrelation coefficient
r	NGTDM/EMM region
t	year
n	season (1=peak, 2=off-peak)

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and/or in the model code.]

Derivation: The peak and off-peak electric markup equations were estimated using panel data for the 16 EMM regions over the 1990 to 2006 time period. The equations were estimated in linear form allowing for region-specific intercepts and with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5. Because the reported point estimates of the parameters yielded projections of the electric generator distributor tariffs that were considered inconsistent with analyst's expectations, a number of alternative values within the 95% confidence interval limits for each of the parameters were tested in the forecasting equations. The final column of the table below reports the values of the parameter estimates actually used. For the most part, changes were made to the constant terms to better align the projected values with more recent historical levels.

Peak Equation

$$MARKUP_{r,t} = \beta_0 + \sum_r \beta_{0,r} REGr + \beta_1 ELEC\_RATIO_{r,t} + \rho * MARKUP_{r,t-1}$$
$$- \rho * (\beta_0 + \sum_r \beta_{0r} REGr + \beta_1 ELEC\_RATIO_{r,t-1})$$

(all parameters, data, and variables representing the peak period)

Off-peak Equation

$$MARKUP_{r,t} = \beta_0 + \sum_r \beta_{0r} REGr + \beta_1 ELEC\_RATIO_{r,t} + \rho * MARKUP_{r,t-1}$$
$$- \rho * (\beta_0 + \sum_r \beta_{0r} REGr + \beta_1 ELEC\_RATIO_{r,t-1})$$

(all parameters, data, and variables representing the off-peak period)

Regression Diagnostics and Parameter Estimates

For Peak Equation

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

Balanced data: N=16, T_I= 17, NOB= 272
Objective function: Exact ML (keep first obs.)

CONVERGENCE ACHIEVED AFTER 4 ITERATIONS

Dependent variable: MARKUP
Number of observations: 272

Mean of dep.var.	= -.704830	R-squared	= .461654
Std. dev. of dep.var.	= 1.35209	Adjusted R-squared	= .441028
Sum of squared residuals	= 266.714	Durbin-Watson	= 1.82691
Variance of residuals	= 1.02189	Schwarz B.I.C.	= 414.196
Std. error of regression	= 1.01089	Log likelihood	= -383.364

Parameter	Estimate	Standard Error	t-statistic	P-value	Parameter Value Used
WT	-.201039	.045196	-4.44820	[.000]	-.178039
REG1	-.454641	.131405	-3.45985	[.001]	-.324641
REG4	-1.14779	.119855	-9.57647	[.000]	-1.00779
REG5	-.24810	.095175	-2.54069	[.011]	-.21810
REG8	-.658708	.226587	-2.90709	[.004]	-.508708
REG10	-.458062	.180560	-2.53690	[.011]	-.278062
REG11	-.265703	.090701	-2.92944	[.003]	-.085703
REG12	1.02538	.490692	2.08967	[.037]	.99538

REG16	.595994	.180627	3.29959	[.001]	.595994
ELEC_RATIO	.248175	.128803	1.92678	[.054]	.174125
RHO	.141027	.064283	2.19384	[.028]	.141027

<u>For Off-peak Equation</u>

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

Balanced data: N= 16, T_I=17, NOB= 272
Objective function: Exact ML (keep first obs.)

CONVERGENCE ACHIEVED AFTER 5 ITERATIONS

Dependent variable: MARKUP
Number of observations: 272

Mean of dep. var.	= -1.61944	R-squared	= .713859
Std. dev. of dep. var.	= 1.81072	Adjusted R-squared	= .697093
Sum of squared residuals	= 254.245	Durbin-Watson	= 1.85513
Variance of residuals	= .993145	Schwarz B.I.C.	= 421.641
Std. error of regression	= .996567	Log likelihood	= -376.795

Parameter	Estimate	Standard Error	t-statistic	P-value	Parameter Value Used
WT	.051338	.094500	.543253	[.587]	.098338
REG1	-1.50589	.177265	-8.49513	[.000]	-1.33589
REG2	-.844010	.168476	-5.00968	[.000]	-.684010
REG4	-1.35540	.140000	-9.53585	[.000]	-1.19540
REG5	-.920821	.109789	-8.38721	[.000]	-.890821
REG6	-.757860	.106933	-7.08723	[.000]	-.717860
REG7	-.677710	.177563	-3.81674	[.000]	-.677710
REG8	-.736044	.174871	-4.20906	[.000]	-.586044
REG9	-.616799	.158685	-3.88693	[.000]	-.466799
REG10	-.835745	.139791	-5.97855	[.000]	-.695745
REG11	-.456143	.111254	-4.10002	[.000]	-.236143
REG13	-.494618	.227251	-2.17653	[.030]	-.344618
REG14	-.401268	.133237	-3.01168	[.003]	-.271268
REG15	-.485912	.183717	-2.64489	[.008]	-.455912
ELEC_RATIO	.143507	.044995	3.18941	[.000]	.100455
RHO	.262643	.060171	4.36497	[.000]	.262643

Data used for estimation

		Peak		Off-Peak			Peak		Off-Peak	
t	r	MARK UP	ELEC_ RATIO	MARK UP	ELEC_ RATIO	r	MARK UP	ELEC_ RATIO	MARK UP	ELEC_ RATIO
1990	1	-0.380	0.024	-0.699	0.264	9	-0.313	0.035	-0.495	0.130
1991	1	-0.294	0.025	-0.959	0.176	9	-0.199	0.043	-1.077	0.113
1992	1	-0.429	0.006	-0.876	0.143	9	-0.351	0.043	-0.734	0.089
1993	1	-0.592	0.016	-1.384	0.093	9	0.409	0.020	-1.472	0.081
1994	1	-0.627	0.013	-1.841	0.155	9	0.200	0.041	-1.283	0.147
1995	1	-0.899	0.055	-1.780	0.233	9	0.139	0.072	-0.345	0.168
1996	1	-0.548	0.051	-1.509	0.203	9	-0.157	0.034	-0.348	0.142
1997	1	-0.813	0.173	-1.156	0.383	9	-0.256	0.036	-0.610	0.135
1998	1	-0.511	0.191	-1.505	0.351	9	0.274	0.041	-0.613	0.181
1999	1	-0.710	0.054	-1.649	0.408	9	-0.144	0.069	-0.293	0.189
2000	1	-1.428	0.166	-1.440	0.407	9	-0.282	0.081	0.118	0.196
2001	1	-1.329	0.246	-2.549	0.476	9	-1.246	0.095	-0.758	0.307
2002	1	-0.575	0.319	-1.394	0.516	9	-0.754	0.175	-0.373	0.330
2003	1	-0.023	0.280	-0.473	0.581	9	0.325	0.161	-0.325	0.245
2004	1	0.111	0.318	-1.326	0.599	9	-0.295	0.136	-0.185	0.291
2005	1	0.134	0.291	-0.906	0.608	9	0.627	0.140	-0.021	0.334
2006	1	-1.309	0.340	-1.666	0.627	9	-1.119	0.124	-0.731	0.384
1990	2	-0.091	0.056	-0.827	0.221	10	-1.126	0.035	-1.241	0.130
1991	2	-0.151	0.058	-0.894	0.219	10	-0.902	0.043	-1.093	0.113
1992	2	-0.275	0.056	-0.842	0.173	10	-1.126	0.043	-1.173	0.089
1993	2	-0.303	0.044	-0.865	0.156	10	-0.350	0.020	-0.346	0.081
1994	2	-0.511	0.032	-0.825	0.179	10	-0.456	0.041	-0.891	0.147
1995	2	-0.438	0.061	-0.676	0.196	10	-0.610	0.072	-0.860	0.168
1996	2	0.192	0.020	-0.627	0.124	10	0.509	0.034	-0.720	0.142
1997	2	-0.642	0.099	-1.478	0.297	10	-0.849	0.036	-0.746	0.135
1998	2	-0.381	0.106	-0.766	0.303	10	-0.662	0.041	-0.844	0.181
1999	2	-0.291	0.099	-0.828	0.334	10	-0.561	0.069	-0.594	0.189
2000	2	-0.091	0.112	-0.885	0.297	10	-0.827	0.081	-0.617	0.196
2001	2	-0.679	0.106	-1.524	0.317	10	-2.006	0.095	-1.250	0.307
2002	2	-0.506	0.129	-0.231	0.328	10	-0.774	0.175	-0.396	0.330
2003	2	0.704	0.093	-0.049	0.276	10	0.269	0.131	-0.373	0.245
2004	2	0.148	0.103	-0.120	0.297	10	-0.446	0.136	-0.372	0.291
2005	2	0.394	0.098	0.213	0.324	10	0.614	0.140	0.035	0.334
2006	2	-0.833	0.131	-1.164	0.392	10	-1.333	0.124	0.914	0.384
1990	3	-0.225	0.008	-0.819	0.019	11	-0.505	0.212	-0.589	0.332
1991	3	-0.804	0.008	-0.905	0..24	11	-0.477	0.203	-0.479	0.326
1992	3	-0.881	0.011	-1.157	0.017	11	-0.399	0.206	-0.441	0.318
1993	3	-0.905	0.007	-0.343	0..19	11	-0.388	0.197	-0.412	0.321
1994	3	0.149	0.010	0.053	0.029	11	-0.386	0.194	-0.367	0.330
1995	3	-0.134	0.013	-0.527	0.041	11	-0.557	0.208	-0.508	0.319
1996	3	0.412	0.008	-0.209	0.030	11	-0.187	0.178	-0.302	0.298
1997	3	-0.746	0.029	-1.047	0.082	11	-0.773	0.195	-0.400	0.336
1998	3	0.054	0.032	-0.200	0.113	11	-0.254	0.209	-0.126	0.399
1999	3	0.068	0.029	-0.737	0.110	11	-0.417	0.249	-0.219	0.402
2000	3	-0.156	0.037	-0.037	0.087	11	-0.265	0.259	-0.211	0.387
2001	3	0.598	0.031	1.277	0.108	11	-0.956	0.248	-0.591	0.399
2002	3	-0.234	0.039	-0.393	0.125	11	-0.434	0.272	-0.241	0.408

t	r	MARK UP	ELEC_ RATIO	MARK UP	ELEC_ RATIO	r	MARK UP	ELEC_ RATIO	MARK UP	ELEC_ RATIO
2003	3	-0.065	0.032	0.159	0.086	11	0.265	0.272	0.119	0.396
2004	3	-0.066	0.038	-0.289	0.096	11	-0.228	0.270	-0.022	0.391
2005	3	0.141	0.036	-0.161	0.146	11	0.074	0.292	-0.033	0.451
2006	3	-0.206	0.029	0.664	0.126	11	-0.695	0.296	-0.470	0.451
1990	4	-2.066	0.008	-1.615	0.019	12	-0.619	0.025	-0.972	0.099
1991	4	-1.519	0.008	-1.411	0.024	12	0.149	0.025	0.792	0.094
1992	4	-1.589	0.011	-1.672	0.017	12	0.911	0.029	-0.396	0.099
1993	4	-1.513	0.007	-1.577	0.019	12	0.649	0.031	0.268	0.072
1994	4	-1.309	0.010	-1.378	0.029	12	-0.736	0.030	-0.907	0.111
1995	4	-1.094	0.013	-1.221	0.041	12	5.031	0.049	1.109	0.106
1996	4	-1.306	0.008	-1.226	0.030	12	3.869	0.038	1.609	0.115
1997	4	-1.837	0.029	-1.799	0.082	12	1.827	0.066	4.319	0.220
1998	4	-1.323	0.032	-1.144	0.113	12	4.097	0.085	0.898	0.226
1999	4	-1.030	0.029	-1.261	0.110	12	0.592	0.111	1.116	0.241
2000	4	-0.806	0.037	-1.023	0.087	12	0.273	0.144	0.003	0.313
2001	4	-1.887	0.031	-1.216	0.108	12	-1.142	0.173	-0.926	0.308
2002	4	-0.393	0.039	-0.565	0.125	12	0.567	0.144	0.415	0.301
2003	4	-1.061	0.032	-0.882	0.086	12	-0.023	0.144	-0.134	0.336
2004	4	-1.104	0.038	-1.341	0.096	12	-0.666	0.162	-0.447	0.351
2005	4	-1.209	0.036	-1.696	0.146	12	-0.117	0.172	0.014	0.361
2006	4	-1.622	0.029	-0.699	0.126	12	-0.224	0.170	-0.222	0.362
1990	5	-0.598	0.011	-0.871	0.064	13	-0.431	0.025	-1.182	0.099
1991	5	-0.573	0.013	-0.942	0.088	13	-1.039	0.025	-1.616	0.094
1992	5	-0.490	0.011	-0.864	0.032	13	-0.990	0.029	-1.601	0.099
1993	5	-0.402	0.008	-0.701	0.049	13	-0.333	0.031	-0.761	0.072
1994	5	-0.378	0.009	-1.019	0.058	13	-0.648	0.030	-1.138	0.111
1995	5	-0.484	0.014	-0.849	0.071	13	-0.723	0.049	-0.790	0.106
1996	5	-0.144	0.009	-0.864	0.051	13	-0.169	0.038	-0.454	0.115
1997	5	-0.599	0.011	-1.151	0.064	13	-0.700	0.066	-0.527	0.220
1998	5	-0.302	0.011	-0.864	0.116	13	-0.456	0.085	-0.051	0.226
1999	5	-0.467	0.017	-0.780	0.112	13	-0.107	0.111	-0.049	0.241
2000	5	-0.570	0.022	-0.784	0.116	13	1.055	0.144	0.268	0.313
2001	5	-1.217	0.020	-0.996	0.117	13	0.503	0.173	0.680	0.308
2002	5	-0.496	0.023	-0.620	0.094	13	0.509	0.144	0.366	0.301
2003	5	0.190	0.019	-0.387	0.089	13	0.549	0.144	0.406	0.336
2004	5	-0.242	0.024	-0.731	0.081	13	-0.084	0.162	0.142	0.351
2005	5	0.076	0.035	-1.167	0.140	13	0.015	0.172	0.128	0.361
2006	5	-0.692	0.028	-0.919	0.147	13	-0.402	0.170	-0.368	0.362
1990	6	0.097	0.010	-0.583	0.067	14	-0.140	0.137	-0.575	0.347
1991	6	-0.264	0.016	-0.824	0.075	14	-0.682	0.117	-0.868	0.359
1992	6	-0.117	0.017	-0.579	0.043	14	-0.320	0.121	-0.390	0.372
1993	6	-0.111	0.021	-0.663	0.051	14	-0.082	0.133	-0.219	0.323
1994	6	-0.257	0.021	-0.976	0.064	14	-0.165	0.145	-0.187	0.342
1995	6	-0.148	0.029	-0.682	0.085	14	-0.141	0.146	-0.189	0.317
1996	6	-0.035	0.015	-0.620	0.058	14	0.420	0.109	0.144	0.315
1997	6	-0.620	0.021	-0.870	0.085	14	-0.026	0.120	-0.227	0.387
1998	6	0.001	0.018	-0.724	0.156	14	0.080	0.158	-0.128	0.440
1999	6	-0.113	0.029	-0.744	0.169	14	-0.059	0.203	-0.147	0.450
2000	6	-0.777	0.025	-0.430	0.157	14	0.225	0.270	-0.046	0.541
2001	6	0.062	0.023	-1.071	0.170	14	-0.114	0.340	-0.482	0.592
2002	6	-0.223	0.068	-0.697	0.205	14	0.344	0.362	-0.211	0.629

t	r	MARK UP	ELEC_ RATIO	MARK UP	ELEC_ RATIO	r	MARK UP	ELEC_ RATIO	MARK UP	ELEC_ RATIO
2003	6	0.099	0.044	-0.413	0.134	14	0.279	0.381	0.304	0.662
2004	6	-0.428	0.062	-0.715	0.184	14	0.135	0.437	0.156	0.710
2005	6	-0.349	0.085	-0.600	0.246	14	0.578	0.448	0.510	0.696
2006	6	-1.373	0.093	-0.605	0.262	14	-0.267	0.487	-0.321	0.737
1990	7	0.347	0.010	-0.144	0.067	15	-0.291	0.018	-0.311	0.039
1991	7	0.174	0.016	-0.215	0.075	15	0.108	0.016	-0.247	0.057
1992	7	0.577	0.017	-0.415	0.043	15	-0.185	0.041	0.492	0.093
1993	7	0.675	0.021	-0.350	0.051	15	0.493	0.079	-0.035	0.052
1994	7	0.471	0.021	-0.163	0.064	15	-0.341	0.071	-0.210	0.091
1995	7	1.571	0.029	-0.267	0.085	15	-0.297	0.051	-0.126	0.090
1996	7	1.351	0.015	-0.715	0.058	15	0.564	0.003	-0.178	0.088
1997	7	-0.062	0.021	-1.099	0.085	15	-0.602	0.059	0.271	0.168
1998	7	-1.067	0.018	-0.472	0.156	15	-0.456	0.090	-0.389	0.252
1999	7	-0.871	0.029	-1.107	0.169	15	-0.278	0.073	-0.407	0.223
2000	7	0.588	0.025	-0.953	0.157	15	-0.124	0.160	0.207	0.378
2001	7	-1.145	0.023	-1.759	0.170	15	-0.069	0.254	0.289	0.374
2002	7	-0.391	0.068	-0.873	0.205	15	-0.445	0.162	-0.949	0.278
2003	7	0.003	0.044	-0.499	0.134	15	-0.238	0.220	-0.819	0.349
2004	7	-0.394	0.062	-0.679	0.184	15	-0.772	0.228	-0.925	0.394
2005	7	0.405	0.085	-0.308	0.246	15	-0.553	0.236	-0.876	0.381
2006	7	-1.938	0.093	-1.134	0.262	15	-1.127	0.186	-1.491	0.373
1990	8	-0.133	0.509	-0.098	0.620	16	0.737	0.159	0.295	0.307
1991	8	-0.356	0.524	-0.239	0.633	16	0.666	0.200	0.353	0.270
1992	8	-0.566	0.499	-0.158	0.631	16	0.124	0.220	0.030	0.341
1993	8	-0.370	0.436	-0.258	0.570	16	0.251	0.220	0.082	0.267
1994	8	-0.551	0.406	-0.420	0.542	16	-0.035	0.232	0.008	0.331
1995	8	-0.389	0.484	-0.379	0.686	16	0.387	0.174	0.091	0.238
1996	8	-0.217	0.450	-0.448	0.647	16	0.428	0.111	0.065	0.228
1997	8	-1.488	0.583	-1.070	0.691	16	0.216	0.180	-0.069	0.350
1998	8	-0.998	0.562	-0.835	0.687	16	0.429	0.248	0.346	0.317
1999	8	-0.435	0.559	-0.249	0.704	16	0.305	0.314	0.028	0.322
2000	8	-0.847	0.637	-0.428	0.707	16	2.561	0.287	0.283	0.407
2001	8	-1.313	0.600	-0.511	0.739	16	1.235	0.345	1.380	0.441
2002	8	0.310	0.659	0.223	0.810	16	0.637	0.275	0.360	0.358
2003	8	0.309	0.707	0.119	0.820	16	0.402	0.268	0.132	0.347
2004	8	-0.155	0.727	0.046	0.843	16	-0.118	0.263	-0.169	0.365
2005	8	-0.578	0.738	-0.341	0.851	16	0.426	0.260	-0.308	0.347
2006	8	-0.385	0.752	0.402	0.874	16	-0.482	0.254	0.175	0.392

Table F9

Data: Costs associated with producing natural gas for liquefaction at foreign facilities (SCRV_PPR)

Author: Chetha Phang, EI-83

Sources: Gas Technology Institute, "Liquefied Natural Gas (LNG) Methodology Enhancements in NEMS," report submitted to Energy Information Administration, March 31, 2003. Analyst judgment.

Derivation: Average natural gas supply costs to liquefaction plants are about $0.55 (2001$/Mcf) depending on location. Upstream investment costs, the amount of liquids produced in association with the gas, and host government fiscal policies are major factors in determining the gas supply costs. For example, in Qatar, revenues from condensate produced in association with the gas more than offset the upstream capital and operating costs, so the actual cost of the gas supplied to the LNG plant is effectively zero. However, the Qatari government charges the country's two LNG plants $0.55/Mcf for gas supply. For Algeria, the gas production and liquefaction facilities are 100 percent owned by Sonatrach, so there is no cost information available on separate facilities. The gas supply infrastructure is well established and a cost of $0.55/Mcf is assumed to be a reasonable estimate for supply to the existing LNG plants. Supply to a new LNG train (4.0 mmtpa), which is under consideration, would require the development of new gas production facilities. In this case, a higher cost of $0.88/Mcf accounts for infrastructure development. The average supply cost for existing and new gas production facilities is $0.72/Mcf. For Trinidad, gas supply comes from a number of license areas, each with its own production costs. BP/Repsol's offshore acreage to the east of Trinidad is the main supply source and has the lowest costs, estimated to be $0.44/Mcf. Other supplies to the plant from reserves north of Trinidad have higher associated costs and the cost for this gas supply is estimated as $0.83/Mcf. Therefore, given that the predominant share of gas is from the BP/Repsol acreage, an average cost of $0.55/Mcf is considered realistic. For Nigeria, an increasing share of the supply to the country's LNG plants is from gas produced in association with oil, which would otherwise be flared. The Nigerian government is in the process of phasing out flaring. Consequently, the gas has to be consumed or gathered and piped to an LNG plant. A gas supply cost of $0.33/Mcf including the cost of gathering and transporting the gas, is estimated. For Oman, the Omani government owns the gas and charges the liquefaction plant $0.83/Mcf. For Australia, the existing Northwest Shelf project is fully integrated. The gas is produced from two large offshore fields that have relatively high development costs. However, the gas has significant liquids content, providing an additional revenue stream to offset the high costs, resulting in an estimated supply cost of $0.55/Mcf. A number of new projects are planned based on gas reserves offshore northern and northwestern Australia. These projects will have higher gas supply costs, which are estimated at $0.88/Mcf. The average supply cost for existing and new projects of $0.72/Mcf is assumed. For Peru, an additional $0.39/Mcf pipeline tariff charge is added to the assumed supply cost of added to the assumed supply cost of $0.77/Mcf. The Sakhalin 2 LNG project (phase 2) is an integrated project, which includes the design, construction and operation of the upstream, pipeline and LNG plant under the same tax regime and cost recovery structure. In July 2005, Sakhalin Energy Investment Company (SEIC) announced that the phase 2 project could cost up to U.S. $20 billion. The high capital costs associated with the upstream development in an area subject to adverse climatic conditions lead to an estimated average supply cost of $1.32/Mcf. This supply cost also includes $0.38/Mcf pipeline tariff charge from the over 500-miles onshore pipeline from landfall to the LNG plant at Prigorodnoye in the South of Sakhalin Island. EIA also assumes that the average gas supply cost in Northwest Russia is the same as that in Sakhalin. For Norway, the Snohvit LNG project is an integrated project including the design, construction and operation of the upstream, pipeline and LNG plant under the same tax regime. The current tax rate is 78 percent consisting of a 28 percent national corporation tax and a 50 percent special tax which is levied on offshore oil and gas developments. EIA estimates that the average gas supply cost including tax and pipeline tariff charge is $1.50/Mcf. For all other supply sources, different supply factors are estimated based on their existing and potential upstream projects and are applied to the average supply cost of $0.55/Mcf.

LNG Gas Production Costs (2001 dollars per Mcf, assuming 1,100 Btu/cf)

Source	**Production Cost**	**Source**	**Production Cost**
Algeria	0.72	Indonesia	0.88
Nigeria	0.33	Sakhalin	1.32
Norway	1.50	Egypt	0.88
Venezuela	0.83	Peru	1.16
Trinidad	0.55	Oman	0.83
Qatar	0.55	Angola	0.55
Australia	0.72	Equatorial Guinea	0.33
Malaysia	0.88	Northwest Russia	1.32
Indonesia	0.88	Other	0.78

Table F10

Data: Costs associated with liquefying natural gas at foreign facilities (SCRV_PLQ)

Author: Chetha Phang, EI-83

Sources: Gas Technology Institute, "Liquefied Natural Gas (LNG) Methodology Enhancements in NEMS," report submitted to Energy Information Administration, March 31, 2003. Wood Mackenzie. Analyst judgment.

Derivation: Liquefaction is the most technologically advanced and expensive step in the LNG supply chain. Several sources were consulted to find liquefaction facility capital cost data. The estimates were developed by the various sources independently of each other, and very little consistency was found among sources. It was decided to use Wood Mackenzie as the sole source of data since Wood Mackenzie has enough data points (1969-2011) for performing regression analyses.

For *AEO2008*, data of estimated liquefaction capital costs from Wood Mackenzie were updated as of August 2007. The average capital cost for the liquefaction plants proposed between 2008 and 2011 was estimated at around $500 per ton of capacity (2006 dollars), or 50 percent higher than the 2006 estimated capital cost for *AEO2007* at $333 per ton. The rising capital costs for the proposed and future liquefaction plants were due to the escalations in commodity costs (e.g. steel, nickel, cement), higher labor costs, scarce human capital, and higher contract charges for engineering, procurement, and construction (EPC).

To capture these rising capital costs, the following three scenarios were used:

<u>Reference Case</u>: Increase the average liquefaction capital cost by 50 percent to $500/ton (2006 dollars) in 2007 from the 2006 level of $333/ton that was used for *AEO2007*. Hold the capital cost constant between 2007 and 2015 at $500/ton. Gradually decrease this level starting in 2016 to 15 percent above the 2006 level or $383/ton. Hold this new level constant from 2019 through 2030.

<u>High Capital Cost Case</u>: Retain the average capital cost at 50 percent above the 2006 level for 2007 and 2008 at $500/ton. Increase an additional 20 percent over the 2008 level and hold it constant from 2009 through 2030.

<u>Low Capital Cost Case</u>: For 2007, the average capital cost is 50 percent higher than the 2006 level at $500/ton. Gradually decrease this level to the 2006 level (at $333/ton) from 2008 to 2015 and hold the 2015 level constant from 2016 through 2030.

A technology improvement factor which uses last year's learning curve is applied to the average capital cost throughout the forecast period from 2007 for each of the above three scenarios.

Based on the methodology used to estimate the average capital cost for *AEO2007*, a learning cost curve function[3] was developed and is written as follows:

$$Cost = 333 * (1+ Percent/100) * T^{-0.0245}$$

where,

Cost	=	the per-unit average capital cost for liquefaction in 2006$/ton
Percent	=	the assumed percentage difference of the cost from the 2006 level
T	=	Year, where T=1 for 2007

For the reference case, it follows that the per-unit capital cost declines from $500 per ton in 2007 to $473 per ton in 2015 and then gradually declines to $360 per ton in 2018 (15 percent above the 2006 estimate combined with the effect of technology improvement). From 2019 the capital cost is slowly declining due to technology improvement and stays at $354 per ton in 2030. Hence, the decline in capital cost between 2007 and 2030 is almost 30 percent. The above equation is used in the liquefaction routine within the NGTDM.

In 2007, a liquefaction plant of one LNG train capable of producing 3.9 million metric tons per year (186 Bcf per year) of LNG costs an average of $1,950 million (2006 dollars). This cost is based on a per-unit development cost of $500 per tonne[4] of LNG. The plant is assumed to be amortized over a 20-year period with the cost of debt linked to the AA utility bond rate, an 18 percent cost of equity, a debt-to-equity ratio of 60/40 percent, and a 30 percent corporate tax rate. The project is considered turnkey so no interest charges are added to the liquefaction plant costs during construction. A capital recovery method is used to calculate the annual return on capital.

The average per-unit liquefaction plant charge is set endogenously because the cost of debt is linked to the AA utility bond rate provided by the Macroeconomic Activity Module. If the cost of debt is assumed to be 9.5 percent, the average per-unit liquefaction plant charge can be computed off-line. Table F10.1 is an example of per-unit liquefaction plant charge calculation based on a 9.5 percent cost of debt and other parameters summarized in Table F10.2.

With a 186 Bcf liquefaction capacity, the annual return on capital is $248 million and the per-unit return on capital is $1.33/Mcf in 2007. Gas liquefaction is an energy-intensive process, with typically about 13 percent of the plant's input consumed as plant fuel. Based on a $0.95/Mcf average supply cost, the liquefaction plant fuel cost is $0.12/Mcf of output. Average total taxes are assumed to be $0.15/Mcf, and

[3] Energy Information Administration, "Natural Gas Transmission and Distribution Model, 2007 Model Documentation," Appendix F, Table F10, p.G-40 to G-42. The document is accessible via the EIA website at http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model%20documentation

[4] A metric ton is equivalent to 2204.62 U.S. pounds.

administrative and general costs are assumed to be $0.30/Mcf.[5] The total per-unit liquefaction plant charge per Mcf (in 2006 dollars) is computed by summing up the return on capital, fuel cost, taxes, and administrative and general expenditures in Table F10.1.

The liquefaction plant utilization rate is assumed to be 93 percent, so the total liquefaction plant cost from each supply location in 2007 is $2.38/Mcf (in 2006 dollars). This cost declines to $1.83/Mcf in 2030. The cost parameters are summarized in Table F10.2.

Table F10.1. Example of Per-Unit Liquefaction Plant Charge Calculation for the Reference Case

(2006 dollars per Mcf)	**2007**	**2030**
Return on capital (at 11.2 percent rate of return)	$1.33	$0.94
Fuel cost at 13 percent of supply cost	$0.12	$0.12
Taxes	$0.30	$0.30
Administrative and General	$0.45	$0.33
Total per-unit charge at 100 percent utilization	$2.21	$1.70
Planned Utilization Rate (fraction)	0.93	0.93
Per-unit liquefaction plant charge	$2.38	$1.83

[5]Administrative and general expenses are set to a constant term of $4 million plus 4 percent of the capital costs, all divided by the volume of the train size in Bcf.

Table F10.2. Gas Liquefaction Plant Costs in 2007 and 2030 (Generic plant design) for the Reference Case

Assumptions:	**2007**	**2030**
Train capacity (million metric tons per annum)	3.9	3.9
Liquefaction plant capacity	510 MMcfd/train	510 Mcfd/train
	186 Bcf/train	186 Bcf/train
Total plant cost[a] (2006 dollars)	$1,950 million/train	$1,380 million/train
Per-unit capital cost (2006 dollars per ton)	$500	$354
Depreciation life	20 years	20 years
Debt-to-equity ratio	60 percent	60 percent
Cost of debt[b]	9.5 percent	9.5 percent
Rate of return on equity	18 percent	18 percent
Corporate tax rates	30 percent	30 percent
Cost of capital (after taxes)	11.2 percent	11.2 percent
Return on capital[c]	$248 million	$176 million
Total annual operating cost[d]	$163 million	$140 million
Planned Utilization rate	93 percent	93 percent
Results (2006 dollars per Mcf):		
Generic per unit charge	$2.38	$1.83

[a] Excludes interest expenses in 3 year construction period (a turnkey project is assumed)
[b] In the code, the cost of debt is linked to the AA utility bond rate provided by the Macroeconomic Activity Module. The 9.5 figure is included for illustrative purposes.
[c] Capital recovery over 20-year period (capital recovery factor = 0.1271)
[d] Includes fuel cost, taxes, and administrative and general expenses

Table F11

Data: Equation for base price on natural gas supply curves

Author: Dana Van Wagener, EI-83, 2006.

Source: Natural gas price data from EIA's *Natural Gas Annual*, DOE/EIA-0131. Drilling cost data from the Joint Association Survey of the American Petroleum Institute. Total reserves data came EIA's *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, (DOE/EIA-0216), with unconventional reserves from Office of Integrated Analysis and Forecasting. Heating degree data and international refinery acquisition prices from EIA's *Annual Energy Review*, (DOE/EIA-0384).

Variables:

PBASE	base wellhead price for natural gas supply curve (1987 dollars per Mcf)
ZWPRLAG	annual lagged value of PBASE (1987 dollars per Mcf)
UGRRSSHR	share of gas reserves from unconventional sources (fraction)
UGRRESSHRLAG	annual lagged value of UGRRESSHR (fraction)
oEXSPEND	national average drilling cost per well (1987 dollars)
HDD	heating degree-days
ZOGRESNG	beginning-of-year natural gas reserves (Bcf)
ZOGRESNGLAG	annual lagged value of ZOGRESNG (Bcf)
oIT_WOP	international refinery acquisition price (1987$/bbl)
r	supply region
t	year
α	estimated parameters
ρ	autocorrelation coefficient

Derivation: Using TSP version 4.5 and data from 1990 through 2004, the following equation was estimated in log-linear form using ordinary least squares regression, with a correction for autocorrelation:

$$\ln PBASE = CNST + (\alpha_1 * \ln UGRRESSHR) + \alpha_2 * \ln oEXSPEND_{t-1}) + (\alpha_3 * \ln HDD_t) + (\alpha_4 * \ln ZOGRESNG_r) + (\alpha_5 * \ln oIT\_WOP_t) + (\rho * ZWPRLAG_r) + (-\rho) * \{CNST + (\alpha_1 * \ln UGRRESSHRLAG) + \alpha_2 * \ln oEXSPEND_{t-2}) + (\alpha_3 * \ln HDD_{t-1}) + (\alpha_4 * \ln ZOGRESNGLAG_r) + (\alpha_5 * \ln oIT\_WOP_{t-1})\}$$

Regression Diagnostics and Parameter Estimates

Dependent variable: lnPBASE
Number of observations: 252

Mean of dep. var.	=	3.54305	R-squared	=	.845342
Std. dev. of dep. var.	=	2.29610	Adjusted R-squared	=	.841555
Sum of squared residuals	=	205.618	Durbin-Watson	=	2.01181

Variance of residuals = .839258 Schwarz B.I.C. = 350.747
Std. error of regression = .916110 Log likelihood = -331.394

Parameter	Estimate	Standard Error	t-statistic	P-value
CONST	-8.45472	2.27705	-3.71301	[.000]
α_1	.961499	.077278	12.4421	[.000]
α_2	.066877	.010227	6.53951	[.000]
α_3	.524556	.269854	1.94385	[.052]
α_4	-.012052	.00831339	-1.44973	[.147]
α_5	.367606	.069074	5.32191	[.000]
ρ	.321886	.064556	4.98616	[.000]

Table F12

Data: Equation for natural gas price at the Henry Hub

Author: Philip Budzik, EI-83, 2006

Source: Annual natural gas wellhead price data from EIA's *Annual Energy Review 2005*, DOE/EIA-0384(2005), published July 2006. Henry Hub spot price data from EIA's Short-Term Energy Outlook database series NGHHUUS; the annual Henry Hub prices equal the arithmetic average of the monthly data. Chain-type GDP price deflator (in 2000 equals 100.0) from U.S. Bureau of Economic Analysis website Table 1.1.4. Price Indexes for Gross Domestic Product.

Variables:

HHPRICE	Henry Hub spot natural gas price (1987 dollars per MMBtu)
EIAPRICE	Average U.S. natural gas wellhead price (1987 dollars per Mcf)
HHPRICE_HAT	estimated values for Henry Hub price (1987 dollars per MMBtu)
α	estimated parameter
const1	constant term
const2	constant term

Derivation: Using TSP version 4.5 and annual price data from 1995 through 2005, the first equation was estimated in log-linear form using ordinary least squares. The second equation estimates an adjustment factor that is applied in cases where the value of "y" is predicted from an estimated equation where the dependent variable is the natural log of y. The adjustment is due to the fact that generally predictions of "y" using the first equation only tend to be biased downward.

1) lnHHPRICE = const1 + (α * lnEIAPRICE)
2) HHPRICE = const2 * HHPRICE_HAT

Regression Diagnostics and Parameter Estimates

First Equation

Dependent variable: lnHHPRICE
Current sample: 2 to 10
Number of observations: 9

Mean of dep. var.	= .905435	LM het. test	= .701566 [.402]
Std. dev. of dep. var.	= .335768	Durbin-Watson	= 2.17814 [<.679]
Sum of squared residuals	= .042010	Jarque-Bera test	= .399919 [.819]
Variance of residuals	= .600144E-02	Ramsey's RESET2	= .164184 [.699]
Std. error of regression	= .077469	F (zero slopes)	= 143.284 [.000]
R-squared	= .953422	Schwarz B.I.C.	= -9.18414
Adjusted R-squared	= .946767	Log likelihood	= 11.3814

`

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
CONST	.115718	.070848	1.63334	[.146]
lnEIAPRICE	.977713	.081679	11.9701	[.000]

Second Equation

Dependent variable: HHPRICE
Current sample: 2 to 10
Number of observations: 9

Mean of dep. var.	= 2.60010	LM het. test	= .891382E-02 [.925]
Std. dev. of dep. var.	= .874761	Durbin-Watson	= 2.53445 [<1.00]
Sum of squared residuals	= .242932	Jarque-Bera test	= .157719 [.924]
Variance of residuals	= .030367	Ramsey's RESET2	= .027744 [.872]
Std. error of regression	= .174260	Schwarz B.I.C.	= -2.38583
R-squared	= .960419	Log likelihood	= 3.48444
Adjusted R-squared	= .960419		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
HHPRICE_HAT	1.00082	.021351	46.8751	[.000]

Data used for Estimation:

Year	Henry Hub Spot Natural Gas Price ($/MMBtu, in 1987 dollars)	Average U.S. Wellhead Natural Gas Price ($/Mcf, in 1987 dollars)	U.S. Bureau of Economic Analysis Chain-Type GDP Price Deflator
1995	1.34	1.23	92.106
1996	2.15	1.69	93.852
1997	1.91	1.78	95.414
1998	1.58	1.49	96.472
1999	1.70	1.64	97.868
2000	3.15	2.69	100.000
2001	2.83	2.86	102.399
2002	2.36	2.07	104.187
2003	3.77	3.36	106.404
2004	3.94	3.65	109.426
2005	5.60	4.88	112.737

Appendix G

Liquefied Natural Gas Costs

The methodology used to project liquefied natural gas imports is described in Chapter 2. The algorithm requires assumptions and/or estimates of the per-unit cost of producing, liquefying, shipping, and regasifying natural gas from the countries that are anticipated to be the most likely suppliers of the fuel to the east and west coasts of the United States. Background information about the assumptions used for production costs are provided in Table F9, Appendix F. Specifics about the derivation of the other three costs are provided below.

Liquefaction Costs

The regional liquefaction charge is the sum of the per-unit return on capital of a representative liquefaction plant and the per-unit total operation and maintenance expenses in the region, all divided by the assumed utilization rate, as follows:

$$L\_PUCHARGE_{s,y} = (L\_PUYR\_CCOST_{y} + L\_TOTOMEXP_{s,y}) / L\_UTILRATE \qquad (G\text{-}1)$$

where,

L_PUCHARGE	=	average per-unit charge for liquefaction (2006$/Mcf)
L_PUYR_CCOST	=	average per-unit annual return on capital for liquefaction (2006$/Mcf)
L_TOTOMEXP	=	per-unit total operation and maintenance expenses for liquefaction (2006$/Mcf)
L_UTILRATE	=	average liquefaction plant utilization rate (Appendix E), ratio
s	=	LNG supply region
y	=	forecast year

While available cost information on construction costs of liquefaction facilities is relatively sparse, there is a general trend of per unit capital costs declining over time. In order to capture this trend, per-unit charges for liquefaction are reevaluated each forecast year for any expansion at existing facilities or for greenfield facilities. Because of the scarcity of data on liquefaction plants by supply region, only a per-unit annual return on capital of a representative liquefaction plant is considered. However, total operation and maintenance expenses still depend on the fuel costs, which vary by supply region.

Per-Unit Return on Capital

In order to compute the return portion of the per-unit charge for a liquefaction plant in a supply region, the determination of the liquefaction plant per-unit capital cost and its capital recovery factor is necessary. The capital recovery factor depends on the weighted average cost of capital after taxes and the depreciation time period for a liquefaction plant. The capital recovery factor is applied to the per-unit capital cost of the liquefaction plant to determine the per-unit annual return on capital, as follows:

$$L\_PUYR\_CCOST_{y} = (L\_PUCAPCOST_{y} * L\_CAPRECFAC) / L\_CONV\_FAC \qquad (G\text{-}2)$$

where,

L_PUYR_CCOST	=	per-unit annual return on capital for a liquefaction plant (2006$/Mcf)
L_PUCAPCOST	=	per-unit capital cost for a liquefaction plant (2006$/ton of plant capacity)
L_CAPRECFAC	=	capital recovery factor for a representative liquefaction plant (ratio)

L_CONV_FAC = capacity conversion factor for a liquefaction plant, from million tons to Bcf (Bcf per million tons of LNG)
y = forecast year

The per-unit capital cost for a greenfield liquefaction project ($L\_PUCAPCOST_t$) is estimated as a function of time. It was developed to approximate a capital cost learning curve,[6] defined as a function of the plant's cumulative capacity. The declining capital cost equation is specified as follows:

$$L\_PUCAPCOST_y = L\_PARM\_A * T^{L\_PARM\_B} \quad \text{(G-3)}$$

where,
L_PUCAPCOST = per-unit capital cost of a liquefaction plant (2006$/ton of plant capacity)
L_PARM_A = estimated parameter representing the average per-unit capital cost of a liquefaction plant in 2007 (2006$/ton of capacity, Table F10, Appendix F)

L_PARM_B = estimated parameter reflecting the decline rate (Table F10, Appendix F)
T = time trend (XTREND) equals 1 when the year is 2007, 2 when the year is 2008, etc. (if y is less than or equal to 2007 then T equals 1, otherwise T equals y minus 2006)
y = forecast year

The per-unit capital cost for a liquefaction plant expansion is set to a fraction (L_EXPFAC, Appendix E) of the per-unit capital cost for a greenfield project.

The capital recovery factor for a representative liquefaction plant, L_CAPRECFAC, is a function of the nominal weighted average cost of capital after taxes, L_ROR, and the depreciation life of the plant (greenfield or expansion). The capital recovery factor is assigned as follows:

For a greenfield plant:

$$L\_CAPRECFAC = L\_ROR / (1.0 - (1.0 + L\_ROR)^{-L\_DEPREYR}) \quad \text{(G-4)}$$

or for an expansion plant:

$$L\_CAPRECFAC = L\_ROR / (1.0 - (1.0 + L\_ROR)^{-L\_EXPYRS}) \quad \text{(G-5)}$$

where,

$$\begin{aligned} L\_ROR = {} & L\_DEBTRATIO * (L\_COST\_DEBT / 100.) * (1.0 - L\_CORPTAX) + \\ & (1.0 - L\_DEBTRATIO) * L\_COST\_EQUITY \end{aligned} \quad \text{(G-6)}$$

where,
L_CAPRECFAC = capital recovery factor (ratio)
L_ROR = nominal weighted average cost of capital after taxes (ratio)
L_DEPREYR = depreciation life for a greenfield liquefaction plant (number of years, Appendix E)

[6]See detailed description of how this declining liquefaction capital cost equation is derived in Table F10, Appendix F.

L_EXPYRS	=	depreciation life for an expansion at a liquefaction plant (number of years, Appendix E)
L_DEBTRATIO	=	debt-to-equity ratio for a representative liquefaction plant (ratio, Appendix E)
L_COST_DEBT	=	cost of debt (or interest rate) for a representative liquefaction plant, assumed to be equal to the Moody's rate on industrial BAA bonds (percent) (set to MC_RMCORPAA, assigned by the NEMS Macroeconomic Module)
L_CORPTAX	=	corporate tax rate for a representative liquefaction plant (ratio, Appendix E)
L_COST_EQUITY	=	cost of equity for a representative liquefaction plant (ratio, Appendix E)

Per-Unit Operation and Maintenance Expenses

Total operation and maintenance expenses are the sum of three variables: a regional fuel cost for the plant, administrative and general expenses, and a government tax for a representative liquefaction plant, as follows:

$$L\_TOTOMEXP_{s,y} = L\_FUEL\_COST_{s,y} + L\_ADM\_GEN_{y} + L\_AVGTAX_{y} \quad \text{(G-7)}$$

where,

L_TOTOMEXP	=	per unit total operation and maintenance expenses for a liquefaction plant (2006$/Mcf)
L_FUEL_COST	=	regional liquefaction plant fuel costs (2006$/Mcf)
L_ADM_GEN	=	total administrative and general expenses for a representative liquefaction plant (2006$/Mcf)
L_AVGTAX	=	average government tax for a representative liquefaction plant, held constant over the forecast period (2006$/Mcf, Appendix E)
y	=	forecast year

The regional liquefaction plant fuel cost is computed as a fraction of the regional natural gas production cost. Currently, a liquefaction plant consumes about 11 percent of the gas that enters the plant for liquefaction. The fuel cost is computed as:

$$L\_FUEL\_COST_{s,y} = (L\_FUEL\_PCT / 100.0) * SCRV\_PPR_{s,y} \quad \text{(G-8)}$$

where,

L_FUEL_COST	=	regional liquefaction fuel cost (2006$/Mcf)
L_FUEL_PCT	=	percent of natural gas entering the liquefaction plant that is consumed in the process of liquefying the gas (Appendix E)
SCRV_PPR	=	costs associated with producing and delivering natural gas for liquefaction at foreign facilities (2006$/Mcf, Table F9, Appendix F)
y	=	forecast year

Administrative and general expenses for liquefaction plants are the sum of annual maintenance costs, staff salaries, and facility expenses. Staff consists of workers, engineers, operators, accountants, secretaries, and the chief executive officer. Annual maintenance costs represent a fraction (typically 4 percent) of the capital costs of a liquefaction plant. Administrative and general expenses are computed as follows:

$$L\_ADM\_GEN_y = (L\_MAINT\_PCT * L\_CAPCOST_y + L\_STAFF\_NUM * L\_AVG\_SALARY_y / 1{,}000{,}000. + L\_CEO\_FACTY_y / 1000000.) / (CAP * L\_CONV\_FAC) \quad \text{(G-9)}$$

where,

$$L\_CAPCOST = CAP * L\_PUCAPCOST \quad \text{(G-10)}$$

where,

L_ADM_GEN	=	total per-unit administrative and general expenses (2006$/Mcf)
L_MAINT_PCT	=	annual maintenance costs as a percent of plant capital costs (ratio, Appendix E)
L_CAPCOST	=	capital cost of the representative liquefaction plant (2006 dollars)
L_STAFF_NUM	=	average number of employees operating a liquefaction plant (Appendix E)
L_AVG_SALARY	=	average annual salary of an employee operating a liquefaction plant (2006 dollars, Appendix E)
L_CEO_FACTY	=	Chief executive officer's annual salary and benefits plus other staff and facility costs (2006 dollars, Appendix E). This variable's value is reduced by a fraction (L_EXPFAC, Appendix E) for an expansion at an existing facility.
CAP	=	representative capacity per train at a liquefaction plant (million tons of LNG per annum, mmtpa, Appendix E)
L_PUCAPCOST	=	per-unit capital cost for a liquefaction plant (2006$/ton of plant capacity)
L_CONV_FAC	=	liquefaction plant capacity conversion factor from million tons to Bcf (Bcf per million tons of LNG, Appendix E)
y	=	forecast year

Shipping Costs

LNG shipment costs from a supply source to a receiving terminal are computed as the sum of three components: the annual return on invested capital, transportation fuel cost, and operation and maintenance expenses. The annual return on invested capital is computed based on an assumed average price for all the newly built tankers and an average rate of return on invested capital (weighted average cost of capital for the tanker). This average rate of return is a function of debt fraction, cost of debt, cost of equity, average corporate tax rate, and average depreciation life for LNG ships.

All three components are also a function of the number of round trips per year, distance between a supply source and an LNG terminal, average tanker capacity, and other parameters such as ship utilization rate, unloading time, and ship speed. These components are determined as follows.

Annual Return on Capital

The annual return on capital for a tanker per round trip is computed as follows:

$$RET\_ON\_CAP_{i,j} = CAP\_COST * 1000000./(SH\_CAP\_BCF * NUM\_ROUND_{i,j}) \quad \text{(G-11)}$$

where,

$$SH\_CAP\_BCF = SH\_CAP\_CM * CM\_TO\_BCF \quad \text{(G-12)}$$

$$NUM\_ROUND_{i,j} = SH\_AVAIL\_DAY/(DAYS\_ROUND_{i,j} + SH\_LOAD\_DAY) \quad \text{(G-13)}$$

$$DAYS\_ROUND_{i,j} = SH\_MILES_{i,j} * 2./SH\_SPEED \quad \text{(G-14)}$$

where,

RET_ON_CAP(i,j)	=	annual return on capital per tanker per round trip (2006$/Mcf)
CAP_COST	=	annual return on capital (2006 million dollars)
SH_CAP_BCF	=	average ship capacity (Bcf)
NUM_ROUND(i,j)	=	number of round trips per year for each ship from source i to destination j
SH_CAP_CM	=	average ship capacity (cubic meters) (Appendix E)
CM_TO_BCF	=	conversion factor to convert cubic meters of LNG to thousand cubic feet (Appendix E)
SH_AVAIL_DAY	=	number of days in year ships operate (Appendix E)
DAYS_ROUND(i,j)	=	number of days per round trip for each ship from source i to destination j
SH_LOAD_DAY	=	number of loading/unloading days per cargo (Appendix E)
SH_MILES(i,j)	=	miles from a producing country i to a U.S. port j (Appendix E)
SH_SPEED	=	LNG ship speed in miles per day (Appendix E)
i	=	producing country (source)
j	=	a U.S. port (destination)

The annual return on capital for a tanker is determined as the product of the average ship price times its capital cost recovery factor. It is expressed by the following equation:

$$CAP\_COST = CAP\_REC\_METH * CAP\_REC\_FAC \quad \text{(G-15)}$$

where,

CAP_COST	=	annual return on capital (2006 million dollars)
CAP_REC_METH	=	average ship price (2006 million dollars)
CAP_REC_FAC	=	capital cost recovery factor

The average ship price, which includes interest charges during construction, is computed as follows:

$$CAP\_REC\_METH = NPV + EQUITY \quad \text{(G-16)}$$

where,

$$NPV = \sum_{N=1}^{SH\_NUMBLD\_YR} (DEBT/SH\_NUMBLD\_YR) * (1. + oMC\_RMPUAANS_y/100.)^N \quad \text{(G-17)}$$

$$EQUITY = INIT\_COST - DEBT \quad \text{(G-18)}$$

where,

$$INIT\_COST = SH\_UNIT\_COST * SH\_CAP\_CM/1000000. \quad \text{(G-19)}$$

$$DEBT = SH\_DEBT\_EQTY * INIT\_COST \quad \text{(G-20)}$$

where,

CAP_REC_METH	=	average ship price (2006 million dollars)
NPV	=	annual return on capital (2006 million dollars)
EQUITY	=	equity (2006 million dollars)
INIT_COST	=	initial tanker cost (2006 million dollars)
DEBT	=	debt (2006 million dollars)
SH_NUMBLD_YR	=	number of years to build an LNG ship (Appendix E)
oMC_RMPUAANS(y)	=	AA utility bond rate provided by the Macroeconomic Activity Module (percent)
SH_UNIT_COST	=	average initial LNG ship price per cubic meter (Appendix E)
SH_CAP_CM	=	average LNG ship capacity (cubic meters) (Appendix E)
SH_DEBT_EQTY	=	cost of debt (i.e., debt-to-equity ratio) (Appendix E)
y	=	forecast year

The capital cost recovery factor is computed by the following equation:

$$\mathrm{CAP\_REC\_FAC} = \mathrm{ROR\_AFTTAX}/(1. - (1. + \mathrm{ROR\_AFTTAX})^{-\mathrm{SH\_LIFE\_YRS}}) \qquad \text{(G-21)}$$

where,

$$\begin{aligned}\mathrm{ROR\_AFTTAX} = {} & (\mathrm{SH\_DEBT\_EQTY} * (\mathrm{oMC\_RMPUAANS}_y/100.) * \\ & (1. - \mathrm{SH\_CORP\_TAXRAT})) + ((1. - \mathrm{SH\_DEBT\_EQTY}) * \mathrm{RET\_EQ})\end{aligned} \qquad \text{(G-22)}$$

$$\mathrm{RET\_EQ} = (\mathrm{oMC\_RMGFCM\_10NS}_y/100.) + (\mathrm{SH\_RISK\_FAC} * \mathrm{SH\_RISK\_SCAL}) \qquad \text{(G-23)}$$

where,

CAP_REC_FAC	=	capital cost recovery factor
ROR_AFTTAX	=	weighted average rate of return on capital (after-tax)
SH_LIFE_YRS	=	number of life years for an LNG ship financing
SH_DEBT_EQTY	=	cost of debt (i.e., debt-to-equity ratio) (Appendix E)
oMC_RMPUAANS(y)	=	AA utility bond rate provided by the Macroeconomic Activity Module (percent)
SH_CORP_TAXRAT	=	average corporate tax rate for LNG ships (Appendix E)
RET_EQ	=	cost of equity (fraction)
oMC_RMGFCM_10NS	=	10-year treasury note (percent), a macroeconomic variable
SH_RISK_FAC	=	general industry average risk factor on equity (Appendix E)
SH_RISK_SCAL	=	scalar to set risk factor for shipping above average (Appendix E)
y	=	forecast year

Fuel Costs

LNG ship transportation fuel costs per round trip are estimated based on an average bunker fuel cost, average daily bunker fuel consumption, boil-off rate, LNG fuel cost, number of days traveled per round trip per ship for each route, and ship capacity. This transportation fuel cost is computed as follows:

$$\mathrm{TRAN\_FUEL\_COST}_{i,j} = \mathrm{FUEL\_COST\_DAY} * \mathrm{DAYS\_ROUND}_{i,j} \qquad \text{(G-24)}$$

where,

$$\mathrm{FUEL\_COST\_DAY} = \mathrm{BOILOFF\_COST\_DAY} + \mathrm{BUNKER\_COST\_DAY} \qquad \text{(G-25)}$$

$$BOILOFF\_COST\_DAY = SH\_LNG\_COST * SH\_BOIL\_RATE \quad \text{(G-26)}$$

$$BUNKER\_COST\_DAY = (SH\_BUNKER\_DAY * 1000. * SH\_BUNKER\_COST \, / (3.785 * 0.98)) \quad / \quad SH\_CAP\_BCF \quad \text{(G-27)}$$

$$SH\_BUNKER\_COST = (oPRSTR_{c,y} * 6.287/42.) * oMC\_PCWGDP_{iy} \quad \text{(G-28)}$$

where,

TRAN_FUEL_COST	=	transportation fuel cost per round trip (2006$/Mcf)
FUEL_COST_DAY	=	transportation fuel cost per day (2006$/Mcf-day)
DAYS_ROUND(i,j)	=	number of days per round trip for each ship from source i to destination j
BOILOFF_COST_DAY	=	boiloff cost per Mcf per day (2006$/Mcf-day)
BUNKER_COST_DAY	=	bunker fuel cost per day (2006$/Mcf-day)
SH_LNG_COST	=	loss value of LNG (2006$/Mcf) (Appendix E)
SH_BOIL_RATE	=	boiloff rate on LNG ships (fraction per day, Appendix E)
SH_BUNKER_DAY	=	bunker fuel use by LNG ships per day (tones/day) (Appendix E)
SH_BUNKER_COST	=	cost of bunker fuel (2006$/gallon)
SH_CAP_BCF	=	average ship capacity (Bcf)
3.785	=	1 U.S. gallon equals 3.785 liters
0.98	=	bunker fuel density
oPRSTR(c,y)	=	global variable for residual fuel price (1987 dollars per MMBtu)
6.287	=	heat rate for residual fuel oil, conversion factor to convert 6.287 MMBtu to one barrel
42	=	42 gallons per barrel
oMC_PCWGDP(iy)	=	GDP chain-type price deflator variable (from the Macroeconomic Activity Module)
i	=	producing country (source)
j	=	a U.S. port (destination)
c	=	census division mapped from an LNG region
y	=	forecast year
iy	=	index, conversion from year dollars (SH_DOLS, Appendix E) for shipping cost data (=16 if SH_DOLS=2006)

Operation and Maintenance Expenses

Operation and maintenance expenses are estimated based on a percent of the ship capital cost, the ship capacity, and the number of round trips traveled by the ship per year. The equation is specified as follows:

$$OP\_COST\_AAG_{i,j} = SH\_OPC\_PER * CAP\_COST * 1000000. \, / \quad (SH\_CAP\_BCF * NUM\_ROUND_{i,j}) \quad \text{(G-29)}$$

where,

OP_COST_AAG	=	operation and maintenance expenses excluding fuel cost per round trip (2006$/Mcf)
SH_OPC_PER	=	LNG ship operation cost as a percent of capital cost (fraction, Appendix E)
CAP_COST	=	annual return on capital (2006 million dollars)

SH_CAP_BCF	=	average ship capacity (Bcf)
NUM_ROUND(i,j)	=	number of round trips per year for each ship from source i to destination j
i	=	producing country (source)
j	=	a U.S. port (destination)

Per-Unit Cost

Initial LNG shipping costs are estimated as the sum of the three cost components computed above (annual return of capital, transportation fuel cost, and operation and maintenance expenses) divided by the ship's planned utilization rate. A port cost at each receiving terminal is added to these shipping costs to arrive at the final LNG shipping costs. The costs are estimated as follows:

$$\begin{aligned} SCRV\_PSH_{i,j} = {} & (SH\_PORT\_COST + TOT\_TRAN\_COST_{i,j}) * \\ & oMC\_PCWGDP_{1987}/oMC\_PCWGDP_{iy} \end{aligned} \qquad \text{(G-30)}$$

where,

$$\begin{aligned} TOT\_TRAN\_COST_{i,j} = {} & (RET\_ON\_CAP_{i,j} + TRAN\_FUEL\_COST_{i,j} \\ & + OP\_COST\_AAG_{i,j}) \quad / \quad SH\_UTIL\_RATE \end{aligned} \qquad \text{(G-31)}$$

where,

SCRV_PSH(i,j)	=	LNG shipping cost from source i to destination j (1987$/Mcf)
SH_PORT_COST	=	LNG ship port cost at a U.S. terminal (2006$/Mcf, Appendix E)
TOT_TRAN_COST	=	initial LNG shipping cost (2006 $/Mcf)
oMC_PCWGDP	=	GDP chain-type price deflator variable (from the Macroeconomic Activity Module)
RET_ON_CAP(i,j)	=	annual return on capital per tanker per round trip (2006$/Mcf)
TRAN_FUEL_COST	=	transportation fuel cost per round trip (2006$/Mcf)
OP_COST_AAG	=	operation and maintenance expenses excluding fuel cost per round trip (2006$/Mcf)
SH_UTIL_RATE	=	planned utilization rate of LNG ships (Appendix E)
i	=	producing country (source)
j	=	a U.S. port (destination)
iy	=	index, conversion from year dollars (SH_DOLS, Appendix E) for shipping cost data (=17 if SH_DOLS=2006)

Regasification Costs

Regasification costs are computed based on two main components: annual return on capital and total operation and maintenance expenses. The per-unit regasification charge at each terminal is obtained by dividing its regasification cost by its terminal capacity. The resulting per-unit charge is then multiplied by region-specific parameters to account for region-specific costs associated with land purchase, labor, risk premium, site specific permitting, special land and waterway preparation and/or acquisition. Multipliers that were developed to account for these and other general construction and operating cost differences across the United States range from 1.0 to 1.5.

Annual Return on Capital

The annual return on capital for each terminal is determined based on its capital cost, debt fraction, cost of debt, cost of equity, corporate tax rate, and the terminal's economic life. Regasification capital cost depends on the costs of storage tanks, vaporizer units, marine facilities, site improvements and roads, buildings and services, installation, engineering and project management, land, contingency, and plant capacity. The cost of debt is tied to the AA utility bond rate and the cost of equity is linked to the 10-year treasury note yield plus a risk premium.

The annual return on capital for a regasification terminal is computed as the product of its capital cost times its capital recovery factor.

$$\text{RET\_CAP} = \text{CAP\_COST} * \text{REC\_CAP\_FAC} \tag{G-32}$$

where,

$$\begin{aligned}\text{CAP\_COST} = (1. + \text{RG\_CONT\_FRAC}) * (&\text{COST\_TANKS} + \text{COST\_MARINE} \\ &+ \text{COST\_VAP} + \text{COST\_LAND} + \text{RG\_CST\_SITE} + \text{RG\_CST\_BLDS} \\ &+ \text{RG\_CST\_MISC} + \text{RG\_CST\_INSTALL} + \text{RG\_CST\_ENGR})\end{aligned} \tag{G-33}$$

where,

RET_CAP	=	annual return on capital for a regas terminal (2006 million dollars)
REC_CAP_FAC	=	capital cost recovery factor
CAP_COST	=	capital cost (2006 million dollars)
RE_CONT_FRAC	=	fraction of capital costs set as contingency (Appendix E)
COST_TANKS	=	cost of storage tanks (2006 million dollars)
COST_MARINE	=	cost of marine facility (2006 million dollars)
COST_VAP	=	vaporizers' cost (2006 million dollars)
COST_LAND	=	land cost (2006 million dollars)
RG_CST_SITE	=	site improvement costs (Appendix E)
RG_CST_BLDS	=	building and service costs (Appendix E)
RG_CST_MISC	=	miscellaneous (piping, controls, utilities) costs (Appendix E)
RG_CST_INSTALL	=	installation costs (Appendix E)
RG_CST_ENGR	=	engineering and maintenance costs (Appendix E)

The costs of storage tanks, marine facilities, vaporizers, and land need to be estimated and the capital cost recovery factor determined.

The cost of storage tanks is computed as the product of the cost per tank times the number of storage tanks at each terminal. The number of storage tanks is determined as a function of the terminal's capacity. The cost of storage tanks is determined as follows:

$$\text{COST\_TANKS} = \text{RG\_CST\_TANK} * (\text{IFIX}(\text{CAP}/\text{RG\_TANK\_CAP}) + 1) \quad \text{(G-34)}$$

where,

COST_TANKS	=	cost of storage tanks (2006 million dollars)
RG_CST_TANK	=	cost per tank (2006 million dollars, Appendix E)
CAP	=	regasification terminal capacity (Bcf per year)
RG_TANK_CAP	=	throughput of capacity (Bcf per year) per needed tank (153,000 cu.m.) (Appendix E)

The cost of marine facilities depends on the regasification capacity. If the capacity is greater than 2 bcf/d, an additional dock will be added. The cost is determined as follows:

$$\text{COST\_MARINE} = \text{RG\_CST\_MARINE} + \text{RG\_CST\_2MARINE} \qquad \text{if CAP} > 2\text{Bcf/d} \quad \text{(G-35)}$$

$$\text{COST\_MARINE} = \text{RG\_CST\_MARINE} \qquad \text{if CAP} \leq 2\text{Bcf/d} \quad \text{(G-36)}$$

where,

COST_MARINE	=	cost of marine facility (2006 million dollars)
RG_CST_MARINE	=	cost of marine facility for a regasification capacity less than 2 Bcf/d (Appendix E)
RG_CST_2MARINE	=	added cost of additional dock (2006 million dollars, Appendix E)

The cost of vaporizers for a terminal is computed based on the cost of five vaporizer units (the number assumed for the smallest generic terminal) and the size of the terminal, as follows:

$$\text{COST\_VAP} = (\text{RG\_CST\_5VAP}/5.) * (\text{IFIX}(\text{CAP}/\text{RG\_VAP\_CAP}) + 1) \quad \text{(G-37)}$$

where,

COST_VAP	=	cost of vaporizers (2006 million dollars)
RG_CST_5VAP	=	cost per five vaporizer units (2006 million dollars, Appendix E)
CAP	=	regasification terminal capacity (Bcf per year)
RG_VAP_CAP	=	throughput of capacity (Bcf per year) per needed vaporizer (Appendix E)

Land cost is determined as follows:

$$\text{COST\_LAND} = \text{RG\_CST\_ACRE} * (\text{RG\_ACRE\_MIN} + (\text{CAP}/\text{RG\_ACRE\_CAP})) \quad \text{(G-38)}$$

where,

COST_LAND	=	land cost (2006 million dollars)
RG_CST_ACRE	=	cost per acre (2006 million dollars, Appendix E)
RG_ACRE_MIN	=	minimum acreage (Appendix E)
CAP	=	regasification terminal capacity (Bcf per year)
RG_ACRE_CAP	=	throughput of capacity (Bcf per year) per acre above the minimum acreage (Appendix E)

Finally, the capital cost recovery factor, REC_CAP_FAC, is determined as a function of debt fraction, cost of debt, cost of equity, corporate tax rate, and the terminal's economic life. It is calculated as follows:

$$\text{REC\_CAP\_FAC} = \text{WACOC}/(1. - ((1. + \text{WACOC})^{(\text{-RG\_LIFE\_YRS})}))$$

where,

$$\begin{aligned}\text{WACOC} = {} & (\text{RG\_DEBT\_EQTY} * \text{RET\_DEBT} * (1. - \text{RG\_CORP\_TAXRAT})) \\ & + ((1. - \text{RG\_DEBT\_EQTY}) * \text{RET\_EQ})\end{aligned} \qquad \text{(G-39)}$$

$$\text{RET\_DEBT} = (\text{oMC\_RMCORPBAA}_y / 100.) + \text{RG\_RISK\_DEBT} \qquad \text{(G-40)}$$

$$\text{RET\_EQ} = (\text{oMC\_RMGFCM\_10NS}_y / 100.) + (\text{RG\_RISK\_FAC} * \text{RG\_RISK\_SCAL}) \qquad \text{(G-41)}$$

where,

REC_CAP_FAC	=	capital cost recovery factor
WACOC	=	weighted average cost of capital (factor) after tax
RG_LIFE_YRS	=	economic life (in years) for regasification terminal financing (Appendix E)
RG_DEBT_EQTY	=	debt fraction or debt-to-equity ratio (Appendix E)
RET_DEBT	=	cost of debt (fraction) as a function of AA utility bond rate and a risk premium
RG_CORP_TAXRAT	=	corporate tax rate for regasification terminal (Appendix E)
RET_EQ	=	cost of equity (fraction)
oMC_RMCORPBAA	=	AA utility bond rate (percent), a macroeconomic variable
RG_RISK_DEBT	=	risk premium for the cost of debt (fraction, Appendix E)
oMC_RMGFCM_10NS	=	10-year treasury note (percent), a macroeconomic variable
RG_RISK_FAC	=	general industry average risk factor on cost of equity (Appendix E)
RG_RISK_SCAL	=	scalar to set risk factor for the cost of equity (factor, Appendix E)
y	=	forecast year

Operation and Maintenance Expenses

Total operation and maintenance expenses are computed as the sum of administrative and general expenses, operation and maintenance expenses, taxes and insurances, electric power cost, and fuel usage and loss. The equation is as follows:

$$\begin{aligned}\text{OM\_COSTS} = {} & \text{RG\_COST\_WAGES} + \text{COST\_OM} + \text{COST\_TAX\_INSUR} \\ & + \text{COST\_POWER} + \text{COST\_FUEL}\end{aligned} \qquad \text{(G-42)}$$

where,

$$\begin{aligned}&\text{COST\_OM} = \text{RG\_OM\_FRAC} * \text{CAP\_COST} \\ &\text{COST\_TAX\_INSUR} = (\text{RG\_TAX\_FRAC} + \text{RG\_INSUR\_FRAC}) * \\ &\qquad (\text{CAP\_COST} - \text{RG\_INT\_CONST})\end{aligned} \qquad \text{(G-43)}$$

$$COST\_POWER = (RG\_KW\_MMTONS/RG\_BCF\_MMTONS) * CAP * 365. * 24. * RG\_COST\_KWH/1000000. \quad (G-44)$$

$$RG\_COST\_KWH = (oPELIN_{c,y} * 0.3412/100.) * oMC\_PCWGDP_{iy} \quad (G-45)$$

$$COST\_FUEL = RG\_FUEL\_FRAC * CAP * RG\_UTIL\_FIN * RG\_FUEL\_MMBTU \quad (G-46)$$

where,

OM_COSTS	=	total maintenance and operation expenses (2006 million dollars)
RG_COST_WAGES	=	administrative and general based on 50 employees per terminal (2004 million dollars) (Appendix E)
COST_OM	=	operation and maintenance expenses (2006 million dollars)
COST_TAX_INSUR	=	taxes and insurances (2006 million dollars)
COST_POWER	=	electric power cost (2006 million dollars)
COST_FUEL	=	fuel usage and loss (2006 million dollars)
RG_OM_FRAC	=	operations and maintenance as a fraction of capital cost
CAP_COST	=	capital cost (2006 million dollars)
RG_TAX_FRAC	=	taxes as a fraction of capital cost minus interest during construction
RG_INSUR_FRAC	=	insurance as a fraction of capital cost minus interest during construction
RG_INT_CONST	=	interest charges during construction (2006 million dollars, Appendix E)
RG_KW_MMTONS	=	kilowatts of electric power per million tons of regas capacity per year (Appendix E)
RG_BCF_MMTONS	=	conversion factor in Bcf per million tons of LNG (Appendix E)
CAP	=	regasification terminal capacity (Bcf per year)
RG_COST_KWH	=	average cost per kilowatt-hour (2006 dollars per kilowatthour)
oPELIN(c,y)	=	global variable for electricity price to the industrial sector (1987 dollars per MMBtu)
0.3412	=	conversion factor for electricity consumption (=3,412 Btu per kilowatthour)
365	=	365 days per year
24	=	24 hours per day
oMC_PCWGDP(iy)	=	GDP chain-type price deflator variable (from the Macroeconomic Activity Module)
RG_FUEL_FRAC	=	fuel use as a fraction of throughput (Appendix E)
RG_UTIL_FIN	=	utilization rate for financial purposes (Appendix E)
RG_FUEL_MMBTU	=	cost of natural gas (LNG) supply as fuel (2006 dollars per MMBtu)
c	=	census division mapped from an LNG region
y	=	forecast year
iy	=	index, conversion from year dollars (RG_DOLS, Appendix E) for regasification cost data (=17 if RG_DOLS=2006)

Per-Unit Charge

The per-unit regasification charge at each terminal is obtained by dividing its regasification cost by its terminal capacity and utilization rate (for financial purposes). The resulting per-unit charge is then adjusted based on region parameters to account for region-specific costs associated with land purchase, labor, risk premium, site specific permitting, special land and waterway preparation and/or acquisition.

The per-unit regasification charge is computed by the following equation:

$$NGLNG\_RGCOST = (RET\_CAP + OM\_COSTS)/(CAP * RG\_UTIL\_FIN) * RG\_REG\_ADJ_r * (oMC\_PCWGDP_{1987}/oMC\_PCWGDP_{iy}) \quad \text{(G-47)}$$

where,

NGLNG_RGCOST	=	per-unit regasification charge (2006 $/Mcf)
RET_CAP	=	annual return on capital (2006 million dollars)
OM_COSTS	=	total maintenance and operation expenses (2006 million dollars)
CAP	=	regasification terminal capacity (Bcf per year)
RG_UTIL_FIN	=	utilization rate for financial purposes (Appendix E)
RG_REG_ADJ(r)	=	regional adjustment factor by region (Appendix E)
oMC_PCWGDP(iy)	=	GDP chain-type price deflator variable (from the Macroeconomic Activity Module)
iy	=	index, conversion from year dollars (RG_DOLS, Appendix E) for regasification cost data (=17 if RG_DOLS=2006)

The per-unit regasification charge NGLNG_RGCOST is assigned in the first step in the variable SCRV_PRG.

Appendix H

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 H-1 presents cross references between model equation variables defined in this document and in the FORTRAN code for the PTS.

Table H-1. Cross Reference of PTM Variables Between Documentation and Code

Documentation	Code Variable	Equation #
$R_{i,f}$	Not represented	124
$R_{i,v}$	Not represented	125
ALL_f	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	124
ALL_v	AVA_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	125
R_i	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	124, 125
FC_a	Not represented	126
VC_a	Not represented	127
$R_{i,f,r}$	RFC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	128
$R_{i,f,u}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	129
$R_{i,v,r}$	RVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	130
$R_{i,v,u}$	UVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	131
$ALL_{f,r}$	AFR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	128
$ALL_{f,u}$	AFU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	129
$ALL_{v,r}$	AVR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	130
$ALL_{v,u}$	AVU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	131

Documentation	Code Variable	Equation #
ξ_i	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	189, 190, 192-195
$Item_{i,a,t}$	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	189, 190, 192-195
$FC_{a,t}$	Not represented	189
$VC_{a,t}$	Not represented	190
$TCOS_{a,t}$	Not represented	191, 196
$RFC_{a,t}$	RFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	192
$UFC_{a,t}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	192
$RVC_{a,t}$	RVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	194
$UVC_{a,t}$	UVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	195
λ_i	AFR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	192, 193
μ_i	AVR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	194, 195
a - arc, t - year, i - cost-of-service component index		