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Model Documentation

Natural Gas Transmission and

Distribution Model of the

National Energy Modeling System

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Prepared by:

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For Further Information...

The Natural Gas Transmission and Distribution Model (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 James M. Kendell (202) 586-2308, 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 2000*, (DOE/EIA-0383(2000)). 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 2001.

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1. Background/Overview

The Natural Gas Transmission and Distribution Model (NGTDM) is the component of the National Energy Modeling System (NEMS) that is used to represent the domestic natural gas transmission and distribution system. NEMS was developed in 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 domestic energy-economy markets and develop projections. From 1982 through 1993, the Intermediate Future Forecasting System (IFFS) was used by the EIA for its analyses, and the Gas Analysis Modeling System (GAMS) was used within IFFS to represent natural gas markets. Prior to 1982, the Midterm Energy Forecasting System (MEFS), also referred to as the Project Independence Evaluation System (PIES), was employed.

NEMS was developed to enhance and update EIA's modeling capability, (e.g., by internally incorporating models of energy markets that had previously been analyzed off-line). Greater structural detail in NEMS permits the analysis of a broader range of energy issues. The time horizon of NEMS is the midterm period, through the year 2020.[1] In order to represent the regional differences in energy markets, the component models 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 using a market-based approach[2] to energy analysis, as had the earlier 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 models represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international models. More recently a routine was added to the system that determines annual fees for carbon to limit carbon emissions from fuel combustion to user-specified levels. The primary flows of information between each of these models are the delivered prices of energy to the end user and the quantities consumed by product, Census Division, and end-use sector. The delivered prices of fuel encompass all the activities necessary to produce (or 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.

An integrating routine of NEMS controls the execution of each of the component models. The modular design provides the capability to execute models individually, thus allowing independent analysis with, as well as development of, individual models. This modularity allows the use of the methodology and level of detail most appropriate for each energy sector. NEMS solves by iteratively calling each model in sequence until the delivered prices and quantities of each fuel in each region have converged within tolerance both within individual models and between the various models, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Model 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.

NGTDM Overview

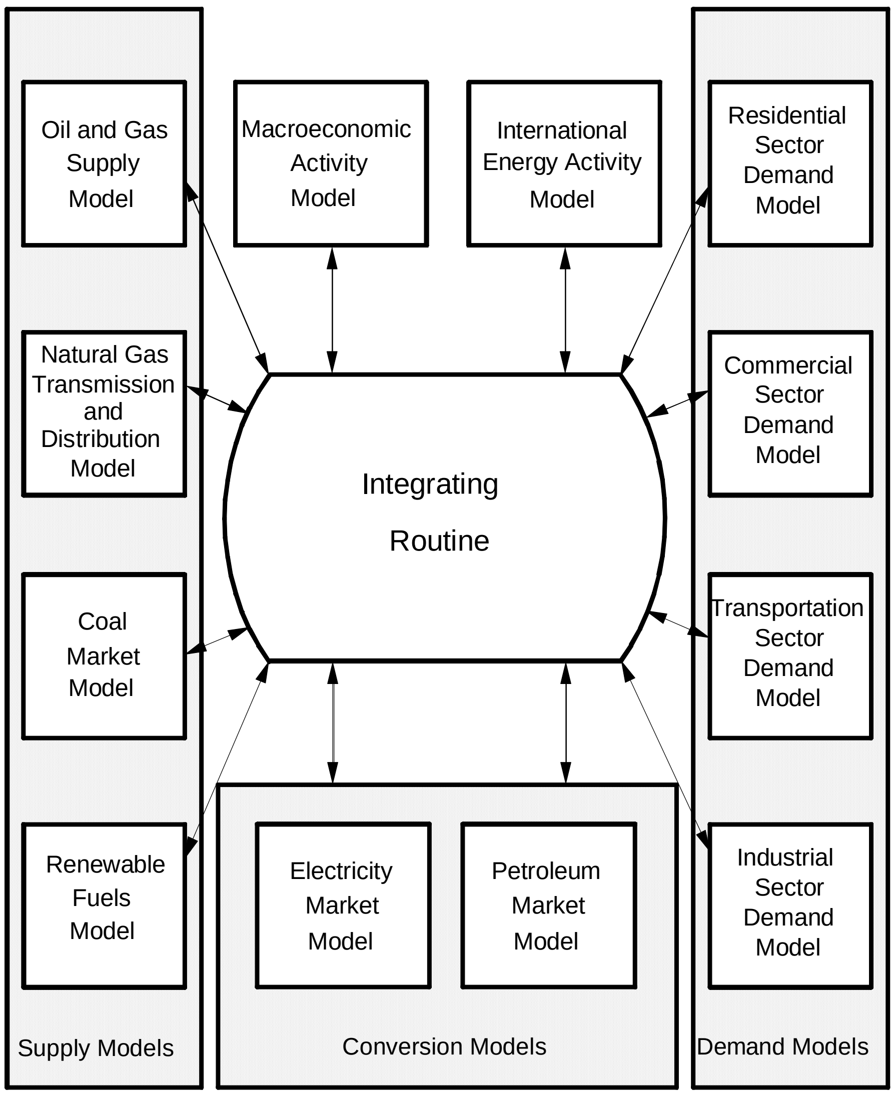
The NGTDM is the model within the NEMS that represents the transmission, distribution, and pricing of natural gas. Based on information received from other NEMS models, the NGTDM also includes representations of the end-use

[1]For the *Annual Energy Outlook 2000* the NEMS was executed for each year from 1990 through 2020.

[2]The central theme of a market-based approach 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 models including a system integration routine. These components are frequently referred to as "modules" in other NEMS related publications; however, in this publication they will all be referred to as "models." Footnotes will be added when the formal name is different from the referenced name. The components of the NGTDM will be referred to as "modules."

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



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. Although the focus of the NGTDM is on domestic natural gas markets, a simplified representation of the Canadian natural gas market is incorporated within the model as well. For two seasons of each forecast year, the NGTDM determines the production, flows, and prices of natural gas in an aggregate, 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 basis, NGTDM results are passed to other NEMS models representing annual totals or quantity-weighted averages.

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. End-use demand is represented by sector (residential, commercial, industrial, electric generators, and natural gas vehicles), with the industrial and electric generator sectors disaggregated into core and noncore segments. The methodology employed allows 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 forecast, 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). 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. The representation of the natural gas market in Canada is much less detailed than for the U.S. since the primary focus of the model is on the domestic market. Finally, four liquefied natural gas import facilities (and one export facility in Alaska), as well as three import/export border crossings at the Mexican border, are included.

The model structure consists of three major components. the Interstate Transmission Module (ITM), the Pipeline Tariff Module (PTM), and the Distributor Tariff Module (DTM). The ITM is the integrating module of the NGTDM. It 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, including pipeline and storage capacity expansion decisions. The Pipeline Tariff Module (PTM) generates a representation of tariffs for interstate transportation and storage services, both existing and expanded. The Distributor Tariff Module (DTM) 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 ITM, an accounting algorithm for the PTM, and a largely empirical process based on historical data for the DTM.

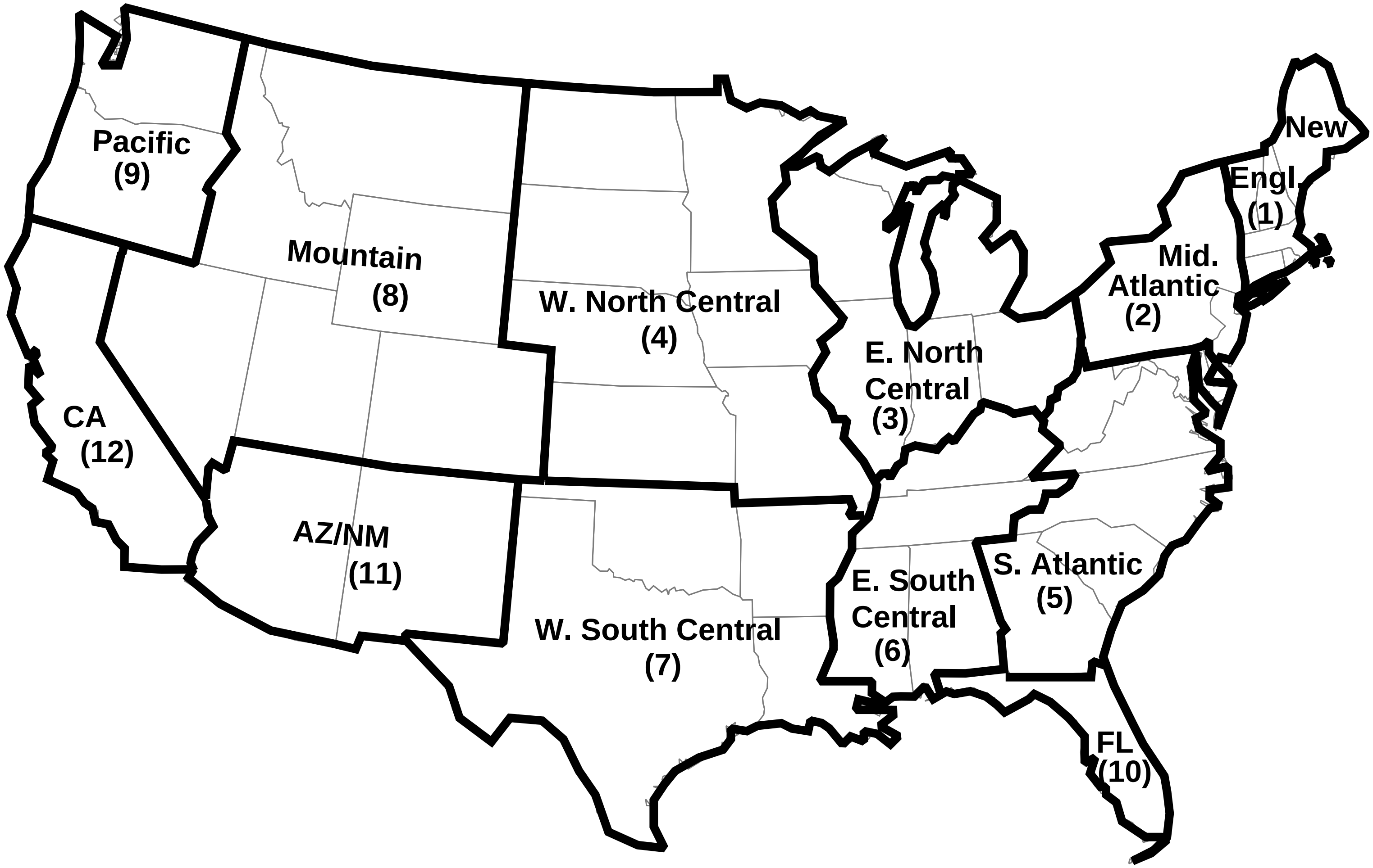
NGTDM Objectives

The purpose of the NGTDM is to derive natural gas end-use and wellhead prices and 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 domestic supply, imports, and demand representations are provided as inputs to the NGTDM from other NEMS modules. 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 capabilities include:

- Represent interregional flows of gas and pipeline capacity constraints

- Represent regional supplies

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



- Determine the amount and the location of additional pipeline and storage facilities on a regional basis, capturing the economic tradeoffs between pipeline and storage capacity additions

- Provide a peak/off-peak, or seasonal analysis capability

- Represent transmission and distribution service pricing

These capabilities will be described in greater detail in the subsequent chapters of this report which describe the individual modules 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 2000,* DOE/EIA-0383(2000) is documented in this report. The major modification to the NGTDM since it was used for the *AEO99* is the incorporation of an updated and simplified version of the Pipeline Tariff Module. 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).

A previous version of this report represented Volume I of a two-volume set. Volume II was intended to report on model performance, details of convergence criteria and properties, results of sensitivity testing, comparisons of model outputs with the literature and/or other model results, and major unresolved issues. A second volume was generated based upon the *Annual Energy Outlook 1995,* version of the model; however, a Volume II was not produced for subsequent issues of the *Annual Energy Outlook,* and will not be produced for the *Annual Energy Outlook 2000* version or in the foreseeable future. Subsequent chapters of this report provide:

- A description of the interface between the NEMS and the NGTDM (Chapter 2)

- An overview of the solution methodology of the NGTDM (Chapter 3)

- The solution methodology for the Interstate Transmission Module (Chapter 4)

- The solution methodology for the Distributor Tariff Module (Chapter 5)

- The solution methodology for the Pipeline Tariff Module (Chapter 6)

- A description of model assumptions, inputs, and outputs (Chapter 7).

The archived version of the model is available from the National Energy Information Center (NEIC) and is identified as NEMS2000 (part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 2000*, DOE/EIA-0383(2000)).

The document includes a number of appendices to support the material presented in the main body of the report. Appendix A presents the model 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 model variables which are assigned values through READ statements in the model and the data input files that are read. In addition these files contain detailed descriptions of the input data, including variable names, definitions, sources, units and derivations.[4] Appendix F

[4]A PC diskette with these data files is available upon request by contacting Joe Benneche at (202) 586-6132.

documents the derivation of all empirical estimations used in the NGTDM. Finally, variable cross reference tables are provided in Appendix G.

2. Interface Between the NEMS and the NGTDM

This chapter presents the general role that the Natural Gas Transmission and Distribution Model (NGTDM) plays 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 models will be described along with the methodology used within the NGTDM to transform these prior to their use in the model. The natural gas demand representation used in the model based on consumption provided by the Electricity Market Module (EMM) and the end-use demand models of NEMS is described, followed by a section on the natural gas supply interface. Finally, the information that is passed to other NEMS models from the NGTDM will be 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 an equilibrium in each forecast year by iteratively operating a series of fuel supply and demand models to compute the end-use prices and consumption of the fuels represented.[5] The end-use demand models—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 models 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 models determine the end-use prices needed in order to supply the amount of fuel demanded by the customers, as determined by the demand models. 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 Model (OGSM) and the demand models in NEMS, including the EMM. The NGTDM incorporates a relatively simple representation of Canadian natural gas markets and determines the price and flow of dry natural gas supplied internationally from the contiguous U.S. border[6] 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 (local distribution companies) of natural gas in the contiguous United States.[7] The primary data flows between the NGTDM and the other oil and gas models in NEMS, the Petroleum Market Model (PMM) and the OGSM, are depicted in Figure 2-1.

Functionally, each of the demand models in NEMS provides the level of natural gas that would be consumed at the burnertip by the represented sector at a given end-use price. The OGSM provides parameters for establishing the level of natural gas which would be produced (domestically or in Canada) at the wellhead for a given supply price. The NGTDM uses this information to build "short-term" supply and demand curves which are used to approximate a given model's response to prices within a limited range.[8] Given these short-term demand and supply curves, the NGTDM model solves for the end-use, wellhead, and border prices that represent a natural gas market equilibrium, while

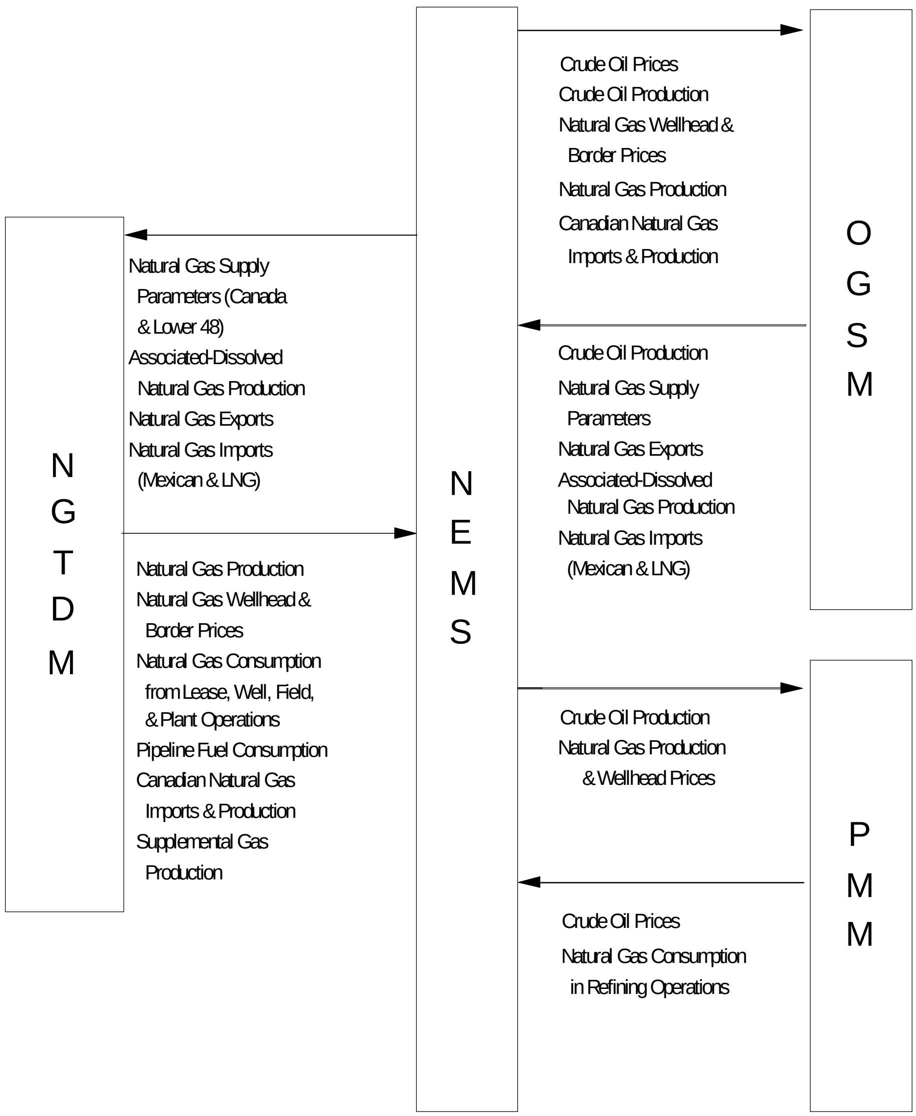
[5]A more detailed description of the NEMS system, including the convergence algorithm used, can be found in "National Energy Modeling System Integrating Module Documentation Report." DOE/EIA-M057(99), December 1998 or "National Energy Modeling System, An Overview," DOE/EIA-0581(98), February 1998.

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

[7]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.

[8]Parameters are provided by OGSM for the construction of supply curves for domestic nonassociated and 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.

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



accounting for the costs and market for transmission and distribution services (including its physical and regulatory constraints). These solution prices, and associated production levels, are in turn passed to the OGSM and the demand models, including the EMM, as primary input variables. In addition to the basic calculations performed within these models, the parameters which define the natural gas supply or demand curves used in the NGTDM are updated (as appropriate) to reflect the prices most recently provided by the NGTDM.

The NGTDM model is composed of three primary components or modules: the Interstate Transmission Module, the Pipeline Tariff Module, and the Distributor Tariff Module. The Interstate Transmission Module is the central module of the NGTDM, since it is used to derive flows and prices of natural gas in conjunction with a peak and offpeak natural gas market equilibrium. Conceptually the Interstate Transmission Module 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 modules to the Interstate Transmission Module, providing parameters which define the tariffs to be charged along each of the interregional, intraregional, intrastate, and distribution arcs. Data are also passed back to these satellite modules from the Interstate Transmission Module. Other parameters for defining the natural gas market (such as supply and demand curves) are derived based on information passed from other NEMS models.

The NGTDM is called once for each iteration of NEMS, but all modules are not run for every call. The Pipeline Tariff Module is executed only once for each forecast year, on the first iteration of each year. The Interstate Transmission Module and the Distributor Tariff Module are executed once every NEMS iteration. The calling sequence of and the interaction among the NGTDM modules is as follows for each forecast year of execution of NEMS (1999 to 2020):

- First Iteration:

  The Pipeline Tariff Module determines the revenue requirements associated with interregional/ interstate pipeline company transportation and storage services, using a cost based simulation, and uses this information and cost of expansion estimates as a basis in establishing volume dependent tariff curves for existing and expanded pipeline and storage usage.

- Each Iteration:

  The Distributor Tariff Module sets markups for intrastate transmission and for distribution services based on historical data and assumed parameters. Next, the Interstate Transmission Module processes inputs from other NEMS models as required, (e.g., annual consumption levels are disaggregated into peak and offpeak levels) before determining a market equilibrium solution across the two-period NGTDM network. The module employs an iterative process, whereby consumption levels are flowed from the consumption regions through the network, down to the supply regions. Along the way, routes are selected based on their associated relative prices (initially set to last NEMS iteration's or last year's prices). The desired production levels are fed into the supply curves to determine the resulting prices. These prices are then flowed back up the network, adding tariffs from the Pipeline and Distributor Tariff modules along the way, to the end-use regions, thus ending a cycle. Consumption levels can be reevaluated by applying this cycle's resulting end-use prices to demand curves or the same consumption levels can be flowed back down the network. The routes taken will vary as the relative prices associated with the various routes have shifted. Convergence of the system is checked at the wellhead (i.e., prices are checked from one cycle to the next to be within a prespecified tolerance). Because of the interrelation of the peak and offpeak periods through storage usage, the model solves as follows: 1) consumption is flowed down the peak period network, 2) peak period "demands" for storage set the level of storage that must be filled in the offpeak period, 3) consumption is flowed down the offpeak period, 4) given the desired production levels wellhead prices are determined on an annual and seasonal basis, 5) prices are flowed up the offpeak period network, 6) the price of gas coming out of storage in the peak period is set as the price going in during the offpeak plus a relevant markup for storage costs, 7) prices are flowed up the peak period network. Finally seasonal end-use prices can be established and the process is repeated as necessary until convergence is realized.

- Last Iteration:

In the process of establishing a network/market equilibrium, the Interstate Transmission Module also determines the associated pipeline and storage capacity expansion requirements. These expansion levels are passed to the Pipeline Tariff Module 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 analyst's judgement 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. Finally, other outputs from the model are passed to report writing routines.

For the historical years (1990 through 1998), 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 offpeak 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 (1998) 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 models, result from establishing a natural gas market equilibrium solution: end-use prices, wellhead and border crossing prices, nonassociated natural gas production, and Canadian import levels. In addition, the model 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 which is produced within the United States is consumed in lease and plant operations, delivered to consumers, exported internationally, and 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 an historically observed percentage of dry gas production.[9] Pipeline fuel use depends on the amount of gas flowing through each region, as described in Chapter 4. The level of natural gas exports are currently determined 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 by OGSM). Peak and offpeak period export levels to the Lower 48 States are generated by applying average (1991 or 1992 to 1998) historical shares (PKSHR_EMEX, PKSHR_ECAN, respectively) to the annual forecast levels. The representation 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.[10] These demands are further distinguished by customer class (core or noncore), reflecting the type of natural gas transmission and distribution service that is predominately purchased. The "core" customers generally require guaranteed service,

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[9]The regional factors used in calculating lease and plant fuel consumption (PCTLP) are initially based on historical averages (1991 through 1998) and held constant throughout the forecast period. However, a model option allows for these factors to be scaled in the first two forecast years so that the resulting national lease and plant fuel consumption will match the annual published values as 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). A similar adjustment is performed on the factors used in calculating pipeline fuel consumption using STEO values from STQGPTR (Appendix E).

[10]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 cogenerators.

particularly during peak days/periods during the year. The "noncore" customers require a lower quality of transmission services and therefore, consume gas under a less certain and/or less continuous basis.

Currently in NEMS, all customers in the transportation, residential, and commercial sectors are classified as core.[11] Within the industrial sector the noncore segment includes the industrial boiler market and refineries. 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) noncore—dual-fired turbine units, gas turbine units, or dual-fired steam plants (consuming both natural gas and residual fuel oil).

For any given NEMS iteration and forecast year, the individual demand models in NEMS determine the level of natural gas consumption for each region and customer class at the end-use 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 a short-term 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 model during the next NEMS iteration to determine the consumption level that the model would actually forecast at this price. The NGTDM disaggregates the 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 nonelectric[12] sectors are provided by the NEMS demand models 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). Electricity generation in Alaska and Hawaii is handled separately. Within the EMM, the electric generators' consumption of natural gas is disaggregated into subregions which 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 and Hawaii are not connected to the rest of the Nation by pipeline and are 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 which are 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 (Figure 2-2). Therefore, demand in the electric generation sector is represented in the NGTDM at the regions (NGTDM/EMM) resulting from the combination of the NGTDM regions overlapped with the EMM regions, translated to the nearest State border (Figure 2-3). For example, the South Atlantic NGTDM region (number 5) includes three NGTDM/EMM regions (part of EMM regions 1, 3, and 9). 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.

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

[12]The "nonelectric" sectors refer to sectors (other than industrial cogenerators) that do not produce electricity using natural gas (i.e., the residential, commercial, industrial, and transportation demand sectors).

Annual consumption levels for each of the nonelectric sectors are disaggregated from the nine Census divisions to the two seasonal periods and the twelve NGTDM regions by applying average historical shares (1990 to 1998-- residential and commercial, 1997 to 1998 -- industrial and transportation) which are held constant throughout the forecast (census – NG_CENSHR, seasons – PKSHR_DMD). For the Pacific Division, natural gas consumption estimates for Alaska

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

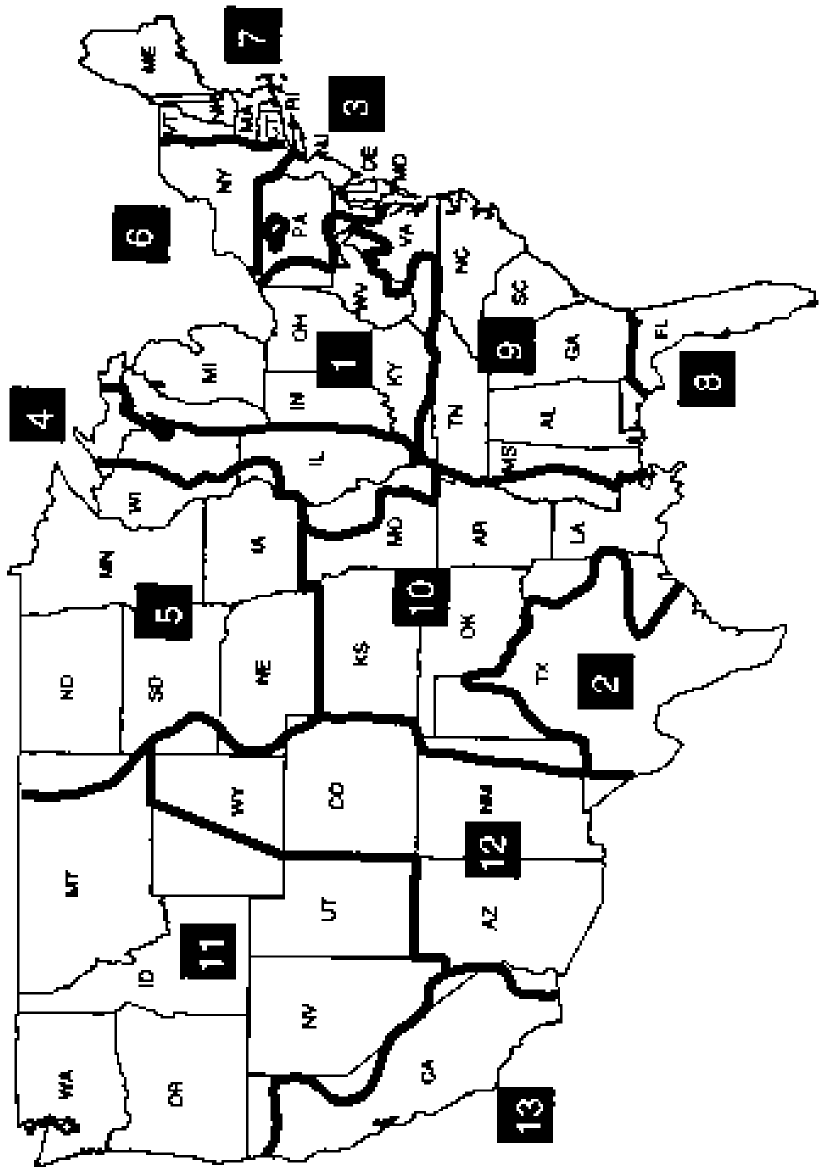
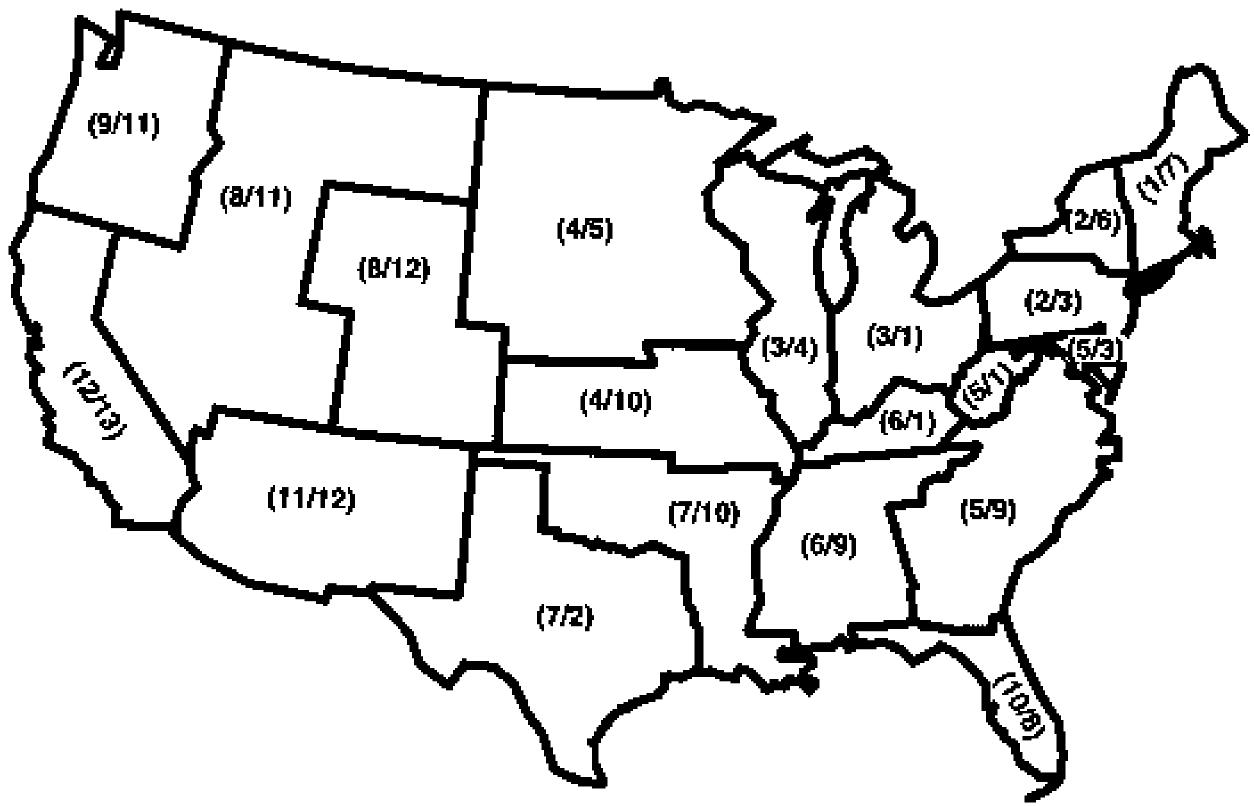


Figure 2-3. Natural Gas Transmission and Distribution Model/Electricity Market Model (NGTDM/EMM) Regions



(NGTDM Region Number/EMM Region Number)

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. Within the NGTDM, a relatively simple module (described later) was included for approximating the consumption of natural gas by each nonelectric sector in Alaska. These estimates, combined with the consumption levels provided by the EMM for consumption by electric generators in Alaska, are also used in the calculation of the production of natural gas in Alaska.

Unlike the nonelectric sectors, the factors (core -- PKSHR_UDMD_F, noncore -- PKSHR_UDMD_I) for disaggregating the annual electric generator sector consumption levels (for each NGTDM/EMM region and customer type -- core and noncore) into seasons is dynamically changed over the forecast period, based on seasonal consumption forecasts provided by the Electricity Market Module (EMM). Initially historical average historical shares (1994 to 1998, except for New England -- 1997 to 1998) are established as base level shares (core -- BASN_PKSHR_UF, noncore -- BASN_PKSHR_UI). These are adjusted based on how the seasonal consumption share, as provided by the EMM (ESHR_F, ESHR_I), changes over the forecast period relative to its value in the first year of the forecast (BASE_PKSHR_UF, BASE_PKSHR_UI). This adjustment is slightly different depending on whether or not the seasonal consumption share from the EMM is greater or less than the historical based share, as illustrated in the following for the core customer type:

if ESHR_F is less than BASE_PKSHR_UF for a given region:

$$\text{PKSHR\_UDMD\_F} = \text{BASN\_PKSHR\_UF} * \frac{\text{ESHR\_F}}{\text{BASE\_PKSHR\_UF}} \tag{1}$$

else:

$$\text{PKSHR\_UDMD\_F} = 1 - (1 - \text{BASN\_PKSHR\_UF}) * \frac{(1 - \text{ESHR\_F})}{(1 - \text{BASE\_PKSHR\_UF})} \tag{2}$$

The above equation was necessary to insure that the seasonal share does not result in a value greater than 1. The form of the above two equations is identical for the noncore customer type with the following variables substituted: PKSHR_UDMD_I, BASN_PKSHR_UI, ESHR_I, BASE_PKSHR_UI.

Natural Gas Demand Curves

While the primary analysis of energy demand takes place in the NEMS demand models, the NGTDM itself directly incorporates limited 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 end-use prices for fixed consumption levels (represented by setting the price elasticity of demand in the demand curve equation to zero). These demand curves are defined within a limited range around the price/quantity pair solved for during the most recent NEMS iteration. The form of the demand curves for the firm transmission service type for each nonelectric sector and region is:

$$\text{NGDMD\_CRVF}_{s,r} = \text{BASQTY\_F}_{s,r} * (\text{PR} \ / \ \text{BASPR\_F}_{s,r})^{\text{NONU\_ELAS\_F}_{s}} \tag{3}$$

where,

$\text{BASPR\_F}_{s,r}$	=	end-use price to core sector s in NGTDM region r in the previous NEMS iteration (dollars per Mcf)
$\text{BASQTY\_F}_{s,r}$	=	natural gas quantity which the NEMS demand models 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 *AEO99*) Note: Demand curves can be represented with fixed consumption levels by setting elasticities equal to zero.
PR	=	end-use price at which demand is to be evaluated (dollars per Mcf)
$\text{NGDMD\_CRVF}_{s,r}$	=	estimate of the natural gas which would be consumed by core sector s in region r at the price PR (Bcf)

s = core sector (1-residential, 2-commercial, 3-industrial, 4-transportation)

The form of the demand curve for the nonelectric interruptible transmission service type is identical, with the following variables substituted: NGDMD_CRVI, BASPR_I, BASQTY_I, and NONU_ELAS_I (*for AEO2000* set to -.5 for the industrial sector and -.1 for the other nonelectric sectors). For the electric generation sector the form is identical as well, except there is no sector index and the regions represent the 20 NGTDM/EMM regions, not the 12 NGTDM regions. The corresponding set of variables for the core and noncore 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 *AEO2000* all of the electric generator demand curve elasticities were set to zero.

Natural Gas Supply Interface

The primary categories of natural gas supply represented in the NGTDM are nonassociated and associated-dissolved gas from onshore and offshore U.S. regions, pipeline imports from Mexico, total eastern and western Canadian production, liquefied natural gas imports, natural gas production in Alaska including that which is transported through Canada via the Alaskan Natural Gas Transportation System (ANGTS), 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 nonassociated gas from onshore and offshore U.S. regions and from the western Canadian region. 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) which varies with a change in the oil production in the current forecast year.[13] Both liquefied natural gas imports and the flow via ANGTS are also set in OGSM and are dependent on the previous year's natural gas price. The NGTDM applies average historical relationships to convert annual "fixed" supply levels to peak and offpeak 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) shown in Figure 2-4. The six onshore OGSM regions within the contiguous United States do not generally share common borders with the NGTDM regions. As was done with the EMM 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 sources of natural gas which are transported via pipeline from Canada and Mexico, and by way of oceanic vessels in liquefied form. Seven Canadian and three Mexican border crossings demarcate the foreign pipeline interface in the NGTDM. Supplies from the four existing liquefied natural gas terminals are also represented as supply points in the NGTDM, although only two of the four existing terminals are currently in operation.

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 forecast represents assumed future natural gas production from the Great Plains Coal Gasification Plant in North Dakota. Regional forecast values for other supplemental supplies are set at historical averages (1990-1997) and held constant over the forecast period. Synthetic natural gas is no longer produced from liquid hydrocarbons, although small amounts were produced in Illinois in some historical years. This production level is set to zero for the forecast. 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 is progressively phased out over the first STPHAS_YR (Appendix E) forecast years of the NGTDM.

[13]The annual oil production level is determined in the Oil and Gas Supply Model and can vary between each iteration of NEMS.

Regional peak and offpeak supply levels for the three supplemental gas supplies are generated by applying the same average (1990-1998) historical share (PKSHR_SUPLM) of national supplemental supplies in the peak period.

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

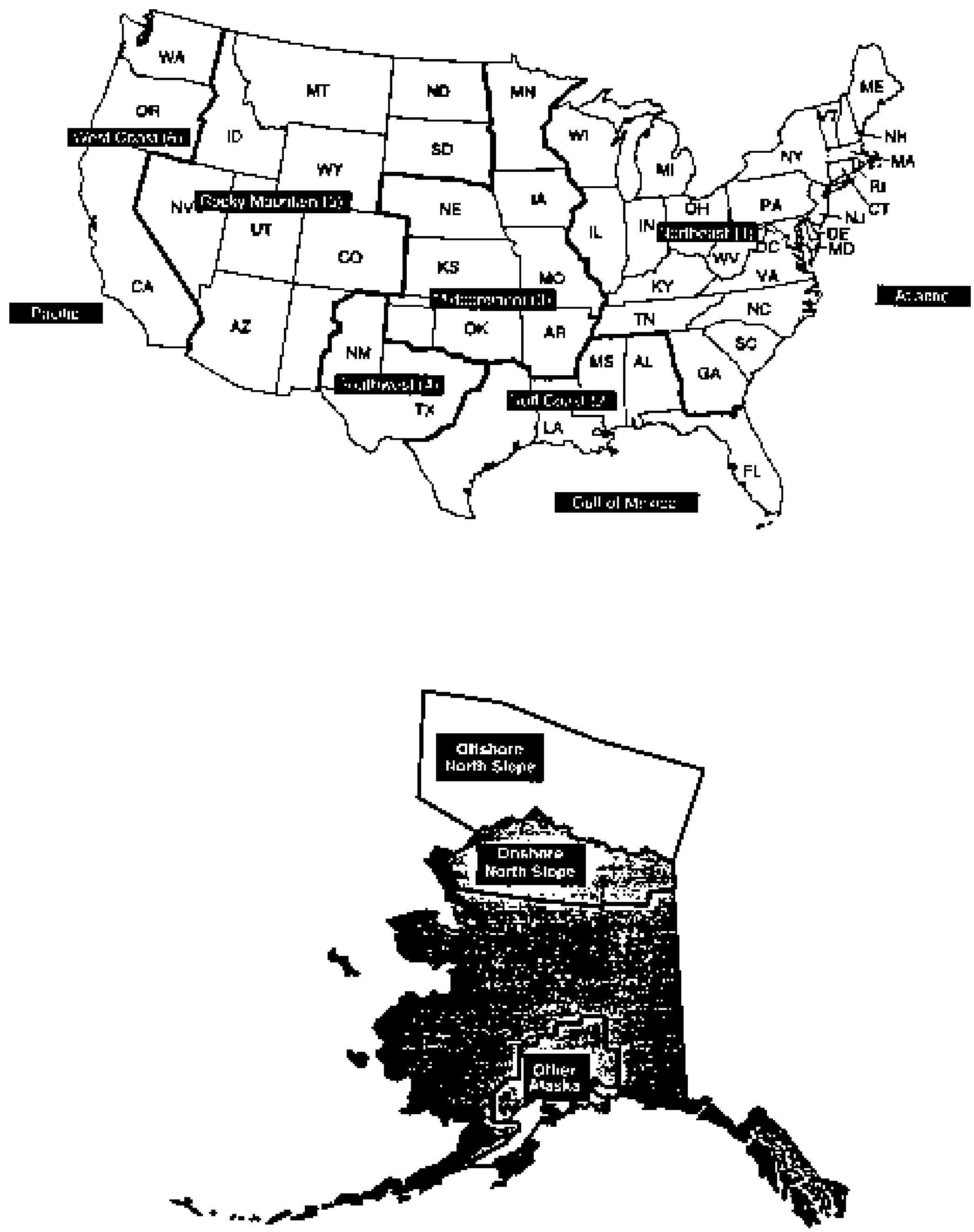
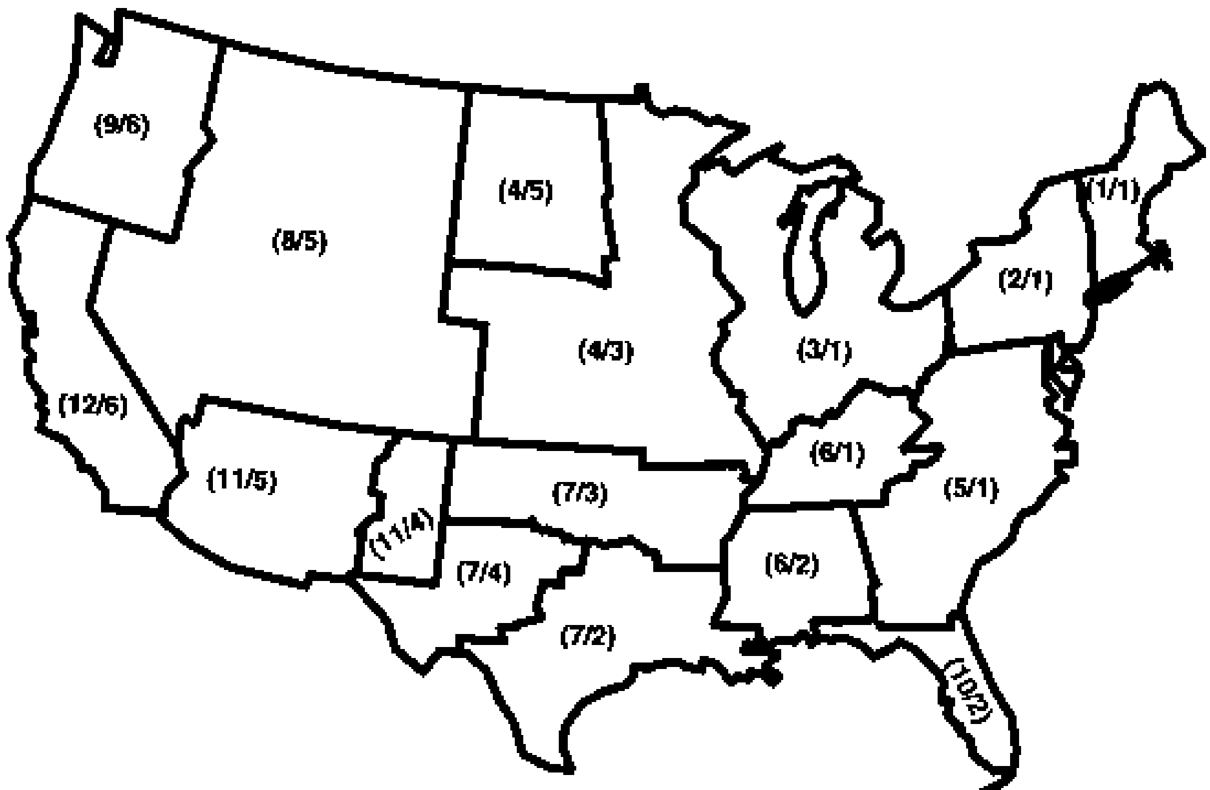


Figure 2-5. Natural Gas Transmission and Distribution Model/Oil and Gas Supply Model (NGTDM/OGSM) Regions



(NGTDM Region Number/OGSM Region Number)

Associated-Dissolved Natural Gas Production

Associated-dissolved natural gas refers to the natural gas which 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 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 offpeak values based on average (1994-1998) historical shares of total (including nonassociated) peak production in the year (PKSHR_PROD).

Natural Gas Imports

The NGTDM sets most of the parameters and forecast values associated with the Canadian gas market; while the OGSM sets the forecast values for imports from Mexico and for the gas imported through liquefied natural gas facilities, as well as some of the parameters for establishing a supply curve for natural gas in western Canada. Mexican imports are set exogenously and read within OGSM to be passed to the NGTDM. Liquefied natural gas imports are set at the beginning of each forecast year within the OGSM based on natural gas prices from the previous forecast year in the region containing the facility. Peak and offpeak values from both of these sources are based on average (1994 or 1990 to 1998) historical shares (PKSHR_IMEX and PKSHR_ILNG, respectively).

A few of the forecast elements used in representing the Canadian gas market are set exogenously in the NGTDM. When required, such annual forecasts are split into peak and offpeak values using historically based or assumed peak shares that are held constant throughout the forecast. While most Canadian import levels 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 Canada for the western frontier areas and for all of the eastern Canadian region are set exogenously (Appendix E, CN_FIXSUP) and split into peak and offpeak periods using PKSHR_PROD (Appendix E). Similarly, consumption of natural gas in eastern and western Canada (Appendix E, CN_DMD) is set exogenously, and split into seasonal periods using PKSHR_CDMD (Appendix E). Both the Canadian consumption and fixed supply forecasts are largely based on recent forecasts published by the National Energy Board of Canada. These forecasted values for Canadian consumption include natural gas used in lease, plant, and pipeline operations. The NGTDM also exogenously sets a forecast of the physical capacity of natural gas pipelines crossing at seven border points from Canada into the United States (Appendix E, ACTPCAP and PLANPCAP).[14] This physical capacity limit is then multiplied by 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, based in part on the expected demand profiles of the customers being served. 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.[15]

The vast majority of natural gas produced in Canada is from the west. Therefore, a significantly more detailed approach was used in modeling the supply from this region. The OGSM contains a series of estimated and accounting equations for forecasting wells drilled, reserves added, reserve levels, and expected production-to-reserve ratios in western Canada. These beginning-of-year reserves and the expected production-to-reserve ratios are used within the NGTDM to build a supply curve for natural gas production in western Canada. The form of this supply curve is nearly identical to the one used to represent nonassociated natural gas production in the lower 48 regions. This curve is described below, with the exceptions related to Canada noted. The primary difference is that the supply curve for the

[14]If total U.S. end-use consumption levels are declining (which tends not to occur except is some special side case runs of the NEMS), Canadian pipeline builds are delayed until they start to increase.

[15]A significant amount of natural gas flows into Minnesota from Canada on an annual basis only to be routed back to Canada through Michigan. [A very small amount went through Montana at one time.] The levels of gas in this category are specified exogenously (Appendix E, FLOW_THRU_IN) and split into peak and offpeak levels based on average (1990-1998) historically based shares for general Canadian imports (PKSHR_ICAN).

lower 48 States represents nonassociated natural gas production net of lease and plant fuel consumption; where as the western Canadian supply curve represents total natural gas production inclusive of lease and plant fuel consumption.

"Variable" Dry Natural Gas Production Supply Curve

The two "variable" (or price responsive) natural gas supply categories represented in the model are domestic nonassociated production and total western Canadian production. Nonassociated 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. Whereas, 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. The 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 is reflective of annual production levels. The methodology for translating this annual form into a seasonal representation is presented in Chapter 4.

The supply curve for regional nonassociated lower 48 natural gas production and for western Canadian production is built from a price/quantity (P/Q) pair, where price is the wellhead price from the previous year and quantity is the "expected" production 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 previous forecast year if the current year's production levels exceeds the expected production; and just the opposite will occur if current production is less. In addition, it is assumed that the relative price response will be greater for a marginal increase in production above the expected production, compared to below, if outside of a narrow range around the base point. 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 3 percent (PARM_SUPCRV3) from the base quantity, and is nearly horizontal. The next two segments, on either side of the middle, extend more vertically (with a positive slope), forming what looks like a reclining chair, and reach an additional plus or minus 9 percent (PARM_SUPCRV5) beyond the end of the middle segment. These two segments are extended even further with the remaining two segments, which can be assigned the same (as in *AEO2000*) or different slopes from their adjacent segments. The slope of the upper segment(s) is greater than that of the lower segment(s). The general structure [in terms of P=f(Q)] for all five segments is:

$$NGSUP\_PR = PBASE * \left(\left(\left(\frac{1}{ELAS}\right) * \left(\frac{QVAR - QBASE}{QBASE}\right) \right) + 1 \right) \tag{4}$$

Each of the five segments are assigned different values for the variables ELAS, PBASE, and QBASE, as shown below.

Lowest segment:

PBASE = CPBASE = APBASE * (1. - (PARM_SUPCRV5 / $PARM\_SUPELAS_2$))
QBASE = CQBASE = AQBASE * (1. - PARM_SUPCRV5)
ELAS = $PARM\_SUPELAS_1$ = 2.00

Lower segment:

PBASE = APBASE = XPBASE * (1. - (PARM_SUPCRV3 / $PARM\_SUPELAS_3$))
QBASE = AQBASE = XQBASE * (1. - PARM_SUPCRV3)
ELAS = $PARM\_SUPELAS_2$ = 2.00

Middle segment:

PBASE = XPBASE = $ZWPRLAG_s$ - $ZOGTAXPREM_s$
QBASE = XQBASE = $QSUP_s$ / (1. - $PERCNT_n$) — domestic nonassociated supply, historical year
QBASE = XQBASE = $ZOGRESNG_s$ * $ZOGPRRNG_s$ — western Canadian and domestic nonassociated supply in a forecast year
ELAS = $PARM\_SUPELAS_3$ = 4.00

Upper segment:

$PBASE = BPBASE = XPBASE * (1. + (PARM\_SUPCRV3 / PARM\_SUPELAS_3))$
$QBASE = BQBASE = XQBASE * (1. + PARM\_SUPCRV3)$
$ELAS = PARM\_SUPELAS_4 = 1.50$

Uppermost segment:

$PBASE = DPBASE = BPBASE * (1. + (PARM\_SUPCRV5 / PARM\_SUPELAS_4))$
$QBASE = DQBASE = BQBASE * (1. + PARM\_SUPCRV5)$
$ELAS = PARM\_SUPELAS_5 = 1.50$

where,

NGSUP_PR	=	Wellhead price
QVAR	=	Production, including lease & plant
PBASE	=	Base wellhead price
QBASE	=	Base wellhead production
ELAS	=	Elasticity (percentage change in quantity over percentage change in price)
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
$ZOGTAXPREM_s$	=	Tax simulation variable provided by OGSM (currently set to zero)
$ZOGRESNG_s$	=	Natural gas reserves for supply source s
$ZOGPRRNG_s$	=	Natural gas production to reserves ratio for supply source s
$PERCNT_n$	=	Percent lease and plant
s	=	supply source
n	=	region/node

The parameters in the above equation 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 before it can be evaluated to generate a corresponding supply price. The adjustment equation is:

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

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 zero for Canada)
$ZOGCCAPPRD_s$	=	Coalbed methane production related to the Climate Change Action Plan (from OGSM)[16]
FIXSUP	=	ZOGCCAPPRD net of lease and plant consumption
s	=	NGTDM/OGSM supply region
n	=	region/node

[16]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.

Alaskan Natural Gas Module

The NEMS demand models provide a forecast of natural gas consumption for the total Pacific Census Division, which includes Alaska. Currently natural gas which 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 Alaskan 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 models. The use of natural gas in compressed natural gas vehicles in Alaska is assumed to be negligible. The consumption of gas by Alaskan residential customers is a function of a forecast for the number of customers (exogenously derived):

$$\text{(res):}\quad AKQTY\_F_d = EXP(AK\_C_1) * AK\_RN_y^{AK\_C_2} \tag{5}$$

where,

$AKQTY\_F_d$	=	consumption of natural gas by residential (d=1) customers in Alaska (Bcf)
AK_C	=	estimated parameters for residential consumption equation (Appendix F, Table F1)
AK_RN_y	=	number of residential customers (exogenously specified, Appendix F, Table F2)

Gas consumption by Alaskan commercial customers is a function of the previous year's consumption level and the number of commercial customers in the current and previous forecast year, as follows:

$$\begin{aligned}\text{(com):}\quad AKQTY\_F_d = {} & EXP(AK\_D_1) * (PREV\_AKQTY_{2,y-1})^{AK\_D_2} * \\ & AK\_CN_y^{AK\_D_3} * AK\_CN_{y-1}^{AK\_D_4}\end{aligned} \tag{6}$$

where,

$AKQTY\_F_d$	=	consumption of natural gas by commercial (d=2) customers in Alaska in the current forecast year (Bcf)
$PREV\_AKQTY_d$	=	consumption of natural gas by commercial (d=2) customers in Alaska in the previous forecast year (Bcf)
AK_D	=	estimated parameters for commercial consumption equation (Appendix F, Table F1)
AK_CN_y	=	number of commercial customers (exogenously specified, Appendix F, Table F2)

Gas consumption by Alaskan industrial customers is a function of time and the level of industrial consumption in the previous forecast year, as follows:

$$\begin{aligned}\text{(ind):}\quad AKQTY\_F_d = {} & (\ EXP(AK\_E_1)\ *\ (1000. * PREV\_AKQTY_{d,y-1})^{AK\_E_2}\ * \\ & T^{AK\_E_3}\ *\ (T-1)^{AK\_E_4}\ )\ /\ 1000.\end{aligned} \tag{7}$$

where,

$AKQTY\_F_d$	=	consumption of natural gas by industrial customers (d=3), (Bcf)
$PREV\_AKQTY_d$	=	consumption of natural gas by industrial (d=2) customers in Alaska in the previous forecast year (Bcf)
AK_E	=	estimated parameters for industrial consumption equation (Appendix F, Table F1)
T	=	time parameter, where T=1 for 1969 (the first historical data point) and T=CNTYR+21 in forecast year CNTYR (where CNTYR equals 1 for 1990).

At a sectoral level, Alaskan consumption is disaggregated into the total delivered to customers in South Alaska (AK_CONS_S) versus a North Alaska (AK_CONS_N) total using historically derived shares (Appendix E, AK_PCTSOUTH). This distinction is needed for the derivation of natural gas production forecasts for the north and south regions [not accounting for the additional production necessary should the Alaskan Natural Gas Transportation System (ANGTS) open], as follows:

$$\text{(S. AK):}\quad AK\_PROD_{r=1} = \frac{(EXPJAP + AK\_CONS\_S - AK\_DISCR)}{AK\_PCTALL_{r=1}} \tag{8}$$

$$\text{(N. AK):}\quad AK\_PROD_{r=2} = AK\_CONS\_N \ / \ AK\_PCTALL_{r=2} \tag{9}$$

where,

AK_PROD_r	=	dry gas production in South (r=1) or North (r=2) Alaska (Bcf)
AK_CONS_S	=	total gas consumption by customers in South Alaska (Bcf)
AK_CONS_N	=	total gas consumption by customers in North Alaska (Bcf)
EXPJAP	=	quantity of gas liquefied and exported to Japan (from OGSM in Bcf)
AK_DISCR	=	discrepancy, the historically based difference in reported supply levels and consumption levels in Alaska (Bcf)
AK_PCTLSE_r	=	$(1. - AK\_PCTLSE_r - AK\_PCTPLT_r - AK\_PCTPIP_r)$ assumed percent of gas production which is consumed in lease and plant operations and as pipeline fuel in region r (fraction)

The forecast values for the variable AK_DISCR are set to the level in the most recent historical year. The variables for AK_PCTLSE, AK_PCTPLT, and AK_PCTPIP are based on historical percentages (Appendix E) and are held constant throughout the forecast, with the exception that PCTLSE is decreased by 50 percent should ANGTS become fully operational. (These variables are also used to estimate the consumption levels for pipeline fuel and lease and plant fuel in Alaska.)

The OGSM provides a forecast of natural gas exports to Japan, the level of flow through ANGTS which would reach the contiguous U.S. border when and if it is connected, and the maximum production level for South Alaska (currently used only as a verification check in the NGTDM). The production of natural gas in Alaska which is necessary to support ANGTS ($AK\_PROD_{r=3}$) is derived in the NGTDM using the flow level at the border established in OGSM, and assumed values for PCTLSE, PCTPLT, and PCTPIP related to production to be marketed via ANGTS.

Estimates for natural gas wellhead and end-use prices in Alaska are roughly estimated in the NGTDM for proper accounting, but have a very limited impact on the NEMS system. The average Alaskan wellhead price (AK_WPRC) over the North and South regions (not accounting for the impact should ANGTS be connected) is set to the previous forecast year's value plus an average historical annual increase (AK_F_1, Appendix F, Table F1). However, if ANGTS is connected, the wellhead price in North Alaska is overwritten to be equal to the price at the U.S./Canadian border crossing point, most representative of where ANGTS will connect, plus an assumed markup (Appendix E, ANGTS_TAR). End-use prices are set equal to the average wellhead price resulting from the equation above plus a fixed markup (Appendix E -- AK_RM, AK_CM, AK_IN, AK_EM).

3. Overview of Solution Methodology

The previous chapter described the function of the NGTDM within the NEMS. 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 modules within the NGTDM is presented, along with an overview of the solution methodology used by each module.

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 offpeak (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.[17] 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 [18] represent imports or exports.

Flows are further represented by establishing arcs from the transshipment node to each demand sector/subregion represented in the NGTDM region. A demand group in a particular NGTDM region can only be satisfied by gas flowing from that same region's transshipment node. Similarly, arcs are also established from supply points into transshipment nodes. The supply from each NGTDM/OGSM region is directly available to only one transshipment node, through which it must first pass if it is to be made available to the interstate market (at an adjoining transshipment node). During a peak period, one of the supply sources feeding into each transshipment node represents net storage withdrawals in the region during the peak period. Conversely during the offpeak period, one of the demand nodes represents net storage injections in the region during the offpeak 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.[19] Mexican exports and (in the offpeak 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. These supply points may 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 the Alaskan Natural Gas Transportation System, Mexican imports, or (in the peak period) net storage withdrawals in the region. Two items accounted for but not presented in Figure 3-2 are

[17]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 going from 9 to 8, 11 to 8, 4 to 8, 7 to 11, 4 to 7, 3 to 4, 5 to 6, 5 to 3, 2 to 3, 2 to 5, 6 to 7, and 1 to 2. 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.

[18]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.

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

discrepancies (i.e., average historically observed differences between independently reported natural gas supply and disposition levels –

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

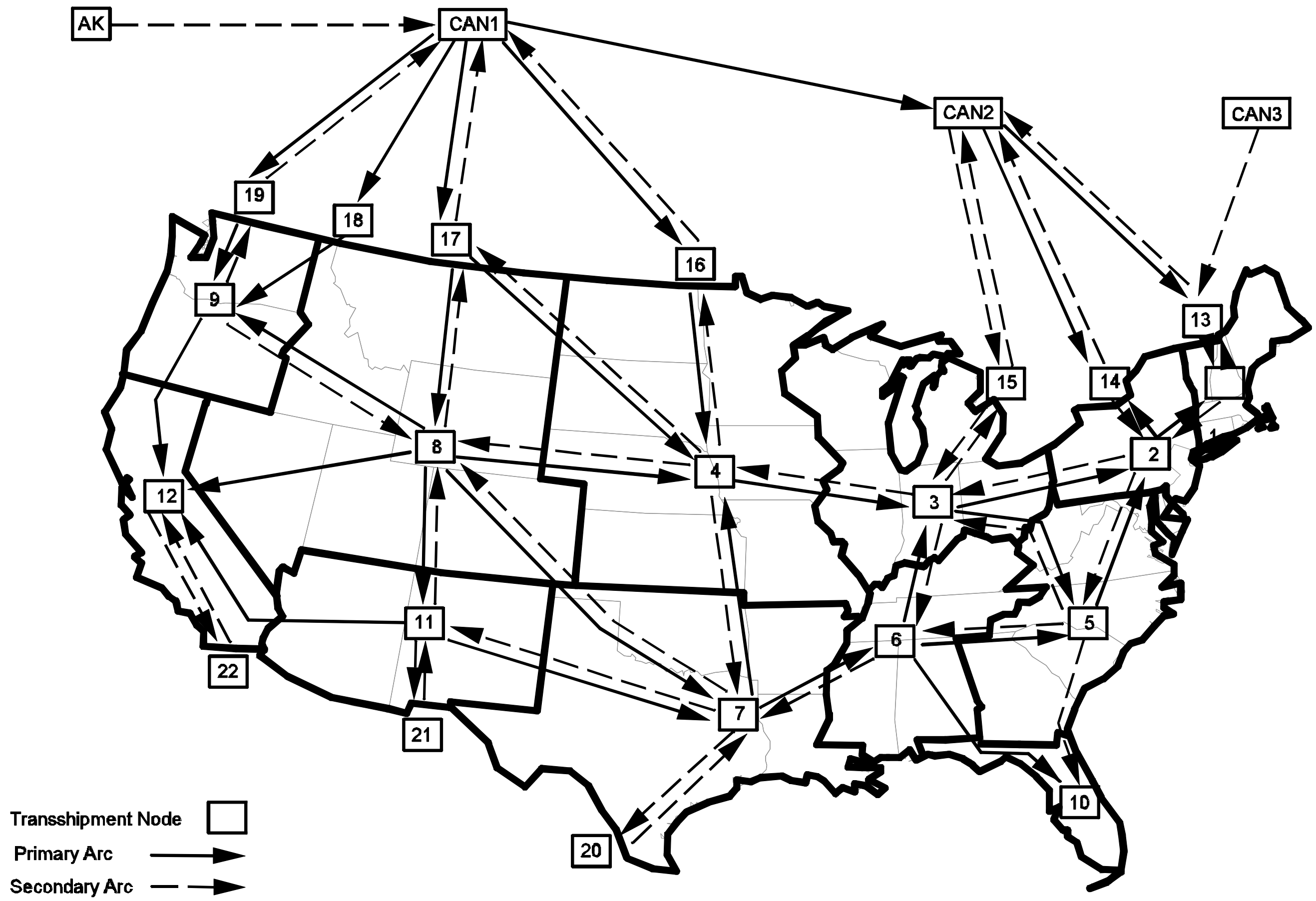
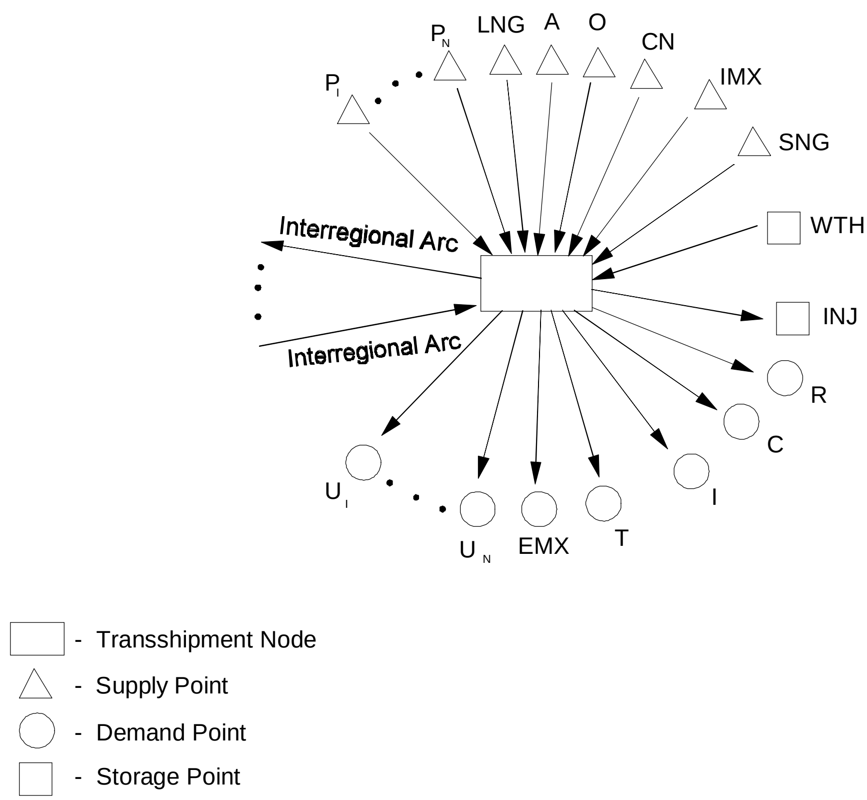


Figure 3-2. Transshipment Node



P_i - Production in NGTDM/OGSM Region i
LNG - Liquefied Natural Gas Imports
A - Alaskan Supplies via ANGTS
O - Offshore Supplies
CN - Canadian Supplies
IMX - Mexican Imports
SNG - Supplemental Supplies
WTH - Net Storage Withdrawals (peak only)
INJ - Net Storage Injections (offpeak only)
R - Residential Demand
C - Commercial Demand
I - Industrial Demand
T - Transportation Demand
EMX- Mexican Exports
U_i - Electric Generator Demand in NGTDM/EMM Region i

DISCR, CN_DISCR) and backstop supplies.[20] Most of the types of supply listed above 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. In reality, within the model only the price responsive sources of supply (i.e., onshore and offshore lower 48 U.S. production, nonfrontier western Canadian production, and storage withdrawals) are explicitly represented with supply nodes and connecting arcs to the transshipment nodes.

Once all of the types of end-use destinations and supply sources are defined into and out of each transshipment node, a general network structure results. 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 indicates in tabular form the mapping of Electricity Market Model regions and Oil and Gas Supply Model regions to NGTDM regions, (Figures 2-3 and 2-5 in Chapter 2).

As described earlier, the NGTDM determines the flow and price of natural gas in both a peak and offpeak period. The basic network structure separately represents the flow of gas during the two periods within the Interstate Transmission Module. 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 the pipeline going into Florida). These levels are then used as constraints for pipeline flow in the offpeak period. Second, the net withdrawal from storage in the peak period establishes the net amount of natural gas that will be injected in the offpeak 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 offpeak, plus an established storage tariff. Third, the supply curves provided by the Oil and Gas Supply Model are specified on an annual basis. Although, these curves are used to approximate peak and offpeak 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 offpeak 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 parameters (inputs) and model variables (outputs). The parameters that define an interregional arc are the pipeline direction, available capacity from the previous forecast year, the 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). Once a model solution has been reached (i.e., the quantity of the natural gas flow along each interregional arc is determined), the required capacity to support that flow can be determined, given the assumed maximum utilization rates allowed.

For the peak period the maximum capacity levels are set to a factor above the 1990 levels. The factor is set high enough that this constraint is rarely binding. However, the structure could be used to limit growth along a particular path. In the offpeak period the maximum capacity levels are set to the capacity level determined in the peak period. The maximum utilization rate along each arc is set exogenously and is meant to capture the impact that varying demand loads over a season have on the utilization along an arc. Capacity and flow levels from the last forecast year are used as input to the solution algorithm. In some cases, capacity that is newly available in the current forecast year will be exogenously set as "planned" (i.e., highly probable that it will be built by the given forecast year). Any additional capacity beyond the planned levels are determined during the solution process and are 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 Module. During the solution process in the Interstate Transmission Module, the resulting tariff in the peak period is added to the price at the source node to arrive at a price for the gas along the interregional arc right before it reaches its destination node. Through an iterative process, the relative value of these prices for all of the arcs entering a node are used as the basis for reevaluating the flow along each

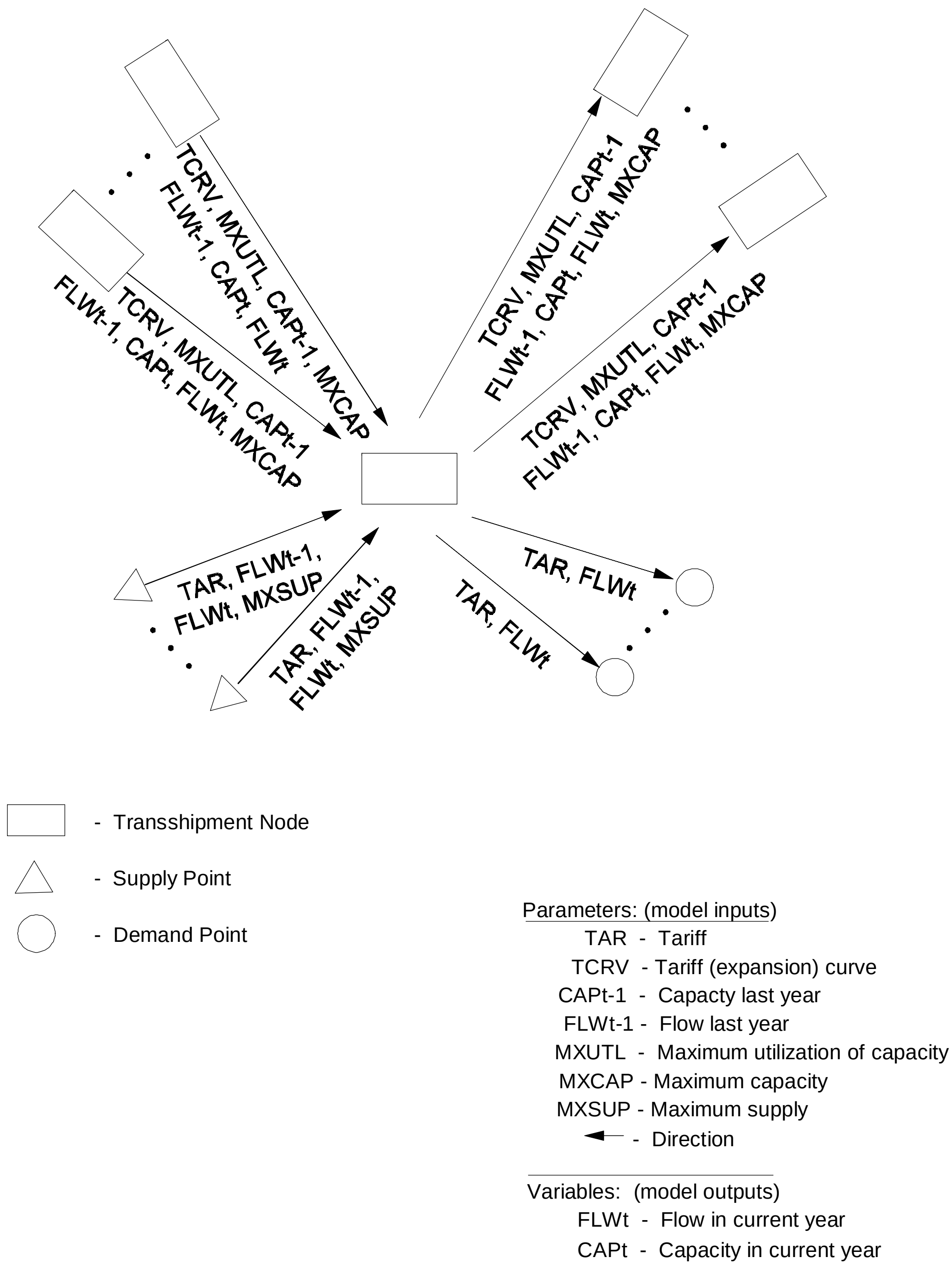
[20]Backstop supplies are allowed when the flow out of a transshipment node exceeds the maximum flow into a transshipment node. A high price is assigned to this supply source and it is generally expected not to be required (or desired). Chapter 4 provides a more detailed description of the setting and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

Table 3-1. Demand and Supply Types at Each Transshipment Node in the Network

Transshipment Node	Demand Types	Supply Types
1	R, C, I, T, U(1/7)	P(1/1), LNG Everett Mass.
2	R, C, I, T, U(2/6), U(2/3), INJ	P(2/1), WTH
3	R, C, I, T, U(3/1), U(3/4), INJ	P(3/1), WTH
4	R, C, I, T, U(4/5), U(4/10), INJ	P(4/3), P(4/5), Synthetic natural gas from coal, WTH
5	R, C, I, T, U(5/1), U(5/3), U(5/9), INJ	P(5/1), LNG Cove Pt Maryland, LNG Elba Island Georgia, Atlantic Offshore, WTH
6	R, C, I, T, U(6/1), U(6/9), INJ	P(6/1), P(6/2), WTH
7	R, C, I, T, U(7/2), U(7/10), INJ	P(7/2), P(7/3), P(7/4), LNG Lake Charles Louisiana, Offshore Louisiana, Gulf of Mexico, WTH
8	R, C, I, T, U(8/11), U(8/12), INJ	P(8/5), WTH
9	R, C, I, T, U(9/11), INJ	P(9/6), WTH
10	R, C, I, T, U(10/8), INJ	P(10/2), WTH
11	R, C, I, T, U(11/12), INJ	P(11/4), P(11/5), WTH
12	R, C, I, T, U(12/13), INJ	P(12/6), Pacific Offshore, WTH
13	--	--
14	--	--
15	--	--
16	--	--
17	--	--
18	--	--
19	--	--
20	Mexican Exports	Mexican Imports
21	Mexican Exports	Mexican Imports
22	Mexican Exports	Mexican Imports
23	Eastern Canadian consumption, INJ	Eastern Canadian supply, WTH
24	Western Canadian consumption, INJ	Western Canadian supply, WTH, Alaskan Supply via ANGTS

R - Residential demand; C - Commercial demand; I - Industrial demand; T - Transportation demand
U(n1/n2) - Electric generator's demand in NGTDM/EMM region (n1/n2) as shown in Figure 2-3
P(n1/n2) - Production in NGTDM/OGSM region (n1/n2) as shown in Figure 2-5
SNG - Other supplemental supplies are supplied to regions 1 through 12.
LNG - Liquified Natural Gas

Figure 3-3. Network Parameters and Variables



of these arc. During the offpeak period, only the usage fee is used as a basis for determining the relative flow along the arcs entering a node. However, the total tariff is ultimately used when setting end-use prices.

For the arcs from the transshipment nodes to the end-use sectors, the parameters 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 end-use sector represented. For arcs from supply points to transshipment nodes, the input parameters 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 set to zero. 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 model does not impose such limits on the flows along these arcs.

Note that any of the above parameters may have a value of zero. For instance, some pipeline arcs may be defined in the network that currently have zero capacity 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.

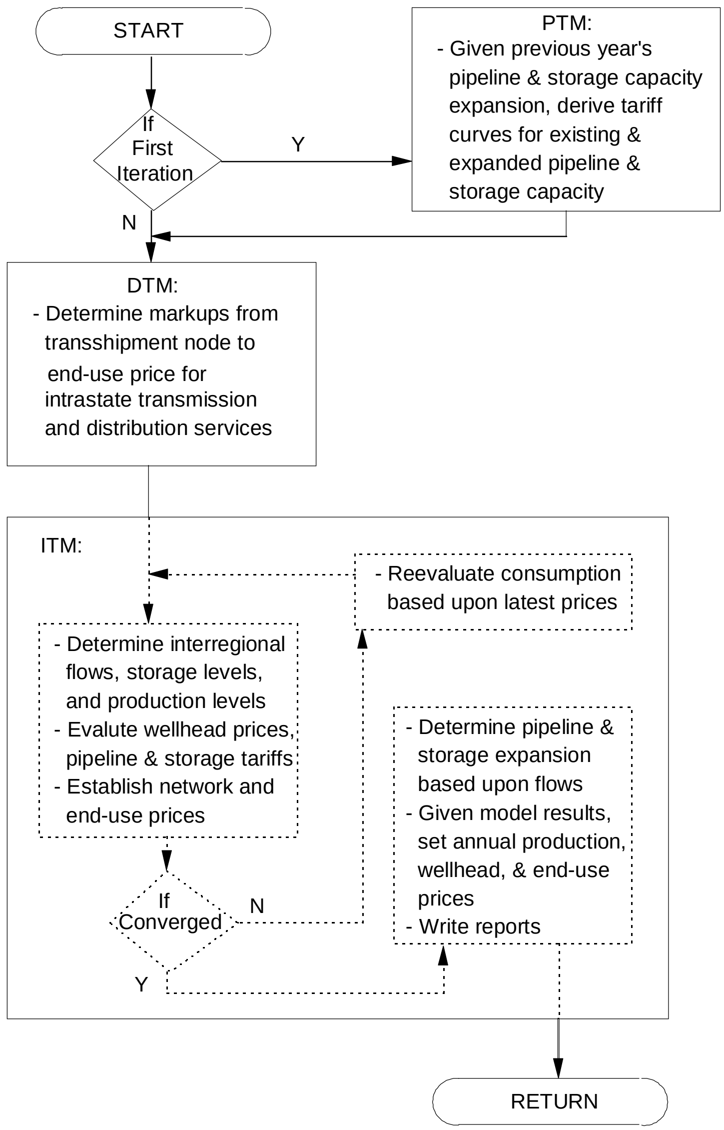
Overview of the NGTDM Modules and Their Interrelationships

The NEMS generates an annual forecast of the outlook for U.S. energy markets for the years 1990 through 2020. During the historical years, many of the models 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 model outputs during these years. However, some of the required outputs from the model 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, probable 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 model be executed for all iterations. Of the NGTDM's three components or modules, the Pipeline Tariff Module is executed only once per forecast year since the module's input values do not change from one iteration of NEMS to the next. However, the Interstate Transmission Module and the Distributor Tariff Module are executed every iteration of each forecast year because their input values can change by iteration. Within the Interstate Transmission Module an iterative process is used. The basic solution algorithm is repeated multiple times until the resulting wellhead prices and production levels from one iteration are within a user-specified tolerance of the resulting values from the previous iteration, and an equilibrium is reached. A process diagram of the NGTDM is provided in Figure 3-4, showing the general calling sequence.

The Interstate Transmission Module is the primary module 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 Module uses an accounting process to derive revenue requirements for the current forecast year. The module builds pipeline and storage tariff curves based on these revenue requirements for use in the Interstate Transmission Module. 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 Module provides distributor tariffs for use in the Interstate Transmission Module. The Distributor Tariff Module must be called each iteration because some of the distributor tariffs are based on consumption levels which may change from iteration to iteration. Finally, using the information provided by these other NGTDM modules and other NEMS models, the Interstate Transmission Module 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 modules follows.

Figure 3-4. NGTDM Process Diagram



Interstate Transmission Module

The Natural Gas Interstate Transmission Module (ITM) is the main integrating module of the NGTDM. One of its major functions is to simulate the natural gas price determination process. The ITM 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 offpeak) it is needed. In the process, the ITM simulates 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 ITM employs an iterative heuristic algorithm in establishing a market equilibrium solution. Given the consumption levels from other NEMS models, the basic process followed by the ITM 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 ITM 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 offpeak period. Second, using the model's supply curves, wellhead prices are set corresponding to the desired production volumes. Also, using the pipeline and storage tariffs from the Pipeline Tariff Module, 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 offpeak to arrive at the price of the gas when withdrawn in the peak period. End-use prices are derived for residential, commercial, and transportation customers, as well as for both core and noncore industrial and electric generation sectors using the distributor tariffs provided by the Distributor Tariff Module. At this point consumption levels can be reevaluated given the resulting set of end-use prices. Either way, the process is repeated until the solution has converged.

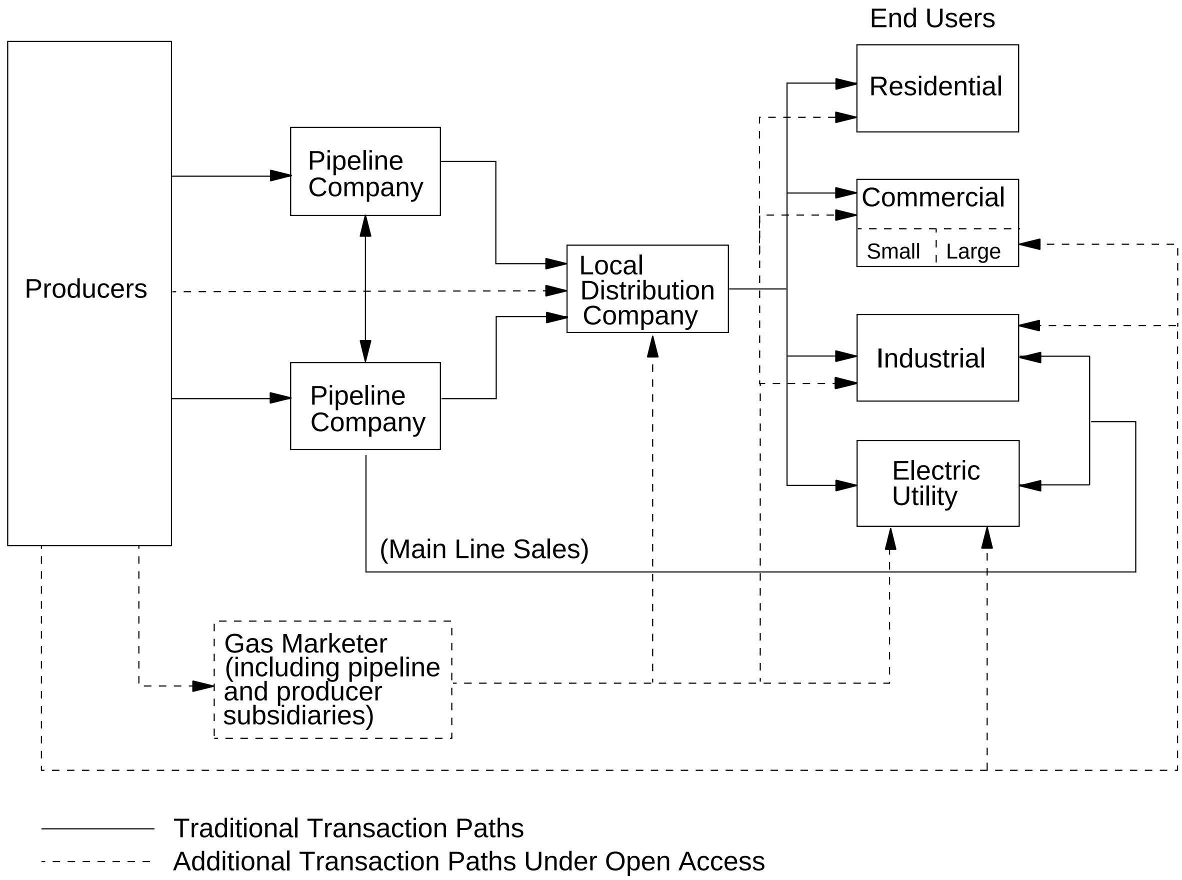
In the end, the ITM derives average seasonal (and ultimately annual) natural gas prices (wellhead, city gate, and end-use), and the associated production and flows, that reflect an interregional market equilibrium among the competing participants in the market. In the process of determining interregional flows and storage injections/withdrawals, the ITM also forecasts pipeline and storage capacity additions. In the next forecast year, the Pipeline Tariff Module 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 ITM is depicted schematically in Figure 3-5. Until recently, the marketing chain was very straightforward, with end-users and local distribution companies contracting with pipeline companies, and the pipeline companies in turn contracting with producers. Prices typically reflected average costs of providing service plus some regulator-specified rate of return. Although this approach is still used as a basis for setting pipeline tariffs, more pricing flexibility is being introduced, particularly in the interstate pipeline industry and more recently by local distributors. Pipeline companies are also offering a range of services under competitive and market-based pricing arrangements. Additionally, new 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 will 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 beginning to have an effect on firm service prices. Currently, there are significant differences across regions in pipeline capacity utilization.[21] These regional differences are evolving as new pipeline capacity has been and is being constructed to relieve the capacity constraints in the Northeast and on the West Coast, to expand markets in the

[21]Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618 (Washington, DC, May 1998).

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



Midwest and the Southeast, and to move more gas out of Canada 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. Potential 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. Some combination of these mechanisms will probably be used in the future. As the outcome is unknown at this point, the ITM 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 Module

The primary purpose of the Pipeline Tariff Module (PTM) is to provide volume dependent curves for computing tariffs for interstate transportation and storage services within the Interstate Transmission Module. 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 various rate design and regulatory scenarios. Other than an assortment of macroeconomic indicators, the primary input to the PTM from other models/modules in NEMS is the level of pipeline and storage capacity expansions in the previous forecast year. Once an expansion is forecast to occur, the module calculates the resulting impact on the revenue requirement. The PTM currently assumes rolled-in (or average), not incremental rates for new capacity

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 supplying the network arc. Storage tariff curves are defined at regional NGTDM network nodes, and, likewise, reflect an aggregation of individual company storage revenue requirements. Note that these services are unbundled and do not include the price of gas, except for the cushion gas used to maintain minimum gas pressure. Furthermore, the module 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 PTM 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 Module.

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 who 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 who 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) can be assumed to purchase firm transportation services, while the latter group (noncore customers) can be assumed to purchase nonfirm 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 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 nonfirm service). Previous versions of the NGTDM (and therefore the PTM) included representations of natural gas moved (or stored) using firm and nonfirm service. However, in an effort to simplify the model, this distinction has been removed in favor of moving from an annual to a seasonal model. The impact of the distinction of firm versus nonfirm service on core and noncore end-use prices is indirectly captured in the markup established in the Distributor Tariff Module. 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 currently under discussion by FERC may 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, transportation rates based on marginal costs will generally be significantly above the full cost of service rates.

The pipeline tariff curves generated by the PTM are used within the ITM when determining the relative cost of purchasing and moving gas from one source versus another in the peak and offpeak seasons. They are also used when setting the price of gas along the NGTDM network and ultimately to the end-users. During the peak period, when core customers dominate the market and pipelines utilization rates are generally much greater, the total revenue requirement (reservation plus usage) is used as a basis for setting pipeline tariffs and assessing the flow of gas into a region. However, in the offpeak period, core customers have a much lower share of the market, utilization rates are less, and reservation fees are largely considered a “sunk” cost. Therefore at this time, the pipeline tariff that is used when assessing the trade off between the optional sources of gas into a region is based just on the usage fee. However, the core customers are ultimately charged a rate that is reflective of the total revenue requirement.

Distributor Tariff Module

The primary purpose of the Distributor Tariff Module (DTM) is to determine the components of end-use prices that are regulated by State and local authorities. These consist of (1) distributor markups charged by local distribution companies for the distribution of natural gas from the city gate 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. However, these tariffs are accounted for in the model indirectly. End-use distribution service is distinguished within the DTM by sector, season, and service type.

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. For example, the core customers in the model (residential, transportation, commercial and some industrial and electric generator customers) 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 noncore. They can elect to receive some gas supplies through a lower priority (and lower cost) interruptible transportation service. 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 may select to bypass the local distribution company pipelines and hook up directly to interstate or intrastate pipelines.

The actual 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 DTM does not directly account for the separate cost components in deriving a revenue requirement for distribution services, but incorporates forecasted changes in labor and capital costs, as well as changes in consumption levels, when setting distributor tariffs. Finally, while the unbundling of distribution services (sales versus delivery, and sometimes local storage) has made considerable inroads, the DTM does not specifically model this industry restructuring. However, the module does assume that it will contribute to a downward pressure on distribution costs.

The DTM represents distribution tariffs to the core customers (excluding the transportation and electric generator sectors) by estimating annual changes in these tariffs, starting from a base year. Base year values for distributor tariffs by sector and season are established using historical data. The annual change in distributor tariffs is dependent on an assumed increase in operational efficiencies combined with a depreciation rate, as well as the annual change in natural gas consumption and in national average capital and employment costs. User-specified parameters allow adjustment of the markups to account for shifts due to regulatory policy. Many of these modeling choices are the result of data limitations.[22]

Distributor markups to the noncore customers are set at historical levels and are held constant. A user-specified option is available for allowing these rates to decline (or increase) steadily throughout the forecast. Distributor markups to core electric generators are initially set at historical levels, then allowed to change in response to annual changes in consumption levels within the sector. The natural gas vehicle (NGV) sector markups are calculated separately for fleet and personal vehicles. Markups for fleet vehicles are set and held constant at historical levels with taxes added (although a user-specified decline rate is allowed). Markups for personal vehicles are set at the industrial sector core price, plus taxes, plus an assumed distribution cost. This price is capped at the gasoline equivalent price, as long as minimum costs are covered.

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[22]EIA data surveys currently do not collect the cost components required to derive revenue requirements and cost-of-service for local distribution companies and intrastate carriers; nor are these data regularly collected by other public or private sources. 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. This data collection may be considered for a future development effort.

Since the markups determined by the DTM represent an aggregation of individual local distribution companies and intrastate pipeline companies, this module is not designed to address the issue of analyzing competition for distribution services within a region. It should also be noted that the DTM deals only with issues at an aggregate regional level, and thus does not capture the impacts of State-specific regulations on intrastate tariffs and by-pass issues. Finally, the procedures used by the DTM to estimate markups are limited by the types and availability of data.

4. Interstate Transmission Module Solution Methodology

As a key component of the NGTDM, the Interstate Transmission Module (ITM) 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 model--a peak and an offpeak 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 offpeak) 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, supply prices, and end-use prices until mass balance and convergence are achieved. (Distributor tariffs are calculated using a modified version of a previously developed algorithm, as described in Chapter 5.) Primary input requirements include seasonal and market-specific (core versus noncore)[23] 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, network flows, and prices. Some of the inputs are provided by other NEMS models, some are exogenously defined and provided in input files, and others are generated by the model in previous years or iterations and used as starting values. Wellhead, import, and end-use prices, supply quantities, and resulting flow patterns are obtained from the ITM and sent to other NGTDM modules or other NEMS models after some processing. Network characteristics, input requirements, and the heuristic process are presented more fully below.

Network Characteristics in the ITM

As described in an earlier chapter, the NGTDM network consists of twelve 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 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 models (e.g. Mexican imports and exports). In the ITM, 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). Flows along secondary arcs are implicitly represented, as 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 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 ITM, two interconnected acyclic networks are used to represent the following natural gas flow categories: flow to end-use markets during the peak period (PK) and flow to end-use markets during the offpeak period (OP). These networks are connected regionally through common supply sources and storage nodes (Figure 4-2). Storage within the model only represents the transfer of natural gas produced in the offpeak period to meet the higher demands in the peak period. Therefore, net storage injections are included only in the offpeak 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 offpeak 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.

[23]Other models in NEMS determine consumption levels for core and noncore natural gas consumers. In theory, core customers are assumed to subscribe to firm transportation service (even though they may not always move their gas on a reserved line); and noncore customers are assumed to move gas under nonfirm service.

Figure 4-1. Acyclic Hierarchical Network of Primary Arcs

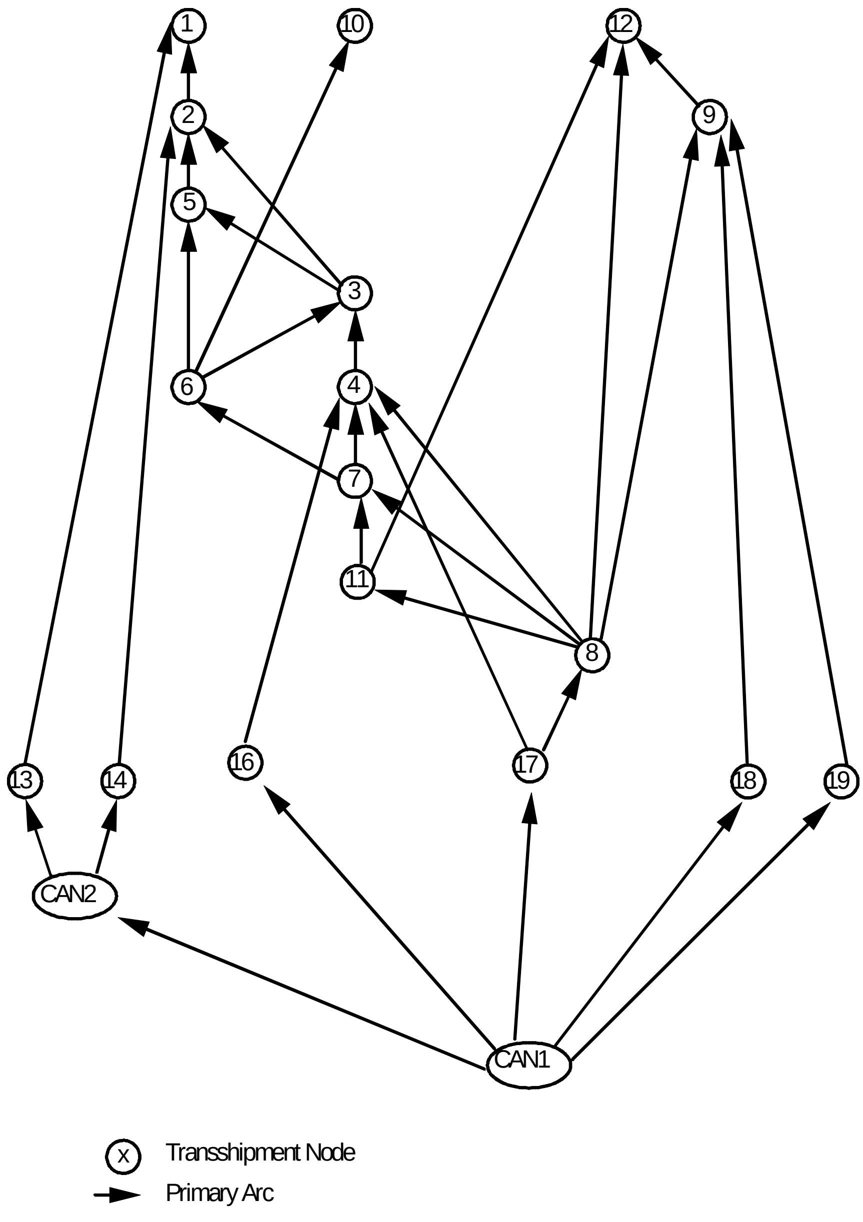
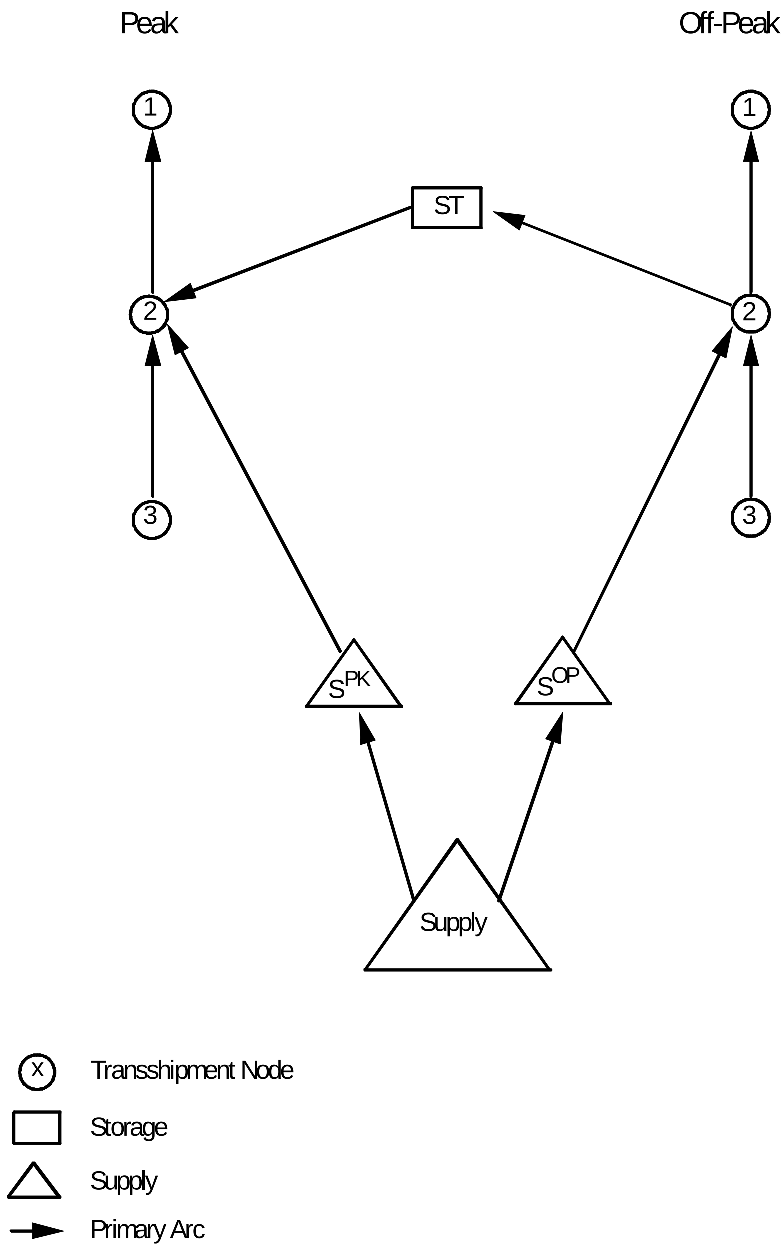


Figure 4-2. Simplified Example of Supply and Storage Links Across Networks



Input Requirements in the ITM

The following is a list of the key inputs required during ITM 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 in the northern frontier areas, by season.
- Regional supply curve parameters for U.S. nonassociated (NA) and western Canadian natural gas supply[24]
- Seasonal supply quantities for U.S. associated-dissolved (AD) 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 market and region

Many of the inputs are provided by other NEMS models, some are defined from data within the ITM, and others are ITM model results from operation in the previous year. For example, supply curve parameters for U.S. NA onshore and offshore and western Canadian natural gas supplies, U.S. AD gas supplies, Mexican imports and exports, LNG imports and exports, and natural gas supplies from Alaska via ANGTS are provided by the Oil and Gas Supply Module (OGSM). While Canadian data, with the exclusion of western Canadian supply curves, are set as direct input to the ITM. U.S. end-use consumption levels are provided by NEMS demand models; pipeline and storage capacity expansion/tariff curve parameters are provided by the Pipeline Tariff Module (PTM, see chapter 6); and seasonal distributor tariffs are defined by the Distributor Tariff Module (DTM, see Chapter 5). Seasonal network flow patterns and prices are determined within the ITM. They are initially set based on historical data, and then from model results in the previous model year. Initial maximum seasonal pipeline utilizations[25] are based in part on historical monthly consumption and supply data, and in part on assumption.

Because the ITM 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 on an annual basis as market-specific quantities (core or noncore). The ITM disaggregates each of these market-specific quantities into a seasonal peak and offpeak representation, and then combines the core and noncore components within each season. 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 offpeak 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.

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

[25]These utilizations are used primarily to relate a peak period throughput to a peak day throughput (Appendix E -- PKUTZ, OPUTZ). Throughout the forecast these maximum utilization rates currently do not change. Future versions of the NGTDM will handle the impact on capacity due to the differences between peak day to period consumption levels differently.

Heuristic Process

The basic process used to determine supply and end-use prices in the ITM involves starting from the top of the network with end-use consumption levels, systematically moving down each network (in the opposite direction from the 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 to define transmission, node, storage, and end-use prices.

While progressively moving down the peak or offpeak 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[26] 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 offpeak period, injections into regional storage facilities. Regional fixed supplies include imports, 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.

Starting with the region (transshipment node) at the top of the network, a sharing algorithm is used to determine the percent of the region's net demand that is satisfied by each arc going into the node. The resulting shares are used to define flows along each arc (supply, storage, and interregional pipeline) into the region (or node). The interregional flows then become additional consumption requirements (i.e., primary flows out of a region) at the corresponding source node (region). If the arc going into the original node is from a supply or storage[27] source, then the flow represents the production or storage withdrawal level, respectively. The sharing algorithm is systematically applied (going down the network) to each regional node until flows have been defined for all arcs along a network, such that consumption in each region is satisfied and a mass balance of the flows is achieved throughout the network.

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 end-use prices. By systematically moving up each network, regional wellhead prices are used with pipeline tariffs and 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, market-specific distributor tariffs, to generate end-use prices. Seasonal prices are then converted to annual, market-specific end-use prices using quantity-weighted averaging. To speed overall NEMS convergence, the market-specific prices can be applied to representative demand curves (not used for *AEO2000*) to approximate the demand response and generate a new set of consumption levels. This process 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. When proceeding down the networks, the peak network flows are established first, followed by the offpeak network. This order has been established for two reasons. First, capacity expansion is decided based on peak flow requirements.[28] This in turn is used to define the upper limits put on flows along arcs in the offpeak network. Second, storage injections (represented as consumption) in the offpeak season cannot be defined until storage withdrawals (represented as supplies) in the peak season are established. When going up the networks, prices are determined for the offpeak 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 offpeak season plus a storage tariff.

---

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

[27]For the peak period networks only.

[28]Pipeline capacity into region 10 (Florida) is allowed to expand in either the peak or offpeak period because the region experiences its peak usage of natural gas in what is generally the offpeak period for consumption in the rest of the country.

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 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 is no longer needed.

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

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 end-use 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 storage injections in the offpeak), pipeline fuel consumption, end-use consumption, discrepancies, Canadian demands, exports, and other secondary flows exiting the region. Fixed supplies include associated-dissolved (AD) gas and ANGTS supply, synthetic natural gas, other supplemental supplies, LNG imports, fixed Canadian supplies, and other secondary flows entering the region. Seasonal net node demands are represented by the following equations:

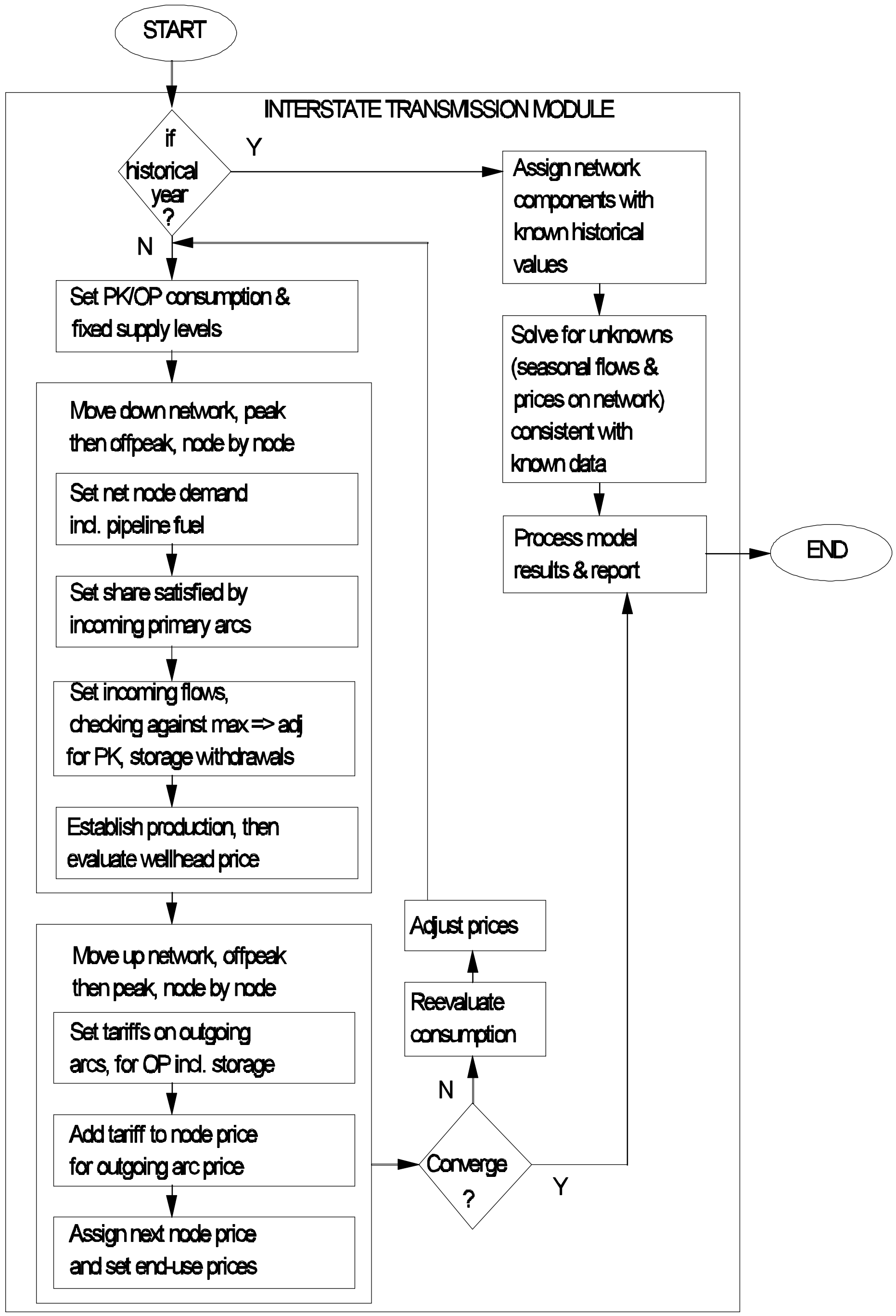
Peak:

$$\begin{aligned} NODE\_DMD_{PK,r} = {} & PFUEL_{PK,r} + FLOW_{PK,a} + \\ & \sum_{nonu} (PKSHR\_DMD_{nonu,r} * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \\ & \sum_{jutil \subset r} (PKSHR\_UDMD_{jutil} * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil})) + \\ & NODE\_CDMD_{PK,r} \end{aligned} \tag{10}$$

$$NODE\_CDMD_{PK,r} = YEAR\_CDMD_{PK,r} - (PKSHR\_PROD_s * ZADGPRD_s) \tag{11}$$

$$\begin{aligned} YEAR\_CDMD_{PK,r} = {} & DISCR_{PK,r,t} + CN\_DISCR_{PK,cn} + (PKSHR\_CDMD * CN\_DMD_{cn,r}) + \\ & (PK1 * SAFLOW_{a,t}) - (PK2 * SAFLOW_{a',t}) - \\ & (PKSHR\_YR * OGQANGTS_t) - (PKSHR\_SUPLM * ZTOTSUP_r) - \\ & (PKSHR\_ILNG * OGQNGIMP_{L,t}) - (PKSHR\_PROD_s * CN\_FIXSUP_{cn,t}) \end{aligned} \tag{12}$$

Figure 4.3 Interstate Transmission Module System Diagram



Off-Peak:

$$
\begin{aligned}
NODE\_DMD_{OP,r} = {} & PFUEL_{OP,r} + FLOW_{OP,a} + FLOW_{PK,st} + \\
& \sum_{nonu} ((1 - PKSHR\_DMD_{nonu,r}) * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \\
& \sum_{jutil \in r} ((1 - PKSHR\_UDMD_{jutil}) * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil})) + \\
& NODE\_CDMD_{OP,r}
\end{aligned}
\tag{13}
$$

$$
NODE\_CDMD_{OP,r} = YEAR\_CDMD_{OP,r} - ((1 - PKSHR\_PROD_s) * ZADGPRD_s) \tag{14}
$$

$$
\begin{aligned}
YEAR\_CDMD_{OP,r} = {} & DISCR_{OP,r,t} + CN\_DISCR_{OP,cn} + ((1 - PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\
& ((1 - PK1) * SAFLOW_{a,t}) - ((1 - PK2) * SAFLOW_{a',t}) - \\
& ((1 - PKSHR\_YR) * OGQANGTS_t) - ((1 - PKSHR\_SUPLM) * ZTOTSUP_r) - \\
& ((1 - PKSHR\_ILNG) * OGQNGIMP_{L,t}) - ((1 - PKSHR\_PROD_s) * CN\_FIXSUP_{cn,t})
\end{aligned}
\tag{15}
$$

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 AD gas production in supply subregion s (bcf)
$DISCR_{n,r,t}$ =	L48 discrepancy in region r, for network n, in forecast year t (bcf)[29]
$CN\_DISCR_{n,cn}$ =	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 L48 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 flow through the U.S., and L48 bidirectional flows] (bcf)
$OGQANGTS_t$ =	ANGTS supply in forecast year t (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)
$PKSHR\_DMD_{nonu,r}$ =	Portion of annual demand in each nonelectric sector in region r corresponding to the peak season (fraction)

[29]Lower 48 discrepancies are adjusted in the STEO years to account for STEO discrepancy (Appendix E, STDISCR) and annual net storage withdrawal (Appendix E, NNETWITH) forecasts. These adjustments are phased out over a user-specified number of years (STPHAS_YR).

$PKSHR\_UDMD_{jutil}$ = Portion of annual demand in the utility sector in region r corresponding to the peak season (fraction)
$PKSHR\_PROD_s$ = Portion of annual production in supply region s corresponding to the peak season (fraction) (Appendix E)
PKSHR_CDMD = Portion of annual Canadian demand corresponding to the peak season (fraction) (Appendix E)
PKSHR_YR = Portion of the year represented by the peak season (fraction)
PKSHR_SUPLM = Portion of supplemental supply corresponding to the peak season (fraction)
PKSHR_ILNG = Portion of LNG supply corresponding to the peak season (fraction)
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 (PK or OP)
PK,OP = Peak and offpeak 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)
cn = Canadian supply subregion ID in region r (1-2)
L = LNG import region ID into region r (1-4)
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 ITM, 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 (lower 48) *Short-Term Energy Outlook (STEO)* forecast[30] 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:

$$PFUEL_{n,r} = PFUEL\_FAC_{n,r} * NODE\_DMD_{n,r} * SCALE\_PF \qquad (16)$$

where,

$PFUEL_{n,r}$ = Pipeline fuel consumption in region r, for network n (bcf)
$PFUEL\_FAC_{n,r}$ = Average (1990-1997) historical pipeline fuel factor in region r, for network n (calculated historically for each region as equal PFUEL/NODE_DMD)[31]
$NODE\_DMD_{n,r}$ = Net demands (w/o pipeline fuel) in region r, for network n (bcf)
SCALE_PF = STEO benchmark factor for pipeline fuel consumption
n = network (peak and offpeak)
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

[30]EIA produces a separate quarterly forecast for primary national energy statistics over the next few years. For certain forecast items, the NEMS model is calibrated to produce an equivalent (within 3 to 5 percent) result at a national level for these years. For *AEO2000*, the years calibrated to *STEO* results were 1999 and 2000.

[31]The region for Arizona and New Mexico is assigned a PFUEL_FAC based on an average since 1995.

algorithm (described below). The regional pipeline fuel quantity (net of intraregional pipeline fuel consumption)[32] 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:

$$ARC\_PFUEL_{n,a} = (PFUEL_{n,r} - INTRA\_PFUEL_{n,r}) * \frac{FLOW_{n,a}}{TFLOW} \quad (17)$$

where,

$ARC\_PFUEL_{n,a}$ = Pipeline fuel consumption along arc a (into region r), for network n (bcf)
$PFUEL_{n,r}$ = Pipeline fuel consumption in region r, for network n (bcf)
$INTRA\_PFUEL_{n,r}$ = Intraregional pipeline fuel consumption in region r, for network n (bcf)
$FLOW_{n,a}$ = Interregional pipeline flow along arc a (into region r), for network n (bcf)
TFLOW = Total interregional pipeline flow [into region r] (bcf)
n = network (peak and offpeak)
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 citygate 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:

$$FLO\_FAC_{n,r} = INTRA\_FLO_{n,r} \; / \; (NODE\_DMD_{n,r} - PFUEL_{n,r}) \quad (18)$$

Forecast of intraregional flow:

$$INTRA\_FLO_{n,r} = FLO\_FAC_{n,r} * (NODE\_DMD_{n,r} - PFUEL_{n,r}) \quad (19)$$

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)
$FLO\_FAC_{n,r}$ = Historical relationship between net node demand and intraregional flow
n = network (peak and offpeak)
r = region/node

Historical annual intraregional flows are set for the peak and offpeak periods based on the peak and offpeak share of net node demand in each region. The value of FLO_FAC used in the forecast represents an average of its value over the historical years represented in the model (1990 through 1998).

[32]Note: 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 assumed to be 0.

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 either local supply sources, storage (withdrawals during peak period only), or other regions (interregional arcs). If any of the resulting flows exceed their corresponding maximum levels,[33] 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 states 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.[34] This proportion is a multiplicative value represented as the ratio of the inverse price (defined the previous cycle up the network) 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 in other sections below.) The variable γ is an assumed parameter which 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:

$$SHR_{n,a,t} = \frac{ARC\_SHRPR_{n,a}^{-\gamma}}{\dfrac{\sum_b ARC\_SHRPR_{n,b}^{-\gamma}}{N}} * SHR_{n,a,t-1} \tag{20}$$

where,

$SHR_{n,a,t}$, $SHR_{n,a,t-1}$	=	The percentage of demand represented along inflow arc a on network n, in year t [or year t-1,] (fraction) [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	=	current year
n	=	network (peak or offpeak)
a	=	arc into a region
r	=	region/node
b	=	set of arcs into a region

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

Seasonal flows are generated for each arc using the resulting shares and net node demands.

$$FLOW_{n,a} = SHR_{n,a,t} * NODE\_DMD_{n,r} \tag{21}$$

where,

$FLOW_{n,a}$	=	Interregional flow (into region r) along arc a, for network n (bcf)
$SHR_{n,a,t}$	=	The percentage of demand represented along inflow arc a on network n, in year t (fraction)
$NODE\_DMD_{n,r}$	=	Net node demands in region r, for network n (bcf)
n	=	network (peak or offpeak)

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

[34]When planned pipeline capacity is added at the beginning of a forecast year, the value of SHR_{t-1} is adjusted to reflect a 30 percent usage of the new capacity. This adjustment is based on the assumption that last year's share would have been higher if not constrained by the existing capacity levels.

a = 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 *offpeak* network arcs are a function of the annual capacity defined by peak flows and offpeak utilization factors. Thus, maximum flows along the offpeak network depend on whether or not capacity was added during the peak period. Also, maximum flows from *supply* sources in the offpeak network are limited by maximum annual capacity levels and offpeak utilization. (Note: *storage* arcs do not enter nodes on the offpeak 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):

$$MAXFLO_{PK,a} = MAXPCAP_{PK,a} * (PKSHR\_YR * PKUTZ_a) \tag{22}$$

such that $MAXPCAP_{PK,a}$

for Supply[35]*:*

$$MAXPCAP_{PK,a} = ZOGRESNG_s * ZOGPRRNG_s * MAXPRRFAC * (1 - (PCTLP_r * SCALE\_LP_t)) \tag{23}$$

for Pipeline:

$$MAXPCAP_{PK,a} = PTMAXPCAP_{i,j} \tag{24}$$

for Storage:

$$MAXPCAP_{PK,a} = PTMAXPSTR_{st} \tag{25}$$

for Canadian imports

$$MAXPCAP_{PK,a} = CURPCAP_{a,t} \tag{26}$$

Maximum offpeak pipeline flows:

$$MAXFLO_{OP,a} = MAXPCAP_{OP,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \tag{27}$$

such that $MAXPCAP_{OP,a}$ *is*

either current capacity,

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

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} \tag{28}$$

or current capacity plus capacity additions,

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} + \left((1 + XBLD) * \left(\frac{FLOW_{PK,a}}{(PKSHR\_YR * PKUTZ_a)} - CURPCAP_{a,t} \right) \right) \tag{29}$$

or, for pipeline arc entering region 10, peak maximum capacity,

$$MAXPCAP_{OP,a} = MAXPCAP_{PK,a} \tag{30}$$

Maximum offpeak flows from supply sources:

$$MAXFLO_{OP,a} = MAXPCAP_{PK,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \tag{31}$$

where,

$MAXFLO_{n,a}$ =	Maximum flow on arc a, in network n [PK or OP] (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)
MAXPRRFAC =	Factor to set maximum production-to-reserves ratio [MAXPRRCAN for Canada] (Appendix E)
$PCTLP_t$ =	Percent lease and plant consumption in forecast year t (fraction)
$SCALE\_LP_t$ =	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 PTM] (bcf)
$PTMAXPSTR_{st}$ =	Maximum storage capacity for storage source st [defined by PTM] (bcf)
$FLOW_{PK,a}$ =	Flow along arc a for the peak network (bcf)
PKSHR_YR =	Portion of the year represented by peak season (fraction)
$PKUTZ_a$ =	Pipeline utilization along arc a for the peak season (Appendix E, fraction)
$OPUTZ_a$ =	Pipeline utilization along arc a for the offpeak season (Appendix E, fraction)
XBLD =	Percent increase over capacity builds to account for weather (=5%)
a =	arc
t =	model year
n =	network (peak or offpeak)
PK, OP =	peak and offpeak network, respectively
s =	supply source
st =	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. For completeness a maximum utilization (Appendix E, SUTZ) is assigned to the secondary pipeline arcs as well; although since secondary flows are not determined in the model, they are not used to bound secondary flows.

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 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,[36] 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, 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 model, new capacity levels are defined as follows:

Storage:

$$ACTPCAP_a = \frac{FLOW_{PK,a}}{PKUTZ_a} \tag{32}$$

Pipeline:

$$ACTPCAP_a = MAXPCAP_{OP,a} \tag{33}$$

Pipeline arc entering region 10:

$$ACTPCAP_a = \text{MAX between } \frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} \text{ and } \frac{FLOW_{OP,a}}{(1 - PKSHR\_YR) * OPUTZ_a} \tag{34}$$

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 offpeak utilization of capacity along arc a (fraction -- Appendix E)
PKSHR_YR =	Portion of the year represented by the peak season (fraction)
a =	pipeline and storage arc
n =	network (peak or offpeak)
PK =	peak season
OP =	offpeak season

[36]Capacity expansion on Canadian import arcs are exogenously defined.

Wellhead Prices

Ultimately, all the network-specific consumption levels are transferred down the networks and into supply nodes, where corresponding supply prices are calculated. The Oil and Gas Supply Model (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 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:

$$ANNSUP = \frac{NODE\_QSUP_{PK,s}}{PKSHR\_YR} \tag{35}$$

Offpeak:

$$ANNSUP = \frac{NODE\_QSUP_{OP,s}}{(1 - PKSHR\_YR)} \tag{36}$$

where,

ANNSUP	=	Equivalent annual production level (bcf)
$NODE\_QSUP_{n,s}$	=	Seasonal (n=PK or OP) production level for supply region s (bcf)
PKSHR_YR	=	Portion of year represented by peak season (fraction)
PK	=	peak season
OP	=	offpeak 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, using the sum of the seasonal production levels and the annual supply curve function. The *average* annual supply price is then compared to the *actual* price. The corresponding ratio (FSF) is used to adjust the estimated seasonal prices to generate final seasonal supply prices ($NODE\_PSUP_{n,s}$) for a region.

For a supply source s,

$$FSF = \frac{PSUP_s}{SPAVG_s} \tag{37}$$

and,

$$NODE\_PSUP_{n,s} = SPSUP_n * FSF \tag{38}$$

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 offpeak 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 offpeak)
s =	supply source

During the STEO years (1999 and 2000 for *AEO2000*), 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 be more in line with STEO results. The benchmark factor is applied to model results during and after the STEO years, but is gradually phased out by a user-specified year (Appendix E, STPHAS_YR). The benchmark factor is applied as follows:

Annual:

$$PSUP_s = PSUP_s * SCALE\_WPR_t \tag{39}$$

Seasonal:

$$NODE\_PSUP_{n,s} = NODE\_PSUP_{n,s} * SCALE\_WPR_t \tag{40}$$

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 offpeak)
s =	supply source
t =	model year

Arc Fees (Tariffs)

Fees (or tariffs) along arcs are used in conjunction with supply, storage, and node prices to determine competing arc prices which, in turn, are used to determine network flows, transshipment node prices, and end-user 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 offpeak 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 and can also be used to establish pricing differences between seasons.

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 PTM 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 is currently not used and set to zero (although this will be different in future versions of the model). The variable term is obtained from tariff/capacity curves provided by two PTM functions and represents reservation fees for pipelines and all charges for storage. These two functions are NGPIPE_VARTAR and NGSTR_VARTAR. When determining network flows a different set of tariffs ($ARC\_SHRFEE_{n,a}$) are used than are used when setting end-use prices ($ARC\_ENDFEE_{n,a}$).

In the peak period ARC_SHRFEE equals ARC_ENDFEE and the total tariff (reservation plus usage fee). In the offpeak period, ARC_ENDFEE represents the total tariff as well, but ARC_SHRFEE only represents the usage fee. The assumption behind this structure is that end-use prices will ultimately reflect reservation charges, but that during the offpeak period in particular, decisions regarding the purchase and transport of gas are made largely independently of where pipeline is reserved and the associated fees. During the peak period, the gas is more likely to flow along routes where pipeline is reserved; and therefore the flow decision is more greatly influenced by the relative reservation fees.[37] Thus, the following arc tariff equations apply:

Pipeline:

$$\begin{aligned} \text{peak} -- \quad & ARC\_SHRFEE_{n,a} = ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n,a,i,j,FLOW_{n,a}) \\ \text{offpeak} -- \quad & ARC\_SHRFEE_{n,a} = ARC\_FIXTAR_{n,a,t} \\ \text{both} -- \quad & ARC\_ENDFEE_{n,a} = ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(xn,a,i,j,FLOW_{n,a}) \end{aligned} \tag{41}$$

Storage:

$$\begin{aligned} ARC\_SHRFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGSTR\_VARTAR(st,FLOW_{n,a}) \\ ARC\_ENDFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGSTR\_VARTAR(st,FLOW_{n,a}) \end{aligned} \tag{42}$$

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 end-use 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 =	PTM function to define pipeline tariffs representing reservation fees
NGSTR_VARTAR =	PTM function to define storage fees
n =	network (1=PK, 2= OP)
xn =	special network ID used to signal *process-specific* processing (1=PK, 3=OP)
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.[38] 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).

Arc, Node, and Storage Prices

Prices at the transshipment nodes (or node prices) represent intermediate prices that are used to determine regional end-use 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, nor deemed desirable (as described above), to set end-use 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 $ARC\_SHRFEE_{n,a}$).

---

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

[38]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 ITM. In the past an effort was made, with little success, to derive representative gathering charges. The gathering charge portion of the tariff along the supply arcs was assumed to be zero.

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

$$\begin{aligned} ARC\_SHRPR_{n,a} &= NODE\_SHRPR_{n,r} + ARC\_SHRFEE_{n,a} \\ ARC\_ENDPR_{n,a} &= NODE\_ENDPR_{n,r} + ARC\_ENDFEE_{n,a} \end{aligned} \tag{43}$$

with adjustment:

$$\begin{aligned} ARC\_SHRPR_{n,a} &= \frac{(ARC\_SHRPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})} \\ ARC\_ENDPR_{n,a} &= \frac{(ARC\_ENDPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})} \end{aligned} \tag{44}$$

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 end-use 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 end-use 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 end-use 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 (PK or OP)
a =	arc
r =	region corresponding to source link on arc a

Although each type of node price may be calculated differently (e.g., average prices for end-use calculation, marginal prices for flow sharing calculation, or some combination of these for each), the current model uses the quantity-weighted averaging approach to establish node prices for both the end-use pricing and flow sharing algorithm pricing. 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:

$$\begin{aligned} NODE\_SHRPR_{n,r} &= \frac{\Sigma_a\ (ARC\_SHRPR_{n,a} * FLOW_{n,a})}{\Sigma_a\ FLOW_{n,a}} \\ NODE\_ENDPR_{n,r} &= \frac{\Sigma_a\ (ARC\_ENDPR_{n,a} * FLOW_{n,a})}{\Sigma_a\ FLOW_{n,a}} \end{aligned} \tag{45}$$

and,

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

$$NODE\_ENDPR_{n,r} = \frac{(NODE\_ENDPR_{n,r} * NODE\_DMD_{n,r})}{(NODE\_DMD_{n,r} - INTRA\_PFUEL_{n,r})} \qquad (46)$$

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 end-use 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 end-use 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 (PK or OP)
a =	arc
r =	region r destination link along arc a

Once node prices are established for the offpeak 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 offpeak regional node price. This applies for both the end-use pricing and the flow sharing algorithm pricing:

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

$$NODE\_ENDPR_{PK,i} = NODE\_ENDPR_{OP,r} \qquad (47)$$

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 offpeak network [used with sharing algorithm] (87$/mcf)
$NODE\_ENDPR_{PK,i}$ =	Price at node i [used with end-use pricing] (87$/mcf)
$NODE\_ENDPR_{OP,r}$ =	Price at node r in offpeak network [used with end-use pricing] (87$/mcf)
PK, OP =	peak and offpeak network, respectively
i =	node ID for storage
r =	region ID where storage exists

Backstop Price Adjustment

Backstop supply 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 price adjustment ($BKSTOP\_PADJ_{n,r}$) is not sufficient to eliminate backstop on the next cycle down the network, an additional adjustment ($RBKSTOP\_PADJ_{n,r}$) is added to the cumulative adjustment. This continues until backstop subsides, or until the maximum number of ITM 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 ITM convergence is achieved. Maintaining a backstop adjustment is necessary because complete removal of this penalty 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 ½ and added to the cumulative adjustment variable, with the process continuing as described above for backstop. 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:

$$NODE\_SHRPR_{n,r} = NODE\_SHRPR_{n,r} + RBKSTOP\_PADJ_{n,r} \tag{48}$$

$$RBKSTOP\_PADJ_{n,r} = RBKSTOP\_PADJ_{n,r} + BKSTOP\_PADJ_{n,r} \tag{49}$$

where,

$NODE\_SHRPR_{n,r}$ =	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 (PK or OP)
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.

ITM Convergence

The ITM 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 ITM 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 ITM 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:

$$\begin{aligned} NODE\_QSUP_{n,s} = {} & (QSUP\_WT * NODE\_QSUP_{n,s}) + \\ & ((1 - QSUP\_WT) * NODE\_QSUPPREV_{n,s}) \end{aligned} \tag{50}$$

where,

$NODE\_QSUP_{n,s}$ =	Production level at supply source s on network n for current ITM cycle (bcf)
$NODE\_QSUPPREV_{n,s}$ =	Production level at supply source s on network n for previous ITM cycle (bcf)
QSUP_WT =	Weighting applied to production level for current ITM cycle
n =	network (PK or OP)
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 prices for the Electricity Market Model (electric generation sector) and the other NEMS demand models (nonelectric sectors). For the nonelectric sectors, prices correspond to core and noncore service 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 lower 48 subregion level (Chapter 2).

The first step toward generating these end-use prices is to translate regional, seasonal node prices into corresponding citygate 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 citygate benchmark factor ($CGBENCH_{n,r}$) which represents the difference between historical citygate prices and model results during the last year that historical data are available (1998 for *AEO2000*). These equations are defined below:

$$CGPR_{n,r} = NODE\_ENDPR_{n,r} + INTRAREG\_TAR_{n,r} + INTRAST\_TAR_{r} + CGBENCH_{n,r} \tag{51}$$

such that:

$$CGBENCH_{n,r} = HCG\_BENCH_{n,r,EHISYR} = (\ HCGPR_{n,r,EHISYR} - CGPR_{n,r}\ ) \tag{52}$$

where,

$CGPR_{n,r}$ =	Citygate price in region r on network n in EHISYR (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)
$CGBENCH_{n,r}$ =	Citygate benchmark factor for region r on network n (87$/mcf)
$HCGPR_{n,r,EHISYR}$ =	Historical citygate price in region r on network n in historical year EHISYR (87$/mcf)
n =	network (peak and offpeak)
r =	region (lower 48 only)
EHISYR =	last year that historical data are available

The intraregional tariffs are the sum of a usage fee (INTRAREG_FIXTAR), provided by the Pipeline Tariff Module, 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 citygate prices to historical values.

Seasonal distributor tariffs are then added to the citygate prices to get seasonal, market-specific end-use prices by the NGTDM regions for nonelectric sectors and by the NGTDM/EMM subregions for the electric generation sector. The core prices for residential, commercial, and electric generation sectors, as well as the noncore electric generation prices, are then adjusted using STEO benchmark factors ($SCALE\_FPR_{sec,t}$, $SCALE\_IPR_{sec,t}$)[39] to calibrate the results to equal the corresponding national STEO end-use prices. Each seasonal sector price is then averaged to get an annual, market-specific end-use price for each representative region. The following equations apply.

Nonelectric Sectors (except core transportation):

$$\begin{aligned} NGPR\_SF_{n,sec,r} &= CGPR_{n,r} + DTAR\_SF_{n,sec,r} + SCALE\_FPR_{sec,t} \\ NGPR\_SI_{n,sec,r} &= CGPR_{n,r} + DTAR\_SI_{n,sec,r} + SCALE\_IPR_{sec,t} \end{aligned} \tag{53}$$

[39]The STEO scale factors are linearly phased out over five years after the last STEO year (2000 in *AEO2000*).

$$
\begin{aligned}
NGPR\_F_{sec,r} &= NGPR\_SF_{PK,sec,r} * PKSHR\_DMD_{sec,r} + \\
&\quad NGPR\_SF_{OP,sec,r} * (1. - PKSHR\_DMD_{sec,r}) \\
NGPR\_I_{sec,r} &= NGPR\_SI_{PK,sec,r} * PKSHR\_DMD_{sec,r} + \\
&\quad NGPR\_SI_{OP,sec,r} * (1. - PKSHR\_DMD_{sec,r})
\end{aligned} \tag{54}
$$

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)
$CGPR_{n,r}$	=	Citygate 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)
$PKSHR\_DMD_{sec,r}$	=	Peak season share of annual demand for the nonelectric sector (sec) in region r (fraction)
$SCALE\_FPR_{sec,t}$	=	STEO benchmark factor for core end-use prices for sector sec, in year t (87$/mcf)
$SCALE\_IPR_{sec,t}$	=	STEO benchmark factor for noncore end-use prices for sector sec, in year t (87$/mcf)
n	=	network (PK or OP)
sec	=	nonelectric sector
r	=	region (lower 48 only)

Electric Generation Sector:

$$
\begin{aligned}
NGUPR\_SF_{n,j} &= CGPR_{n,r} + UDTAR\_SF_{n,j} + SCALE\_FPR_{sec,t} \\
NGUPR\_SI_{n,j} &= CGPR_{n,r} + UDTAR\_SI_{n,j} + SCALE\_IPR_{sec,t}
\end{aligned} \tag{55}
$$

$$
\begin{aligned}
NGUPR\_F_{j} &= NGUPR\_SF_{PK,j} * PKSHR\_UDMD_{j} + \\
&\quad NGUPR\_SF_{OP,j} * (1. - PKSHR\_UDMD_{j}) \\
NGUPR\_I_{j} &= NGUPR\_SI_{PK,j} * PKSHR\_UDMD_{j} + \\
&\quad NGUPR\_SI_{OP,j} * (1. - PKSHR\_UDMD_{j})
\end{aligned} \tag{56}
$$

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)
$CGPR_{n,r}$	=	Citygate 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)
$PKSHR\_UDMD_{j}$	=	Peak season share of annual demand for the utility sector in region j (fraction)
$SCALE\_FPR_{sec,t}$	=	STEO benchmark factor for core end-use prices for sector sec, in year t (87$/mcf)
$SCALE\_IPR_{sec,t}$	=	STEO benchmark factor for noncore end-use prices for sector sec, in year t (87$/mcf)
n	=	network (PK or OP)

sec = utility sector (electric generation only)
r = region (lower 48 only)
j = NGTDM/EMM subregion

Core Transportation Sector

A somewhat different methodology is used to determine natural gas end-use 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 citygate prices to determine seasonal end-use prices for both components. Annual core prices are then established for each component in a region by averaging the corresponding seasonal prices.

$$\begin{aligned} NGPR\_TRPV\_SF_{n,r} &= CGPR_{n,r} + DTAR\_TRPV\_SF_{n,r} + SCALE\_FPR_{sec,t} \\ NGPR\_TRFV\_SF_{n,r} &= CGPR_{n,r} + DTAR\_TRFV\_SF_{n,r} + SCALE\_FPR_{sec,t} \end{aligned} \tag{57}$$

$$\begin{aligned} NGPR\_TRPV\_F_{r} = {} & NGPR\_TRPV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + \\ & NGPR\_TRPV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r}) \\ NGPR\_TRFV\_F_{r} = {} & NGPR\_TRFV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + \\ & NGPR\_TRFV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r}) \end{aligned} \tag{58}$$

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)
$CGPR_{n,r}$ = Citygate 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)
$PKSHR\_DMD_{sec,r}$ = Peak season share of annual demand for the transportation sector (sec=4) in region r (fraction)
$SCALE\_FPR_{sec,t}$ = STEO benchmark factor for core end-use prices for sector sec, in year t (set to 0 for transportation sector), (87$/mcf)
n = network (PK or OP)
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, an additional step in the process is applied to the personal vehicles component. The annual end-use price determined above is compared to the price of commercial motor gasoline (units are converted into $/mcf equivalents). If the personal vehicles price for natural gas is greater (TRPV_DIFF > 0.) than the gasoline price, then the natural gas price is discounted to be competitive with the commercial motor gasoline price, but not more than a predefined discount level (TRPV_ADJ).

$$\begin{aligned} TRPV\_DIFF = {} & (NGPR\_TRPV\_F_{r} + JNGTR_{t} * CFNGN) - \\ & [(PMGCM_{c,t} + JMGCM_{t}) * CFNGN] \end{aligned} \tag{59}$$

$$TRPV\_ADJ = RETAIL\_COST * RETAIL\_PCT \tag{60}$$

$$NGPR\_TRPV\_F_r = NGPR\_TRPV\_F_r - AMIN1(\ TRPV\_DIFF,\ TRPV\_ADJ\ ) \tag{61}$$

where,

$NGPR\_TRPV\_F_r$ =	Price of natural gas used for personal vehicles (core) in region r (87$/mcf)
TRPV_DIFF =	Difference between price of motor gasoline and natural gas used for personal vehicles (87$/mcf)
$PMGCM_{c,t}$ =	Price of motor gasoline in census division c, in model year t (87$/mmBTU)
$JNGTR_t$ =	NEMS price adjustment for natural gas in transportation sector in model year t (87$/mmBTU)
$JMGCM_t$ =	NEMS price adjustment for motor gasoline in model year t (87$/mmBTU)
CFNGN =	Natural gas conversion factor--mmBTU / mcf
TRPV_ADJ =	Maximum discount allowed for personal vehicles (87$/mcf)
RETAIL_COST =	Retail cost (87$/mcf)
RETAIL_PCT =	Percent of retail cost to define discount (fraction)
r =	region (lower 48 only)
t =	model 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 ($NGPR\_SF_{n,sec=4,r}$).

Use of End-Use Prices

Regional end-use prices could be used to speed NEMS convergence by approximating a demand response within the ITM cycle. Although the model structure exits to carry out this capability, a functional form of the demand curves was not established within the *AEO2000* version of the NGTDM. Finally, once the ITM has converged, regional prices are averaged using quantity weights into Census Division prices and sent to the corresponding NEMS models.

Import Prices

The price associated with Canadian imports at each of the model's border crossing points is established during the ITM 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) which 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 citygate prices are used instead of wellhead prices. For the facilities that are not currently operating (one in Maryland and one in Georgia) and for which there are no data, the differential between the citygate and the import price is set to the historical citygate to import price differential for the Massachusetts facility. For the facility in Georgia, this differential is decreased by an additional 20 cents (in 1987 dollars per million cubic feet).

5. Distributor Tariff Module Solution Methodology

This chapter discusses the solution methodology for the Distributor Tariff Module (DTM) of the Natural Gas Transmission and Distribution Model (NGTDM). Within each region, the DTM develops seasonal, market-specific distributor tariffs that are applied to seasonal citygate prices to derive end-use prices. Because end-users can be classified as either core or noncore customers, distributor tariffs must be defined accordingly. 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 the core transportation sector is composed of two categories of compressed natural gas (CNG) consumers (fleet vehicles and personal vehicles), separate distributor tariffs for each of these categories are required.

The primary task of the DTM is to determine seasonal core and noncore (where applicable) distributor tariffs for each end-use sector in each region. Different methodologies are used depending on sector and market. Distributor tariffs to residential, commercial, and industrial core customers are based on estimates of the cost of providing service to the core end user, depreciation of equipment, and assumed industry efficiency improvements. Electric generator, noncore industrial, and (for the most part) transportation distributor tariffs are based on historical tariffs, with annual growth or decline rates applied. A primary factor in the selection of methodologies for developing distributor tariffs was the lack of publicly available data to develop a detailed cost-based accounting methodology similar to the approach used for interstate pipeline tariffs in the Pipeline Tariff Module. The specific methodologies used to calculate distributor tariffs are discussed in the remainder of this chapter.

Core Distributor Tariffs

Residential, Commercial, and Industrial Sectors

The algorithm that sets seasonal distributor tariffs for residential, commercial, and industrial core customers is based on coefficients generated by an historically based estimation of total distribution costs. Underlying the approach is the assumption that the change in the distributor tariff paid by each sector is reflective of the level to which each sector contributes to total distribution costs. In addition, the distributor tariffs are adjusted to reflect depreciation effects and a user-specified assumption about future industry efficiency improvements. The core transportation sector is not included among the sectors for which this algorithm is used because of the current nature of the market -- the use of compressed natural gas as a vehicle fuel is evolving from government/industry sponsored demonstration programs to large scale commercial use. The core electric generation sector is also not included in these calculations because in most cases they do not buy gas through a local distribution company. Therefore, a separate methodology is used to determine seasonal distributor tariffs for the transportation and electric generation sectors. These are described separately below.

The equation for forecasting distributor tariffs for the residential, commercial, and core industrial sectors is presented below, followed by a more detailed description of each of the equation's components:

$$\begin{aligned} DTAR\_SF_{n,s,r} = {} & DTAR\_SFPREV_{n,s,r} * \left[\frac{BASQTY\_SF_{n,s,r}}{BASQTY\_SFPREV_{n,s,r}}\right]^{-TCF\_COEFF_s} \\ & * RTCOSTCAP^{TCF\_COEFF_5} * RTEMPLCOST^{TCF\_COEFF_6} \\ & * (1.-TCF\_COEFF_7) * TECHEFF_t \end{aligned} \qquad (62)$$

where,

$DTAR\_SF_{n,s,r}$ = core distributor tariffs for sector s, region r, in season n for current forecast year (87$/Mcf)
$DTAR\_SFPREV_{n,s,r}$ = core distributor tariffs for sector s, region r, in season n for previous forecast year (87$/Mcf)
$BASQTY\_SF_{n,s,r}$ = seasonal volume of core natural gas consumption for sector s, region r, in the current forecast year (Bcf)

$BASQTY\_SFPREV_{n,s,r}$ =	seasonal volume of core natural gas consumption for sector s, region r, in the previous forecast year (Bcf)
RTCOSTCAP =	ratio of current year's to previous year's cost of capital
RTEMPLCOST =	ratio of current year's to previous year's cost of employment
$TCF\_COEFF_{1\text{-}6}$ =	estimated parameters [Appendix E, (scaler)]
TCF_COEFF_7 =	assumed annual depreciation rate
$TECHEFF_t$ =	technical efficiency factor, by year [Appendix E, (scaler)]
n =	network (PK or OP)
r =	NGTDM region
s =	sector
t =	year

Historically, distributor tariffs for a sector in a particular region can be estimated by taking the difference between the average sectoral end-use price and the average citygate price in the region. For the initial forecast year the values for DTAR_SFPREV represent these historical differences. Historical seasonal citygate prices (Appendix E, $HCGPR_{n,r,yr}$) are subtracted from each of the relevant end-use prices (Appendix E – $HPGFRSGR_{n,r,yr}$, $HPGFCMGR_{n,r,yr}$, and Appendix F, Table F5 --$HPGFINGR_{n,r,yr}$)

The previous forecast year's distributor tariffs are adjusted as a function of the relative change in the associated sectors' consumption, capital costs, and employment costs. The coefficients (TCF_COEFF) associated with these variables are taken from an econometric estimation of the total cost of distribution as a function of a number of parameters, including sector specific consumption and capital and employment costs. This estimation was performed by Mary Lashley Barcella and presented in a coauthored paper titled "Wholesale and Retail Analysis for Estimating the Price Effect of Natural Gas Conservation" (Appendix B). The paper presents a total distributor cost equation as a change in last year's total costs, with parameters estimated on the basis of data from 64 local gas distribution companies covering the period 1969 through 1993. The terms for representing the cost of capital and employment in the above equation follow.

The rate of change in employment costs (RTEMPLCOST) is calculated using the economic variables MC_ECIWSP_{yr} and $MC\_CPI_{cr,yr}$, set within the macroeconomic model of the NEMS, as follows:

$$RTEMPLCOST = \frac{MC\_ECIWSP_{yr}}{MC\_CPI_{cr,yr}} \Big/ \frac{MC\_ECIWSP_{yr-1}}{MC\_CPI_{cr,yr-1}} \tag{63}$$

where,

RTEMPLCOST =	ratio of current year's to previous year's cost of employment
$MC\_CPI_{cr,yr}$ =	consumer price index [provided by the Macroeconomic Model]
MC_ECIWSP_{yr} =	employment cost index -- private wage and salary [provided by the Macroeconomic Model]
cr =	census division
yr =	year

Comparable forecast values were unavailable for the historical series representing the cost of capital that was used to estimate the coefficients in equation 62. For the forecast, the cost of capital is approximated using a weighted average of the yield on AA bonds (20-year rolling average, DEBTYR) and the yield on 10-year government bonds. In order to use this representation for cost of capital in the forecast, it was necessary to establish a relationship between this series and the cost of capital measure used in estimating the coefficients in equation 62. For this purpose, an equation was estimated [Appendix F, Table F4] to forecast the series used in the original estimation ($AVG\_COSTCAP_{yr}$) as a function of the series used in the forecast to approximate the cost of capital ($AVG\_COSTCAP\_OLD_{yr}$). The series of equations used to set the rate of change in the cost of capital (RTCOSTCAP) follow:

$$RTCOSTCAP = AVG\_COSTCAP_{yr} \ / \ AVG\_COSTCAP_{yr-1} \tag{64}$$

given,

$$AVG\_COSTCAP_{yr} = 7.44691 + 1.22689 * AVG\_COSTCAP\_OLD_{yr} + 71.60079 * (YR-1979)^{-0.7} \tag{65}$$

$$AVG\_COSTCAP\_OLD_{yr} = \frac{COSTCAP_{yr} + COSTCAP_{yr-1} + COSTCAP_{yr-2}}{3} \tag{66}$$

$$\begin{aligned} COSTCAP_{yr} = \; & WT\_DEBT * AVG\_RMPUAANS + \\ & (1-WT\_DEBT) * NG\_REALRMGBLUS \end{aligned} \tag{67}$$

$$AVG\_RMPUAANS = \frac{\sum_{t=yr-DEBTYR}^{yr} [\; MC\_RMPUAANS_t - (\; (100 * \frac{MC\_PCWGDP_{yr}}{MC\_PCWGDP_{yr-1}}\;) -1)\;]}{DEBTYR} \tag{68}$$

where,

RTCOSTCAP =	ratio of current year’s to previous year’s cost of capital
$AVG\_COSTCAP_{yr}$ =	average cost of capital [derived in Appendix F, Table F4, (87$)]
$AVG\_COSTCAP\_OLD_{yr}$ =	3-year rolling average cost of capital, used to define AVG_COSTCAP (87$)
$COSTCAP_{yr}$ =	real cost of capital (debt + equity) in forecast year yr (87$)
AVG_RMPUAANS =	20-year rolling average of yield on AA utility bonds (fraction)
WT_DEBT =	weighting for debt/equity contribution to cost of capital [Appendix E, (fraction)]
NG_REALRMGBLUS =	real yield on 10 year U.S. Government bonds (forecast values provided by the Macroeconomic Model, historical values in H_REALRMGBLUS -- Appendix E)
DEBTYR =	number of years rolling average taken on debt (years)
$MC\_RMPUAANS_{yr}$ =	yield on AA utility bonds, used to define AVG_RMPUAANS [forecast values provided by the Macroeconomic Model, historical values in H_RMPUAANS -- Appendix E, (fraction)]
MC_PCWDGP_{yr} =	GDP deflator index [provided by Macroeconomic Model]
YR =	current forecast year (4 digits)
yr =	year

Finally, the distributor tariffs are adjusted further to reflect annual depreciation and efficiency improvements. The factor for representing efficiency improvements can be set to a different value for each forecast year and was set to 1.0 for AEO2000 (effectively no improvement). Although these two factors are specified separately, the combined impact from both can be incorporated into one or the other of the variables. For AEO2000, the TCF_COEFF_6 variable (in equation 62) was set to 0.1, to represent the combination of both factors.

Electric Generation Sector

Seasonal distributor tariffs for the core electric generation sector are initially set as a simple average of the last three years for which historical data are available (1996-1998 for *AEO2000*), and then adjusted based on analyst judgement. First, a check is made each forecast year to ensure that the previous year's distributor tariffs are not below a lower limit of -1.00 (87$/mcf).[40] If any tariff falls below this threshold, then the corresponding tariff is set to 95% of the previous year's level. Next, for each forecast year after 2002, an adjustment factor is added to the core tariffs which reflects additional costs incurred resulting from an expanded infrastructure (not captured elsewhere in the model) needed to support increased electric generator consumption. This adjustment factor is a function of the percentage change in the seasonal regional electric generator consumption each year. Thus, seasonal distributor tariffs are calculated as follows:

$$UDTAR\_SF_{n,j} = UDTAR\_SFPREV_{n,j} * (\text{threshold factor}) + CHQTY_{n,j} * 0.05 \tag{69}$$

where,

$UDTAR\_SF_{n,j}$ = seasonal distributor tariff for core electric generation sector in current forecast year ($/Mcf)

[40] In some isolated cases (e.g., Michigan) the data indicate extremely low prices of natural gas to electric utilities. It is assumed that such prices can not be maintained indefinitely.

$UDTAR\_SFPREV_{n,j}$	=	seasonal distributor tariff for core electric generation sector in previous forecast year ($/Mcf)
threshold factor	=	set to 0.95 if UTIL_DTAR_FPREV is less than -1.00 (87$/mcf), else set to 1.0 (analyst judgement)
$CHQTY_{n,j}$	=	percentage change in seasonal core electric generator consumption each yr (fraction)
n	=	network (PK or OP)
j	=	region

The percentage change in core electric consumption is limited to be between -200% and 200% (analyst judgement), and is set as follows:

$$CHQTY_{n,j} = \frac{BASUQTY\_SF_{n,j} - BASUQTY\_SFPREV_{n,j}}{BASUQTY\_SFPREV_{n,j}} \tag{70}$$

where,

$CHQTY_{n,j}$	=	percentage change in seasonal core electric generator consumption each yr (fraction)
$BASUQTY\_SF_{n,j}$	=	seasonal core electric generator consumption for subregion j (BCF)
$BASUQTY\_SFPREV_{n,j}$	=	seasonal core electric generator consumption for subregion j in previous yr (BCF)
n	=	network (PK or OP)
j	=	region

In historical years, seasonal distributor tariffs paid by core customers ($UDTAR\_SF_{n,j}$) are set as the difference between historical seasonal end-use [$HPGFELGR_{n,j,hyr}$][41] and citygate prices [Appendix E, $HCGPR_{n,r,hyr}$].

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. Two different pricing methodologies are defined for determining distributor tariffs to these two end-use categories, with the sector average ($DTAR\_SF_{n,s=4,r}$) being determined as a quantity weighted average of both end-use categories. Distributor tariffs associated with fleet vehicles are a function of the historical distributor tariffs, a decline rate, and state and federal taxes[42] (adjusted to 1987 year dollars), as shown:

$$DTAR\_TRFV\_SF_{n,r} = HDTAR\_SF_{n,s=4,r,EHISYR} * (1 - TRN\_DECL)^{YR\_DECL} + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_{yr}} \tag{71}$$

where,

$DTAR\_TRFV\_SF_{n,r}$	=	distributor tariff for the fleet vehicle transportation sector (87$/Mcf)
$HDTAR\_SF_{n,s,r,EHISYR}$	=	historical distributor tariff for the transportation sector,[43] assumed to be primarily for fleet vehicles (87$/ Mcf)
TRN_DECL	=	fleet vehicle distributor decline rate, set to zero for *AEO2000* [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 for CNG [Appendix E, (current yr $/Mcf)]

[41]Core and noncore electric generator prices are initially assumed to vary by 4 percent above and below the average price, respectively, and then scaled to equal published data as read by the model. Core and noncore quantity weights for the electric utility calculations are aggregates of MN_ST_QEUF and MN_ST_QEUI (Appendix E).

[42]When revenue data are collected for establishing natural gas prices for compressed natural gas vehicles, respondents are asked to include all relevant taxes. However, the resulting figures indicate that the majority may not be including such taxes into their calculations.

[43]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.

MC_PCWGDP_{yr}	=	GDP conversion from current year dollars to $87 [from the Macroeconomic Model]
n	=	network (PK or OP)
s	=	end-use sector index (s=4 for transportation sector)
r	=	region index
EHISYR	=	index defining last year that historical data are available
yr	=	current forecast year

Distributor tariffs for CNG consumed by personal vehicles is derived as a function of the full cost of delivering CNG to these alternate fuel vehicles. Thus, the distributor tariff is set equal to the sum of the core industrial distributor tariff, the cost of dispensing CNG at a high volume service station, and State and Federal motor vehicle fuel tax applied to CNG (converted to 1987 dollars),[44] as shown in the following equation:

$$DTAR\_TRPV\_SF_{n,r} = DTAR\_SF_{n,s=3,r} + RETAIL\_COST + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_{yr}} \tag{72}$$

where,

$DTAR\_TRPV\_SF_{n,r}$	=	distributor tariff for the personal vehicle transportation sector (87$/Mcf)
$DTAR\_SF_{n,s,r}$	=	distributor tariff for the core industrial sector, s=3 (87$/Mcf)
RETAIL_COST	=	cost of dispensing CNG [Appendix E, (87$/Mcf)]
$STAX_r$	=	State motor vehicle fuel tax for CNG [Appendix E, (current yr $/Mcf)]
FTAX	=	Federal motor vehicle fuel tax for CNG [Appendix E, (current yr $/Mcf)]
MC_PCWGDP_{yr}	=	conversion from current year to $87
n	=	network (PK or OP)
s	=	end-use sector index (s=3 for the industrial sector)
r	=	region index
yr	=	current forecast year

Noncore Distributor Tariffs

The specific methodology used for setting noncore seasonal distributor tariffs for both the industrial and electric generator sectors is described below. Both sectors base their forecast-year tariffs on historical distributor tariffs. Historical distributor tariffs are calculated on a seasonal basis as the historical end-use price minus a seasonal citygate price. Historical seasonal citygate prices are set exogenously, and read into the model [Appendix E, HCGPR]. Historical seasonal end-use prices for the non-core industrial and electric generator sectors are set in the model, as footnoted above.

Industrial Sector

Seasonal distributor tariffs for noncore industrial customers are assumed to remain constant over the forecast horizon. Currently, these noncore industrial distributor tariffs are set equal to the corresponding distributor tariffs established for the last historical year. Thus, the equation is:

$$DTAR\_SI_{n,s=3,r} = HPGIINGR_{n,r,EHISYR} - HCGPR_{n,r,EHISYR} \tag{73}$$

where,

$DTAR\_SI_{n,s,r}$	=	seasonal distributor tariff for the noncore industrial sector (s=3) in region r (87$/Mcf)
$HPGIINGR_{n,r,EHISYR}$	=	seasonal historical end-use price for the noncore industrial sector in region r [Appendix F, Table F5 (87$/Mcf)]

[44]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.

$HCGPR_{n,r,EHISYR}$ = seasonal historical citygate price in region r during the last historical year EHISYR [Appendix E, (87$/Mcf)]
n = network (PK or OP)
s = end-use sector index (s=3 for industrial sector)
r = region index
EHISYR = index defining last year that historical data are available.

Electric Generator Sector

Seasonal distributor tariffs for the noncore electric generator sector are defined for each NGTDM/EMM subregion using corresponding historical distributor tariffs, which are then kept constant over the forecast years or slowly increased if they are below a lower limit (as is done with the core electric generator sector). First, seasonal distributor tariffs are initially set as a simple average of the last three years for which historical data are available. Then each forecast year, distributor tariffs from the previous year are checked to see if they are less than a lower threshold of -1.00 (87$/mcf). If yes, the corresponding tariff is set to 95% of the previous year's level. The corresponding equations are:

Historical,

$$HUDTAR\_SI_{n,j,hyr} = HPGIELGR_{n,j,hyr} - HCGPR_{n,r,hyr} \tag{74}$$

Average,

$$UDTAR\_SI_{n,j} = \frac{(HUDTAR\_SI_{n,j,EHISYR} + HUDTAR\_SI_{n,j,EHISYR-1} + HUDTAR\_SI_{n,j,EHISYR-2})}{3} \tag{75}$$

If $UDTAR\_SI_{n,j} \leq -1.0$, then

$$UDTAR\_SI_{n,j} = UDTAR\_SIPREV_{n,j} * 0.95 \tag{76}$$

where,

$UDTAR\_SI_{n,j}$ = seasonal distributor tariff for the noncore electric generation sector in subregion j in the current forecast year (87$/Mcf)
$UDTAR\_SIPREV_{n,j}$ = seasonal distributor tariff for the noncore electric generation sector in subregion j in the previous forecast year (87$/Mcf)
$HUDTAR\_SI_{n,j,EHISYR}$ = historical seasonal distributor tariff for the noncore electric generation sector in subregion j (87$/Mcf)
$HPGIELGR_{n,j,hyr}$ = seasonal historical end-use price for the noncore electric generation sector in subregion j (87$/Mcf)
$HCGPR_{n,r,hyr}$ = seasonal historical citygate price in region r [Appendix E, (87$/Mcf)]
n = network (PK or OP)
r = region index
j = NGTDM/EMM subregion index
EHISYR = index defining last year that historical data are available
hyr = index for historical years

6. Pipeline Tariff Module Solution Methodology

This chapter discusses the solution methodology for the *Annual Energy Outlook 2000* version of the Pipeline Tariff Module (PTM) of the Natural Gas Transmission and Distribution Model (NGTDM), which is a simplified module compared with its predecessors.[45] The main distinctions between the new and previous modules are the following:

-The new module computes and forecasts the cost-of-service (also referred to in this document as revenue requirements) components directly for the NGTDM arcs and nodes using a 1988-1996 pipeline financial database as input, while the previous modules first determined the cost-of-service components by pipeline company based on the 1990 pipeline financial database and then aggregated costs to the network arcs and nodes. The elimination of the company level calculations greatly simplifies model complexity, as well as maintenance and data update requirements. The methodology to allocate individual line item costs to fixed and variable components and then to reservation and usage costs is still the same.

- The new module has four main cost-of-service components for a network arc: total return on rate base, depreciation, taxes, and total operating and maintenance expense. The previous modules had six cost-of-service components for each company: total return on rate base, depreciation, taxes, total administrative and general expense, total customer expense, and total operating and maintenance expense. The new module reduces the number to four by including total administrative and general expense and total customer expense in total operating and maintenance expense.

- The new module does not directly incorporate the effects of capacity release on firm pipeline tariffs. The previous modules incorporated these effects through revenue credits. Because the credits represent less than 2 percent of the cost-of-service, which translates to less than a penny per thousand cubic feet, the revenue credit is assumed to be embedded in the cost-of-service in the new module.

- The new module forecasts the cost-of-service components for the combined existing and new transmission capacity directly, while the previous modules determined the cost-of-service components separately for existing and generic new pipelines, and then aggregated them to determine the combined existing and new capacity.

In this module, the rates developed are used as actual costs for transportation and storage services. The PTM tariff calculation is divided into two phases: a historical year initialization phase and a forecast year update phase. These two phases include the following steps: (1) determine the various components, in dollars, of the total cost-of-service, (2) classify these components as fixed and variable costs based on the rate design, (3) allocate these fixed and variable costs to rate components (reservation and usage costs) based on the rate design, and (4) compute rates for services during peak and offpeak time periods. For the historical year phase, the cost of service is developed from the financial database, while for the forecast year update phase the costs are estimated using a set of econometric equations and accounting algorithms. These steps are used to determine transportation rates for the Interstate Transmission Module (ITM). A placeholder is implemented to assign storage tariffs for the NGTDM regions until the necessary data are available to incorporate storage tariff calculations in the PTM (expected for *AEO 2001*).

A general overview of the methodology for deriving rates is presented in the following box. The PTM system diagram is presented in Figure 6-1.

[45]Energy Information Administration, Office of Integrated Analysis and Forecasting, Module Documentation, *Natural Gas Transmission and Distribution Model of the National Energy Modeling System*, DOE/EIA-M062/1(99) (Washington, DC, February 1999)

PTM Methodology for Deriving Rates

- Process the 1988-1996 financial database for 28 major interstate natural gas pipelines off-line by a mainframe SAS code to create pipeline financial database by pipeline, arc, and historical year, to be used as input data for the PTM.

For Each Arc

- Derive the total cost of service (TCOS)

  - Historical years
    - Read total cost of service (TCOS) items by pipeline, arc, and historical year (1988-1996) from the above database
    - Aggregate pipeline TCOS items to network arcs
    - Adjust TCOS components to reflect all U.S. pipelines based on an annual *Pipeline Economics* Report in 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

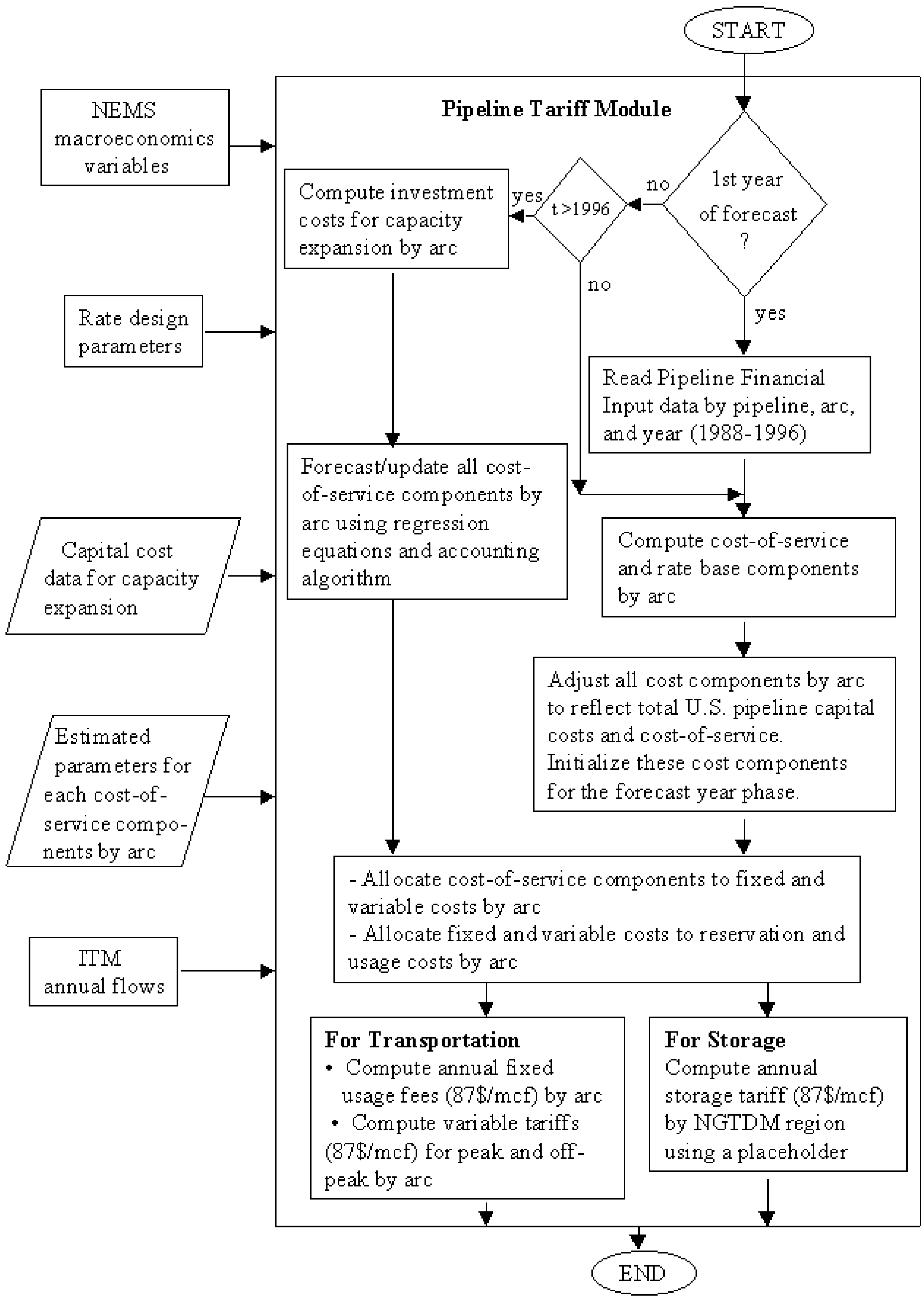
- Allocate costs to rate components (reservation and usage costs) based on rate design

- Compute rates for services for peak and offpeak time periods

For Each Node

- Implement a placeholder to assign storage tariffs

Figure 6-1. Pipeline Tariff Module System Diagram



Historical Year Initialization Phase

The purpose of the historical year initialization phase is to provide an initial set of NGTDM network-level transportation revenue requirements and tariffs. The historical year information is developed from existing pipeline company transportation data. The historical year initialization process draws heavily on three databases: (1) the pipeline financial database (1988-1996) of 28 major interstate natural gas pipelines developed by Foster Associates, (2) the '*competitive profile of natural gas services*' database developed by Foster Associates, and (3) the pipeline capacity database developed by the Office of Oil and Gas, EIA. The first database represents the existing physical U.S. interstate pipeline and storage system, which includes production processing , gathering, transmission, storage, and others. 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, which contains detailed data on gross plant in service and accumulated depreciation for the individual plants (production processing and gathering plants, gas storage plants, gas transmission plants, and other plants), is processed offline to compute the factors by pipeline and year that are used to single out financial cost data for transmission plants from the 'total plants' data. The third database contains the transmission capacity data by pipeline company NGTDM regions, by year (1990-1996). This database is used to compute the capacity shares at the arc level for each pipeline company across the network. These capacity shares are used as proxies for cost-of-service shares for each pipeline company by arc. These shares are applied to the pipelines' cost-of-service components in order to disaggregate the costs items by pipeline, arc, and year. These three databases are pre-processed offline by a SAS code on the EIA mainframe to generate the pipeline transmission financial database by pipeline company, arc, and historical year (1988-1996), which is used as input into the PTM.

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. These procedures are discussed in detail below. Rates are calculated in nominal dollars and then converted to real dollars for use in the ITM.

Computation and Initialization of Cost-of-Service Components

In the historical year initialization phase of the PTM, rates are computed using the following four-step process: (Step 1) derivation and initialization of the total cost-of-service components, (Step 2) classifying cost-of-service components as fixed and variable costs, and (Step 3) allocation of fixed and variable costs to rate components (reservation and usage costs) based on rate design. The last step (Step 4) is the computation of rates at the arc level for transportation and the node level for storage (using a placeholder).

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. The total cost of service is computed as follows:

$$TCOS_{a,t} = TRRB_{a,t} + TNOE_{a,t} \qquad (77)$$

where,

TCOS = total cost-of-service (dollars[46])
TRRB = total return on rate base (dollars)
TNOE = total normal operating expenses (dollars)
a = arc

[46]All costs discussed in this chapter are in nominal dollars, unless explicitly stated otherwise.

t = historical year

Derivations of return on rate base and total normal operating expenses are presented in the following subsections.

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 on 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:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \tag{78}$$

where,

TRRB = total return on rate base [before taxes, (dollars)]
WAROR = weighted-average before-tax return on capital (fraction)
APRB = adjusted pipeline rate base (dollars)
a = arc
t = historical year

In addition, the return on rate base is broken out into the three components as shown below.

$$PFEN_{a,t} = \sum_p [(PFES_{a,p,t}/TOTCAP_{a,p,t}) * PFER_{a,p,t} * APRB_{a,p,t}] \tag{79}$$

$$CMEN_{a,t} = \sum_p [(CMES_{a,p,t}/TOTCAP_{a,p,t}) * CMER_{a,p,t} * APRB_{a,p,t}] \tag{80}$$

$$LTDN_{a,t} = \sum_p [(LTDS_{a,p,t}/TOTCAP_{a,p,t}) * LTDR_{a,p,t} * APRB_{a,p,t}] \tag{81}$$

such that,

$$TRRB_{a,t} = (PFEN_{a,t} + CMEN_{a,t} + LTDN_{a,t}) \tag{82}$$

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-in as D_PFER]
APRB = adjusted pipeline rate base (dollars) [read-in 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-in 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-in 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 79 to 81 represent the capital structure ratios for each pipeline company on a network arc. These fractions are computed offline and read-in along with the rates of return and the adjusted rate base as input into the PTM. Thus, the total returns on preferred stock, common equity, and long-term debt at the arc level defined in above equations are computed immediately after all the input variables' values are read-in. The capital structure ratios (read-in) described above are as follows:

$$GPFESTR_{a,p,t} = PFES_{a,p,t} / TOTCAP_{a,p,t} \tag{83}$$

$$GCMESTR_{a,p,t} = CMES_{a,p,t} / TOTCAP_{a,p,t} \tag{84}$$

$$GLTDSTR_{a,p,t} = LTDS_{a,p,t} \; / \; TOTCAP_{a,p,t} \qquad (85)$$

where,

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

$$TOTCAP_{a,p,t} = APRB_{a,p,t} \qquad (86)$$

where,

TOTCAP	=	total capitalization (dollars)
APRB	=	adjusted rate base (dollars)
a	=	arc
p	=	pipeline company
t	=	historical year

Substituting the estimated capital $TOTCAP_{a,t}$ for the adjusted rate base $APRB_{a,t}$ in equations 83 to 85, 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:

$$\begin{aligned} PFES_{a,p,t} &= GPFESTR_{a,p,t} * APRB_{a,p,t} \\ CMES_{a,p,t} &= GCMESTR_{a,p,t} * APRB_{a,p,t} \\ LTDS_{a,p,t} &= GLTDSTR_{a,p,t} * APRB_{a,p,t} \\ GPFESTR_{a,p,t} &+ GCMESTR_{a,p,t} + GLTDSTR_{a,p,t} = 1.0 \end{aligned} \qquad (87)$$

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:

$$WAROR_{a,t} = \sum_{p} [(PFES_{a,p,t} * PFER_{a,p,t} + CMES_{a,p,t} * CMER_{a,p,t} + LTDS_{a,p,t} * LTDR_{a,p,t})] \;/\; APRB_{a,t} \qquad (88)$$

$$APRB_{a,t} = PFES_{a,t} + CMES_{a,t} + LTDS_{a,t} \qquad (89)$$

where,

WAROR = weighted-average before-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 PTM. The computation is as follows:

$$APRB_{a,p,t} = NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t} \qquad (90)$$

where,

APRB = adjusted rate base (dollars)
NPIS = net capital cost of plant in service (dollars) [read-in as D_NPIS]
CWC = total cash working capital (dollars) [read-in as D_CWC]
ADIT = accumulated deferred income taxes (dollars) [read-in 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 PTM. The computation is as follows:

$$NPIS_{a,p,t} = GPIS_{a,p,t} - ADDA_{a,p,t} \qquad (91)$$

where,

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

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

$$\begin{aligned} APRB_{a,,t} = \sum_{p} APRB_{a,p,t} &= \sum_{p} (NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t}) \\ &= (NPIS_{a,t} + CWC_{a,t} - ADIT_{a,t}) \end{aligned} \qquad (92)$$

with,

$$NPIS_{a,,t} = \sum_p (GPIS_{a,p,t} - ADDA_{a,p,t}) \\ = (GPIS_{a,t} - ADDA_{a,t}) \tag{93}$$

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 PTM, taxes are disaggregated further into Federal, State, and other taxes and deferred income taxes. The equation for total normal operating expenses at the arc level is given as follows:

$$TNOE_{a,t} = \sum_p (DDA_{a,p,t} + TOTAX_{a,p,t} + TOM_{a,p,t}) \tag{94}$$

where,

TNOE	=	total normal operating expenses (dollars)
DDA	=	depreciation, depletion, and amortization costs (dollars) [read-in as D_DDA]
TOTAX	=	total Federal and State income tax liability (dollars)
TOM	=	total operating and maintenance expense (dollars) [read-in as D_TOM]
p	=	pipeline
a	=	arc
t	=	historical year

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

$$DDA_{a,t} = \sum_p DDA_{a,p,t} \tag{95}$$

$$TOM_{a,t} = \sum_p TOM_{a,p,t} \tag{96}$$

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:

$$TOTAX_{a,t} = \sum_p (FSIT_{a,p,t} + OTTAX_{a,p,t} + DIT_{a,p,t}) \tag{97}$$

$$FSIT_{a,t} = \sum_p FSIT_{a,p,t} = \sum_p (FIT_{a,p,t} + SIT_{a,p,t}) \tag{98}$$

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-in as D_OTTAX]
DIT	=	deferred income taxes (dollars) [read-in 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:

$$ATP_{a,t} = \sum_{p} (PFER_{a,p,t} * PFES_{a,p,t} + CMER_{a,p,t} * CMES_{a,p,t}) \tag{99}$$

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

$$FIT_{a,t} = \frac{FRATE * ATP_{a,t}}{(1. - FRATE)} \tag{100}$$

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:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{101}$$

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:

$$TOTAX_{a,t} = (FSIT_{a,t} + OTTAX_{a,t} + DIT_{a,t}) \tag{102}$$

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:

$$OTTAX_{a,t} = \sum_{p} OTTAX_{a,p,t} \tag{103}$$

$$DIT_{a,t} = \sum_{p} DIT_{a,p,t} \tag{104}$$

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[47], there were more than 110 natural gas pipelines operating in the United States in 1998. 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 natural gas pipelines in the U.S. declines from 135 percent of total annual gross plant in service for the 28 major interstate pipelines in 1988 to about 120 percent in 1996, while the total annual operating revenues for all the natural gas pipelines in the U.S. fall from 270 percent of total annual operating revenues for the 28 major natural gas pipelines in 1988 to 150 percent in 1996.

All the cost-of-service and rate base components at the arc level computed in the above sections are scaled up as follows:

For the capital costs and adjusted rate base components,

$$\begin{aligned}
GPIS_{a,t} &= GPIS_{a,t} * HFAC_GPIS_{t} \\
ADDA_{a,t} &= ADDA_{a,t} * HFAC_GPIS_{t} \\
NPIS_{a,t} &= NPIS_{a,t} * HFAC_GPIS_{t} \\
CWC_{a,t} &= CWC_{a,t} * HFAC_GPIS_{t} \\
ADIT_{a,t} &= ADIT_{a,t} * HFAC_GPIS_{t} \\
APRB_{a,t} &= APRB_{a,t} * HFAC_GPIS_{t}
\end{aligned} \tag{105}$$

For the cost-of-service components,

$$\begin{aligned}
PFEN_{a,t} &= PFEN_{a,t} * HFAC_REV_{t} \\
CMEN_{a,t} &= CMEN_{a,t} * HFAC_REV_{t} \\
LTDN_{a,t} &= LTDN_{a,t} * HFAC_REV_{t} \\
DDA_{a,t} &= DDA_{a,t} * HFAC_REV_{t} \\
FSIT_{a,t} &= FSIT_{a,t} * HFAC_REV_{t} \\
OTTAX_{a,t} &= OTTAX_{a,t} * HFAC_REV_{t} \\
DIT_{a,t} &= DIT_{a,t} * HFAC_REV_{t} \\
TOM_{a,t} &= TOM_{a,t} * HFAC_REV_{t}
\end{aligned} \tag{106}$$

where,

GPIS	=	original capital cost of plant in service (dollars)
HFAC_GPIS	=	adjustment factor for capital costs to total U.S. [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]

[47]*Pipeline Economics*, Oil and Gas Journal, 1991, 1993, 1994, 1995, 1997, 1999

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

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 1997.

Step 2: Classification of Cost-of-Service Line Items as Fixed and Variable Costs

The PTM 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:

$$R_{i,f} = ALL_f * R_i/100 \tag{107}$$

$$R_{i,v} = ALL_v * R_i/100 \tag{108}$$

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
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:

$$FC_a = \sum_i R_{i,f} \tag{109}$$

$$VC_a = \sum_i R_{i,v} \tag{110}$$

where,

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

Step 3: Allocation of Fixed and Variable Costs to Rate Components

Allocation of fixed and variable costs to rate components is conducted only for transportation services because storage service is modeled in a more simplified manner using a one-part rate.

The rate design to be used within the PTM is specified by input parameters, which can be modified by the user to reflect changes in rate design over time. The PTM 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

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

Cost of Service Line Item	Total	Cost Allocation Factors (percent)		Cost Component	
		Fixed	Variable	Fixed	Variable
Total Return					
Preferred Stock	1,000	100	0	1,000	0
Common Stock	30,000	100	0	30,000	0
Long-Term Debt	29,000	100	0	29,000	0
Normal Operating Expenses					
Depreciation	30,000	100	0	30,000	0
Taxes					
Federal Tax	25,000	100	0	25,000	0
State Tax	5,000	100	0	5,000	0
Other Tax	1,000	100	0	1,000	0
Deferred Income Taxes	1,000	100	0	1,000	0
Total Operations & Maintenance	105,000	90	10	94,500	10,500
Total Cost-of-Service	227,000			216,500	10,500

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, then more costs are recovered based on throughput. This results in high load factor customers paying a larger share of system costs. Allocating a larger share of fixed costs to reservation fees, however, leads to low load factor customers bearing a larger share of system costs.

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 PTM 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 volumetric-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 following equations:

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.

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

Cost of Service Line Item	Total	Allocation Factors (percent) Reservation	Allocation Factors (percent) Usage	Cost Assigned to Rate Component Reservation	Cost Assigned to Rate Component 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	94,500	100	0	94,500	0
Total Cost-of-Service	216,500			155,500	61,000

Table 6-3b. Illustration of Allocation of Variable Costs to Rate Components

		Allocation Factors (percent)		Cost Assigned to Rate Component	
Cost of Service Line Item	**Total**	**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	10,500	0	100	0	10,500
Total Cost-of-Service	10,500			0	10,500

The classification of transportation line item costs $R_{i,f}$ and $R_{i,v}$ to reservation and usage cost is determined as follows:

$$R_{i,f,r} = ALL_{f,r} * R_{i,f}/100 \tag{111}$$

$$R_{i,f,u} = ALL_{f,u} * R_{i,f}/100 \tag{112}$$

$$R_{i,v,r} = ALL_{v,r} * R_{i,v}/100 \tag{113}$$

$$R_{i,v,u} = ALL_{v,u} * R_{i,v}/100 \tag{114}$$

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

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.

$$RCOST_a = \sum_i (R_{i,f,r} + R_{i,v,r}) \tag{115}$$

$$UCOST_a = \sum_i (R_{i,f,u} + R_{i,v,u}) \tag{116}$$

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*. The development of both rates is described below.

Variable Tariff Curves

Variable tariffs are proportional to reservation charges and are broken up into peak and offpeak 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 PTM code, these variable tariff curves are defined by FUNCTION (NGPIPE_VARTAR) which is used by the ITM to compute the variable peak and offpeak tariffs by arc and by forecast year. The PTM defines the tariff curves as a function of a base point [price and quantity (PNOD, QNOD)] using *process-specific* parameters, peak or offpeak flow, and a price elasticity. This functional form is presented below:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA\_PIPE} \tag{117}$$

such that,

For peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR\_YR}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{118}$$

$$\begin{aligned} QNOD_{a,t} = {} & PTCURPCAP_{a,t} * PKSHR\_YR * PTPKUTZ_{a,t} * ADJ\_PIP + \\ & PTNETFLOW_{a,t} * (1.0 - ADJ\_PIP) \end{aligned} \tag{119}$$

For offpeak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{120}$$

$$\begin{aligned} QNOD_{a,t} = {} & PTCURPCAP_{a,t} * (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * ADJ\_PIP + \\ & PTNETFLOW_{a,t} * (1.0 - ADJ\_PIP) \end{aligned} \tag{121}$$

where,

NGPIPE_VARTAR = PTM 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
RCOST = reservation cost-of-service (dollars)
PTPKUTZ = peak pipeline utilization (fraction)
PTOPUTZ = offpeak pipeline utilization (fraction)
PTCURPCAP = current pipeline capacity (bcf)
PTNETFLOW = natural gas flow (throughput, bcf)
ADJ_PIP = pipeline tariff curve adjustment factor (fraction)
PKSHR_YR = portion of the year represented by the peak season (fraction)
MC_PCWGDP = implicit 1987 GDP price deflator (from the Macroeconomic Activity Model)
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 offpeak time periods, and annual arc capacity. These fees are computed as the average fees over each historical year, as follows:

$$FIXTAR_{a,t} = UCOST_{a,t} \,/\, [(PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_{t}] \quad (122)$$

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 = offpeak pipeline utilization (fraction)
MC_PCWGDP = implicit 1987 GDP price deflator (from the Macroeconomic Activity Model)
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) annual wellhead price.

Computation of Storage Rates

Pending the availability of the financial storage data, which will be ready for the *Annual Energy Outlook 2001*, a placeholder FUNCTION (NGSTR_VARTAR) is implemented in the PTM routine to assign an annual storage tariff by NGTDM region. This placeholder is defined as a function of a base point [price and quantity (PNOD, QNOD)] using process-specific parameters, storage flow, and a price elasticity, as follows:

$$NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} \,/\, QNOD_{r,t})^{ALPHA\_STR} \quad (123)$$

such that,

$$PNOD_{r,t} = \frac{PNOD\_VALUE_{r} * CFNGC}{MC\_PCWGDP_{1998}} \quad (124)$$

$$QNOD_{r,t} = ADJ\_STR * PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \quad (125)$$

where,

NGSTR_VARTAR =	PTM 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
PNOD_VALUE =	1998 regional storage tariff (1998$/Dth) [set to PNOD in NGSTR_VARTAR FUNCTION]
CFNGC =	heat content for natural gas dry production (Btu/cf)
PTSTUTZ =	storage utilization (fraction)
PTCURPSTR =	current storage capacity (bcf)
ADJ_STR =	storage tariff curve adjustment factor (fraction)
MC_PCWGDP =	implicit 1987 GDP price deflator (from the Macroeconomic Activity Model)
r =	NGTDM region
t =	historical year

Forecast Year Update Phase

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

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

Investment Costs for Generic Pipeline Companies

The PTM projects the capital costs to expand pipeline capacity at the arc level, as opposed to determining costs of expansion for individual companies. The PTM creates arc-specific generic pipeline companies to the cost of capacity expansion by arc. Thus, the PTM tracks costs attributable to capacity added during the forecast period separately from the costs attributable to facilities in service in the historical years. The PTM uses an exogenous database to obtain the capital costs which correspond to the level of capacity expansion forecast by the Interstate Transmission Module (ITM) in the forecast year.[48] The exogenous database contains arc-specific capital costs per unit of expansion compiled by Foster Associates in 1998 dollars-day per mcf-mile. These costs are provided by type of expansion (compression, looping, and new pipeline) within and between NGTDM regions. These costs are assumed to remain fixed from 1998 throughout the forecast period (these capital costs per unit of expansion are not adjusted for inflation). Along with these unit capital costs, the mileage and 1998 average tariffs are also provided by and between NGTDM regions.

Given the unit capital costs by type of expansion by arc and by NGDTM region, the PTM uses a linear interpolation methodology to compute the unit capital cost ($CCOST_{a,t}$) as a function of an expansion factor ($X_{a,t}$) relative to the 1990 capacity. This expansion factor represents an increase in capacity since 1990. Whenever the ITM forecasts capacity additions in year t on an arc, the increased capacity is computed for that arc from 1990 and the unit capital cost is computed using the above methodology. Hence, the capital cost to expand capacity on a network arc can be estimated from any amount of capacity additions in year t provided by the ITM and the associated unit capital cost. This capital cost represents the investment cost for generic pipeline companies associated with that arc.

[48]Capital requirements for new storage capacity expansion are determined from the incremental base gas capacity expansion and the wellhead price in the forecast year which is used as cushion gas to maintain adequate pressures.

The unit capital cost ($CCOST_{a,t}$) is computed by the following equations:

$$
\begin{aligned}
CCOST_{a,t} &= CC\_COMPR_a && \text{if } (X_{a,t} \le EXP\_A) \\
&= CC\_COMPR_a + CC\_SLOPE1_a * (X_{a,t} - EXP\_A) && \text{if } (EXP\_A < X_{a,t} \le EXP\_B) \\
&= CC\_LOOPI_a + CC\_SLOPE2_a * (X_{a,} - EXP\_B) && \text{if } (EXP\_B < X_{a,t} \le EXP\_C) \\
&= CC\_NEWPI_a && \text{if } (X_{a,t} > EXP\_C)
\end{aligned}
\tag{126}
$$

where,

$$X_{a,t} = \frac{PTCURPCAP_{a,t}}{PTCURPCAP_{a,1990}} - 1.0 \tag{127}$$

and,

CCOST	=	capital cost per unit of expansion (dollars-day per mcf-mile)
X	=	expansion factor relative to 1990 capacity by arc (set to $EXPFAC90_a$ variable)
PTCURPCAP	=	current pipeline capacity at the arc level (bcf)
CC_COMPR	=	unit capital cost for compression [Appendix E]
CC_SLOPE1	=	slope for unit capital cost from compression to looping
EXP_A	=	base expansion factor for compression (set to 0.50 across network arcs –Appendix E)
CC_LOOPI	=	unit capital cost for looping [Appendix E]
CC_SLOPE2	=	slope for unit capital cost from looping to new pipeline
EXP_B	=	base expansion factor for looping (set to 2.0 across network arcs –Appendix E)
CC_NEWPI	=	unit capital cost for new pipeline [Appendix E]
EXP_C	=	base expansion factor for new pipeline (set to 3.0 across network arcs –Appendix E)
a	=	arc
t	=	forecast year

A capital cost curve depicting how the capital cost per unit of expansion ($CCOST_{a,t}$) on a network arc is computed from the above equation is illustrated in Figure 6-2.

The new capacity expansion expenditures allowed in the rate base within a forecast year are derived from the above unit capital cost ($CCOST_{a,t}$) and the amount of incremental capacity additions determined by the ITM for each arc, as follows :

$$NCAE_{a,t} = CCOST_{a,t} * (CAPADD_{a,t} / 365) * MILES_a * 1{,}000{,}000 \tag{128}$$

where,

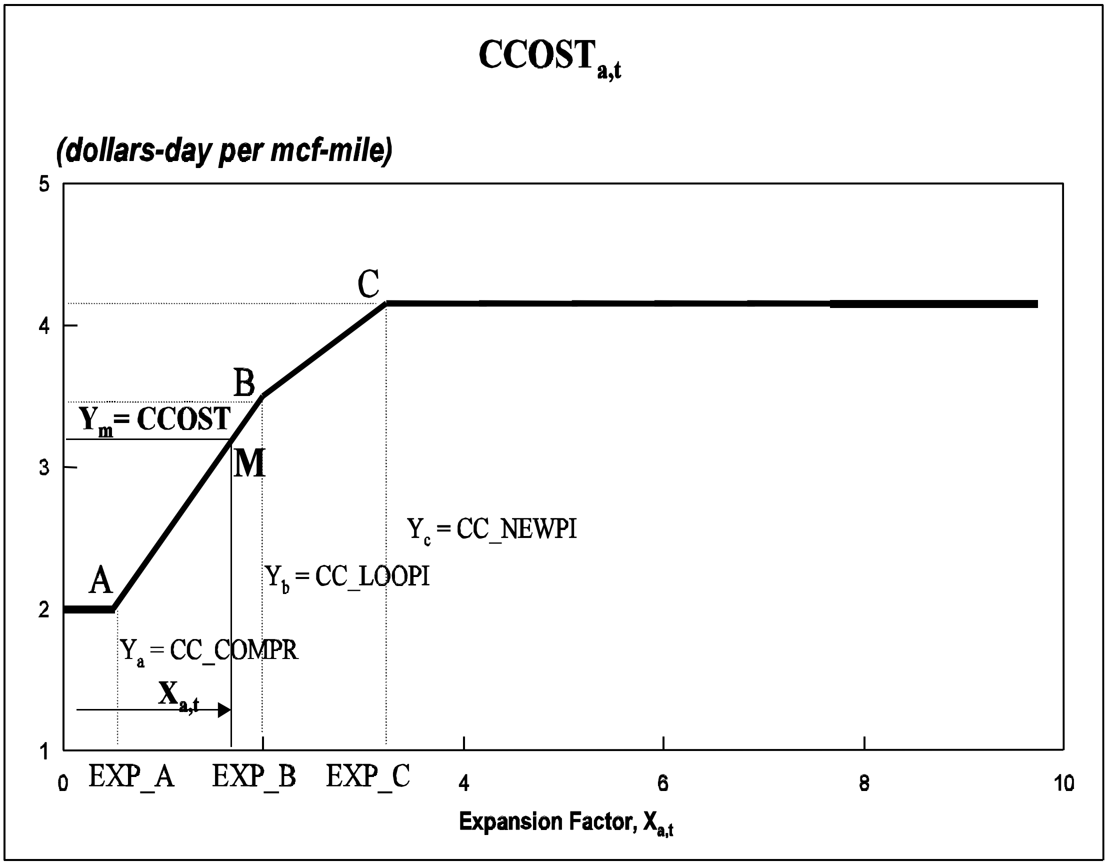
NCAE	=	capital cost to expand capacity on a network arc (dollars)
CCOST	=	capital cost per unit of expansion (dollars-day per mcf-mile)
CAPADD	=	capacity additions for an arc (bcf/yr)
MILES	=	length of transportation arc in miles [Appendix E]
a	=	arc
t	=	forecast year

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 will be used in the computation of updated cost-of-service components for the existing and new capacity for an arc.

Forecasting Cost-of-Service [49]

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

Figure 6-2. A Representative Unit Capital Cost Curve of Capacity Expansion on a Network Arc



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 which, 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 PTM (e.g., annual throughput, etc.) which 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.
- The projection of components of the revenue requirements.
- The computation of variable and fixed rates for peak and offpeak 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 in 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.

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

$$APRB_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} + CWC_{a,t} - ADIT_{a,t} \tag{129}$$

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:

$$GPIS_{a,t} = GPIS\_E_{a,t} + GPIS\_N_{a,t} \tag{130}$$

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 (1996)
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 (1996). 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 1997 to year t and is determined by the following equation:

$$GPIS\_N_{a,t} = \sum_{s=1997}^{t} NCAE_{a,s} \tag{131}$$

where,

GPIS_N = gross plant in service for new capacity expansion in dollars
NCAE = new capacity expansion expenditures occurring in year s after 1996 (in dollars)
s = the year new expansion occurred
a = arc
t = forecast year

The new capacity expansion expenditures allowed in the rate base within a forecast year are derived for each arc from the amount of incremental capacity additions determined by the ITM:

$$NCAE_{a,t} = CCOST_{a,t} * (CAPADD_{a,t} / 365) * MILES_a * 1{,}000{,}000 \tag{132}$$

where,

NCAE = total capital cost to expand capacity at a network arc (dollars)
CCOST = capital cost per unit of expansion (dollars-day per mcf-mile)
CAPADD = capacity additions for an arc (bcf/yr)
MILES = length of transportation arc in miles [Appendix E]
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.

$$NPIS_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} \tag{133}$$

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:

$$ADDA_{a,t} = ADDA\_E_{a,t} + ADDA\_N_{a,t} \tag{134}$$

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

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 (1996)
II. Capacity expansion costs for new capacity	Accounting algorithm
b. Accumulated Depreciation, Depletion & Amortization	Existing Capacity: empirically estimated New Capacity: accounting algorithm
c. Cash and other working capital	User defined option for the combined existing and new capacity
d. Accumulated deferred income taxes	Empirically estimated for the combined existing and new capacity
f. Depreciation, depletion, and amortization	Existing Capacity: empirically estimated New Capacity: accounting algorithm
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

Using the relationship of existing and new plants in service from equation 130 and that of accumulated depreciation, depletion, and amortization for existing and new capacity from equation 134, total net plant in service $NPIS_{a,t}$ in equation 133 can be developed further and is equal to the sum of net plants in service for existing pipelines and new capacity expansions:

$$NPIS_{a,t} = NPIS\_E_{a,t} + NPIS\_N_{a,t} \tag{135}$$

$$NPIS\_E_{a,t} = GPIS\_E_{a,t} - ADDA\_E_{a,t-1} \tag{136}$$

$$NPIS\_N_{a,t} = GPIS\_N_{a,t} - ADDA\_N_{a,t-1} \tag{137}$$

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 (1996)
ADDA_E = accumulated depreciation, depletion, and amortization for existing capacity in dollars
GPIS_N = gross plant in service for new capacity in dollars
ADDA_N = accumulated depreciation, depletion, and amortization 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.

$$ADDA_{a,t} = ADDA_{a,t-1} + DDA_{a,t} \tag{138}$$

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.

$$DDA_{a,t} = DDA\_E_{a,t} + DDA\_N_{a,t} \tag{139}$$

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:

$$DDA\_E_{a,t} = DDA\_C_{a} + DDA\_NPIS * NPIS\_E_{a,t-1} \tag{140}$$

where,

DDA_E = annual depreciation, depletion, and amortization costs for existing capacity in dollars
DDA_C = constant term estimated by arc based on an empirical study (Appendix F, Table F3)
DDA_NPIS = coefficient for net plant in service for existing capacity (Appendix F, Table F3)
NPIS_E = net plant in service for existing capacity (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:

$$DDA\_N_{a,t} = GPIS\_N_{a,t} \; / \; 30 \qquad (141)$$

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 131]
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 on an arc is set to a declining percentage of the transmission portion (this portion is assumed to be 20 percent) of the total plant's 1990 total cash working capital for the arc. The percentage is assumed to decline over the forecast period based on a user-defined discount rate. Total plant includes production processing, gathering, transmission, storage, and all other facilities. Thus, total cash working capital for the existing and new capacity can be determined by:

$$CWC_{a,t} = 0.20 \, * \, TOTCWC90_{a} \, * \, (1 - CWC\_DISC)^{curiyr} \qquad (142)$$

where,

CWC = total pipeline transmission cash working capital for existing and new capacity in dollars
TOTCWC90 = total plant cash working capital in 1990 in dollars (D_CWC, Appendix E)
CWC_DISC = discount rate (set to 10 percent across the network)
curiyr = t-1989
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:

$$ADIT_{a,t} = ADIT\_C_{a} + ADIT\_ADIT \, * \, ADIT_{a,t-1} + ADIT\_NEWCAP \, * \, NEWCAP_{a,t} \qquad (143)$$

where,

ADIT = accumulated deferred income taxes in dollars
ADIT_C = constant term by arc estimated based on empirical study (Appendix F, Table F3)
ADIT_ADIT = coefficient estimated based on empirical study (Appendix F, Table F3)
ADIT_NEWCAP = coefficient estimated based on empirical study (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)
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 before-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 Model as a percent) in year t adjusted by a historical average deviation constant , as follows:

$$PFER_{a,t} = MC\_RMPUAANS_t \ / \ 100.0 + ADJ\_PFER_a \tag{144}$$

$$CMER_{a,t} = MC\_RMPUAANS_t \ / \ 100.0 + ADJ\_CMER_a \tag{145}$$

$$LTDR_{a,t} = MC\_RMPUAANS_t \ / \ 100.0 + ADJ\_LTDR_a \tag{146}$$

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 Model (percentage)
ADJ_PFER_a = historical average deviation constant (fraction) for preferred stock rate of return [D_PFER/100., Appendix E]
ADJ_CMER_a = historical average deviation constant (fraction) for common equity rate of return [D_CMER/100., Appendix E]
ADJ_LTDR_a = historical average deviation constant (fraction) for long term debt rate [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:

$$WAROR_{a,t} = [(PFER_{a,t} * PFES_{a,t}) + (CMER_{a,t} * CMES_{a,t}) + (LTDR_{a,t} * LTDS_{a,t})] \ / \ TOTCAP_{a,t} \tag{147}$$

$$TOTCAP_{a,t} = (PFES_{a,t} + CMES_{a,t} + LTDS_{a,t}) \tag{148}$$

where,

WAROR = weighted-average before-tax rate of return on capital (fraction)
PFER = coupon rate 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:

$$WAROR_{a,t} = [(PFER_{a,t} * GPFESTR_{a,t}) + (CMER_{a,t} * GCMESTR_{a,t}) + (LTDR_{a,t} * GLTDSTR_{a,t})] \tag{149}$$

where,

$$GPFESTR_{a,t} = PFES_{a,t} \ / \ TOTCAP_{a,t} \tag{150}$$

$$GCMESTR_{a,t} = CMES_{a,t} \ / \ TOTCAP_{a,t} \tag{151}$$

$$GLTDSTR_{a,t} = LTDS_{a,t} \ / \ TOTCAP_{a,t} \tag{152}$$

and,

WAROR = weighted-average before-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 148 is equal to the adjusted rate base $APRB_{a,t}$ defined in equation 129:

$$TOTCAP_{a,t} = APRB_{a,t} \tag{153}$$

where,
TOTCAP = estimated capital in dollars
APRB = adjusted rate base in dollars
a = arc
t = forecast year

Substituting the estimated capital $TOTCAP_{a,t}$ for the adjusted rate base variable $APRB_{a,t}$ in equations 150 to 152, 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:

$$\begin{aligned} PFES_{a,t} &= GPFESTR_a * APRB_{a,t} \\ CMES_{a,t} &= GCMESTR_a * APRB_{a,t} \\ LTDS_{a,t} &= GLTDSTR_a * APRB_{a,t} \end{aligned} \tag{154}$$

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 (1988-1996).

$$GPFESTR_a = \frac{\sum_{t=1988}^{1996} \sum_{p} (GPFESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1988}^{1996} \sum_{p} APRB_{a,p,t}} \tag{155}$$

$$GCMESTR_a = \frac{\sum_{t=1988}^{1996} \sum_{p} (GCMESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1988}^{1996} \sum_{p} APRB_{a,p,t}} \tag{156}$$

$$GLTDSTR_a = \frac{\sum_{t=1988}^{1996} \sum_{p} (GLTDSTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1988}^{1996} \sum_{p} APRB_{a,p,t}} \tag{157}$$

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 (1988-1996) [Appendix E]
$GCMESTR_{a,p,t}$	=	capital structure for common stock (fraction) by pipeline company in the historical years (1988-1996)[Appendix E]
$GLTDSTR_{a,p,t}$	=	capital structure for long term debt (fraction) by pipeline company in the historical years (1988-1996) [Appendix E]
$APRB_{a,p,t}$	=	adjusted rate base (capitalization) by pipeline company in the historical years (1988-1996) [Appendix E]
p	=	pipeline company
a	=	arc
t	=	historical year (1988-1996)

The weighted average cost of capital in the forecast year in equation 139 is forecast as follows:

$$WAROR_{a,t} = [(PFER_{a,t} * GPFESTR_a) + (CMER_{a,t} * GCMESTR_a) + (LTDR_{a,t} * GLTDSTR_a)] \tag{158}$$

where,

WAROR	=	weighted-average before-tax rate of return on capital (fraction)
PFER	=	coupon rate for preferred stock (fraction), function of AA utility bond rate [equation 144]
CMER	=	common equity rate of return (fraction), function of AA utility bond rate [equation 145]
LTDR	=	long-term debt rate (fraction), function of AA utility bond rate [equation 146]
$GPFESTR_a$	=	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 before-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 (before taxes), also known as the before-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 (before 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:

$$TCOS_{a,t} = TRRB_{a,t} + DDA_{a,t} + TOTAX_{a,t} + TOM_{a,t} \tag{159}$$

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 [before 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

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:

$$TRRB_t = WAROR_t * APRB_t \tag{160}$$

where,

TRRB = total return on rate base (before taxes) for existing and new capacity in dollars
WAROR = weighted-average before-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 as shown below.

$$PFEN_{a,t} = GPFESTR_a * PFER_{a,t} * APRB_{a,t} \tag{161}$$

$$CMEN_{a,t} = GCMESTR_a * CMER_{a,t} * APRB_{a,t} \tag{162}$$

$$LTDN_{a,t} = GLTDSTR_a * LTDR_{a,t} * APRB_{a,t} \tag{163}$$

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 139.

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:

$$TOTAX_{a,t} = FSIT_{a,t} + DIT_{a,t} + OTTAX_{a,t} \tag{164}$$

$$FSIT_{a,t} = FIT_{a,t} + SIT_{a,t} \tag{165}$$

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)

Table 6-5. Approach to Projection of Revenue Requirement

Projection Component	Approach
1. Capital-Related Costs	
a. Total return on rate base	Direct calculation from projected rate base and rates of return
c. Federal/State income taxes	Accounting algorithms based on tax rates
b. 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

OTTAX	=	all other taxes assessed by Federal, State, or local governments 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:

$$ATP_{a,t} = APRB_{a,t} * (PFER_{a,t} * GPFESTR_a + CMER_{a,t} * GCMESTR_a) \qquad (166)$$

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

$$FIT_{a,t} = (FRATE * ATP_{a,t} \;/\; 1. - FRATE) \qquad (167)$$

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:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \qquad (168)$$

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.

$$DIT_{a,t} = ADIT_{a,t} - ADIT_{a,t-1} \qquad (169)$$

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.

$$OTTAX_{a,t} = OTTAX_{a,t-1} * EXPFAC_{a,t} * (MC\_PCWGDP_{t} \ / \ MC\_PCWGDP_{t-1}) \tag{170}$$

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	=	implicit GDP price deflator (from the Macroeconomic Activity Model)
a	=	arc
t	=	forecast year

The capacity expansion factor is expressed as follows:

$$EXPFAC_{a,t} = PTCURPCAP_{a,t} \ / \ PTCURPCAP_{a,t-1} \tag{171}$$

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 at the arc level ($R\_TOM_{a,t}$) are determined using a log-linear form with correction for serial correlation 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, amount of gross plant in service added to arc a during year t (NEWCAP), ratio of accumulated DDA to GPIS measured at the beginning of year t (DEPSHR), and fraction of pipeline throughput accounted for by third party transportation (CARRIAGE_T), as defined below:

$$\begin{aligned} R\_TOM_{a,t} = \ & e^{(TOM\_C_{a} * (1-\rho))} * GPIS_{a,t}^{TOM\_GPIS} * e^{(TOM\_NEWCAP \, * \, NEWCAP_{a,t})} * e^{(TOM\_DEPSHR \, * \, DEPSHR_{a,t-1}} \\ & e^{(TOM\_CARR \, * \, CARRIAGE\_T_{a,t})} * R\_TOM_{a,t-1}^{\rho} * GPIS_{a,t-1}^{-\rho \, * \, TOM\_GPIS} * \\ & e^{(-\rho \, * \, TOM\_NEWCAP \, * \, NEWCAP_{a,t-1})} * e^{(-\rho \, * \, TOM\_DEPSHR \, * \, DEPSHR_{a,t-2})} * \\ & e^{(-\rho \, * \, TOM\_CARR \, * \, CARRIAGE\_T_{a,t-1})} \end{aligned} \tag{172}$$

where,

R_TOM	=	total operating and maintenance cost for existing and new capacity (1992 real dollars)
TOM_C_a	=	arc specific constant for gas transported from node to node, based on empirical study (Appendix F, Table F3)
ρ	=	autocorrelation coefficient estimated based on empirical study (Appendix F, Table F3 -- TOM_RHO)
GPIS	=	capital cost of plant in service for existing and new capacity in dollars (not deflated)
TOM_GPIS	=	GPIS coefficient estimated based on empirical study (Appendix F, Table F3)
NEWCAP	=	amount of gross plant in service added to arc a during year t
TOM_NEWCAP	=	NEWCAP coefficient estimated based on empirical study (Appendix F, Table F3)
DEPSHR	=	ratio of accumulated DDA to GPIS measured at the beginning of year t
TOM_DEPSHR	=	DEPSHR coefficient estimated based on empirical study (Appendix F, Table F3)
CARRIAGE_T	=	fraction of pipeline throughput accounted for by the third party transportation (this variable is included to account for the effect of open access on the cost efficiency of the pipelines. It is set to 1 in the code to fully account for the effect of open access.)
TOM_CARR	=	CARRIAGE_T coefficient estimated based on empirical study (Appendix F, Table F3)

a = arc
t = forecast year

Finally, the total operating and maintenance costs are converted to nominal dollars to be consistent with the convention used in this module.

$$TOM_{a,t} = R\_TOM_{a,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{1992}} \tag{173}$$

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 (1992 real dollars)
MC_PCWGDP = implicit 1987 GDP price deflator (from the Macroeconomic Activity Model)
MC_PCWGDP_{1992} = implicit 1987 GDP price deflator in 1992
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 of equation 159 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[50]. Note that the return on rate base $TRRB_{a,t}$ has three components $PFEN_{a,t}$, $CMEN_{a,t}$, and $LTDN_{a,t}$ [equations 161, 162, and 163].

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:

$$FC_{a,t} = \sum_i (\xi_i * Item_{i,a,t}) \tag{174}$$

$$VC_{a,t} = \sum_i [(1.0 - \xi_i) * Item_{i,a,t}] \tag{175}$$

$$TCOS_{a,t} = FC_{a,t} + VC_{a,t} \tag{176}$$

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 disaggreagate 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

[50] 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.

Table 6-6. Allocation Factors for a Straight Fixed Variable (SFV) Rate Design

Cost-of-service Items ($Item_{i,a,t}$, 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**	
$\mathbf{Item_{i,a,t}}$	$\mathbf{FC_{i,a,t}}$	$\mathbf{VC_{i,a,t}}$	$\mathbf{RFC_{i,a,t}}$	$\mathbf{UFC_{i,a,t}}$	$\mathbf{RVC_{i,a,t}}$	$\mathbf{UVC_{i,a,t}}$
Cost Allocation Factors	ξ_i	$100 - \xi_i$	λ_i	$100 - \lambda_i$	μ_i	$100-\mu_i$
Before-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	90	10	100	0	0	100
Total Cost-of-Service						

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:

$$RFC_{a,t} = \sum_i (\lambda_i * \xi_i * Item_{i,a,t}) \tag{177}$$

$$UFC_{a,t} = \sum_i [(1.0 - \lambda_i) * \xi_i * Item_{i,a,t}] \tag{178}$$

$$RVC_{a,t} = \sum_i [\mu_i * (1.0 - \xi_i) * Item_{i,a,t}] \tag{179}$$

$$UVC_{a,t} = \sum_i [(1.0 - \mu_i) * (1.0 - \xi_i) * Item_{i,a,t}] \tag{180}$$

$$TCOS_{a,t} = RFC_{a,t} + UFC_{a,t} + RVC_{a,t} + UVC_{a,t} \tag{181}$$

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 (ratios) to disaggregate cost-of-service components into fixed and variable costs
λ_i = second group of allocation factors (ratios) to disaggregate fixed costs into reservation and usage costs
μ_i = third group of allocation factors (ratios) 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 offpeak reservation costs, which are used to develop variable tariffs for peak and offpeak time periods. The summation of fixed and variable usage costs (UFC and UVC), which yields the total usage cost (UCOST), is used to compute the annual average fixed usage fees. Both types of rates are developed in the next section. The equations for the reservation and usage costs can be expressed as follows:

$$RCOST_{a,t} = (RFC_{a,t} + RVC_{a,t}) \tag{182}$$

$$UCOST_{a,t} = (UFC_{a,t} + UVC_{a,t}) \tag{183}$$

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

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 are described below.

Variable Tariff Curves

Variable tariffs are proportional to reservation charges and are broken up into peak and offpeak 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 PTM code, these variable curves are defined by a FUNCTION (NGPIPE_VARTAR) which is called by the ITM to compute the variable tariffs for peak and offpeak 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 offpeak flow, and a price elasticity. This functional form is presented below:

current capacity segment:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA\_PIPE} \tag{184}$$

capacity expansion segment:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA2\_PIPE} \tag{185}$$

such that,

for peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR\_YR}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{186}$$

$$QNOD_{a,t} = PTCURPCAP_{a,t} * PKSHR\_YR * PTPKUTZ_{a,t} * ADJ\_PIP + PTNETFLOW_{a,t} * (1.0 - ADJ\_PIP) \tag{187}$$

for offpeak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{188}$$

$$QNOD_{a,t} = PTCURPCAP_{a,t} * (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * ADJ\_PIP + PTNETFLOW_{a,t} * (1.0 - ADJ\_PIP) \tag{189}$$

where,

NGPIPE_VARTAR = PTM 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 (dollars)
PTPKUTZ = peak pipeline utilization (fraction)
PTOPUTZ = offpeak pipeline utilization (fraction)
PTCURPCAP = current pipeline capacity (bcf)
PTNETFLOW = natural gas flow (throughput, bcf)
ADJ_PIP = pipeline tariff curve adjustment factor (fraction) [Appendix E]
PKSHR_YR = portion of the year represented by the peak season (fraction)
MC_PCWGDP = implicit 1987 GDP price deflator (from the Macroeconomic Activity Model)
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 offpeak utilization rates, and annual arc capacity. These fees are computed as the average fees over each forecast year, as follows:

$$FIXTAR_{a,t} = UCOST_{a,t} / [(PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_{t}] \tag{190}$$

where,

FIXTAR = annual fixed usage fees for existing and new capacity (87$/mcf)
UCOST = annual usage cost 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 = offpeak pipeline utilization (fraction)
MC_PCWGDP = implicit 1987 GDP price deflator (from the Macroeconomic Activity Model)
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 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, $ARC\_FIXTAR_{n,a,t}$*.75), 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 offpeak) is less than 50 percent, then the pipeline tariff is set low (75 percent of CNMAXTAR). If the Canadian pipeline utilization is between 50 and 90 percent, then the pipeline tariff is set to a level between 75 and 85 percent of CNMAXTAR. The sliding scale is determined using the corresponding utilization factor, as follows:

$$NGPIPE\_VARTAR_{a,t} = CNMAXTAR - [CNMAXTAR * (1.0 - 0.9) * 1.5] - [CNMAXTAR * (0.9 - CANUTIL_{a,t}) * 0.25] \tag{191}$$

If the Canadian pipeline utilization is greater than 90 percent, then the pipeline tariff is set to between 85 and 100 percent of CNMAXTAR. This is accomplished again using Canadian pipeline utilization, as follows:

$$NGPIPE\_VARTAR_{a,t} = CNMAXTAR - [CNMAXTAR * (1.0 - CANUTIL_{a,t}) * 1.5] \tag{192}$$

where,

$$CANUTIL_{a,t} = \frac{Q_{a,t}}{QNOD_{a,t}} \tag{193}$$

for peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * PKSHR\_YR * PTPKUTZ_{a,t} \tag{194}$$

for offpeak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} \tag{195}$$

NGPIPE_VARTAR = PTM 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 = offpeak 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.

Computation of Storage Rates

Pending the availability of the financial storage data which will be ready for the *Annual Energy Outlook 2001*, a placeholder FUNCTION (NGSTR_VARTAR) is implemented in the PTM routine to assign an annual storage tariff by NGTDM region. This placeholder is defined as a function of a base point [price and quantity (PNOD, QNOD)] using different process-specific parameters, storage flow, and a price elasticity, as follows:

current capacity segment:

$$NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA\_STR} \tag{196}$$

capacity expansion segment:

$$NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA2\_STR} \tag{197}$$

such that,

$$PNOD_{r,t} = \frac{PNOD\_VALUE_r * CFNGC * (1.0 - STR\_EFF / 100)^t}{MC\_PCWGDP_{1998}} \tag{198}$$

$$QNOD_{r,t} = ADJ\_STR * PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \tag{199}$$

where,
NGSTR_VARTAR = PTM 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]
PNOD_VALUE = 1998 regional storage tariff (1998$/Dth) [set to PNOD in NGSTR_VARTAR FUNCTION]
CFNGC = heat content for natural gas dry production (Btu/cf)
PTSTUTZ = storage utilization (fraction)
PTCURPSTR = current storage capacity (bcf)
ADJ_STR = storage tariff curve adjustment factor (fraction) [Appendix E]
STR_EFF = efficiency factor (percent) for storage operations [Appendix E]
MC_PCWGDP = implicit 1987 GDP price deflator (from the Macroeconomic Activity Model)
r = NGTDM region
t = forecast year

7. Model Assumptions, Inputs, and Outputs

This last chapter summarizes the model and data assumptions used by the Natural Gas Transmission and Distribution Model (NGTDM) solution methodology and also presents the data inputs to and the outputs from the NGTDM.

Assumptions

This section presents a brief summary of the assumptions used within the Natural Gas Transmission and Distribution Model (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. All 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 referred to 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. 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 assumed to transport their gas under firm (or near firm) transportation agreements and noncore customers to transport their gas under nonfirm (interruptible or short-term capacity release) transportation agreements. The residential, commercial, and transportation (vehicles using compressed natural gas) 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.

Demand

The peak period is defined *(using PKOPMON)* to run from December through March, with the offpeak period filling up the remainder of the year.

The Alaskan natural gas consumption levels for residential, commercial, and industrial sectors are primarily defined as a function of the exogenously specified number of customers *(AK_RN, AK_CM, Tables F1, F2 -- AK_C, AK_D, AK_E, AK_F)*. Alaskan gas consumption is disaggregated into North and South Alaska in order to separately compute the natural gas production forecasts in these regions. The value of gas consumption in South Alaska as a percent of total Alaskan gas consumption *(AK_PCTSOUTH)* is based on average historical data. Similarly, the Alaskan lease fuel, plant fuel, and pipeline fuel consumption levels are calculated as historically based percentages of total dry production in Alaska *(AK_PCTPLT, AK_PCTPIP, AK_PCTLSE)*. The forecast for reporting discrepancy in Alaska *(AK_DISCR)* is set to an 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. 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, SQEU, SQTR)*. Similarly, the shares for disaggregating end-use consumption levels to peak and offpeak periods are held constant throughout the forecast, and are directly (U.S. -- 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 an other 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 region. 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 citygate benchmark factor [endogenously defined based on historical seasonal citygate prices *(HCGPR)*]. Historical distributor tariffs are derived for all sectors as the difference between historical citygate and end-use prices *(SPRS, SPCM, SPIN, SPEU, SPTR, PRS, PCM PIN, PEU)*.[51] Historical industrial end-use prices are derived in the model, and in particular for an historical base year *(DTAR_REFYR)*, using an assortment of inputs *(MPIN_CRG, MQIN_CRG, SRVYR, PW_CRG)*.[52] Distributor tariffs are defined differently for the core and noncore markets. The distributor tariff algorithm for the core market (with the exception of the transportation and electric generator sectors) uses parameters such as technical efficiency *(TECHEFF)*, depreciation rate (TCF_COEFF_7), and debt/equity shares *(WT_DEBT, DEBTYR, H_RMPUAANS, H_REALRMGBLUS)*, all of which are exogenously defined. The algorithm also uses exogenously defined cost coefficients *(TCF_COEFF)* which represent the relative contribution of an annual change in demands and economic parameters to the annual change in distribution costs. The core electric generator distributor tariffs are historically based and change based on the annual percentage change in consumption. The fleet vehicle (FV) component of the core transportation sector defines distributor tariffs using historical data, a decline rate *(TRN_DECL)*, and state and federal taxes (STAX, FTAX); while the personal vehicle (PV) component defines distributor tariffs as a markup *(RETAIL_COST, STAX, FTAX)* over the core industrial sector distributor tariff. Noncore distributor tariffs are determined using historically derived tariffs, and decline rates *(currently set to zero)*.

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 model when executed during the historical years).

Pipeline Tariffs and Regulation

Peak and offpeak 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 offpeak 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

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

[52]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 model, these published prices are adjusted using inputs from EIA's survey of industrial customers to derive a more representative set of industrial prices.

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 Module uses a set of data assumptions based on historical data or expert judgment. These include the following:

- Factors *(ARX, 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
- Placeholder to assign a storage tariff for each region
- Capacity expansion cost parameters *(CC_COMPR, CC_SLOPE1, EXP_A, CC_LOOPI, CC_SLOPE2, EXP_B, CC_NEWPI, EXP_C)* and pipe mileage *(MILES)* used to derive total capital costs to expand pipeline capacity
- Input coefficients*(ADJ_PIP, ALPHA_PIPE, ALPH2_PIPE, PNOD, ADJ_STR, STR_EFF, ALPHA_STR, ALPHA2_STR)* for transportation and storage rates.

All interstate pipeline companies are assumed to have completed the switch from modified fixed variable (MFV) to straight fixed variable (SFV) rate design by January 1994 to comply with Federal Energy Regulatory Commission Order 636 rate design changes. Any remaining transition costs related to FERC Order 636 are assumed to be insignificant and are not represented.

Pipeline and Storage Capacity and Utilization

Historical and planned interregional, intraregional, and Canadian pipeline capacities are assigned in the model 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 offpeak 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 model only represents net storage withdrawals in the peak period and net storage injections in the offpeak 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)* to reflect an expected variant in the load throughout a season.

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 nonassociated dry gas production and total gas production from the Canadian Sedimentary Basin are based on an expected production level as set in the Oil and Gas Supply Model. A set of parameters *(PARM_SUPCRV3, PARM_SUPCRV5, SUPCRV, PARM_SUPELAS)* define the price change from the previous forecast 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 Model. Eastern and western Canadian production from other than the Canadian Western Canadian Sedimentary Basin is set exogenously *(CN_FIXSUP)*.

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 Model; (2) Canadian imports are largely *(except Q23TO3)* set endogenously and limited to exogenously specified Canadian pipeline capacities *(ACTPCAP, CNPER_YROPEN)*. 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 provided by the Oil and Gas Supply Model. All supply levels held fixed are converted into peak and offpeak 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 all represented as constant supplies within the Interstate Transmission Module. 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 model. Throughout the forecast, these production levels are split into seasonal periods using an historically *(NSUPLM_TOT)* based share (PKSHR_SUPLM).

The model used an assortment of input values in defining historical production levels and prices (or revenues) by the regions and categories required by the model *(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). The discrepancy variable also includes an additional value *(NG_CCAP)* to account for provisions of the Climate Change Action Plan to expand the Natural Gas Star program (Action 32).

Model Inputs

The NGTDM is a comprehensive framework which simulates the natural gas transmission and distribution industry in the United States as regulated (by the Federal Energy Regulatory Commission) for the pipeline transportation services across States (at the interstate level) and (by State Public Utility Commissions) for the local distribution services within States (at the intrastate level). The natural gas pipeline network (including storage) ties the suppliers to the end-users of natural gas, and captures the interactions among these institutions that ultimately determine market clearing prices and quantities consumed of natural gas. 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
  (STMAP_LNG, STMAP_MEX, STMAP_CAN, CAN_XMAPUS, CAN_XMAPCN, MEX_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, CAN_XMAP)
- 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, AL_ONSH, AL_OFST, AL_OFFD, LA_ONSH, LA_OFST, LA_OFFD)
- State/substate level natural gas production and other supply/storage data
  (ADW, NAW, TGD, MISC_ST, MISC_GAS, MISC_OIL, SMKT_PRD, SDRY_PRD, SIMP, SNET_WTH, SUPPLM, SNGLIQ, SNGCOAL)
- 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)
- Gross Domestic Product deflator
  (GDP_B87)

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)
- Storage data
  (NWTH_TOT, NINJ_TOT, HNETWTH, HNETINJ
- State level consumption and prices
  (CON & PRC -- QRS, QCM, QIN, QEU, PRS, PCM, PIN, PEU)
- Miscellaneous monthly/seasonal data
  (NQPF_TOT, NSUPLM_TOT, WHP_LHIS, QLP_LHIS)

Alaskan & Canadian Demand/Supply Variables

- Alaskan lease, plant, and pipeline fuel parameters
  (AK_PCTPLT, AK_PCTPIP, AK_PCTLSE)
- Alaskan consumption parameters
  (AK_PCTSOUTH, AK_C, AK_D, AK_E, AK_F, AK_RN, AK_CM)
- Alaskan pricing parameters
  (AK_RM, AK_CM, AK_IN, AK_EM, ANGTS_TAR)
- 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)

Supply Inputs

- Supply curve parameters
  (SUPCRV, PARM_MINPR, PARM_SUPCRV3, PARM_SUPCRV5, PARM_SUPELAS, MAXPRRFAC,MAXPRRCAN, PARM_MINPR)
- Synthetic natural gas from coal forecast
  (SNGCOAL)
- Natural gas fugitive emissions savings due to the Climate Change Action Plan
  (NG_CCAP)

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_FXIT, 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)
- Revenue requirement forecasting equation parameters
  (Table F3)
- Rate of return set for generic pipeline companies
  (MC_RMPUAANS, ADJ_PFER, ADJ_CMER, ADJ_LTDR)
- Federal and State income tax rates
  (FRATE, SRATE)
- Parameters for interstate pipeline transportation rates
  (PKSHR_YR, PTPKUTZ, PTOPUTZ, ADJ_PIP, ALPHA_PIPE, ALPHA2_PIPE)
- Depreciation schedule
  (30 year life)
- Parameters for capital cost equations
  (CC_COMPR, CC_SLOPE1, EXP_A, CC_LOOPI, CC_SLOPE2, EXP_B, CC_NEWPI, EXP_C, MILES)
- Canadian pipeline and storage tariff parameters
  (ARC_FIXTAR, ARC_VARTAR, CN_FIXSHR)
- Parameters for storage rates
  (PNOD, PTSTUTZ, ADJ_STR, STR_EFF, ALPHA_STR, ALPHA2_STR)

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 offpeak primary and secondary pipeline utilizations
  (PKUTZ, OPUTZ, SUTZ)
- 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 (offpeak) in Canada
  (HNETWTH, HNETINJ)
- Historical flow data
  (HPKSHR_FLOW, HAFLOW, SAFLOW)

End-Use Pricing Inputs

- Cost coefficients and other parameters used in core distributor tariff algorithm
  (TCF_COEFF, TECHEFF, DTAR_REFYR)
- 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, TST1, TST2YR, TST2, TFD1, TFD2YR, TFD2)
- Historical citygate prices
  (HCGPR)
- Historical data for calculating debt and equity for core distributor tariff
  (DEBTYR, WT_DEBT, H_RMPUAANS, H_REALRMGBLUS)
- Parameters for establishing historical core and noncore industrial prices
  (MPIN_CRG, MQIN_CRG, SRVYR, PW_CRG)

Miscellaneous

- Network processing control variables
  (MAXCYCLE, NOBLDYR, GAMMAFAC, MUFAC, PSUP_DELTA, QSUP_DELTA, QSUP_SMALL, QSUP_WT)
- Miscellaneous control variables
  (PKOPMON, NGDBGRPT)
- STEO input data
  (STEOYRS, STQGPTR, STQLPIN, STOGWPRNG, STPNGRS, STPNGCM, STPNGEL, STOGPRSUP, NNETWITH, STDISCR, STINPUT_SCAL, STSCAL_PFUEL, STSCAL_LPLT, STSCAL_WPR, STSCAL_DISCR, STSCAL_NETSTR, STSCAL_FPR, STSCAL_IPR, STPHAS_YR)

Model Outputs

Once a set of solution values are determined within the NGTDM, those values required by other models of NEMS are passed accordingly. In addition, the NGTDM model results are presented in a series of internal and external reports, as outlined below.

Outputs to NEMS Models

The NGTDM passes its model solution values to different NEMS models 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 Model region (to NEMS REPORTS, Oil and Gas Supply Model, and Petroleum Market Model)
- Core and noncore natural gas prices by sector and Census Division (to NEMS PROPER and REPORTS, and NEMS demand models)
- Dry natural gas production and supplemental gas supplies by Oil and Gas Supply Model region (NEMS REPORTS and Oil and Gas Supply Model)
- Peak/offpeak, core/ noncore natural gas prices to electric generators by NGTDM/Electricity Market Model region (to NEMS PROPER and REPORTS and Electricity Market Model)
- Dry natural gas production by Petroleum Administration for Defense Districts region (to Petroleum Market Model)
- Nonassociated dry natural gas production by NGTDM/Oil and Gas Supply Model region (to NEMS REPORTS and Oil and Gas Supply Model)
- Canadian natural gas wellhead price and production (to Oil and Gas Supply Model)
- Natural gas imports and prices by border crossing (to NEMS REPORTS and Oil and Gas Supply Model)

Internal Reports

The NGTDM produces reports designed to assist in the detailed 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 offpeak flows, shares, and maximum constraints going into each node (NGOBAL)
- Historical and forecast values historically based factors applied in the model (NGOBENCH)
- Intermediate results from the Distributor Tariff Module (NGODTM)
- Intermediate results from the Pipeline Tariff Module (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 wellhead prices and production levels by NGTDM region (and the average for the lower 48 United States)
- Natural gas end-use prices, margins, and revenues
- Natural gas import and export volumes and import prices
- 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[53]

[53]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 Model
Acronym: NGTDM
Title: Natural Gas Transmission and Distribution Model

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: Energy Supply and Conversion
- Branch: Oil and Gas Analysis, EI-823
- Model Contact: Joe Benneche
- Telephone: (202) 586-6132

Documentation: Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, December 1999).

Previous Documentation: Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, February 1999).

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, December 1997).

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, December 1996).

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, December 1995).

Energy Information Administration, *Model Documentation, Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System, Volume II: Model Developer's Report*, DOE/EIA-M062/2 (Washington, DC, January 1995).

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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 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: NEMS2000—(Part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1999*, DOE/EIA-0383(2000)).

NEMS99—(Part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1998*, DOE/EIA-0383(99)).

NEMS98—(Part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1998*, DOE/EIA-0383(98)).

NEMS97—(Part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1997*, DOE/EIA-0383(97)).

NEMS96—(Part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1996*, DOE/EIA-0383(96)).

NEMS95—(Part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1995*, DOE/EIA-0383(95)).

NEMS94—(Part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1994*, DOE/EIA-0383(94)).

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 9 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 3 at the Mexican border, 7 at the Canadian border, and 4 liquefied natural gas import terminals. A simplified Canadian representation is subdivided into an eastern and western region.

Time Unit/Frequency: Annually through 2020, including a peak (December through March) and offpeak forecast.

Product(s): Natural gas

Economic Sector(s): Residential, commercial, industrial, electric generators and transportation

Data Input Sources: (Non-DOE)

- Information Resources, Inc., "Octane Week"
  — Federal vehicle natural gas (VNG) taxes
- Canadian Petroleum Association Statistical Handbook
  — Historical Canadian supply and consumption data
- Canadian Energy Research Institute's North American Natural Gas Outlook
  — Transcanada pipeline tariff
- 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 Financial Cost Data
  — pipeline financial data
- Alaska Department of Natural Resources
  — State of Alaska north to south historical natural gas consumption ratio.
- Data Resources Inc., U.S. Quarterly Model
  — Yield on AA utility bonds
- 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

Data Input Sources: (DOE) **Forms and Publications:**

- EIA-23, "Annual Survey of Domestic Oil and Gas Reserves"
  — Annual estimate of gas reserves by type and State
- EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers"
  — Monthly natural gas price and volume data on deliveries to end users

- EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition"
  — Annual natural gas sources of supply, consumption, and flows on the interstate pipeline network
- EIA-895,"Monthly quantity of Natural Gas Report"
  — Monthly natural gas production
- EIA-860, "Annual Electric Generator Report"
  — Electric generators plant type and code information, used in the classification of power plants as core or noncore customers. Data from this report are also used in the derivation of historical prices and markups for firm/interruptible service.
- EIA-767, "Steam-Electric Plant Operation and Design Report"
  — Electric generators plant type and boiler information, by month, used in the classification of power plants as core or noncore customers. Data from this report are also used in the derivation of historical prices and markups for firm/interruptible service
- EIA-759, "Monthly Power Plant Report"
  — Natural gas consumption by plant code and month, used in the classification of power plants as core or noncore customers. Data from this report are also used in the derivation of historical prices and markups for firm/interruptible service
- Rate case filings under Section 4 of the Natural Gas Policy Act, as submitted to FERC by each pipeline company
  — Contract demand data and cost allocation by pipeline company
- *Annual Energy Review*, DOE/EIA-0384
  — Gross domestic product and implicit price deflator
- FERC Form 2, "Annual Report of Major Natural Gas Companies"
  — Financial statistics of major interstate natural gas pipelines
  — Annual purchases/sales by pipeline (volume and price)
- FERC-567, "Annual Flow Diagram"
  — Pipeline capacity and flow information
- EIA-191, "Underground Gas Storage Report"
  — Base gas and working gas storage capacity and monthly storage injection and withdrawal levels by region and pipeline company
- EIA-846, "Manufacturing Energy Consumption Survey"
  — Base year average annual core industrial end-use prices
- *Capacity and Service on the Interstate Natural Gas Pipeline System 1990*, DOE/EIA-0556
  — Pipeline capacity and capacity reservations by customer.
- Federal Energy Regulatory Commission, NGA Section 7(c) Filings, "Applications for Certification of Public Convenience and Necessity"
  — planned pipeline capacity additions
- *Natural Gas Issues and Trends 1994,* DOE/EIA-0560(94), p. 117
  — Long-term debt as a percent of invested capital
- *Short-Term Energy Outlook*, DOE/EIA-0131.
  — National forecast targets for first two forecast years beyond history
- FERC Form 423, *Cost and Quality of Fuels for Electric Utility Plants*, DOE/EIA-0191.
  — Natural gas prices to electric generators
- Department of Energy www.afdc.doe.gov
  — compressed natural gas vehicle taxes by state
- Department of Energy, *Natural Gas Imports and Exports*, Office of Fossil Energy
  — Import volumes by crossing in the most recent historical year.
- Department of Energy, *The Climate Change Action Plan Technical Supplement*
  — estimated savings from fugitive emissions

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 supply prices and production levels by region
- Pipeline fuel consumption by region
- Lease and plant fuel consumption by region
- 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 Module (ITM), the Pipeline Tariff Module (PTM), and the Distributor Tariff Module (DTM).

  - — ITM Integrating module 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 flows and prices, pipeline capacity expansion and utilization, storage capacity expansion and utilization for a simplified network representing the interstate natural gas pipeline system
  - — PTM Develops parameters for setting tariffs in the ITM for transportation and storage services provided by interstate pipeline companies
  - — DTM Develops markups for distribution services provided by LDC's and intrastate pipeline companies.

- Modeling Technique:
  - — ITM Heuristic algorithm, operates iteratively until supply/demand convergence is realized across the network
  - — PTM Econometric estimation and accounting algorithm
  - — DTM Empirical process

- Special Features:

  - — Represents interregional flows of gas and pipeline capacity constraints for two seasonal periods.
  - — Represents regional supplies
  - — Determines the amount and the location of pipeline and storage facility capacity expansion on a regional basis
  - — Captures the economic tradeoffs between pipeline capacity additions and increases in regional storage capability
  - — Distinguishes end-use customers by type (core and noncore).

Model Interfaces: NEMS

Computing Environment:

- Hardware Used: RS/6000
- Operating System: UNIX
- Language/Software Used: FORTRAN
- Memory Requirement: unknown
- Storage Requirement: 1497K bytes for input data storage; 607K bytes for source code storage; and 3766K bytes for compiled code storage
- Estimated Run Time: varies from 9 to less than 1 second per NEMS iteration, averaging around 3 seconds.

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: September 1999.

Appendix B

References

References

Barcella, Mary, "Natural Gas Distribution Costs and Efficiency Implications for Regulation," as presented at 68th Annual WEA Conference, June 23, 1993.

Barcella, Mary, Chris Marnay, and G. Alan Comnes, "Wholesale and Retail Analysis for Estimating the Price Effect of Natural Gas Conservation," as presented at the Institute for Gas Technology conference on Energy Modeling in Atlanta, GA, April 3-5, 1995.

Carpenter, Paul R., "Review of the Gas Analysis Modeling System (GAMS), Final Report of Findings and Recommendations" (Boston: Incentives Research, Inc., August 1991).

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Energy Information Administration, "Analytical Framework for a Natural Gas Transmission and Distribution Forecasting System," prepared by SAIC for the Analysis and Forecasting Branch within the Reserves and Natural Gas Division of the Office of Oil and Gas (Washington, DC, March 1991).

Energy Information Administration, Office of Integrated Analysis and Forecasting, "Component Design Report, Natural Gas Annual Flow Module for the Natural Gas Transmission and Distribution Model of the National Energy Modeling System" (Washington, DC, June 25, 1992).

Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618(98) (Washington, DC, May 1998).

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Energy Information Administration, Office of Integrated Analysis and Forecasting, "Component Design Report,Distributor Tariff Module for the Natural Gas Transmission and Distribution Model of the National Energy Modeling System" (Washington, DC, January 11, 1993).

Energy Information Administration, Office of Integrated Analysis and Forecasting, "Component Design Report, Pipeline Tariff Module for the Natural Gas Transmission and Distribution Model of the National Energy Modeling System" (Washington, DC, December 29, 1992).

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Energy Information Administration, *Natural Gas 1994: Issues and Trends* DOE/EIA-0560(94) (Washington, DC, July 1994).

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Gujarati, Damodar, *Basic Econometrics* (McGraw Hill).

National Energy Board, *Canadian Energy, Supply and Demand to 2025*, 1999

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 (core) (noncore)	NGDMD_CRVF* NGDMD_CRVI*
2	NGSUP_PR*
3-9	NGTDM_DMDALK

Chapter 4 Equations	
EQ. #	**SUBROUTINE** (or FUNCTION *)
10,13	NGSET_NODEDMD, NGDOWN_TREE
11,14	NGSET_NODECDMD
12,15	NGSET_YEARCDMD
16,17	NGDOWN_TREE
18	NGSET_INTRAFLO
19	NGSET_INTRAFLO
20	NGSHR_CALC
21	NGDOWN_TREE
22	NGSET_MAXFLO*
23-26	NGSET_MAXPCAP
27-31	NGSET_MAXFLO*
32-34	NGSET_ACTPCAP
35-38	NGSET_SUPPR
39-40	NGSTEO_BENCHWPR
41-42	NGSET_ARCFEE
43-46	NGUP_TREE
47	NGSET_STORPR
48-49	NGUP_TREE
50	NGCHK_CONVNG
51	NGSET_SECPR
52	NGSET_BENCH, HNGSET_CGPR
53-61	NGSET_SECPR

Chapter 5 Equations	
EQ. #	**SUBROUTINE** (or FUNCTION *)
62	NGDTM_FORECAST_DTARF
63-66	NGDTM_TCF1
67-68	NGDTM_CALCCOST*
69-70	NGDTM_FORECAST_DTARF
71-72	NGDTM_FORECAST_TRNF
73-75	NGDTM_HISDIST
76	NGDTM_FORECAST_DTARF

Chapter 6 Equations	
EQ #	**SUBROUTINE** (or FUNCTION *)
78-106, 155-157	NGPREAD
126-146, 158, 160-173	NGPSET_PLCOS_COMPONENTS
77, 107-116, 122, 159, 174-183, 190	NGPSET_PLINE_COSTS
117-121, 184-189, 191-195	NGPIPE_VARTAR*
123-125, 196-199	NGSTR_VARTAR*
147-154	(accounting relationships, not part of code)

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 AEO2000 are identified below. Electronic copies of these input files are available upon request from Joe Benneche (202) 586-6132.

ngmap	V1.2	nguser	V1.42	ngdtar	V1.12
ngptar	V1.10	ngmisc	V1.14	ngcap	V1.12
ngcan	V1.19	nghisan	V1.5	nghismn	V1.5

Variable	File
ACTPCAP	NGCAN
ACTPCAP	NGCAP
ADDYR	NGCAP
ADIT_ADIT	NGPTAR
ADIT_C	NGPTAR
ADIT_NEWCAP	NGPTAR
ADJ_PIP	NGPTAR
ADJ_STR	NGPTAR
ADW	NGHISAN
AFR_CMEN	NGPTAR
AFR_DDA	NGPTAR
AFR_DIT	NGPTAR
AFR_FSIT	NGPTAR
AFR_LTDN	NGPTAR
AFR_OTTAX	NGPTAR
AFR_PFEN	NGPTAR
AFR_TOM	NGPTAR
AFX_CMEN	NGPTAR
AFX_DDA	NGPTAR
AFX_DIT	NGPTAR
AFX_FSIT	NGPTAR
AFX_LTDN	NGPTAR
AFX_OTTAX	NGPTAR
AFX_PFEN	NGPTAR
AFX_TOM	NGPTAR
AK_C	NGMISC
AK_CM	NGMISC
AK_CN	NGMISC
AK_D	NGMISC
AK_E	NGMISC
AK_EM	NGMISC
AK_F	NGMISC
AK_G	NGMISC
AK_IN	NGMISC
AK_PCTLSE	NGMISC
AK_PCTPIP	NGMISC
AK_PCTPLT	NGMISC
AK_PCTSOUTH	NGMISC
AK_RM	NGMISC
AK_RN	NGMISC
AL_ONS	NGHISAN
AL_OFST	NGHISAN
AL_OFFD	NGHISAN
ALPHA2_PIPE	NGPTAR
ALPHA2_STR	NGPTAR
ALPHA_CCOST	NGPTAR
ALPHA_PIPE	NGPTAR
ALPHA_STR	NGPTAR
ANGTS_TAR	NGMISC
ARC_2NODE	NGMAP
ARC_FIXTAR	NGCAN
ARC_LOOP	NGMAP
ARC_VARTAR	NGCAN
AVR_CMEN	NGPTAR
AVR_DDA	NGPTAR
AVR_DIT	NGPTAR
AVR_FSIT	NGPTAR
AVR_LTDN	NGPTAR
AVR_OTTAX	NGPTAR
AVR_PFEN	NGPTAR
AVR_TOM	NGPTAR
BETA_CCOST	NGPTAR
CANEXP	NGCAN
CAN_XMAPCN	NGMAP
CAN_XMAPUS	NGMAP
CC_COMPR	NGPTAR
CC_LOOPI	NGPTAR
CC_NEWPI	NGPTAR
CNPER_YROPEN	NGCAP
CN_DMD	NGCAN
CN_FIXSHR	NGCAN
CN_FIXSUP	NGCAN
CON	NGHISMN
CSTFAC	NGPTAR
CWC_C	NGPTAR
CWC_CARR	NGPTAR
CWC_DISC	NGPTAR
CWC_GPIS	NGPTAR
CWC_RHO	NGPTAR
D_ADDA	NGPTAR
D_ADIT	NGPTAR
D_APRB	NGPTAR
D_CMER	NGPTAR
D_CWC	NGPTAR
D_DDA	NGPTAR
D_DIT	NGPTAR
D_FLO	NGPTAR
D_GCMES	NGPTAR
D_GLTDS	NGPTAR
D_GPFES	NGPTAR
D_GPIS	NGPTAR
D_LTDR	NGPTAR
D_MXPKFLO	NGPTAR
D_NPIS	NGPTAR
D_OTTAX	NGPTAR
D_PFER	NGPTAR
D_TOM	NGPTAR
DDA_C	NGPTAR
DDA_NEWCAP	NGPTAR
DDA_NPIS	NGPTAR
DEBTYR	NGDTAR
DTAR_REFYR	NGDTAR
DTM_BETA	NGDTAR
EMMSUB_EL	NGMAP
EMMSUB_NG	NGMAP
EXP_A	NGPTAR

EXP_B	NGPTAR
EXP_C	NGPTAR

Variable	File
FID_WA	NGMISC
FLO_THRU_IN	NGCAN
FMT_ND	NGMISC
FRATE	NGPTAR
GAMMAFAC	NGUSER
GDP_B87	NGMISC
HAFLOW	NGMISC
HCGPR	NGHISAN
HFAC_GPIS	NGPTAR
HFAC_REV	NGPTAR
HNETINJ	NGCAN
HNETINJ	NGHISMN
HNETWTH	NGCAN
HNETWTH	NGHISMN
HOPUTZ	NGCAP
HPKSHR_FLOW	NGMISC
HPKUTZ	NGCAP
HPSUP	NGCAN
HQIMP	NGHISAN
HQSUP	NGCAN
H_REALRMGBLUS	NGDTAR
H_RMPUAANS	NGDTAR
INTRAREG_TAR	NGDTAR
INTRAST_TAR	NGDTAR
I_BYPASS	NGDTAR
LA_OFFD	NGHISAN
LA_OFST	NGHISAN
LA_ONS	NGHISAN
MAPLNG_NG	NGMAP
MAP_PRDST	NGHISMN
MAP_STSUB	NGHISAN
MAXCHNG	NGDTAR
MAXCYCLE	NGUSER
MAXPRRFAC	NGMISC
MAXPRRNG	NGMISC
MAXUTZ	NGCAP
MEX_XMAP	NGMAP
MILES	NGPTAR
MINMU_I	NGDTAR
MINYR	NGPTAR
MISC_GAS	NGHISAN
MISC_OIL	NGHISAN
MISC_ST	NGHISAN
MN_ST_PEUF	NGHISMN
MN_ST_PEUI	NGHISMN
MN_ST_QEUF	NGHISMN
MN_ST_QEUI	NGHISMN
MONMKT_PRD	NGHISMN
MON_PEXP	NGHISMN
MON_PIMP	NGHISMN
MON_QEXP	NGHISMN
MON_QIMP	NGHISMN
MPIN_CRG	NGMISC
MQIN_CRG	NGMISC
MUFAC	NGUSER
NAW	NGHISAN
NG_CCAP	NGMISC
NG_CENMAP	NGMAP
NGDBGCNTL	NGUSER
NGDBGRPT	NGUSER
NINJ_TOT	NGHISMN
NNETWITH	NGUSER
NOBLDYR	NGUSER
NODE_2ARC	NGMAP
NODE_ANGTS	NGMAP
NODE_SNGCOAL	NGMAP
NPROC	NGMAP
NQPF_TOT	NGHISMN
NSUPLM_TOT	NGHISMN
NWTH_TOT	NGHISMN
OCSMAP	NGMAP
OPUTZ	NGCAP
PARM_MINPR	NGUSER
PARM_SUPCRV3	NGUSER
PARM_SUPCRV5	NGUSER
PARM_SUPELAS	NGUSER
PER_YROPEN	NGCAP
PIPE_FACTOR	NGPTAR
PKOPMON	NGMISC
PKSHR_CDMD	NGCAN
PKSHR_PROD	NGCAN
PKUTZ	NGCAP
PLANPCAP	NGCAN
PLANPCAP	NGCAP
PMMMAP_NG	NGMAP
PROC_ORD	NGMAP
PSUP_DELTA	NGUSER
PTCURPCAP	NGCAP
PTMBYR	NGPTAR
PW_CRG	NGMISC
Q23TO3	NGCAN
QLP_LHIS	NGHISMN
QOF_ALFD	NGHISAN
QOF_ALST	NGHISAN
QOF_CA	NGHISAN
QOF_LA	NGHISAN

QOF_LAFD	NGHISAN
QOF_LAST	NGHISAN
QOF_TX	NGHISAN
QSUP_DELTA	NGUSER
QSUP_SMALL	NGUSER
QSUP_WT	NGUSER
RETAIL_COST	NGDTAR
REV	NGHISMN
ROF_CA	NGHISAN
ROF_LA	NGHISAN
ROF_TX	NGHISAN

Variable	**File**	**Variable**	**File**
SAFLOW	NGMISC	STEOYRS	NGUSER
SARC_2NODE	NGMAP	STMAP_CAN	NGHISAN
SBAL_ITM	NGHISAN	STMAP_LNG	NGHISAN
SCEN_DIV	NGHISAN	STMAP_MEX	NGHISAN
SCH_ID	NGHISAN	STOGPRSUP	NGUSER
SDRY_PRD	NGHISAN	STOGWPRNG	NGUSER
SEXP	NGHISAN	STPHAS_YR	NGUSER
SIMP	NGHISAN	STPNGCM	NGUSER
SIM_EX	NGHISAN	STPNGEL	NGUSER
SITM_RG	NGHISAN	STPNGRS	NGUSER
SMKT_PRD	NGHISAN	STQGPTR	NGUSER
SNET_WTH	NGHISAN	STQLPIN	NGUSER
SNGCOAL	NGMISC	STR_2NODE	NGMAP
SNGCOAL	NGHISAN	STR_EFF	NGPTAR
SNGLIQ	NGHISAN	STSCAL_DISCR	NGUSER
SNG_EM	NGHISAN	STSCAL_FPR	NGUSER
SNG_OG	NGHISAN	STSCAL_IPR	NGUSER
SNODE_2ARC	NGMAP	STSCAL_LPLT	NGUSER
SNUM_ID	NGHISAN	STSCAL_NETSTR	NGUSER
SPCM	NGHISAN	STSCAL_PFUEL	NGUSER
SPEU	NGHISAN	STSCAL_SUPLM	NGUSER
SPEX	NGHISAN	STSCAL_WPR	NGUSER
SPIM	NGHISAN	SUPCRV	NGUSER
SPIN	NGHISAN	SUPSUB_NG	NGMAP
SPLANPCAP	NGCAP	SUPSUB_OG	NGMAP
SPRS	NGHISAN	SUTZ	NGCAP
SPTR	NGHISAN	TCF_COEFF	NGDTAR
SPWH	NGHISAN	TECHEFF	NGDTAR
SQCM	NGHISAN	TFD1	NGDTAR
SQEU	NGHISAN	TFD2	NGDTAR
SQIN	NGHISAN	TFD2YR	NGDTAR
SQLP	NGHISAN	TGD	NGHISAN
SQPF	NGHISAN	TOM_C	NGPTAR
SQRS	NGHISAN	TOM_CARR	NGPTAR
SQTR	NGHISAN	TOM_DEPSHR	NGPTAR
SRATE	NGPTAR	TOM_GPIS	NGPTAR
SRVYR	NGMISC	TOM_NEWCAP	NGPTAR
SSUPLM	NGHISAN	TOM_RHO	NGPTAR
STDISCR	NGUSER	TOM_YR	NGPTAR

TRN_DECL	NGDTAR
TST1	NGDTAR
TST2	NGDTAR
TST2YR	NGDTAR
TTRNCAN	NGAN
WHP_LHIS	NGHISMN
WPR4CAST_FLG	NGUSER
WT_DEBT	NGDTAR

Appendix F

Derived Data

Table F1

Data: Parameter estimates for the Alaskan natural gas consumption equations for the residential, commercial, and industrial sectors.

Author: Chetha Phang, EIA, July 8, 1999.

Source: *Natural Gas Annual* 1986, 1988, 1991, 1995, 1997, DOE/EIA-0131.
Annual Energy Review 1998 (Appendix E).

Derivation: An autoregressive procedure (PROC AUTOREG) was used to estimate the parameters of the Alaskan natural gas consumption equation for each sector (except for electric generation). These equations are estimated based on the historical time series data of Alaska natural gas consumption, 1969-1997, and are defined as follows:

Residential Natural Gas Consumption

$$\ln YR_t = AK\_C(1) + AK\_C(2)*\ln {}_{Rnt}$$

N = 29, R-Squared = 0.753 , Durbin-Watson = 1.8
rho = 0.263 (t-1.39), rho is not statistically significant.
There is no correction on the parameter estimates. The forecast function is as follows:

$$YR_t = e^{AK\_C(1)} * RN_t^{AK\_C(2)}$$

Variables:	AK_C(1)	AK_C(2)
Estimated Value:	0.13996	0.579
t-statistic:	(0.4)	(6.9)

Commercial Natural Gas Consumption

$$\ln YC_t = \alpha_c + ß_c*\ln {}_{Cnt}$$

N = 29, R-Squared = 0.82,
rho = 0.495 (t-2.9), Durbin-Watson = 1.33

Variables:	α_c	$ß_c$
Estimated Value:	2.06175	0.42616
t-statistic	(13.7)	(5.8)

Strong serial correlation exists between the disturbance terms. After incorporating the first-order autocorrelation (rho) into the model, the forecast function becomes:

$$YC_t = e^{AK\_D(1)} * YC_{t-1}^{AK\_D(2)} * CN_t^{AK\_D(3)} * CN_{t-1}^{AK\_D(4)}$$

Variables:	AK_D(1)	AK_D(2)	AK_D(3)	AK_D(4)
Estimated Value:	1.0414	0.4949	0.4262	-0.2110

Industrial Natural Gas Consumption

$$\ln YI_t = \alpha_i + ß_i * \ln T \quad \text{(T=1 when year is 1969)}$$

N = 29, R-Squared = 0.89
rho = 0.7016 (t-5.0), Durbin-Watson = 1.34

Variables:	α_i	$ß_i$
Estimated Value:	9.3795	0.5564
t-statistic:	(29)	(4.5)

Strong serial correlation exists between the disturbance terms. After incorporating the first-order autocorrelation (rho) into the model, the forecast function becomes:

$$YI_t = e^{AK\_E(1)} * YI_{t-1}^{AK\_E(2)} * T^{AK\_E(3)} * (T-1)^{AK\_E(4)}$$

Variables:	AK_E(1)	AK_E(2)	AK_E(3)	AK_E(4)
Estimated Value:	2.7982	0.7016	0.5564	-0.3903

where,

ln = natural logarithm operator
t = year index
N = number of observations
RN_t = residential consumers (thousands) at current year. (AK_RN), See Table F2
CN_t = commercial consumers (thousands) at current year. (AK_CN), See Table F2
YR_t = residential Alaskan natural gas consumption (Bcf) (QALK_NONU_F(1))
YC_t = commercial Alaskan natural gas consumption (Bcf) (QALK_NONU_F(2))
YI_t = industrial Alaskan natural gas consumption (MMcf) (QALK_NONU_F(3))
T = time trend variable having value 1, 2, 3,..., 29 starting from 1969 to 1997. In 2020, the T variable will take on the value of 52.
WP_t = average natural gas wellhead price (1987$/Mcf) in current year. (WPRCUR)
TC_t = Total Alaskan natural gas consumption (MMcf) (AK_CONS_S + AK_CONS_N)

Notes: (1) Variables displayed in parentheses are used in the source code.
(2) Industrial Alaskan natural gas consumption was read in Bcf, but was converted in MMCF for performing a regression estimate. The forecast values from the above equation are in MMcf.

Variables:
AK_C Parameters for Alaskan residential natural gas consumption (Appendix E).
AK_D Parameters for Alaskan commercial natural gas consumption (Appendix E).
AK_E Parameters for Alaskan industrial natural gas consumption (Appendix E).

Data used in estimating parameters in Tables F1 and F2
(Bcf, 87$/mcf)

YEAR	YR	YC	YI	YE	PD	RN	CN	WP
1969	4.573	11.018	13.653	6.618	50.864	14.000	4.000	.7164
1970	6.211	12.519	14.744	8.198	111.576	15.000	4.000	.6789
1971	6.893	14.256	10.628	10.260	121.618	18.000	3.000	.6213
1972	8.394	16.011	12.328	13.085	125.596	21.000	3.000	.3721
1973	5.024	12.277	14.985	15.400	130.007	23.000	3.000	.3521
1974	4.163	13.106	13.976	17.117	128.935	22.000	4.000	.3669
1975	10.393	14.415	22.388	19.619	160.270	25.000	4.000	.5908
1976	10.917	14.191	26.687	22.204	166.072	28.000	4.000	.7267
1977	11.282	14.564	49.302	23.534	187.889	30.000	5.000	.6998
1978	12.166	15.208	77.138	24.431	203.088	33.000	5.000	.8490
1979	7.313	15.862	92.733	28.295	220.754	36.000	6.000	.7814
1980	7.917	16.513	69.773	28.763	230.588	37.000	6.000	1.0044
1981	7.904	16.650	53.083	29.071	242.564	40.000	6.000	.7795
1982	10.554	24.232	77.621	30.988	264.364	48.000	7.000	.7458
1983	10.434	24.693	74.641	31.348	276.691	55.000	8.000	.8287
1984	11.833	24.654	72.465	31.582	286.280	63.000	10.000	.7992
1985	13.256	20.344	75.676	34.194	314.643	65.000	10.000	.7824
1986	12.091	20.874	60.439	34.409	300.635	66.000	11.000	.5155
1987	12.256	20.224	67.467	30.530	340.247	68.000	11.000	.9400
1988	12.529	20.842	67.805	30.841	355.398	68.612	11.649	1.2257
1989	13.589	21.738	59.341	32.746	373.797	69.540	11.806	1.2599
1990	14.165	21.622	76.849	34.366	381.431	70.808	11.921	1.2252
1991	13.562	20.897	75.637	31.330	409.381	72.565	12.071	1.2640
1992	14.350	21.299	80.938	28.953	411.593	74.268	12.204	1.1717
1993	13.858	20.003	75.795	28.025	398.093	75.842	12.359	1.1501
1994	14.895	20.698	61.404	29.048	524.457	77.670	12.475	1.0042
1995	15.231	24.979	64.977	29.809	434.498	79.474	12.584	1.2678
1996	16.179	27.315	75.616	31.767	442.375	81.348	12.732	1.2218
1997	15.146	26.908	73.599	33.511	426.776	83.596	12.945	1.3552

Table F2

Data: Exogenous forecast of the number of residential and commercial customers in Alaska

Author: Chetha Phang, EIA, July 8, 1999.

Source: *Natural Gas Annual* (1985-1997), DOE/EIA-0131.

Derivation: The number of residential consumers represents the number of residential households. In the last 25 years this number has been steadily increasing, mirroring the population growth in Alaska. Since the current year population is highly dependent on the previous year population, the number of residential consumers was estimated based on its lag value, as follows:

$$\log(RN_t) = 0.2817 + 0.9420 * \log(RN_{t-1})$$
$$t = \quad (4.4) \quad (56)$$
$$R^2 = 0.99$$
$$DW = 1.50 \text{ (rho is not statistically significant)}$$

This translates into the following forecast equation:

$$RN_t = 1.3254 * RN_{t-1}^{0.942}$$

The number of commercial consumers, based on billing units, showed also a strong relationship to its lag value. The forecast equation is determined as follows:

$$\log(CN_t) = 0.0827 + 0.9792 * \log(CN_{t-1})$$
$$t = \quad (1.04) \quad (25)$$
$$R^2 = 0.96$$
$$DW = 1.96 \text{ (rho is not statistically significant)}$$

This translates into the following forecast equation:

$$CN_t = 1.0862 * CN_{t-1}^{0.9792}$$

Units: Thousands of customers.

Variables:

AK_RN	Number of residential natural gas customers (thousands) in Alaska (Appendix E)
AK_CN	Number of commercial natural gas customers (thousands) in Alaska (Appendix E)

Table F3

Data: Coefficients for the following PTM forecasting equations: depreciation, depletion, and amortization expenses for existing capacity (as of 1996); 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

Source: Pipeline Financial Data, 1988-1996

Derivation: Estimations are done by using accounting algorithm or forecast software. Forecasts are based on a series of Fortran-based econometric equations which have been estimated using the Time Series Package (TSP) software. Equations are estimated by arc: depreciation, depletion, and amortization expenses for existing capacity (as of 1996); 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 Depreciation, Depletion, and Amortization for Existing Capacity

(a) existing capacity (as of 1996)

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

where,

$\beta_{0,a}$	=	constant term estimated by arc (see Table F3.1, $\beta_{0,a} = ARC_{xx\_yy}$)
	=	DDA_C (Appendix E)
$\beta_1, \beta2$	=	(0.036961, 0.022273)
	=	DDA_NPIS, DDA_NEWCAP (Appendix E)
t-statistic	=	(24.1) (12.2)
DW	=	1.98
R-Squared	=	0.929

(b) new capacity (generic pipelines)

A regression equation is not used for the new capacity; instead, an accounting algorithm is used (presented in Chapter 6).

(2) Accumulated Deferred Income Taxes for the Combined Existing and New Capacity

$$ADIT_{a,t} = \beta_{0,a} + \beta_1 * ADIT_{a,t-1} + \beta_2 * NEWCAP_{a,t}$$

where,

$\beta_{0,a}$	=	constant term estimated by arc (see Table F3.2, $\beta_{0,a} = ARC_{xx\_yy}$)
	=	ADIT_C (Appendix E)
$\beta_1, \beta2$	=	(0.78573, 0.035632)
	=	ADIT_ADIT, ADIT_NEWCAP (Appendix E)
t-statistic	=	(19.4) (7.5)
DW	=	2.19
R-Squared	=	0.99

(3) Total Operating and Maintenance Expense for the Combined Existing and New Capacity

$$
\begin{aligned}
R\_TOM_{a,t} = {} & e^{(\beta_{0,a} * (1-\rho))} * GPIS_{a,t}^{\beta_1} * e^{(\beta_2 * NEWCAP_{a,t})} * e^{(\beta_3 * DEPSHR_{a,t-1})} * \\
& e^{(\beta_4 * CARRIAGE\_T_{a,t})} * R\_TOM_{a,t-1}^{\rho} * GPIS_{a,t-1}^{-\rho * \beta_1} * \\
& e^{(-\rho * \beta_2 * NEWCAP_{a,t-1})} * e^{(-\rho * \beta_3 * DEPSHR_{a,t-2})} * \\
& e^{(-\rho * \beta_4 * CARRIAGE\_T_{a,t-1})}
\end{aligned}
$$

where,

$\beta_{0,a}$	=	constant term estimated by arc (see Table F3.3, $\beta_{0,a} = ARC_{xx\_yy}$)
	=	TOM_C (Appendix E)
$\beta_1, \beta_2, \beta_3, \beta_4$	=	(0.38534, 0.402357E-06, 0.59488, -1.52088)
	=	TOM_GPIS, TOM_NEWCAP, TOM_DEPSHR, TOM_CARR (Appendix E)
t-statistic	=	(4.2) (4.0) (2.3) (12.3)
ρ	=	0.182106
	=	TOM_RHO (Appendix E)
t-statistic	=	(3.3)
DW	=	1.66
R-Squared	=	0.99

Variables:

DDA_E	=	annual depreciation, depletion, and amortization costs for existing capacity in dollars
NPIS_E	=	net plant in service for existing capacity in dollars
NEWCAP_E	=	change in existing gross plant in service (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 >= 1997)
ADIT	=	accumulated deferred income taxes in dollars
NEWCAP	=	change in gross plant in service between t and t-1 (in dollars)
R_TOM	=	total operating and maintenance cost for existing and new capacity (1992 real dollars)
GPIS	=	capital cost of plant in service for existing and new capacity in dollars (not deflated)
NEWCAP	=	amount of gross plant in service (dollars) added to arc a during year t
DEPSHR	=	ratio of accumulated DDA to GPIS measured at the beginning of year t
CARRIAGE_T	=	fraction of pipeline throughput accounted for by the third party transportation (this variable is included to account for the effect of open access on the cost efficiency of the pipelines. It is set to 1 in the code to fully account for the effect of open access.)
a	=	arc
t	=	forecast year

Notes: None.

Units: Nominal dollars; except R_TOM (1992 real dollars – later converted to nominal) and DEPSHR and CARRIAGE_T (fractions)

Reference: "Memorandum describing the estimated and forecast equations for TOM, DDA, CWC, and ADIT for the new PTM" by Science Applications International Corporation, January 21, 1999.

Table F3.1. Summary Statistics for Depreciation, Depletion, and Amortization Equation with Dummy Variables

Coefficient	Estimated Value	Standard Error	t-statistic
ARC01_01	41.7205	6.83659	6.10253
ARC02_01	9103.53	1357.14	6.7079
ARC02_02	8254.88	1354.41	6.09481
ARC02_03	3124.67	1369.38	2.28181
ARC02_05	887.744	133.293	6.66008
ARC03_02	12295.9	1868.47	6.58076
ARC03_03	6217	1397.7	4.44802
ARC03_04	2125.87	894.032	2.37785
ARC03_05	9154.56	999.044	9.16332
ARC03_15	-10.3839	195.614	-0.053084
ARC04_03	17521	10596.9	1.65341
ARC04_04	3292.56	5984.74	0.550159
ARC04_07	1392.2	170.077	8.18569
ARC04_08	178.744	280.658	0.636874
ARC05_02	23846.2	2972.18	8.02313
ARC05_03	832.118	640.575	1.29902
ARC05_05	600.983	116.08	5.17732
ARC05_06	747.679	641.278	1.16592
ARC06_03	32756.2	3281.98	9.9806
ARC06_05	33211.8	5415.85	6.13233
ARC06_06	8158.16	981.358	8.31314
ARC06_07	149.105	181.174	0.822993
ARC06_10	4797.42	900.124	5.32974
ARC07_04	31241.9	5227.9	5.97599
ARC07_06	85215.8	5607.43	15.1969
ARC07_07	29125.2	4760.52	6.11807
ARC07_11	5674.28	1344.14	4.22149
ARC08_04	164.596	1644.66	0.100079
ARC08_07	377.865	63.3527	5.96447
ARC08_08	4297	686.712	6.25735
ARC08_09	127.903	222.301	0.575359
ARC08_11	-134.267	433.28	-0.309886
ARC09_08	646.405	391.764	1.64999
ARC09_09	158.905	242.376	0.655615
ARC09_12	-365.946	989.53	-0.369818
ARC10_10	13.7997	1.731	7.97206
ARC11_07	4484.85	581.22	7.71627
ARC11_08	270.886	242.329	1.11784
ARC11_11	372.365	701.211	0.531032
ARC11_12	456.264	962.723	0.473931
ARC14_02	385.979	69.2817	5.57116
ARC16_04	2607.03	1024.18	2.54548
ARC17_04	-487.173	1690.4	-0.2882
ARC18_09	-478.868	1371.55	-0.349144
ARC19_09	2178.7	1415.45	1.53923
ARC20_07	548.025	58.0579	9.43928

Table F3.2. Summary Statistics for Accumulated Deferred Income Tax Equation with Dummy Variables

Coefficient	Estimated Value	Standard Error	t-statistic
ARC01_01	81.303	19.2702	4.2191
ARC02_01	15475.6	3509.45	4.4097
ARC02_02	23705	8431.5	2.81148
ARC02_03	10436.9	2265.42	4.60704
ARC02_05	1598.04	375.83	4.25203
ARC03_02	13431.4	2693.82	4.98599
ARC03_03	13130.6	2797.18	4.69423
ARC03_04	3263.3	2441.61	1.33654
ARC03_05	16669.2	3198.17	5.2121
ARC03_15	341.743	93.224	3.66583
ARC04_03	44151.7	8774.6	5.03177
ARC04_04	55190.1	10904.5	5.06124
ARC04_07	2074.59	411.317	5.04379
ARC04_08	1785.84	781.046	2.28647
ARC05_02	37297.3	7642.86	4.88002
ARC05_03	3403.02	745.563	4.56436
ARC05_05	1580.65	392.031	4.03196
ARC05_06	2752.51	612.537	4.49363
ARC06_03	45954.7	9095.33	5.05256
ARC06_05	43604.2	10273	4.24454
ARC06_06	5985.07	2704.47	2.21303
ARC06_07	1573.44	535.023	2.94088
ARC06_10	834.118	2036.64	0.409555
ARC07_04	48319.6	11030.2	4.38066
ARC07_06	83739.9	18392.9	4.55285
ARC07_07	53577.6	15239.3	3.51575
ARC07_11	17119.2	10167	1.6838
ARC08_04	16034.1	3649.19	4.39389
ARC08_07	618.407	209.004	2.95884
ARC08_08	8988.77	1829.22	4.91398
ARC08_09	1467.3	660.167	2.22263
ARC08_11	6412.26	2286.04	2.80497
ARC09_08	2221.25	1160.49	1.91406
ARC09_09	1689.58	740.662	2.28117
ARC09_12	6100.93	3007.07	2.02886
ARC10_10	4.72151	5.04229	0.936382
ARC11_07	7661.01	1788.69	4.28302
ARC11_08	1232.68	1106.18	1.11435
ARC11_11	8468.82	4349.4	1.94712
ARC11_12	11242	5981.52	1.87946
ARC14_02	517.195	125.35	4.12602
ARC16_04	11945.9	3198.33	3.73505
ARC17_04	14317	3160.78	4.52957
ARC18_09	8877.78	4308.92	2.06033
ARC19_09	8811.37	4147.77	2.12436
ARC20_07	960.088	189.203	5.07439

Table F3.3. Summary Statistics for Total Operating and Maintenance Expense Equation with Dummy Variables

Coefficient	Estimated Value	Standard Error	t-statistic
ARC01_01	3.22886	0.829331	3.89333
ARC02_01	6.49904	1.31344	4.94812
ARC02_02	7.12327	1.30395	5.46285
ARC02_03	6.70714	1.2437	5.39288
ARC02_05	5.3744	1.10901	4.84611
ARC03_02	6.6596	1.34283	4.95939
ARC03_03	6.69983	1.32916	5.04066
ARC03_04	6.1485	1.22034	5.03836
ARC03_05	6.88139	1.32474	5.19453
ARC03_15	4.521	0.993566	4.55027
ARC04_03	7.38456	1.44664	5.10464
ARC04_04	6.50326	1.34444	4.83715
ARC04_07	5.7209	1.16523	4.90967
ARC04_08	5.8189	1.12973	5.15068
ARC05_02	7.31778	1.40878	5.19442
ARC05_03	6.12116	1.15418	5.30345
ARC05_05	5.50026	1.08653	5.06223
ARC05_06	5.98816	1.14636	5.22365
ARC06_03	7.59196	1.45091	5.23255
ARC06_05	7.38441	1.43943	5.13011
ARC06_06	6.58472	1.33863	4.91899
ARC06_07	5.1469	1.0785	4.77226
ARC06_10	5.91492	1.26349	4.6814
ARC07_04	7.64189	1.46822	5.20489
ARC07_06	7.81904	1.52641	5.12249
ARC07_07	7.5999	1.45722	5.21533
ARC07_11	6.94289	1.36914	5.07097
ARC08_04	5.56949	1.21689	4.57682
ARC08_07	4.95311	1.04224	4.75238
ARC08_08	6.49259	1.26568	5.12971
ARC08_09	4.75927	1.09632	4.34113
ARC08_11	5.7622	1.2028	4.79066
ARC09_08	5.0983	1.15496	4.41425
ARC09_09	4.83923	1.10428	4.38226
ARC09_12	5.52799	1.21716	4.5417
ARC10_10	2.3024	0.745787	3.08721
ARC11_07	6.43222	1.3028	4.93723
ARC11_08	5.25445	1.137	4.62134
ARC11_11	6.26685	1.27402	4.91896
ARC11_12	6.44852	1.29955	4.96212
ARC14_02	4.58542	1.03044	4.44996
ARC16_04	5.63366	1.25106	4.5031
ARC17_04	3.4096	1.16916	2.91628
ARC18_09	5.746	1.25133	4.59192
ARC19_09	5.88874	1.27134	4.63191
ARC20_07	5.15703	1.0704	4.81787

Table F4

Data: Parameter estimates for the average cost of capital component in the total cost equation of the Distributor Tariff Module.

Author: Chetha Phang, EIA, September 1996.

Sources: National Income and Product Accounts, Bureau of Economic Analysis, Dept of Commerce (MC_PGDP).
Moody's Investor's Service, Inc. (MC_RMPUAANS)
Board of Governors of the Federal Reserve System Statistical Release G.13, "Selected Interest Rates and Bond Prices" (RMGFCM@10NS)
U.S. Department of Labor, Bureau of Labor Statistics (WPISOP3500)
Mary L. Barcella, Ph.D., Consulting Economist, 2944 Davenport St., N.W., Washington, D.C. 20008 (AVG_COSTCAP)

Note: MC_REALRMGBLUS = RMGFCM@10S -
100 * ((WPISOP3500(1) / WPISOP3500(13))$^{(1/3)}$ - 1)

Derivation: Parameters were estimated for the LDC cost of capital equation, as a function of the previously used proxy for the LDC cost of capital and a time trend, using the method of Ordinary Lease Squares (OLS). The exponent used on the time variable is an assumed value, resulting in a decreasing nonlinear time trend ($T^{-0.7}$). Due to a lack of data it was not possible to obtain a 20-year average for the yield on AA utility bonds. Therefore from 1978 through 1993 the value of AVG_RMPUAANS was based on the average over the available years of data only (e.g., for 1978 a five year average was used). The LDC cost of capital is defined as follows:

AVGCOSTCAP = 7.44691 + (1.22689 * AVG_COSTCAP_OLD) + (72.60079 * $T^{-0.7}$)
t-statistic = (0.876) (0.933) (6.223)
N = 12, R-Squared = 0.849, Durbin-Watson = 1.40
[The coefficient on the time trend (72.60079) was mistyped in the code as (71.60079).]

Variables:

AVG_COSTCAP	Average LDC cost of capital as used in estimated equation for total cost of capital (1994$/$100 of capital)
AVG_COSTCAP_OLD	Previously used proxy for average LDC cost of capital, as defined using MC_RMPUAANS, NG_REALRMGBLUS, MC_PGDP, and WT_DEBT as described in Chapter 5.
T	Time trend, where T=1 for 1980
MC_RMPUAANS	Yield on AA utility bonds (percent per annum, not seasonally adjusted)
NG_REALRMGBLUS	Real average yield on 10-year U.S. Government Bonds, Constant maturity (percent)
MC_PGDP	Implicit price deflator for gross domestic product
RMGFCM@10NS	Yield on 10-year U.S. Treasury notes, Constant Maturity (percent per annum, not seasonally adjusted, average of daily figures, bond yield equivalent basis)
WPISOP3500	Producer price index, finished goods, excluding food and energy (Index base: 1982=1.00, seasonally adjusted)
WT_DEBT	weighting for debt/equity contribution to cost of capital

Data used in estimating parameters in Table F4

YEAR	T	MC_RMPUAANS	NG_REALRMGBLUS	MC_PGDP	AVG_COSTCAP
1974	--	9.04	--	0.463	--
1975	--	9.44	--	0.508	--
1976	--	8.92	--	0.537	--
1977	--	8.43	--	0.572	--
1978	--	9.10	2.17	0.613	--
1979	--	10.22	2.28	0.665	--
1980	1	12.99	2.66	0.727	--
1981	2	15.29	4.32	0.795	51.48
1982	3	14.78	4.13	0.845	44.15
1983	4	12.83	4.59	0.881	38.82
1984	5	13.67	8.25	0.913	41.03
1985	6	12.07	7.81	0.946	35.06
1986	7	9.31	5.33	0.970	28.23
1987	8	9.77	5.98	1.000	28.90
1988	9	10.26	6.29	1.036	31.15
1989	10	9.55	5.28	1.079	31.51
1990	11	9.66	4.92	1.127	30.23
1991	12	9.10	3.93	1.171	26.97
1992	13	8.55	3.62	1.203	23.72
1993	14	7.43	3.21	1.235	21.64

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* 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 Region from 1988, 1991, and 1994 Manufacturing Energy Consumption Surveys (MECS) were used. The procedure outlined below is used in the NGTDM to fill in the intermediate years and expand the regional detail. Through a special request the Census Bureau generated the MECS data used in the NGTDM 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.

Notes:
supply price = average of wellhead and import prices
markup = end-use price minus supply price
type = core or noncore

1) Calculate markups based on MECS data by Census Region, by type, in MECS years.
2) Linear interpolate to get intervening years data for MECS based markups and industrial consumption by Census Region and type.
3) For years beyond the last MECS year, set MECS based markups to the value from the last MECS year and set MECS industrial consumption by applying growth rates (equal to observed growth in NEMS consumption levels) to the consumption in the last MECS year. by Census region and type.
4) Set end-use industrial MECS based prices for all historical years equal to the supply price plus markup, by Census Region and type.
5) Scale the prices in step #4 by a factor that will insure that the resulting prices, when averaged (across types in each Census Region) based on NEMS consumption level weights will equal the prices from step #4 averaged based on MECS consumption level weights.
6) Calculate markups equal to the supply price minus the prices calculated in step 5 by Census Region and type.
7) Add these markups to the average supply price in each NGTDM region, within the associated Census Region, to derive industrial natural gas prices by NGTDM region and type.
8) Scale the prices in step #7 by a factor that will insure that the resulting prices, when averaged (across types and across NGTDM regions in each Census Region) based on NEMS consumption level weights will equal the prices from step #4 averaged based on MECS consumption level weights, to arrive at HPIN_F and HPIN_I.
9) Scale peak and offpeak industrial prices from the Natural Gas Monthly to equal the annual weighted average of the HPIN_F and HPIN_I to arrive at HPGFINGR and HPGIINGR, respectively

Variables:

MPIN_CRG	Industrial core and noncore natural gas price from MECS by Census Region, in MECS survey years (Appendix E, $1987/Mcf)
MQIN_CRG	Industrial core and noncore natural gas consumption from MECS by Census Region, in MECS survey years (Appendix E, Bcf)
PW_CRG	Average natural gas wellhead price by Census Region, in MECS survey years (Appendix E, $1987/Mcf)
HPIN_F	Resulting industrial core natural gas price by NGTDM region (1987$/Mcf)
HPIN_I	Resulting industrial noncore natural gas price by NGTDM region (1987$/Mcf)
HPGFINGR	Resulting industrial core natural gas price by period and NGTDM Division (1987$/Mcf)
HPGIINGR	Resulting industrial noncore natural gas price by period and NGTDM Division (1987$/Mcf)

Appendix G

Variable Cross Reference Table

With the exception of the Pipeline Tariff Module (PTM) all of the equations in this model documentation report are the same as those used in the model Fortran code. Table G-1 presents cross references between model equation variables defined in this document and in the Fortran code for the PTM.

Table G-1. Cross Reference of PTM Variables Between Documentation and Code

Documentation	Code Variable	Equation #
$R_{i,f}$	Not represented	107
$R_{i,v}$	Not represented	108
ALL_f	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	107
ALL_v	AVA_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	108
R_i	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	107
FC_a	Not represented	109
VC_a	Not represented	110
$R_{i,f,r}$	RFC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	111
$R_{i,f,u}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	112
$R_{i,v,r}$	RVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	113
$R_{i,v,u}$	UVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	114
$ALL_{f,r}$	AFR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	111
$ALL_{f,u}$	AFU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	112
$ALL_{v,r}$	AVR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	113
$ALL_{v,u}$	AVU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	114
ξ_i	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	174
$Item_{i,a,t}$	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	174, 175, 177, 178, 179, 180
$FC_{a,t}$	Not represented	174

$VC_{a,t}$	Not represented	175
$TCOS_{a,t}$	Not represented	176, 181
$RFC_{a,t}$	RFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	177
$UFC_{a,t}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	178
$RVC_{a,t}$	RVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	179
$UVC_{a,t}$	UVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	180
λ_i	AFR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	177, 178
μ_i	AVR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	179, 180
a - arc, t - year, i - cost-of-service component index		

APPENDIX I

Ethanol Supply Model

Appendix I. Ethanol Supply Model

I.1 Model Purpose

The objective of the ethanol supply model is to provide the NEMS Petroleum Market Module (PMM) with supply curves for corn and cellulose based ethanol, thus allowing the PMM to forecast transportation ethanol demand throughout the NEMS forecast period. To be consistent with the market clearing mechanism adopted for NEMS, the model provides ethanol prices in the form of annual price-quantity curves. The curves, derived from an ethanol production cost function, represent the prices of ethanol at which associated quantities of transportation ethanol are expected to be available for production of E85 and ETBE, and for blending with gasoline.

The delivered ethanol prices are provided to the PMM linear program in the form of a unique supply curve for each of the nine U.S. Census Divisions. The majority of ethanol currently produced in the United States is made from corn and is produced in the East North Central Census Division (NEMS region 3), and the West North Central Census Division (NEMS region 4). Smaller amounts are available in the East South Atlantic (NEMS region 6), the Mountain (NEMS region 8), and the Pacific (NEMS region 9) Census Divisions. The PMM also models planned cellulose based ethanol production beginning in 2001 in the Middle Atlantic (NEMS region 2) and West South Atlantic (NEMS region 7) Census Divisions. The majority of growth in cellulose ethanol production, however, is forecasted for Census Divisions 3 and 4, where large quantities of corn stover (the most likely biomass feedstock) are available, and in Census Division 9, where ethanol demand is expected to grow in response to the California ban on MTBE in reformulated gasoline.

I.2 Corn-Based Ethanol

Fundamental Assumptions

The corn-based ethanol model uses a process costing approach to model the impacts of net feedstock production costs plus the capital, operating, and process energy costs associated with converting the corn feedstocks to ethanol. In other words, each of the above factors contributes a part of the total price of ethanol.

To determine the delivered ethanol price, the contribution of the net cost of corn feedstock production must be factored in to the total unit price of ethanol. Net cost of corn feedstock is the price of corn less the price of the co-products produced in the conversion of corn to ethanol. Conversion of corn to ethanol is accomplished by either a wet milling or dry milling process. The co-products produced from the wet milling process are corn gluten feed (CGF), corn gluten meal (CGM), and corn oil, while the dry milling process produces distillers dried grains (DDGS). Prices for corn and corn co-products are obtained from the USDA Agricultural Baseline

Projections to 2008. Wet milling accounts for about 60 percent of current total ethanol production, while new ethanol facilities are projected to be dry milling plants.[1] Therefore, the first two steps of the corn ethanol supply curves (representing current production) use a net feedstock price calculated assuming 60 percent of co-products are CGM, CGF, and corn oil, and 40 percent are DDGS. The last two steps, representing new capacity, assume co-products are 100 percent DDGS. The variability of the market price for the feedstock corn and the conversion by-products and the variable influences of competitive uses for corn (e.g., for producing corn syrup) gives rise to broad fluctuations in net corn feedstock prices. All of these factors are considered in the USDA model. In addition, the USDA model was run assuming large increases in ethanol production (3 to 4 billion gallons versus current production of 1.4 billion gallons) to capture feedstock price fluctuations with increased ethanol demand. As ethanol production from corn increases, land becomes scarcer, causing both land and feedstock costs to increase, and feed by-products become less valuable as larger feedstock quantities are produced. These runs were used to develop the last two steps of the corn ethanol supply curves. The USDA price projections end in 2008, therefore prices for 2009-2020 were extrapolated from 2008.

In addition to feedstock prices and quantities, the model requires capital cost, feedstock conversion cost (non-energy operating cost), and energy cost data. The cost data were derived from several sources which are documented in the Inventory of Variables, Data, and Parameters section of this report. Note that with this theoretical approach, only the agricultural, or feedstock production costs are modeled as a function of the total quantity of ethanol produced. The conversion plant process costs, (capital, operating, and process energy) are independent of production quantities. The feedstock production cost components are estimated statistically, whereas the conversion process costs are determined from engineering concepts and data. Actual ethanol conversion process data are, for the most part, proprietary.

Capital and conversion costs were assumed to be constant across all Census Divisions and for all forecast years. Energy costs vary across Census Divisions as a function of fuel price. The model assumes wet milling plants consume 20 percent natural gas and 80 percent coal, while dry milling plants consume 50 percent natural gas and 50 percent coal[2]. Natural gas prices are obtained from the NEMS Natural Gas Transmission and Distribution model, and coal prices are from the NEMS Coal Market Model. It was also assumed that the quantity of energy needed for ethanol conversion decreases through the forecast period as ethanol plants become more efficient over time. The supply/price curves in Census Division 3 and 4 also include a $0.10 per gallon credit on steps one and two. This credit is a weighted average of producer incentives and State tax credits offered by various states within these Census Divisions. The ethanol blender's Federal excise tax credit, which is currently $0.054 per gallon of gasohol (10 percent ethanol, 90 percent gasoline), is modeled separately in the PMM.

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[1] Urbanchuk, J.M. 1998. "Review of Alternative Ethanol Supply Curves Used in the Energy Information Administration's National Energy Modeling System".

[2] Wang, M. et al 1997. "Fuel-Cycle Fossil Energy Use and Greenhouse Gas Emissions of Fuel Ethanol Produced from U.S. Midwest Corn".

Key Computations and Equations

Net feedstock costs are calculated in a separate spreadsheet by subtracting USDA projected co-product prices from the price of corn. These costs are tabulated as a function of ethanol production quantity in the PMM input file WETOHIN. This file also contains the capital cost, conversion cost (non-energy operating cost), and energy cost data. Linear interpolations are performed to calculate intermediate yearly values for the quantity of energy consumed at the ethanol plant, and the net feedstock price for each ethanol quantity step. Once the data is read and the interpolations are performed, the ethanol price is calculated from the following equation:

$$PETOH_{cd,t,e} = FC_{t,e} + CAPCST*CCF + OPCST + QEN_t*PEN_{cd,t} - STSUB_{cd} \qquad \text{(I-1)}$$

where:

$PETOH_{cd,t,e}$	=	Delivered price of ethanol produced in Census Division *cd* in year *t* for volume step *e* ($/gal),
$FC_{t,e}$	=	Feedstock corn production cost in year *t* for volume step *e* ($/gal),
$CAPCST$	=	Capital cost for conversion technology ($/gal),
CCF	=	Capital cost factor (dimensionless),
$OPCST$	=	Operating costs, exclusive of energy ($/gal),
QEN_t	=	Quantity of energy needed to convert corn to ethanol in year *t* (MMBtu/gal),
$PEN_{cd,t}$	=	Price of energy used in the corn-to-ethanol conversion process in Census Division *cd* in year *t* ($/MMBtu),
$STSUB_{cd}$	=	State incentive for ethanol production in Census Division *cd* ($/gal).

The price of energy on the first two steps of the supply curve (current production) is calculated assuming 60 percent of the existing plants are wet mills (consuming 20 percent natural gas and 80 percent coal), and 40 percent are dry mills (consuming 50 percent natural gas and 50 percent coal). The price of energy for the last two steps of the supply curve is calculated assuming all new facilities will be dry mill, consuming 50 percent natural gas and 50 percent coal. The price of energy in each case is calculated as follows:

Steps 1 and 2:

$$PEN_{cd,t} = (0.32*PNGIN_{cd,t}) + (0.68*PCLIN_{cd,t}) \quad \textbf{(I-2)}$$

Steps 3 and 4:

$$PEN_{cd,t} = (0.50*PNGIN_{cd,t}) + (0.50*PCLIN_{cd,t}) \quad \textbf{(I-3)}$$

where:

$PNGIN_{cd,t}$ = Industrial price of natural gas for Census Division *cd* in year *t* ($/MMBtu),

$PCLIN_{cd,t}$ = Industrial price of coal for Census Division *cd* in year *t* ($/MMBtu).

The capital cost factor (CCF) used in equation I-1, which is based on a 8-year amortization period, is calculated as follows:

$$CFF = MC\_RMPUAANS_t * (1 + MC\_RMPUAANS_t)^8 / ((1 + MC\_RMPUAANS_t)^8 - 1) \quad \textbf{(I-4)}$$

where:

$MC\_RMPUAANS_t$ = yield on AA-grade utility bonds in year *t* (a Macroeconomic Activity Module output variable).

Inventory of Variables, Data, and Parameters

<u>MODEL INPUT</u>: *CAPCST*

<u>DEFINITION</u>: Capital cost for conversion technology for crop *I* in year *t*.

The current value is $1.00 per gallon on steps one and two, and $2.00 per gallon on steps three and four of the supply curves. Costs are the same for all years. Located in the WETOHIN input data file.

<u>SOURCE</u>: Walsh, M. et al 1997. *Evolution of the Fuel Ethanol Industry: Feedstock Availability and Price*. Oak Ridge National Laboratory, Oak Ridge, TN.

<u>MODEL INPUT</u>: *OPCST*

<u>DEFINITION</u>: Operating costs, exclusive of energy, for conversion technology of corn.

Value is $0.27/gal. for 2000 thru 2020. Located in the WETOHIN input data file.

<u>SOURCE</u>: USDA/ERS. 1988. *Ethanol: Economic and Policy Tradeoffs*. Agricultural Economic Report No. 585. Resources and Technology Division, Economic Research Service, U.S. Department of Agriculture, Washington, D.C.

<u>MODEL INPUT</u>: *PCLIN*

<u>DEFINITION</u>: Price of coal for industrial use in Census Division *cd* in year *t*.

Located in the Price common block, (MPBLK).

<u>SOURCE</u>: Generated by the Coal Market Model.

<u>MODEL INPUT</u>: *PNGIN*

<u>DEFINITION</u>: Price of natural gas for industrial use in Census Division *cd* in year *t*.

Located in the Price common block, (MPBLK).

<u>SOURCE</u>: Generated by the Natural Gas Transmission and Distribution Model.

MODEL INPUT: *QEN*

DEFINITION: Quantity of energy needed to convert corn to ethanol in year *t*.

Values, in million Btu per gallon, are as follows: 0.050 in 1990, 0.040 in 2005, 0.035 in 2015. This decreasing trend is based on the assumption that energy required decreases linearly over time. Located in the WETOHIN input data file.

SOURCE: Marland, G. and A.F. Turhollow. 1991. "CO_2 Emissions From the Production and Combustion of Fuel Ethanol from Corn." *Energy*, 16(11/12):1307-1316.

I.3 Cellulose-Based Ethanol

Theoretical Approach

The cellulose ethanol model also uses a process costing approach to model the impacts of net feedstock production costs plus the capital, operating, and process energy costs associated with converting the corn feedstocks to ethanol. As with the corn model, each of the above factors contributes a part of the total price of ethanol.

Biomass feedstock supply is not modeled in the Petroleum Market Model ethanol model. Biomass price/quantity data are obtained from the Renewable Fuels Model of NEMS and are used as input to the ethanol model. The "Model Documentation: Renewable Fuels Module of the National Energy Modeling System", DOE/EIA-M069(98) contains a complete description of the approach and assumptions used in generating the biomass feedstock supply functions.

Briefly, the biomass use in NEMS is modeled as two distinct markets, the captive and non-captive biomass markets. The captive market pertains to users with dedicated biomass supplies that obtain energy by burning biomass byproducts resulting from the manufacturing process. The noncaptive market is defined to include the commercial, transportation, and electric utility sectors, as well as the resources marketed in the industrial sector. There is an additional noncaptive market serving residential uses of biomass.

EIA developed a fairly simple model structure consisting of one supply schedule per region. This schedule defines the quantity and cost relationships of biomass resources accessible by all noncaptive, non-residential consumers. It is based on an aggregation of supply/price information from U.S. Forest Service and forest product experts. The wood portion of the cost-supply schedule is static throughout the model period. Energy crop cost-supply schedules are also developed and superimposed onto the wood total.

Fundamental Assumptions

A basic assumption for the biomass feedstock is that the supply price for noncaptive biomass energy is the same across all sectors. Biomass feedstock costs are input from the NEMS Renewable Fuels Model at the Census Division level. Biomass usage by the PMM ethanol model is fed back to the Renewable Fuels Model.

An important modeling consideration for cellulose ethanol production is the imposition of a constraint on the amount of ethanol production capacity assumed for the early years of the forecast. Ethanol from cellulose is relatively new technology and ethanol production from cellulose is currently at the demonstration level. A constraint on cellulose ethanol production prevents unrealistically large increases in production capacity from occurring suddenly in response to favorable market prices. Cellulose ethanol production capacity is allowed to grow 5 percent per year from 2001 to 2005, 10 percent per year from 2006 to 2010, and 15 percent per year after 2010.

In addition to feedstock prices and quantities input from the Renewable Fuels Model, the ethanol model requires feedstock conversion and energy cost data, and capital and operating cost data. The conversion and capital cost data were derived from the Oak Ridge National Laboratory Report *Evolution of the Fuel Ethanol Industry: Feedstock Availability and Price,* Marie Walsh et.al., June, 1997 for year 2000 as follows:

Capital Cost	0.515 $/gal
Operating Cost	0.348 $/gal
Power Credit	-0.157 $/gal
Total Conversion Cost	0.706 $/gal

The AEO 2000 reference case assumes that cellulose conversion technology will improve over time such that full utilization of hemicellulose sugars, combined with modest reductions in cellulase enzyme costs will yield a savings of 27 cents per gallon over year 2000 cost by 2015[3]. The conversion costs are reduced linearly from 2000 to 2015 to a maximum of 27 cents per gallon. Conversion costs are constant from 2015 to 2020. Ethanol production costs are assumed to be constant across the United States, however, feedstock availability and price varies from census division to census division. The largest growth in ethanol production is expected in census regions 3 and 4 where Midwestern corn stover would be desirable raw material because of its large volume, competitive price and proximity to current ethanol production plants. The feedstock available in census region 9 are forest residue and rice straw. Feedstock conversion efficiency also improves over the forecast, from 85 gallons per ton in year 2000 to 103 gallons per ton by 2015. Currently, most state producer and tax incentives (limited by production volume) are at their maximum. Therefore, no state subsidies are assumed in the cellulose ethanol supply/price curves. As with corn-based ethanol, the ethanol blender's Federal excise tax credit, which is currently $0.054 per gallon of gasohol (10 percent ethanol, 90 percent gasoline), is modeled in the PMM.

Key Computations and Equations

The main computations performed by the cellulose portion of the ethanol model involve the derivation of an ethanol supply-price curve for each Census Division. The computations consist of three major steps:

1. Reading in ethanol component cost data from the PMM input file WETOHIN.

[3] National Renewable Energy Laboratory 1999. *Bioethanol Multi-Year Technical Plan*.

2. Obtaining biomass feedstock prices at the census division level from the Renewable Fuels Model.

3. Derivation of delivered ethanol prices, calculated as a function of the biomass feedstock price and the ethanol conversion costs.

Total Conversion Costs are calculated as follows:

$$TOTCONV_t = CAPCST_t + OPCST_t + PWRCDT_t \tag{I-5}$$

where:

$TOTCONV_t$	=	Total ethanol conversion cost for year *t*,
$CAPCST_t$	=	Capital cost for year *t*,
$OPCST_t$	=	Operating cost for year *t*,
$PWRCDT_t$	=	Power credit for co-products combusted and sold as power for year *t*.

The delivered ethanol price equation is as follows:

$$PETOH_{cd,t} = FC_{cd,t} + TOTCONV_t \tag{I-6}$$

where:

$PETOH_{cd,y}$	=	Delivered price of cellulose ethanol in census division *cd* in year *t*
$FC_{cd,y}$	=	Biomass feedstock cost for census division *cd* in year *t*.

Inventory of Variables, Data, and Parameters

MODEL INPUT: *CAPCST*

DEFINITION: Capital cost for conversion technology for cellulose ethanol.

The current value is $0.515 per gallon for year 2000. Located in the WETOHIN input data file.

SOURCE: Marie Walsh et. al., *Evolution of the Fuel Ethanol Industry: Feedstock Availability and Price*. Oak Ridge National Laboratory, June 1997.

MODEL INPUT: *OPCST*

DEFINITION: Operating cost for conversion technology for cellulose ethanol.

The current value is $0.348 per gallon for year 2000. Located in the WETOHIN input data file.

SOURCE: Marie Walsh et. al., *Evolution of the Fuel Ethanol Industry: Feedstock Availability and Price*. Oak Ridge National Laboratory, June 1997.

MODEL INPUT: *PWRCDT*

DEFINITION: Power credit for co-products combusted and sold as power.

The current value is $-0.157 per gallon for year 2000. Located in the WETOHIN input data file.

SOURCE: Marie Walsh et. al., *Evolution of the Fuel Ethanol Industry: Feedstock Availability and Price*. Oak Ridge National Laboratory, June 1997.

MODEL INPUT: *FC*

DEFINITION: Biomass feedstock cost for census division *cd* in year *y*.

Biomass feedstock costs are input from the Renewable Fuels Model under the variable PBMET.

SOURCE: National Energy Modeling System common block WRENEW.