DOE/EIA-M062

Model Documentation

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

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Prepared by:

Oil and Gas Division
Office of Integrated Analysis and Forecasting
Energy Information Administration

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:

Joe Benneche, EI-83
Forrestal Building, Room 2H026
1000 Independence Ave., S.W.
Washington, DC 20585
(202/586-6132)
Joseph.Benneche@eia.doe.gov

This report documents the archived version of the NGTDM that was used to produce the natural gas forecasts presented in the *Annual Energy Outlook 1999*, (DOE/EIA-0383(99)). 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. Previously this report represented Volume I of a two-volume set. Volume II reported on model performance, detailing convergence criteria and properties, results of sensitivity testing, comparison of model outputs with the literature and/or other model results, and major unresolved issues, for the version of the NGTDM used for the *Annual Energy Outlook 1995*, (DOE/EIA-0383(95). There are no plans for producing another version of Volume II in the foreseeable future.

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 2000.

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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

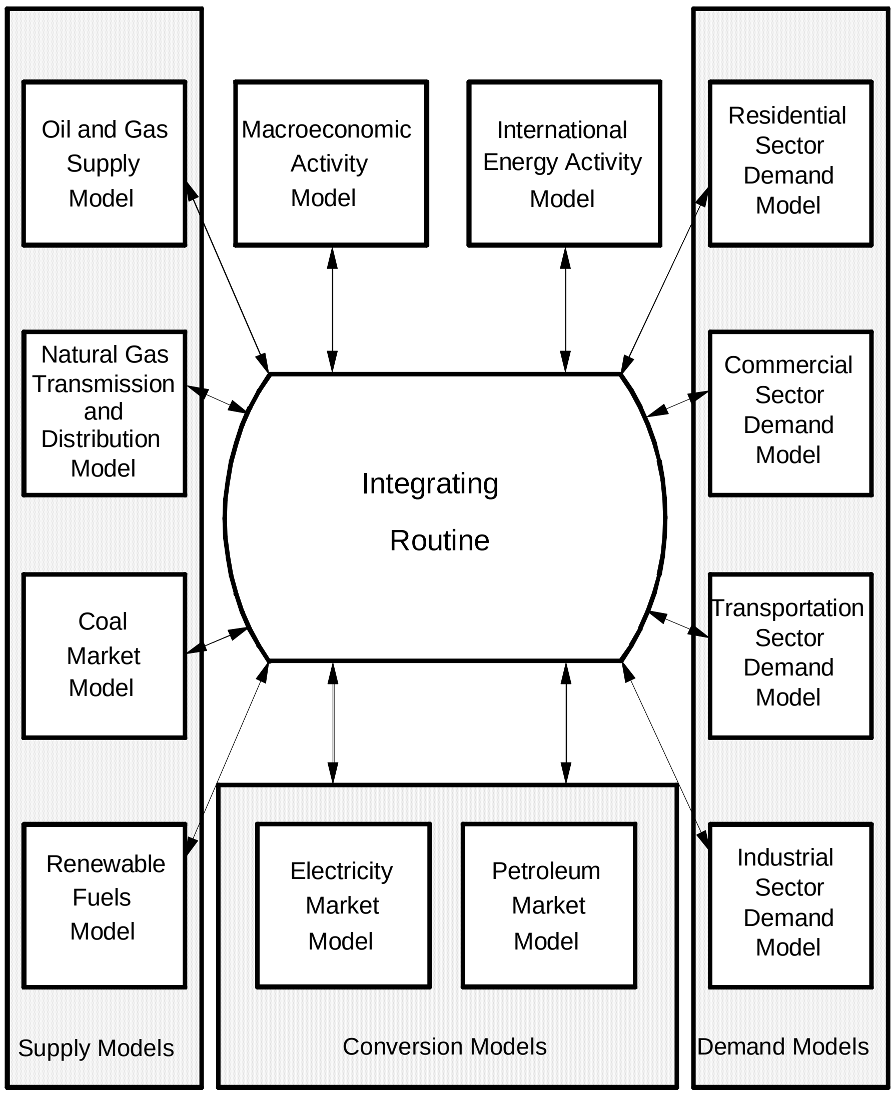
The NGTDM is the model within the NEMS that represents the transmission, distribution, and pricing of natural gas. Based on information received from other NEMS models, the NGTDM also includes representations of the end-use

[1]For the *Annual Energy Outlook 1999* 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 and 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.

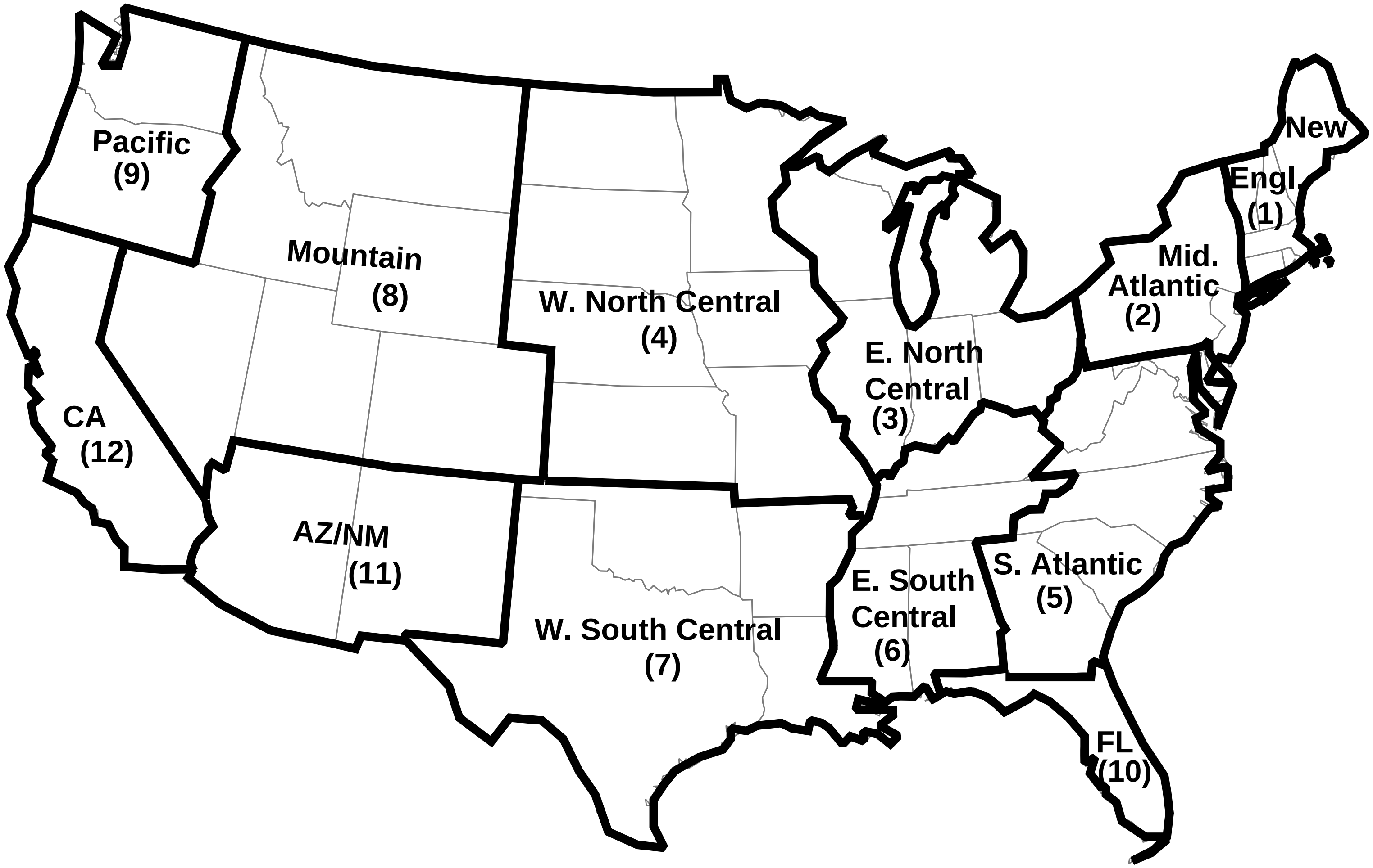
NGTDM Objectives

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 1999*, DOE/EIA-0383(99) is documented in this report. The version of the NGTDM used for the *AEO98* consisted of four modules: the Annual Flow Module, the Capacity Expansion Module, the Pipeline Tariff Module, and the Distributor Tariff Module. For the *AEO99*, the Annual Flow Module and the Capacity Expansion Module were replaced with the Interstate Transmission Module, which combined the functions of the previous two modules into a single structure, while employing a different methodology. The purpose of the 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 1999* 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 NEMS99 (part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1999*, DOE/EIA-0383(99)).

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

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

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 9 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 or 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 accounting for the costs and market for transmission and distribution services (including its physical and regulatory

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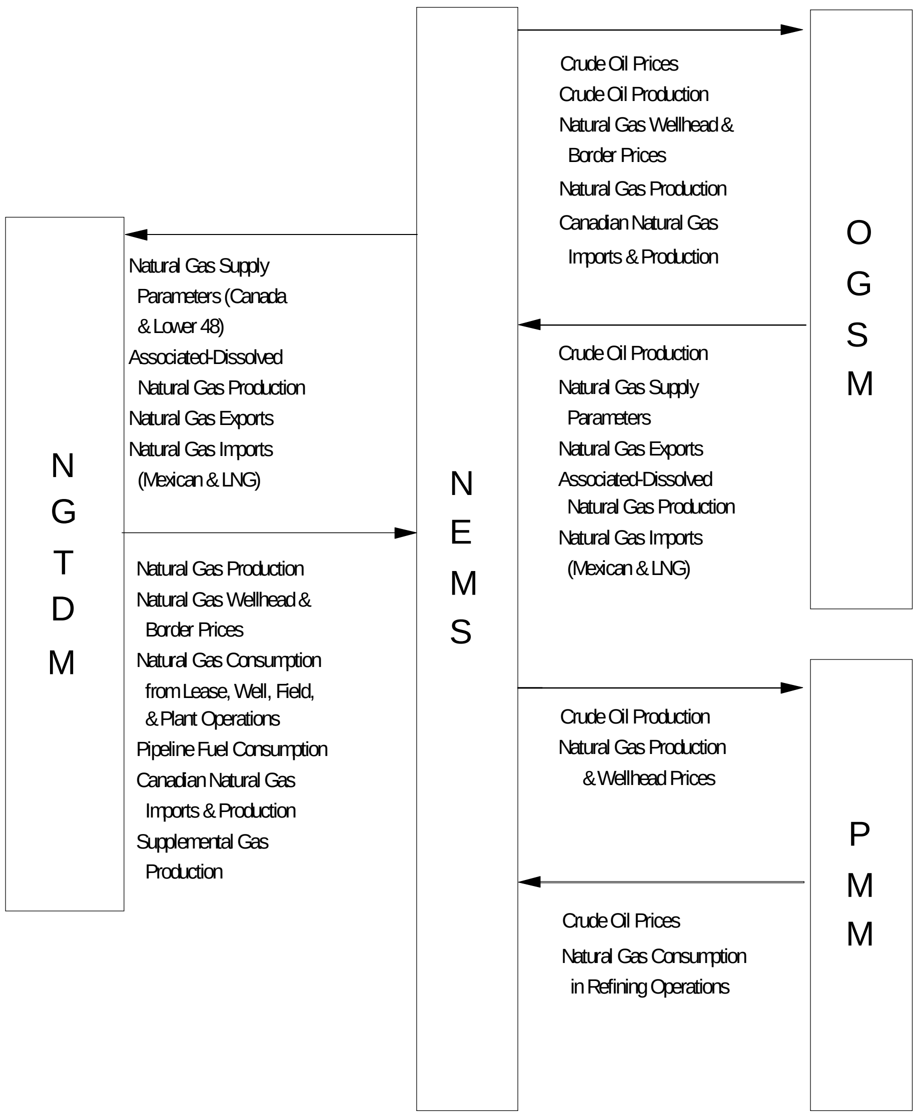
[5]A more detailed description of the NEMS system, including the convergence algorithm used, can be found in "National Energy Modeling System Integrating Module Documentation Report." DOE/EIA-M057(07), May 1997 or “National Energy Modeling System, An Overview,” DOE/EIA-0581(98), February 1998.

[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 cost 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 (1998-2020):

- 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.

- 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 (1990-1997), the 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.

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 and 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 (1990-1997) historical shares (PKSHR_EMEX, PKSHR_ECAN) 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, 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.

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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 1997) 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.

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 9 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 9 North American Electric Reliability Council (NERC) Regions and 4 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 Annual Flow Module 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.

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[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 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 9 Census divisions to the two seasonal periods and the 12 NGTDM regions by applying average historical shares (1990-1997) which are held constant throughout the forecast (census -- NG_CENSHR, seasons -- PKSHR_DMD). For the Pacific Division, natural gas consumption estimates for Alaska are first subtracted to establish a consumption level for just the contiguous Pacific

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

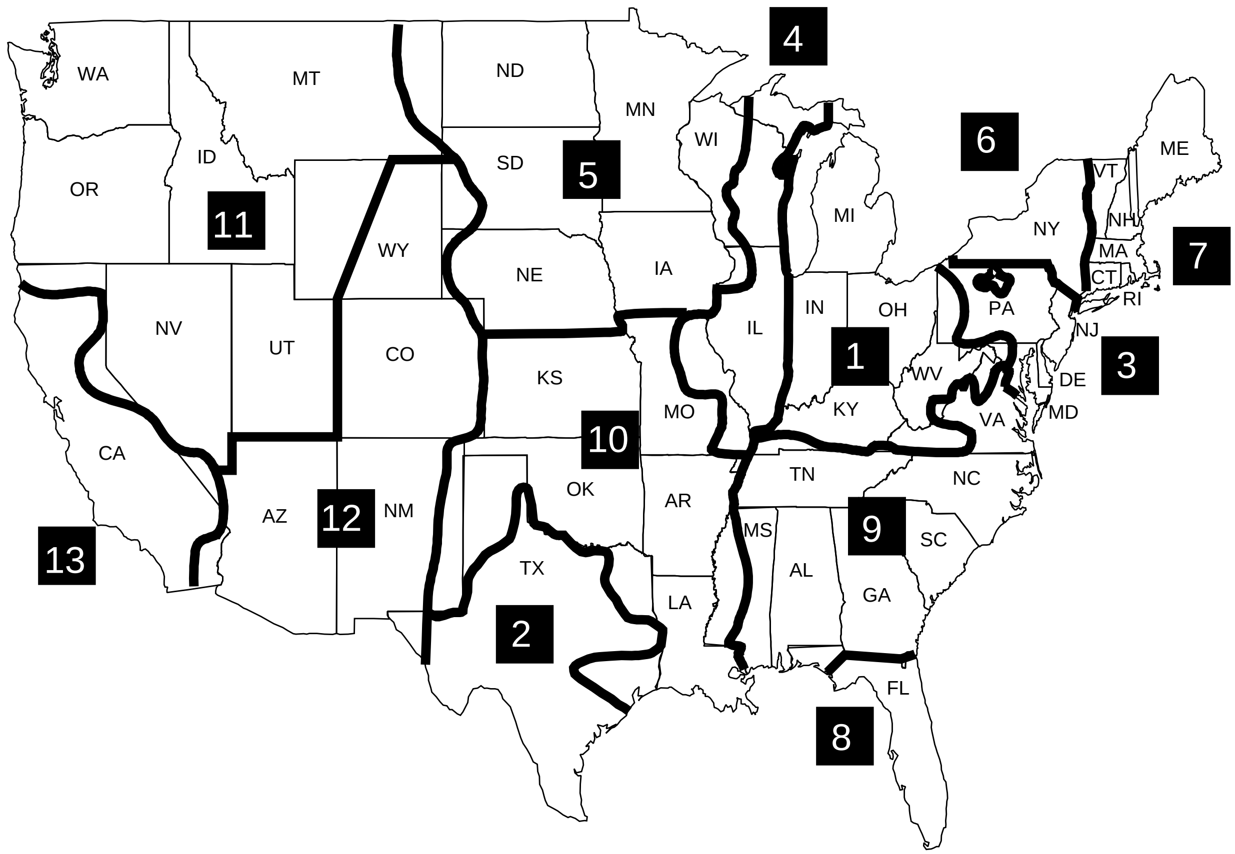
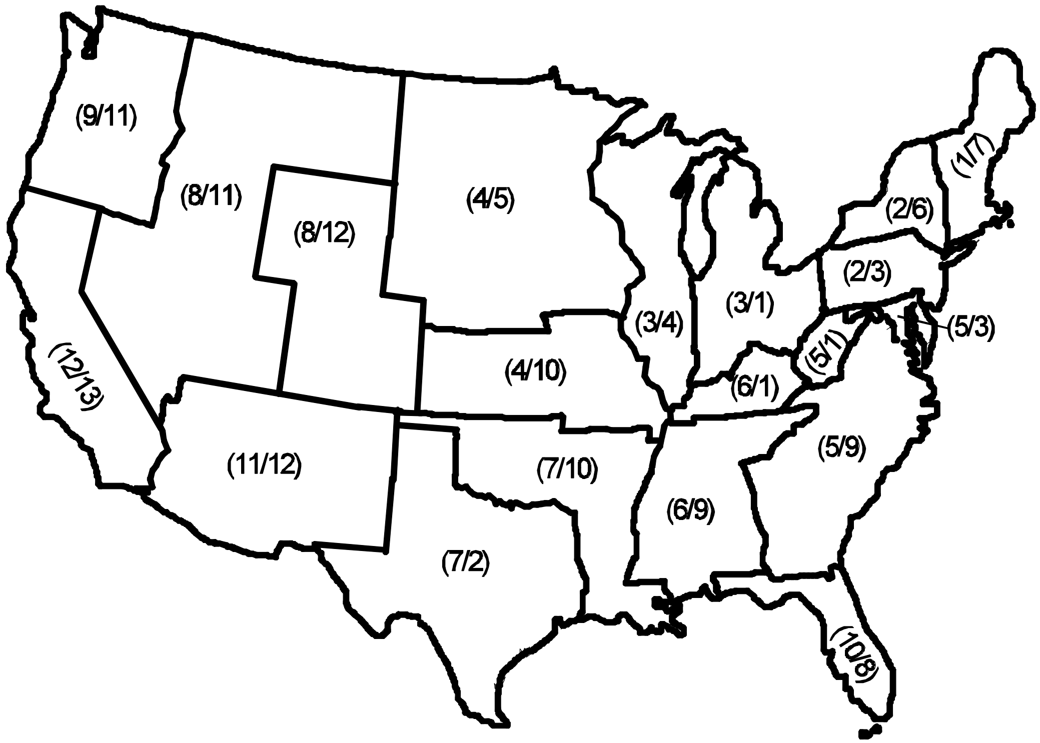


Figure 2-3. Natural Gas Transmission and Distribution Model/Electricity Market Model (NGTDM/EMM) Regions



(NGTDM Region Number/EMM Region Number)

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. The annual consumption levels for each NGTDM/EMM region and customer type (core and noncore) in the electric sector are disaggregated into seasons using average historical shares (1990-1997) which are also held constant over the forecast (core -- PKSHR_UDMD_F, noncore -- PKSHR_UDMD_I).[13]

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:

$$\mathrm{NGDMD\_CRVF}_{s,r} = \mathrm{BASQTY\_F}_{s,r} * (\mathrm{PR} \;/\; \mathrm{BASPR\_F}_{s,r})^{\mathrm{NONU\_ELAS\_F}_s} \quad (1)$$

where,

$\mathrm{BASPR\_F}_{s,r}$	=	end-use price to core sector s in NGTDM region r in the previous NEMS iteration (dollars per Mcf)
$\mathrm{BASQTY\_F}_{s,r}$	=	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)
$\mathrm{NONU\_ELAS\_F}_s$	=	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)
$\mathrm{NGDMD\_CRVF}_{s,r}$	=	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 AEO99* 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 *AEO99* 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

[13]The plan for *AEO2000* is to set seasonal consumption for the electric generator sector based on the six-period seasonal forecast used in the EMM.

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.[14] 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 (1990-1996) 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 there 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. Regional peak and offpeak supply levels for the three supplemental gas supplies are generated by applying the same average (1990-1997) historical share (PKSHR_SUPLM) of national supplemental supplies in the peak period.

Associated-Dissolved Natural Gas Production

Associated-dissolved natural gas refers to the natural gas 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 (1990-1996) historical shares of total (including nonassociated) peak production in the year (PKSHR_PROD).

Natural Gas Imports

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

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

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

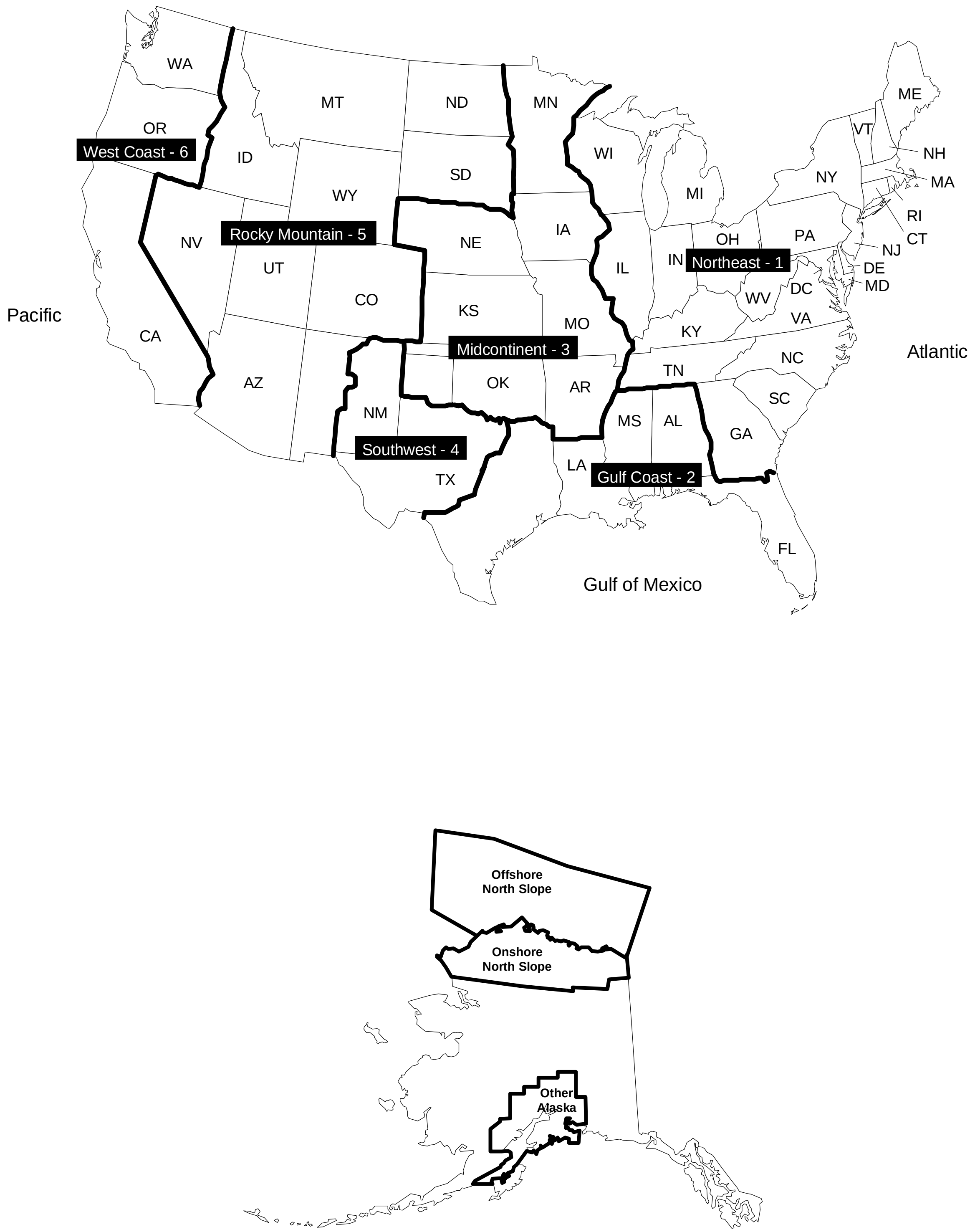
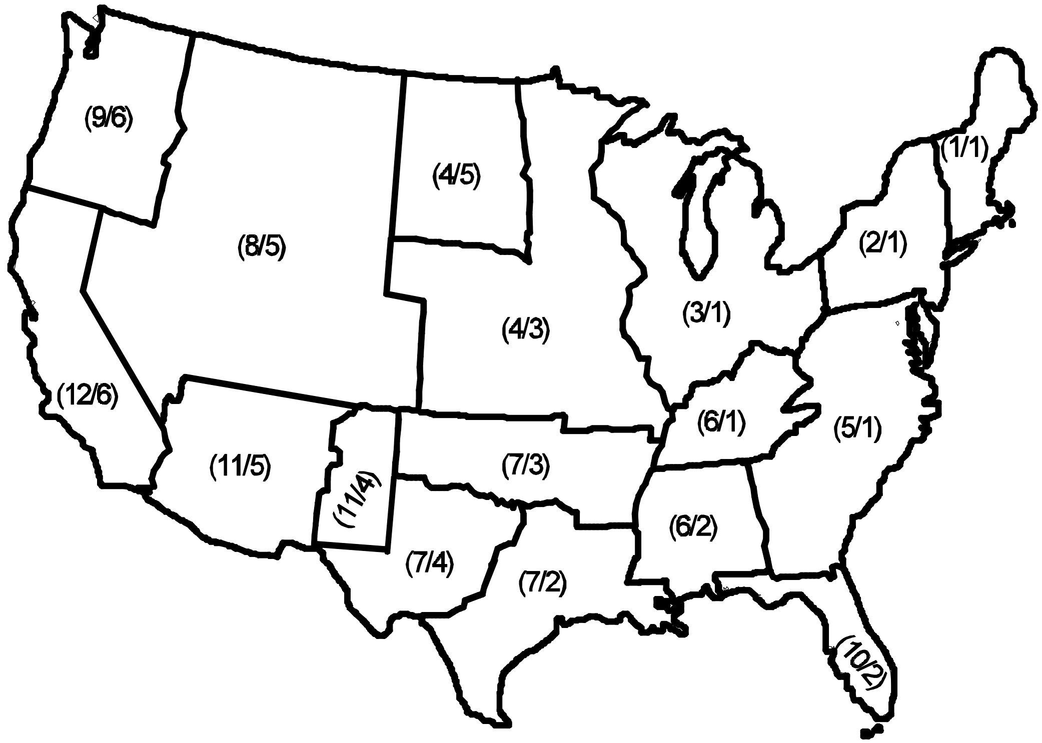


Figure 2-5. Natural Gas Transmission and Distribution Model/Oil and Gas Supply Model (NGTDM/OGSM) Regions



(NGTDM Region Number/OGSM Region Number)

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 (1990-1997) historical shares (PKSHR_IMEX and PKSHR_ILNG).

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_FIXUP) 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, based on a forecast by Natural Resources Canada, and split into seasonal periods using PKSHR_CDMD (Appendix E). 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). 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 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

[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 (1990-1997) historically based shares for general Canadian imports (PKSHR_ICAN).

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, three segments of the curve are defined from the base point. The middle segment is centered around the base point, extends +/- 3 percent from the base quantity, and is nearly horizontal. The remaining two segments extend more vertically (with a positive slope) off the ends of the middle segment, forming what looks like a reclining chair. The slope of the upper segment is greater than that of the lower segment. The general structure [in terms of P=f(Q)] for all three segments is:

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

Each of the three segments have special definitions for the variables ELAS, PBASE, and QBASE, as defined below.

Lower segment:

$PBASE = APBASE = XPBASE * (1. - (PARM\_SUPCRV1 / PARM\_SUPELAS_2))$
$QBASE = AQBASE = XQBASE * (1. - PARM\_SUPCRV1)$
$ELAS = PARM\_SUPELAS_1 = 2.00$

Middle segment:

$PBASE = XPBASE$	=	$ZWPRLAG_s - ZOGTAXPREM_s$	
$QBASE = XQBASE$	=	$ZOGRESNG_s * ZOGPRRNG_s$	domestic nonassociated supply, forecast year
	=	$QSUP_s / (1. - PCTLP_n)$	domestic nonassociated supply, historical year
	=	$1.01 * OGCNQPRD_{2,t-1}$	western Canadian supply

$ELAS = PARM\_SUPELAS_2 = 4.00$

Upper segment:

$PBASE = BPBASE = XPBASE * (1. + (PARM\_SUPCRV1 / PARM\_SUPELAS_2))$
$QBASE = BQBASE = XQBASE * (1. + PARM\_SUPCRV1)$
$ELAS = PARM\_SUPELAS_3 = 1.50$

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_SUPCRV1	=	Supply curve parameter
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
$ZOGRESNG_s$	=	Natural gas reserves for supply source s
$ZOGPRRNG_s$	=	Natural gas production to reserves ratio for supply source s
$PCTLP_n$	=	Percent lease and plant
s	=	supply source
n	=	region/node

In the above equation, the QVAR variable does 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
VALUE	=	Production, net lease & plant
$PCTLP_n$	=	Percent lease and plant 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
s	=	NGTDM/OGSM supply region
n	=	region/node

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):

$$\text{(res):}\quad AKQTY\_F_d = EXP(AK\_C_1) * AK\_RN_y^{AK\_C_2}/1000. \qquad (3)$$

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:

$$\text{(com):}\quad AKQTY\_F_d = EXP(AK\_D_1) * (1000. * PREV\_AKQTY_{2,y-1})^{AK\_D_2} * AK\_CN_y^{AK\_D_3} * AK\_CN_{y-1}^{AK\_D_4}/1000. \qquad (4)$$

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:

[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.

$$\text{(ind):} \quad AKQTY\_F_d = \left(EXP(AK\_E_1) * (1000.*PREV\_AKQTY_{d,y-1})^{AK\_E_2} * T^{AK\_E_3} * (T-1)^{AK\_E_4} \right) / 1000. \tag{5}$$

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:

$$\text{(S. AK):} \quad AK\_PROD_{r=1} = \frac{(EXPJAP + AK\_CONS\_S - AK\_DISCR)}{AK\_PCTALL_{r=1}} \tag{6}$$

$$\text{(N. AK):} \quad AK\_PROD_{r=2} = AK\_CONS\_N \ / \ AK\_PCTALL_{r=2} \tag{7}$$

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 for AK_DISCR are set at the average (1990-1996) historical value. 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 over the North and South regions (not accounting for the impact should ANGTS be connected) is calculated as:

$$AK\_WPRC = (AK\_F_1 * WPRLAG) + (AK\_F_2 * (AK\_CONS\_S + AK\_CONS\_N)) \tag{8}$$

where,

AK_WPRC	=	average Alaskan natural gas wellhead price (dollars per Mcf)
AK_CONS_S	=	total gas consumption by customers in South Alaska (Bcf)

AK_CONS_N	=	total gas consumption by customers in North Alaska (Bcf)
WPRLAG	=	average Alaskan natural gas wellhead price in previous forecast year (dollars per Mcf) [the 1989 value used in forecast year 1990 is WPR89, Appendix E]
AK_F	=	estimated parameters (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). With the exception of the industrial sector, 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_EM). The Alaskan industrial sector price is calculated as:

$$PALK\_NONU\_F_s = AK\_G_1 + (AK\_G_2 * WOPCUR) \tag{9}$$

where,

$PALK\_NONU\_F_s$	=	price of natural gas to Alaskan industrial customers (s=3), (dollars per Mcf)
WOPCUR	=	landed price of crude oil in current forecast year (dollars per barrel)
AK_G	=	estimated parameters (Appendix F, Table F1)

Historically, the industrial price was shown to vary more in response to the crude oil price and much less in response to the natural gas wellhead price.

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 or offpeak 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. Conceptually 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

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[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.

Figure 3-2 are discrepancies (i.e., average historically observed differences between independently reported natural gas supply and

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

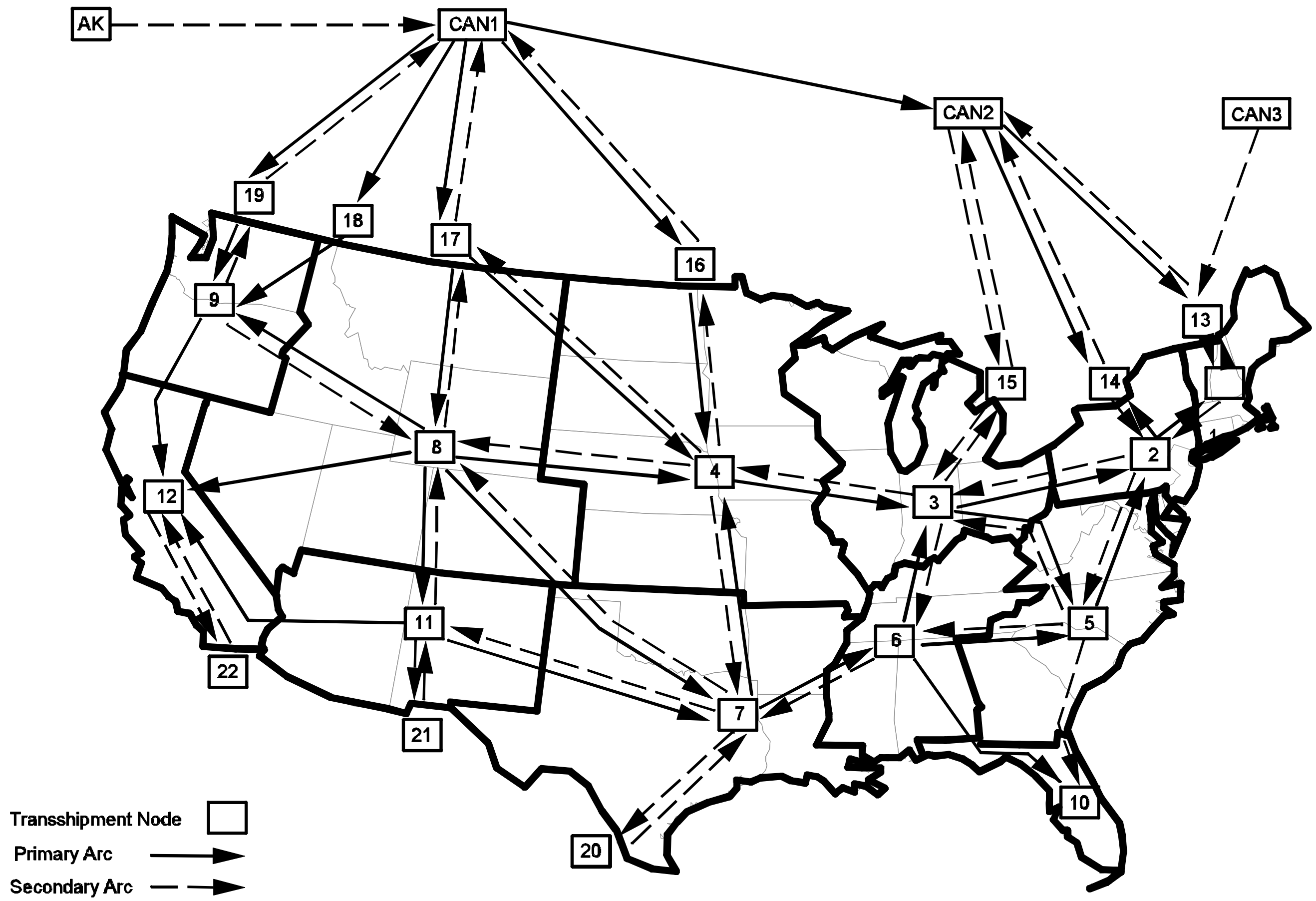
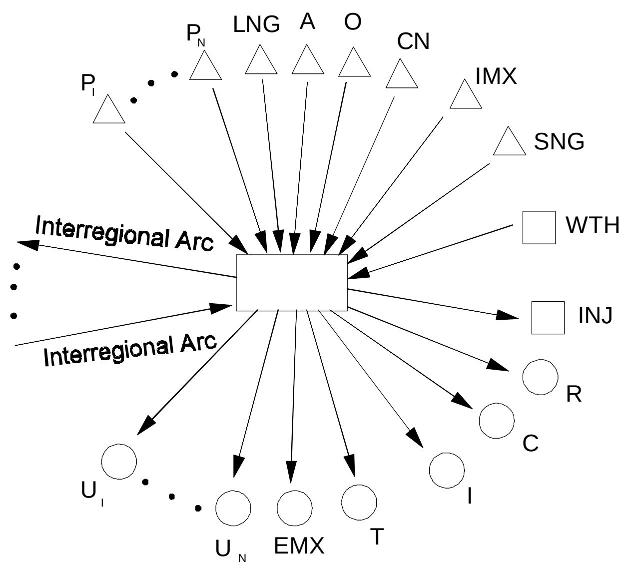


Figure 3-2. Transshipment Node



- Transshipment Node
- Supply Point
- Demand Point
- Storage Point

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

disposition levels -- 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 be 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. Last year's capacity and flow levels 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 of these arcs.

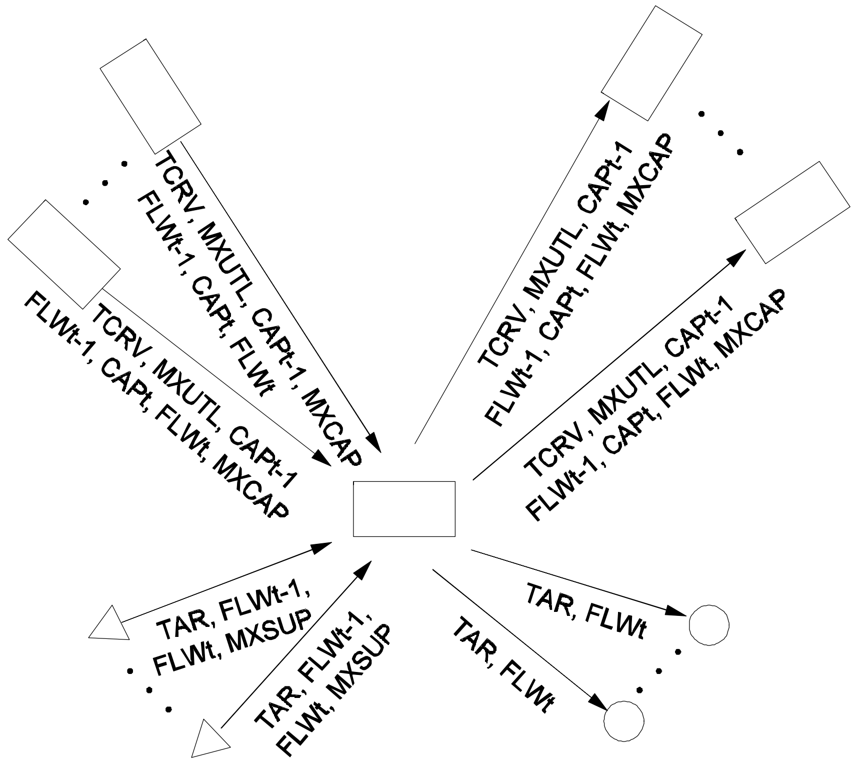
[20]Backstop supplies are allowed when the flow out of a transshipment node exceeds the maximum flow into a transshipment node. A high price is assigned to this supply source and it is generally expected not to be required (or desired). Chapter 4 provides a more detailed description of the setting and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



- Transshipment Node

- Supply Point

- Demand Point

Parameters: (model inputs)

TAR - Tariff
TCRV - Tariff (expansion) curve
CAPt-1 - Capacty last year
FLWt-1 - Flow last year
MXUTL - Maximum utilization of capacity
MXCAP - Maximum capacity
MXSUP - Maximum supply
← - Direction

Variables: (model outputs)

FLWt - Flow in current year
CAPt - Capacity in current year

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.

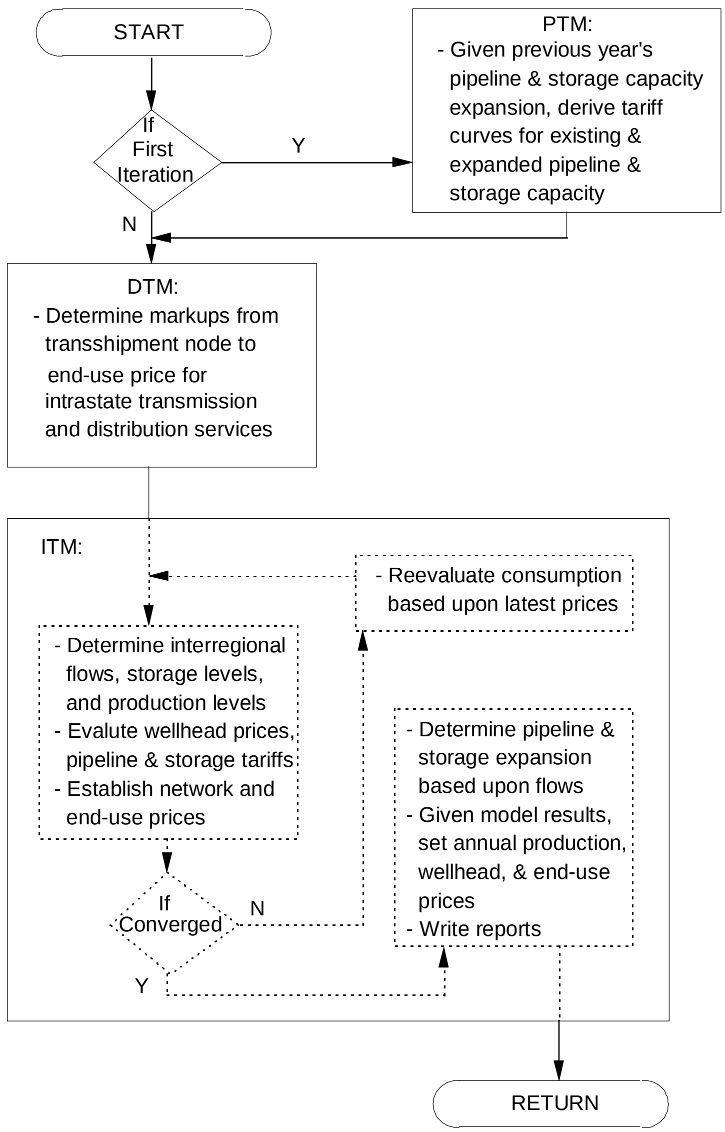
Overview of the NGTDM Modules and Their Interrelationships

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, and 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.

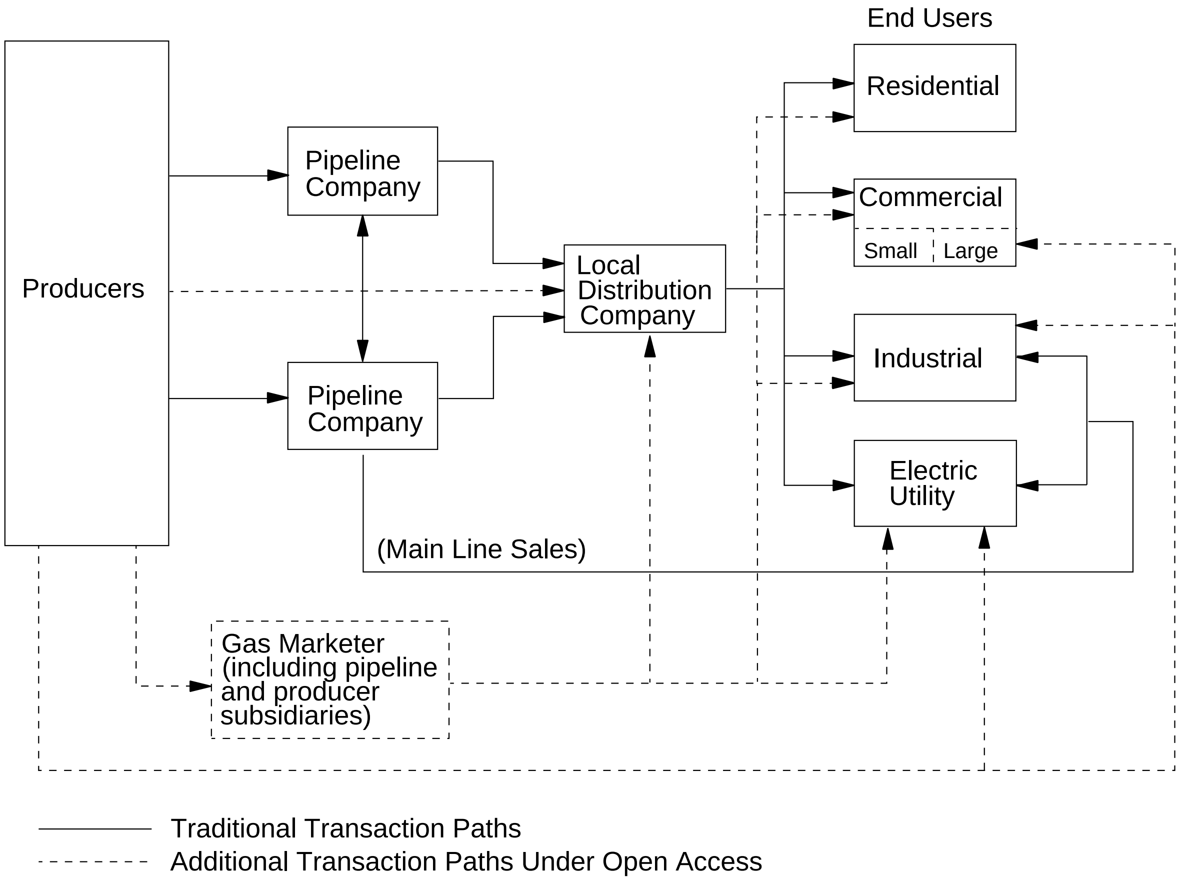
In the end, the ITM derives average seasonal (and ultimately annual) natural gas prices (wellhead, city gate, and end-use), and the associated production and flows, that reflect an interregional market equilibrium among the competing participants in the market. In the process of determining interregional 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 associated revenue 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 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 approximates the change in the total revenue requirement from year to year. 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 to total distribution costs, and subsequently the related tariffs, starting from a base year. Base year values for total costs and distributor tariffs by sector and season are established using historical data. The annual change in total cost is dependent on an assumed increase in operational efficiencies, as well as the annual change in natural gas consumption and in national average capital and employment costs. The revenue requirements from core customers are adjusted due to an assumed contribution of revenues from noncore customers. The allocation of these revenue requirements to individual sectors is primarily dependent on the relative annual change in consumption across sectors. 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.

[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 Heuristic 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. Within the NGTDM, 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

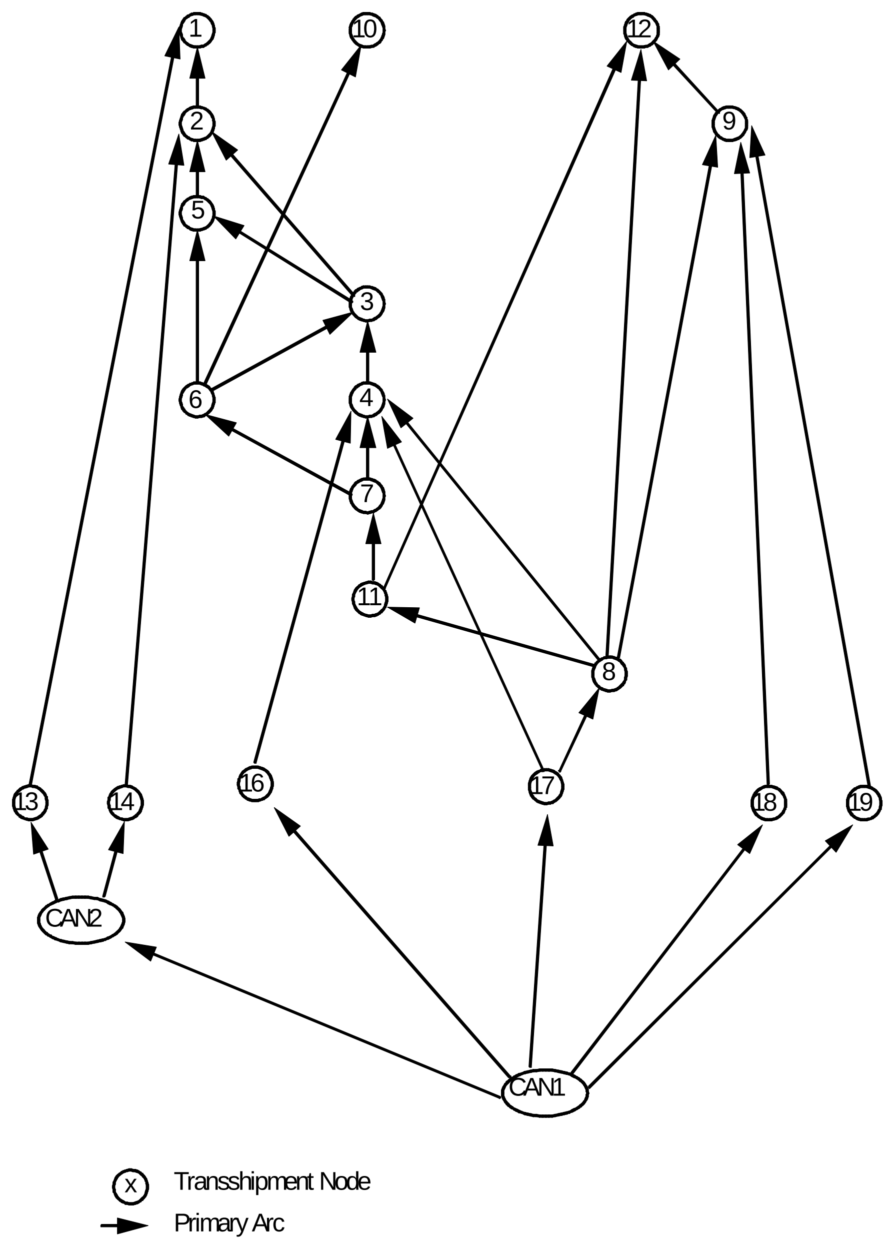
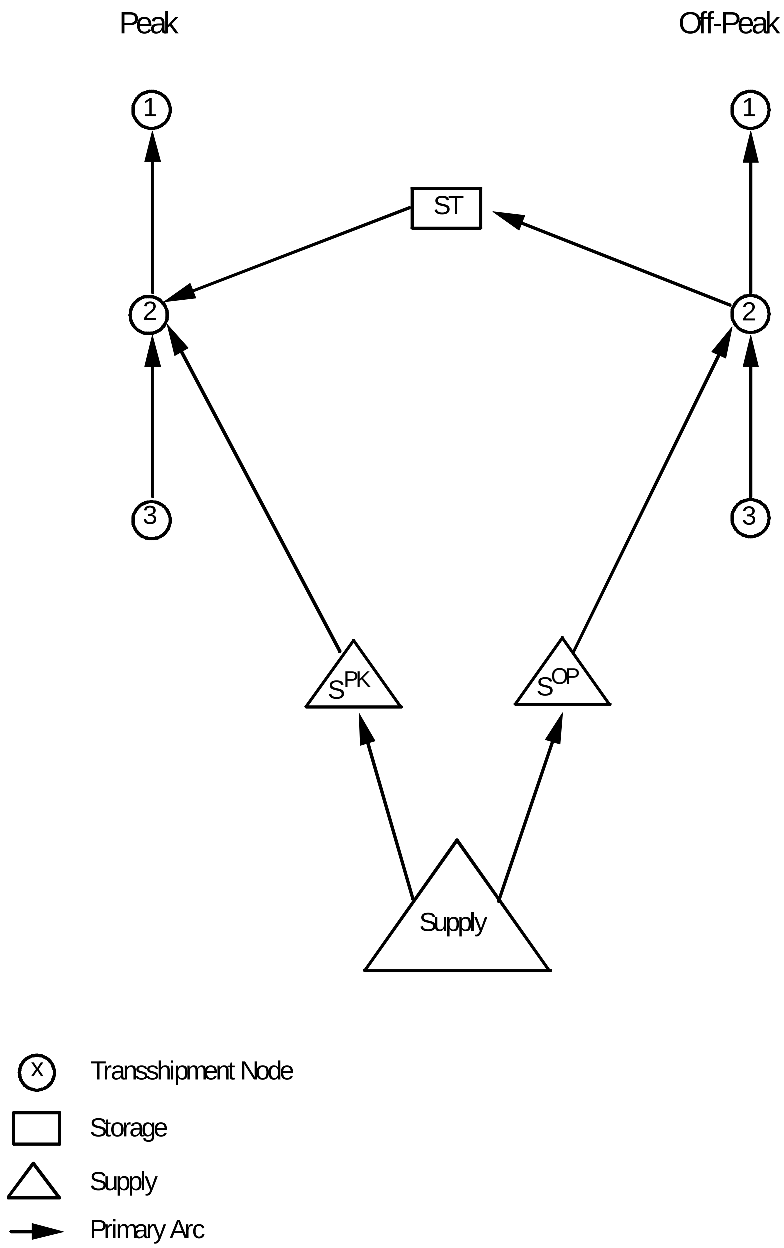


Figure 4-2. Simplified Example of Supply and Storage Links Across Networks



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
- Seasonal imports (except Canada) and exports by border crossing
- Canadian import capacities by border crossing
- 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 imports are determined within the ITM in conjunction with Canadian import capacity levels (provided as input to the ITM). Also, 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.

Heuristic Process

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[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.

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,[28] 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 *AEO99*) to approximate the demand response and generate a new set of consumption levels. This process is repeated until a convergence 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.[29] 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.

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

[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]Distributor tariffs are calculated using a modified form of the original DTM algorithm (described in Chapter 5).

[29]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.

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 tolerance from the supply prices established the last cycle down the network. 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 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:

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

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

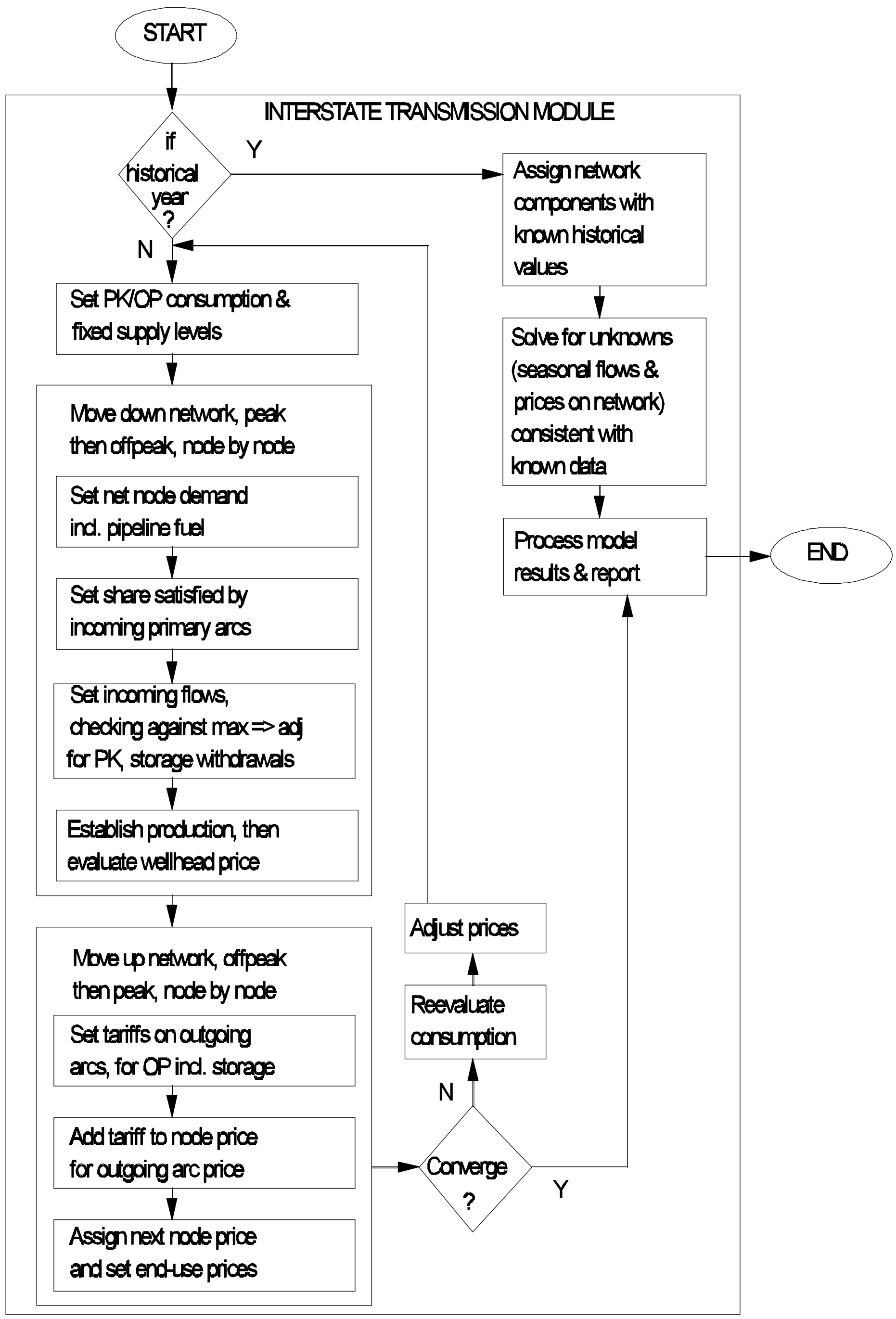
$$\begin{aligned} YEAR\_CDMD_{PK,r} = {} & DISCR_{PK,r,t} + CN\_DISCR_{PK,cn} + (PKSHR\_CDMD * CN\_DMD_{cn,r}) + \\ & (PK1 * SAFLOW_{a,t}) - (PK2 * SAFLOW_{a',t}) - \\ & (PKSHR\_YR * OGQANGTS_t) - (PKSHR\_SUPLM * ZTOTSUP_r) - \\ & (PKSHR\_ILNG * OGQNGIMP_{L,t}) - (PKSHR\_PROD_s * CN\_FIXSUP_{cn,t}) \end{aligned}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

Off-Peak:

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

$$NODE\_CDMD_{OP,r} = YEAR\_CDMD_{OP,r} - ((1 - PKSHR\_PROD_{s}) * ZADGPRD_{s}) \tag{14}$$

Figure 4.3 Interstate Transmission Module System Diagram



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

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)
$CN\_DISCR_{n,cn}$ =	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 Divison, 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)
$PKSHR\_UDMD_{jutil}$ =	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

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)
$NODE\_DMD_{n,r}$ =	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 algorithm (described below). The regional pipeline fuel quantity (net of intraregional pipeline fuel consumption)[31] 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.:

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

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

[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 *AEO99*, the years calibrated to *STEO* results were 1998 and 1999.

[31]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.

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.

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,[32] 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. 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:

$$SHR_{n,a,t} = \frac{ARC\_SHRPR_{n,a}^{-\gamma}}{\dfrac{\sum_{b} ARC\_SHRPR_{n,b}^{-\gamma}}{N}} * SHR_{n,a,t-1} \tag{18}$$

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)
$ARC\_SHRPR_{n,a \text{ or } b}$ = 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.

$$FLOW_{n,a} = SHR_{n,a,t} * NODE\_DMD_{n,r} \tag{19}$$

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)

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

n = network (peak or offpeak)
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):

$$MAXFLO_{PK,a} = MAXPCAP_{PK,a} * (PKSHR\_YR * PKUTZ_a) \quad (20)$$

such that $MAXPCAP_{PK,a}$

for Supply:

$$MAXPCAP_{PK,a} = ZOGRESNG_s * MAXPRRNG_s * MAXPRRFAC * (1 - (PCTLP_r * SCALE\_LP_t)) \quad (21)$$

for Pipeline:

$$MAXPCAP_{PK,a} = PTMAXPCAP_{i,j} \quad (22)$$

for Storage:

$$MAXPCAP_{PK,a} = PTMAXPSTR_{st} \quad (23)$$

for Canadian imports

$$MAXPCAP_{PK,a} = CURPCAP_{a,t} \quad (24)$$

Maximum offpeak pipeline flows:

$$MAXFLO_{OP,a} = MAXPCAP_{OP,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \quad (25)$$

such that $MAXPCAP_{OP,a}$ is

either current capacity,

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} \quad (26)$$

or current capacity plus capacity additions,

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} + \left((1 + XBLD) * \left(\frac{FLOW_{PK,a}}{(PKSHR\_YR * PKUTZ_a)} - CURPCAP_{a,t} \right) \right) \tag{27}$$

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

$$MAXPCAP_{OP,a} = MAXPCAP_{PK,a} \tag{28}$$

Maximum offpeak flows from supply sources:

$$MAXFLO_{OP,a} = MAXPCAP_{PK,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \tag{29}$$

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)
$MAXPRRNG_s$ =	Maximum production to reserves ratio for supply source s [defined by OGSM] (fraction)
MAXPRRFAC =	Factor to set maximum production-to-reserves ratio (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.

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,[33] 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:

$$ACTPCAP_a = \frac{FLOW_{PK,a}}{PKUTZ_a} \tag{30}$$

Pipeline:

$$ACTPCAP_a = MAXPCAP_{OP,a} \tag{31}$$

Pipeline arc entering region 10:

$$ACTPCAP_a = \text{MAX between } \frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} \text{ and } \frac{FLOW_{OP,a}}{(1 - PKSHR\_YR) * OPUTZ_a} \tag{32}$$

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

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

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

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:

$$ANNSUP = \frac{NODE\_QSUP_{PK,s}}{PKSHR\_YR} \tag{33}$$

Offpeak:

$$ANNSUP = \frac{NODE\_QSUP_{OP,s}}{(1 - PKSHR\_YR)} \tag{34}$$

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,

$$FSF = \frac{PSUP_s}{SPAVG_s} \tag{35}$$

and,

$$NODE\_PSUP_{n,s} = SPSUP_n * FSF \tag{36}$$

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 (1998 and 1999 for *AEO99*), 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:

$$PSUP_s = PSUP_s * SCALE\_WPR_t \tag{37}$$

Seasonal:

$$NODE\_PSUP_{n,s} = NODE\_PSUP_{n,s} * SCALE\_WPR_t \tag{38}$$

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. The fixed term ($ARC\_FIXTAR_{n,a,t}$) allows for the inclusion of a separate fixed rate that was intended to account for other variable or usage charges. The variable term was intended to represent reservation charges. With the exception of Canadian import arcs, the fixed rate is set to zero for *AEO99*[34] and the variable rate represents either the total tariff (reservation plus usage) or just the usage rate.

[34]This structure will be modified in a future version of the NGTDM.

The variable term is obtained from tariff/capacity curves provided by two PTM functions. 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 ($ARC\_ENDFEE_{n,a}$). Therefore, the parameters used in the pipeline tariff function (NGPIPE_VARTAR) are defined based on separate *process-specific* variables (with the exception of Canadian import arcs). 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.[35] Thus, the following arc tariff equations apply:

Pipeline:

$$\begin{aligned} ARC\_SHRFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n,a,i,j,FLOW_{n,a}) \\ ARC\_ENDFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(xn,a,i,j,FLOW_{n,a}) \end{aligned} \qquad (39)$$

Storage:

$$\begin{aligned} ARC\_SHRFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGSTR\_VARTAR(st,FLOW_{n,a}) \\ ARC\_ENDFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGSTR\_VARTAR(st,FLOW_{n,a}) \end{aligned} \qquad (40)$$

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 fees along an arc a for a network n in time t (87$/mcf)
NGPIPE_VARTAR	=	PTM function to define pipeline tariffs
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.[36] 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 $ARC\_SHRFEE_{n,a}$).

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[35]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.

[36]In the original Annual Flow Module, “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:

$$ARC\_SHRPR_{n,a} = NODE\_SHRPR_{n,r} + ARC\_SHRFEE_{n,a}$$
$$ARC\_ENDPR_{n,a} = NODE\_ENDPR_{n,r} + ARC\_ENDFEE_{n,a} \qquad (41)$$

with adjustment:

$$ARC\_SHRPR_{n,a} = \frac{(ARC\_SHRPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})}$$
$$ARC\_ENDPR_{n,a} = \frac{(ARC\_ENDPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})} \qquad (42)$$

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:

$$NODE\_SHRPR_{n,r} = \frac{\Sigma_a (ARC\_SHRPR_{n,a} * FLOW_{n,a})}{\Sigma_a FLOW_{n,a}}$$
$$NODE\_ENDPR_{n,r} = \frac{\Sigma_a (ARC\_ENDPR_{n,a} * FLOW_{n,a})}{\Sigma_a FLOW_{n,a}} \qquad (43)$$

and,

$$\text{NODE\_SHRPR}_{n,r} = \frac{(\text{NODE\_SHRPR}_{n,r} * \text{NODE\_DMD}_{n,r})}{(\text{NODE\_DMD}_{n,r} - \text{INTRA\_PFUEL}_{n,r})}$$

$$\text{NODE\_ENDPR}_{n,r} = \frac{(\text{NODE\_ENDPR}_{n,r} * \text{NODE\_DMD}_{n,r})}{(\text{NODE\_DMD}_{n,r} - \text{INTRA\_PFUEL}_{n,r})} \qquad (44)$$

where,

$\text{NODE\_SHRPR}_{n,r}$ =	Node price for region r on network n [used with flow sharing algorithm] (87$/mcf)
$\text{NODE\_ENDPR}_{n,r}$ =	Node price for region r on network n [used with end-use pricing] (87$/mcf)
$\text{ARC\_SHRPR}_{n,a}$ =	Price calculated for natural gas along inflow arc a for network n [used with flow sharing algorithm] (87$/mcf)
$\text{ARC\_ENDPR}_{n,a}$ =	Price calculated for natural gas along inflow arc a for network n [used with end-use pricing] (87$/mcf)
$\text{FLOW}_{n,a}$ =	Network n flow along arc a (bcf)
$\text{INTRA\_PFUEL}_{n,r}$ =	Intraregional pipeline fuel consumption in region r, for network n (bcf)
$\text{NODE\_DMD}_{n,r}$ =	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:

$$\text{NODE\_SHRPR}_{PK,i} = \text{NODE\_SHRPR}_{OP,r}$$

$$\text{NODE\_ENDPR}_{PK,i} = \text{NODE\_ENDPR}_{OP,r} \qquad (45)$$

where,

$\text{NODE\_SHRPR}_{PK,i}$ =	Price at node i [used with flow sharing algorithm] (87$/mcf)
$\text{NODE\_SHRPR}_{OP,r}$ =	Price at node r in offpeak network [used with sharing algorithm] (87$/mcf)
$\text{NODE\_ENDPR}_{PK,i}$ =	Price at node i [used with end-use pricing] (87$/mcf)
$\text{NODE\_ENDPR}_{OP,r}$ =	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 ($\text{NODE\_SHRPR}_{n,r}$) is adjusted upward in an effort to reduce the demand for gas from this source. If this price adjustment ($\text{BKSTOP\_PADJ}_{n,r}$) is not sufficient to eliminate backstop on the next cycle down the network, an additional adjustment ($\text{RBKSTOP\_PADJ}_{n,r}$) 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:

$$NODE\_SHRPR_{n,r} = NODE\_SHRPR_{n,r} + RBKSTOP\_PADJ_{n,r} \tag{46}$$

$$RBKSTOP\_PADJ_{n,r} = RBKSTOP\_PADJ_{n,r} + BKSTOP\_PADJ_{n,r} \tag{47}$$

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 tolerance of the prices 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:

$$\begin{aligned} NODE\_QSUP_{n,s} = {} & (QSUP\_WT * NODE\_QSUP_{n,s}) + \\ & ((1 - QSUP\_WT) * NODE\_QSUPPREV_{n,s}) \end{aligned} \tag{48}$$

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 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 (1997 for *AEO99*). These equations are defined below:

$$CGPR_{n,r} = NODE\_ENDPR_{n,r} + INTRAREG\_TAR_{n,r} + INTRAST\_TAR_{r} + CGBENCH_{n,r} \tag{49}$$

such that:

$$CGBENCH_{n,r} = HCG\_BENCH_{n,r,EHISYR} = (HCGPR_{n,r,EHISYR} - CGPR_{n,r}) \tag{50}$$

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 provided by the Pipeline Tariff Module, and the intrastate tariffs are set exogenously.[37] 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 ($SCALE\_FPR_{sec,t}$, $SCALE\_IPR_{sec,t}$)[38] 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):

$$\begin{aligned} NGPR\_SF_{n,sec,r} &= CGPR_{n,r} + DTAR\_SF_{n,sec,r} + SCALE\_FPR_{sec,t} \\ NGPR\_SI_{n,sec,r} &= CGPR_{n,r} + DTAR\_SI_{n,sec,r} + SCALE\_IPR_{sec,t} \end{aligned} \tag{51}$$

[37]The intrastate tariffs are currently set to zero and are indirectly accounted for within the citygate benchmark factors.
[38]The STEO scale factors are linearly phased out over five years after the last STEO year (1999 in *AEO99*).

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

$$NGPR\_I_{sec,r} = NGPR\_SI_{PK,sec,r} * PKSHR\_DMD_{sec,r} + NGPR\_SI_{OP,sec,r} * (1. - PKSHR\_DMD_{sec,r}) \quad (52)$$

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:

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

$$NGUPR\_SI_{n,j} = CGPR_{n,r} + UDTAR\_SI_{n,j} + SCALE\_IPR_{sec,t} \quad (53)$$

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

$$NGUPR\_I_{j} = NGUPR\_SI_{PK,j} * PKSHR\_UDMD_{j} + NGUPR\_SI_{OP,j} * (1. - PKSHR\_UDMD_{j}) \quad (54)$$

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.

$$\begin{aligned} NGPR\_TRPV\_SF_{n,r} &= CGPR_{n,r} + DTAR\_TRPV\_SF_{n,r} + SCALE\_FPR_{sec,t} \\ NGPR\_TRFV\_SF_{n,r} &= CGPR_{n,r} + DTAR\_TRFV\_SF_{n,r} + SCALE\_FPR_{sec,t} \end{aligned} \tag{55}$$

$$\begin{aligned} NGPR\_TRPV\_F_{r} = {} & NGPR\_TRPV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + \\ & NGPR\_TRPV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r}) \\ NGPR\_TRFV\_F_{r} = {} & NGPR\_TRFV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + \\ & NGPR\_TRFV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r}) \end{aligned} \tag{56}$$

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).

$$\begin{aligned} TRPV\_DIFF = {} & (NGPR\_TRPV\_F_{r} + JNGTR_{t} * CFNGN) - \\ & [(PMGCM_{c,t} + JMGCM_{t}) * CFNGN] \end{aligned} \tag{57}$$

$$TRPV\_ADJ = RETAIL\_COST * RETAIL\_PCT \tag{58}$$

$$NGPR\_TRPV\_F_r = NGPR\_TRPV\_F_r - AMIN1(\ TRPV\_DIFF,\ TRPV\_ADJ\ ) \tag{59}$$

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 *AEO99* 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.

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 1) the cost of providing service to the core end user, 2) recovery of fixed costs from the noncore segment of the market, 3) industry efficiency improvements, and 4) bypass of local distribution companies (LDCs) by large industrial and electric utility consumers. 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

The algorithm that sets seasonal distributor tariffs for residential, commercial, and industrial core customers is responsive in part to revenues generated from the noncore segment of the market, user-specified industry efficiency improvements, and user-specified assumptions on bypass by large industrial and electric utility consumers. The methodology is based on the concept that a portion of the revenues from interruptible customers are used to offset firm revenue requirements as viewed by a local distribution company (LDC). 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.

Residential, Commercial, and Industrial Sectors

In general, this DTM algorithm estimates the annual change in total costs associated with providing distribution services to core[39] customers, accounts for any recovery of fixed costs from the noncore segment of the market, and adjusts the previous year's distributor tariffs for each of the end-use sectors to reflect the resulting annual change in revenue requirement. First, regional core market revenue requirements (RR_F_r) are set based on an endogenously derived total cost ($TC\_F_{r,yr}$) for core distribution services and an assumed noncore market contribution (ICC_r) to fixed costs. (The change in total cost is a function of the change in consumption levels, macroeconomic impacts, and an assumed efficiency improvement.) Next, seasonal core distributor tariffs ($EST\_DTAR\_SF_{n,s,r}$) are estimated for each sector and region based on the estimated contribution of a sector's consumption change to the change in total costs (i.e., not accounting for the macroeconomic and efficiency effects). These tariffs are then used to calculate the annual revenue requirements ($EST\_RR\_F_r$) that would be obtained from core customers if these estimated distributor tariffs ($EST\_DTAR\_SF_{n,s,r}$) were charged. Final core distributor tariffs ($DTAR\_SF_{n,s,r}$) for each season in the current forecast

[39]In this section "core" refers only to the residential, commercial, and core industrial sectors.

year are set by adjusting the estimated regional core distributor tariffs by apportioning the associated difference in revenue requirements (RR_RATIO_r)[40] between the forecasted and estimated values to the sectors represented based on their relative contribution to the total revenue requirement. The equations which describe this process in mathematical terms are presented following the list of variable definitions.

Variable Definitions

The variables used in the subsequent equations are defined as follows.

Subscripts and Superscripts

cr =	Census Division region
n =	network (PK or OP)
r =	NGTDM region
s =	sector
t,yr =	year
t-1 =	previous year
res =	residential sector
com =	commercial sector
ind =	industrial sector
F =	core market (receiving firm transportation service)
I =	noncore market (receiving interruptible transportation service)
YR =	current forecast year (4 digits)

Variables

$adjDTARSF_{n,s,r}$ =	an adjustment factor, used to define DTAR_SF (87$/Mcf)
$AVG\_COSTCAP_{yr}$ =	average cost of capital [derived in Appendix F, Table F4, (87$)]
AVG_COSTCAP_OLD =	3-year rolling average cost of capital, used to define AVG_COSTCAP (87$)
AVG_RMPUAANS =	20-year rolling average of yield on AA utility bonds (fraction)
$BASQTY\_F_{s,r}$ =	volume of core natural gas consumption for sector s, region r, in the current forecast year (Bcf)
$BASQTY\_FPREV_{s,r}$ =	volume of core natural gas consumption for sector s, region r, in the previous forecast year (Bcf)
$BASQTY\_SF_{n,s,r}$ =	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)
$BASQTY\_SIPREV_{n,s,r}$ =	seasonal volume of noncore natural gas consumption for sector s, region r, in the previous forecast year (Bcf)
CHCOSTCAP =	annual percentage change in capital costs, as a fraction (87$)
CHEMPLCOST =	annual percentage change in employment costs, as a fraction (87$)
$CHQTY_{n,s,r}$ =	percentage change in natural gas consumption for sector s, region r, in season n (fraction)
CHQTY_COM =	annual percentage change in commercial natural gas consumption in region r (fraction)
CHQTY_IND =	annual percentage change in industrial natural gas consumption in region r (fraction)
CHQTY_RES =	annual percentage change in residential natural gas consumption in region r (fraction)
$COSTCAP_{yr}$ =	real cost of capital (debt + equity) in forecast year yr (87$)
DEBTYR =	number of years rolling average taken on debt (years)
$DTAR\_SF_{n,s,r}$ =	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)
$DTAR\_SIPREV_{n,s,r}$ =	noncore distributor tariff for sector s, region r, in season n for previous forecast year (87$/Mcf)
DTM_BETA =	percent of profit from noncore revenues contributed to offset core market distribution costs [Appendix E, (fraction)]

[40] RR_RATIO_r is largely equal to the change in total cost attributable to macroeconomic and efficiency effects.

$EST\_DTAR\_SF_{n,s,r}$ =	estimated core market distributor tariffs for sector s, region r, in season n (87$/Mcf)
$EST\_RR\_F_r$ =	estimated core market revenue requirements in region r (87$)
$HCGPR_{n,r,hyr}$ =	seasonal citygate prices in region r, for historical year hyr [Appendix E, (87$/Mcf)]
$HPGFCMGR_{n,r,hyr}$ =	seasonal commercial sector end-use price in region r, for historical year hyr (87$/Mcf)]
$HPGFINGR_{n,r,hyr}$ =	seasonal industrial sector end-use price in region r, for historical year hyr [Appendix F, Table F5, (87$/Mcf)]
$HPGFRSGR_{n,r,hyr}$ =	seasonal residential sector end-use price in region r, for historical year hyr (87$/Mcf)
I_BYPASS_r =	percent of noncore volumes that bypass the LDC [Appendix E, (fraction)]
ICC_r =	noncore revenue contribution to fixed costs (87$)
$MC\_CPI_{cr,yr}$ =	consumer price index [provided by the Macroeconomic Model]
MC_ECIWSP_{yr} =	employment cost index -- private wage and salary [provided by the Macroeconomic Model]
MC_PCWDGP_{yr} =	GDP deflator index [provided by Macroeconomic Model]
$MC\_RMPUAANS_{yr}$ =	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)]
$MIN\_DTAR\_F_n$ =	minimum offset to shift DTAR from negative to positive [set equal to $0.00 plus the lowest nonpositive distributor tariff from the previous year] (87$/Mcf)
MINMU_I =	minimum noncore distributor tariff [Appendix E, (87$/Mcf)]
NG_REALRMGBLUS =	real yield on 10 year U.S. Government bonds (forecast values provided by the Macroeconomic Model, historical values in H_REALRMGBLUS -- Appendix E)
RR_F_r =	market revenue requirements for core customers in region r (87$)
RR_RATIO_r =	delta between forecasted revenue requirement (RR_F) and estimated revenue requirement (EST_RR_F) in region r (87$)
$TC\_F_{r,yr}$ =	total cost to provide distribution services to core customers in region r (87$)
TCF_CHANGE =	percent change in total core market distribution costs (fraction)
TCF_COEFF =	estimated parameters [Appendix E, (scaler)]
$TECHEFF_{yr}$ =	technical efficiency factor, by year [Appendix E, (scaler)]
WT_DEBT =	weighting for debt/equity contribution to cost of capital [Appendix E, (fraction)]

Determine Regional Core Revenue Requirements

Core revenue requirements are determined for each region, thus providing the model with the total regional revenues that must be generated by the residential, commercial, and industrial sectors from their corresponding seasonal distributor tariffs and consumption levels. These regional core revenue requirements are a function of 1) total core customer related costs and 2) the recovery of fixed costs from noncore customers within the region, as follows:

Regional core revenue requirements = regional total firm costs - regional noncore contribution to fixed costs

$$RR\_F_r = TC\_F_{r,yr} - ICC_r \tag{60}$$

Noncore contribution to fixed costs (ICC). The noncore contribution to fixed costs component (ICC_r) is built on the assumptions that 1) a portion [Appendix E, (I_BYPASS_r)] of the noncore customers bypass the LDC,[41] 2) the regional noncore recovery of fixed costs is a proportion [Appendix E, DTM_BETA[42]] of the regional noncore profits collected by the LDC, and 3) noncore profits represent noncore revenues that exceed the cost of providing noncore services. The corresponding equation is:

Regional noncore contribution to fixed costs = sum over regions and seasons [noncore volume * (1 - LDC bypass) * (regional/ seasonal noncore distributor tariff - minimum regional noncore distributor tariff)] * fraction

$$\begin{aligned} ICC_r = \sum_{n,s} [\ & BASQTY\_SIPREV_{n,s,r} * (1 - I\_BYPASS_r) * \\ & (DTAR\_SIPREV_{n,s,r} - MINMU\_I)\ ] * DTM\_BETA \end{aligned} \tag{61}$$

[41]Only noncore customers are assumed to bypass the local distribution companies.

[42] For *AEO99*, DTM_BETA has been set to zero; thus, ICC equals zero.

Total core costs (TC_F). Due to the lack of available data for regional costs ($TC\_F_{r,yr}$) related to core distributor services, historical values for these costs are derived from the limited data that are available, *and* annual changes in costs are forecast using model input parameters. Some of these parameters were based on statistical estimates presented by Mary Lashley Barcella in her paper, "Wholesale and Retail Analysis for Estimating the Price Effect of Natural Gas Conservation." The paper presents a total distributor cost equation as a change in last year's total costs (TCF_CHANGE), with parameters estimated on the basis of data from 64 local gas distribution companies covering the period 1969 through 1993. Selected parameter estimates [Appendix E, TCF_COEFF] from her work have been used to forecast the annual change in total regional distributor costs associated with core customers, as shown below:

$$\begin{aligned} TCF\_CHANGE = [\ & TCF\_COEFF_1 * CHQTY\_RES + TCF\_COEFF_2 * CHQTY\_COM + \\ & TCF\_COEFF_3 * CHQTY\_IND + TCF\_COEFF_4 * CHCOSTCAP + \\ & TCF\_COEFF_5 * CHEMPLCOST\ ] \end{aligned} \tag{62}$$

The CHQTY_RES, CHQTY_COM, and CHQTY_IND terms represent percentage change in core volume for each corresponding sector within a region, calculated as follows:

$$CHQTY\_RES = \frac{BASQTY\_F_{res,r} - BASQTY\_FPREV_{res,r}}{BASQTY\_FPREV_{res,r}} \tag{63}$$

$$CHQTY\_COM = \frac{BASQTY\_F_{com,r} - BASQTY\_FPREV_{com,r}}{BASQTY\_FPREV_{com,r}} \tag{65}$$

$$CHQTY\_IND = \frac{BASQTY\_F_{ind,r} - BASQTY\_FPREV_{ind,r}}{BASQTY\_FPREV_{ind,r}} \tag{64}$$

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

$$CHEMPLCOST = \frac{\dfrac{MC\_ECIWSP_{yr}}{MC\_CPI_{cr,yr}} - \dfrac{MC\_ECIWSP_{yr-1}}{MC\_CPI_{cr,yr-1}}}{\dfrac{MC\_ECIWSP_{yr-1}}{MC\_CPI_{cr,yr-1}}} \tag{66}$$

Before the *AEO97* version of the model, the percentage change in cost of capital (CHCOSTCAP) was obtained using an average cost of capital (represented as a three year rolling average). The cost of capital was approximated using a weighted average of the yield on AA bonds (20-year rolling average, DEBTYR) and the yield on 10-year government bonds. For the *AEO97* version forward, the actual historical series for the average cost of capital that was used in the total cost estimation was obtained from Mary Barcella. Then, an equation was estimated [Appendix F, Table F4] to forecast this series ($AVG\_COSTCAP_{yr}$) as a function of the previously used series for the average cost of capital ($AVG\_COSTCAP\_OLD_{yr}$). The corresponding equations are:

$$CHCOSTCAP = \frac{AVG\_COSTCAP_{yr} - AVG\_COSTCAP_{yr-1}}{AVG\_COSTCAP_{yr-1}} \tag{67}$$

where,

$$AVG\_COSTCAP_{yr} = 7.44691 + 1.22689 * AVG\_COSTCAP\_OLD_{yr} + 71.60079 * (YR - 1979)^{-0.7} \tag{68}$$

$$AVG\_COSTCAP\_OLD_{yr} = \frac{COSTCAP_{yr} + COSTCAP_{yr-1} + COSTCAP_{yr-2}}{3} \tag{69}$$

$$COSTCAP_{yr} = WT\_DEBT * AVG\_RMPUAANS + (1 - WT\_DEBT) * NG\_REALRMGBLUS \tag{70}$$

$$AVG\_RMPUAANS = \frac{\sum_{t=yr-DEBTYR}^{yr} [\ MC\_RMPUAANS_t - (\ (100 * \frac{MC\_PCWGDP_{yr}}{MC\_PCWGDP_{yr-1}}\ ) - 1)\ ]}{DEBTYR} \tag{71}$$

Finally, the total cost for distributor service to core customers for the forecast year, by region, is:

$$TC\_F_{r,yr} = TC\_F_{r,yr-1} * (1 + TCF\_CHANGE) * TECHEFF_{yr} \tag{72}$$

The TECHEFF term (Appendix E) is present to capture the impact of technological advancements.

Estimate Seasonal Core Distributor Tariffs and Revenue Requirements

Seasonal core distributor tariffs ($EST\_DTAR\_SF_{n,s,r}$) are estimated for each end-use sector within a region as a function of corresponding core tariffs in the previous year and the change in core consumption or volumes ($CHQTY_{n,s,r}$) as a fraction of annual core consumption in the previous year. These estimated distributor tariffs capture the change in total distribution costs attributable to the change in consumption, but excluding the macroeconomic and efficiency impacts.

$$EST\_DTAR\_SF_{n,s,r} = [\ (\ DTAR\_SFPREV_{n,s,r} * BASQTY\_SFPREV_{n,s,r}) + (TCF\_COEFF_s * CHQTY_{n,s,r} * TC\_F_{r,t-1})\ ]\ /\ BASQTY\_SF_{n,s,r} \tag{73}$$

and

$$CHQTY_{n,s,r} = \frac{(\ BASQTY\_SF_{n,s,r} - BASQTY\_SFPREV_{n,s,r}\ )}{BASQTY\_FPREV_{s,r}} \tag{74}$$

The TCF_COEFF variables (Appendix E) are the various parameter estimates for the end-use sector terms from Mary Lashley Barcella's study (also used in equation 62 above). The annual change in the EST_DTAR_SF value is limited to a user specified level [Appendix E, MAXCHNG] to prevent an unreasonable adjustment from one year to the next. These distributor tariffs are then used to obtain an annual estimate of regional core revenue requirements:

$$EST\_RR\_F_r = \sum_n (\ EST\_DTAR\_SF_{n,res,r} * BASQTY\_SF_{n,res,r} + EST\_DTAR\_SF_{n,com,r} * BASQTY\_SF_{n,com,r} + EST\_DTAR\_SF_{n,ind,r} * BASQTY\_SF_{n,ind,r}\ ) \tag{75}$$

Determine Final Seasonal Core Distributor Tariffs

Final core distributor tariffs for each region and season are determined by adding an adjustment factor to the estimated distributor tariff to account for the difference between the forecasted and estimated core revenue requirements. This last step allocates across the sectors the portion of total distribution costs attributable to macroeconomic and efficiency effects. This adjustment factor ($adjDTARSF_{n,s,r}$) is set by apportioning the difference in revenue requirements over the represented sectors and seasons based on an estimate of each sector's relative contribution to the total revenue requirement, as follows:

$$DTAR\_SF_{n,s,r} = EST\_DTAR\_SF_{n,s,r} + adjDTARSF_{n,s,r} \tag{76}$$

such that:

$$adjDTARSF_{n,s,r} = \frac{(DTAR\_SFPREV_{n,s,r} + MIN\_DTAR\_F_n) * RR\_RATIO_r}{\sum_{n,s} [(DTAR\_SFPREV_{n,s,r} + MIN\_DTAR\_F_n) * BASQTY\_SF_{n,s,r}]} \tag{77}$$

$$RR\_RATIO_r = RR\_F_r - EST\_RR\_F_r \tag{78}$$

The $MIN\_DTAR\_F_n$ term was added to counter the impact of having any negative tariffs in the equation. It is set equal to the absolute value of the largest negative distributor tariff across the three sectors (residential, commercial, and industrial) in a given region and season. If there are no negative distributor tariffs, $MIN\_DTAR\_F_n$ is set to zero.

Determine Base Year Total Core Market Distribution Costs

Total core market distribution costs need to be established in a base year (1995 for *AEO99*) to provide a lagged value for total costs in equations 72 and 73 above. This can be calculated using a form of equation 60 above:

$$TC\_F_{r,hyr} = RR\_F_r + ICC_r \tag{79}$$

Thus, core revenue requirements and interruptible contributions to fixed costs need to be set for this historical year. Historical revenue requirements (RR_F_r) for the core market in each region are set equal to the sum of the peak and offpeak core revenue requirements for the residential, commercial, and industrial sectors. These seasonal revenues are estimated for each sector as the product of the corresponding seasonal firm distributor tariffs and historical volumes. Seasonal distributor tariffs for each sector are defined as the difference between seasonal core end-use prices[43] [$HPGFRSGR_{n,r,hyr}$, $HPGFCMGR_{n,r,hyr}$, and $HPGFINGR_{n,r,hyr]}$ and seasonal citygate prices [Appendix E, $HCGPR_{n,r,hyr}$]. Also, given user specified assumptions for I_BYPASS_r, MINMU_I, and DTM_BETA (Appendix E), equation 61 above is used to derive ICC_r for the year indicated.

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 (1995-1997 for *AEO99*), 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).[44] 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 reflect 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:

$$UDTAR\_SF_{n,j} = UDTAR\_SFPREV_{n,j} * (\text{threshold factor}) + CHQTY_{n,j} * 0.05 \tag{80}$$

where,

UDTAR_SF	=	seasonal distributor tariff for core electric generation sector in current forecast year ($/Mcf)
UDTAR_SFPREV	=	seasonal distributor tariff for core electric generation sector in previous forecast year ($/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	=	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:

[43]Quantity-weighted average, regional, seasonal historical end use prices are derived in the model using State level monthly data (Appendix E, CON and PRC). To account for data limitations, an adjustment is made to the industrial prices while deriving core and noncore prices (Appendix F, Table F5).

[44]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.

$$CHQTY_{n,j} = \frac{BASUQTY\_SF_{n,j} - BASUQTY\_SFPREV_{n,j}}{BASUQTY\_SFPREV_{n,j}} \quad (81)$$

where,

CHQTY	=	percentage change in seasonal core electric generator consumption each yr (fraction)
BASUQTY_SF	=	seasonal core electric generator consumption for subregion j (BCF)
BASUQTY_SFPREV	=	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 [$HPGFELGR_{n,j,hyr}$][45] 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[46] (adjusted to 1987 year dollars), as shown:

$$DTAR\_TRFV\_SF_{n,r} = HDTAR\_SF_{n,s=4,r,EHISYR} * (1-TRN\_DECL)^{YR\_DECL} + \frac{(STAX_r+FTAX)}{MC\_PCWGDP_{yr}} \quad (82)$$

where,

DTAR_TRFV_SF	=	distributor tariff for the fleet vehicle transportation sector (87$/Mcf)
HDTAR_SF	=	historical distributor tariff for the transportation sector,[47] assumed to be primarily for fleet vehicles (87$/ Mcf)
TRN_DECL	=	fleet vehicle distributor decline rate, set to zero for *AEO99* [Appendix E, (fraction)]
YR_DECL	=	difference between the current year and the last historical year over which the decline rate is applied
STAX	=	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	=	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,

[45]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).

[46]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.

[47]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.

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),[48] as shown in the following equation:

$$DTAR\_TRPV\_SF_{n,r} = DTAR\_SF_{n,s=3,r} + RETAIL\_COST + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_{yr}} \tag{83}$$

where,

DTAR_TRPV_SF	=	distributor tariff for the personal vehicle transportation sector (87$/Mcf)
DTAR_SF	=	distributor tariff for the core industrial sector, s=3 (87$/Mcf)
RETAIL_COST	=	cost of dispensing CNG [Appendix E, (87$/Mcf)]
STAX	=	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	=	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:

$$DTAR\_SI_{n,s=3,r} = HPGIINGR_{n,r,EHISYR} - HCGPR_{n,r,EHISYR} \tag{84}$$

where,

DTAR_SI	=	seasonal distributor tariff for the noncore industrial sector (s=3) in region r (87$/Mcf)
HPGIINGR	=	seasonal historical end-use price for the noncore industrial sector in region r [Appendix F, Table F5 (87$/Mcf)]
HCGPR	=	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.

[48]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.

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,

$$HUDTAR\_SI_{n,j,hyr} = HPGIELGR_{n,j,hyr} - HCGPR_{n,r,hyr} \tag{85}$$

Average,

$$UDTAR\_SI_{n,j} = \frac{(\ HUDTAR\_SI_{n,j,EHISYR} + HUDTAR\_SI_{n,j,EHISYR-1} + HUDTAR\_SI_{n,j,EHISYR-2}\ )}{3} \tag{86}$$

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

$$UDTAR\_SI_{n,j} = UDTAR\_SIPREV_{n,j} * 0.95 \tag{87}$$

where,

UDTAR_SI	=	seasonal distributor tariff for the noncore electric generation sector in subregion j in the current forecast year (87$/Mcf)
UDTAR_SIPREV	=	seasonal distributor tariff for the noncore electric generation sector in subregion j in the previous forecast year (87$/Mcf)
HUDTAR_SI	=	historical seasonal distributor tariff for the noncore electric generation sector in subregion j (87$/Mcf)
HPGIELGR	=	seasonal historical end-use price for the noncore electric generation sector in subregion j (87$/Mcf)
HCGPR	=	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 Pipeline Tariff Module (PTM) of the Natural Gas Transmission and Distribution Model (NGTDM). In this Module, the rates developed by the methodology are used as actual costs for transportation and storage services. The PTM tariff calculation is divided into two phases: a base-year initialization phase and a forecast year update phase. These two phases include the following steps: (1) determine the total cost of service, (2) classify line items of the cost of service as fixed and variable costs, (3) allocate fixed and variable costs to the rate component (reservation and usage fee [volumetric charge]) based on the rate design, (4) aggregate costs to the network arc/network node, (5) for transportation services, allocate costs to type of service (reservation and usage)[49], and (6) compute arc-specific (node-specific) rates. For the base-year phase, the cost of service is developed from the financial data base while for the forecast year update phase the costs are estimated using a set of econometric equations. These steps are used to determine transportation and storage rates for the Interstate Transmission Module. A general overview of the methodology for deriving rates is presented in the box on the next page, while the PTM system diagram is presented in Figure 6-1.

Base-Year Initialization Phase

The purpose of the base-year initialization phase is to provide, for the base year of the NEMS forecast horizon (currently 1990), an initial set of NGTDM network-level transportation and storage revenue requirements and tariffs. The base-year information is developed from existing pipeline company transportation and storage data. The base-year initialization process draws heavily on two data bases developed by the Office of Oil and Gas, EIA. These data represent the existing physical pipeline and storage system. The physical system is at a more disaggregate level than the NGTDM network. The first data base provides detailed company-level financial, cost, and rate base parameters. This financial data base contains information on capital structure, rate-base, and revenue requirements by major line item of the cost of service for the base year of the model. The second data base covers the physical attributes of the natural gas pipelines, including contract demand and pipeline layout. The physical pipeline layout data are used, along with the contract data, to derive the cost allocation factors. These factors subsequently are used to compute unit rates for transportation services along each arc (and for storage services at each node) of the NGTDM network.

This section discusses two separate processes that occur during the base-year initialization phase: (1) the computation of the cost of service and rates for services, and (2) the construction of capacity expansion cost/tariff curves.

The computation of base-year cost of service and rates for services involves six distinct procedures as outlined in the box below. Each of these procedures is discussed in detail below.

The PTM constructs cost/tariff curves which relate pipeline or storage facility capacity expansion to corresponding rates. These curves are developed from historically based estimates of capital and revenue requirements for capacity expansion projects using the computational procedures for determining base-year cost of service and rates.

PTM rates are calculated in nominal dollars and then converted to real dollars for use in the Interstate Transmission Module.

Computation of Cost of Service and Rates

An overview of the processing of costs in the PTM ratemaking procedure is illustrated in Figure 6-2. In the base-year initialization phase of the PTM, rates are computed using the six-step process outlined above. The first three steps are performed for the transportation and storage functions at the company level: (1) derivation of the total cost of service, (2) classifying line item costs as fixed and variable costs, and (3) allocation of fixed and variable costs to rate

[49]This step is not carried out for storage service because no distinction is made between reservation and usage.

PTM Methodology for Deriving Rates

For Each Company

- Derive the Total Cost of Service (COS)
  - Base Year - Read COS Line Items from Data Base
  - Forecast Year
    - Include Costs for Capacity Expansion
    - Estimate COS Line Items from Forecasting Equations

- Classify Line Items as Fixed and Variable Costs

- Allocate Costs to Rate Component Based on Rate Design

For Each Node and Arc

- Aggregate Costs to Network Arcs and Nodes

- Allocate Costs to Services

- Compute Rates for Services

components based on rate design. The fourth step is to transform the costs from the company level to the network (arcand node) level. Allocation of costs to services (Step 5) and computation of rates (Step 6) are carried out at the arc level for transportation and the node level for storage. Step 5 is only executed for the transportation function because there is only one type of storage service represented in the PTM.

The equations apply, in general, to both transportation and storage functions. However, not all variables used in an equation are defined for both functions. For example, costs associated specifically with transportation services, such as compressor station labor costs are set to zero when the equation is used to determine storage-related costs.

Step 1: Derivation of the Total Cost-of-Service

The total cost-of-service for a pipeline company is computed as the revenue requirement minus any revenue credits. The total revenue requirement (TRR) consists of a just and reasonable return on the rate base plus normal operating expenses. Revenue credits reflect revenues generated by nonjurisdictional services and one time costs that are outside of the scope of the PTM. Therefore, the total cost of service is computed as follows:

$$TCOS = TRR - REVC \qquad (88)$$

$$TRR = TRRB + TNOE \qquad (89)$$

where,

Figure 6-1. Pipeline Tariff Module System Diagram

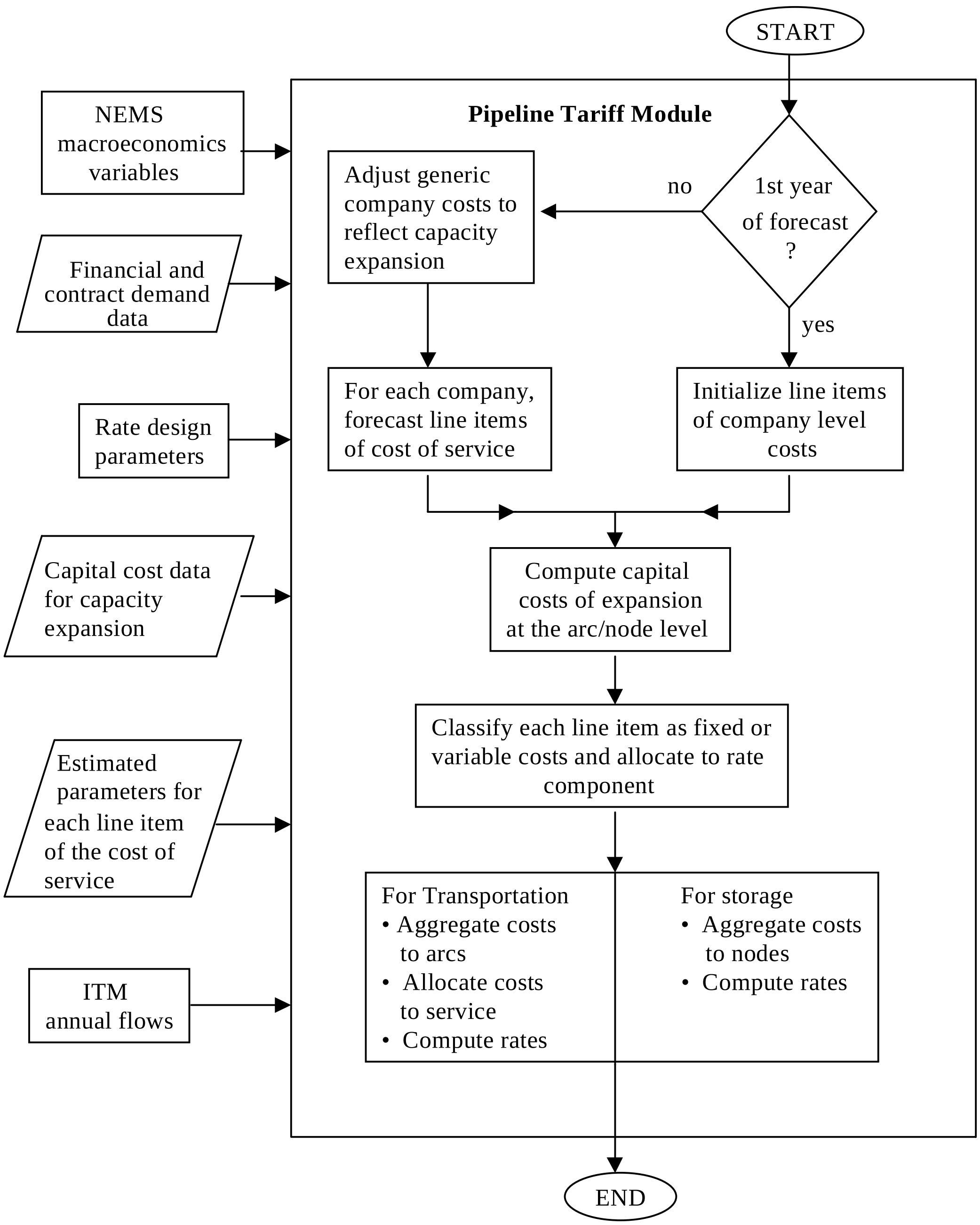
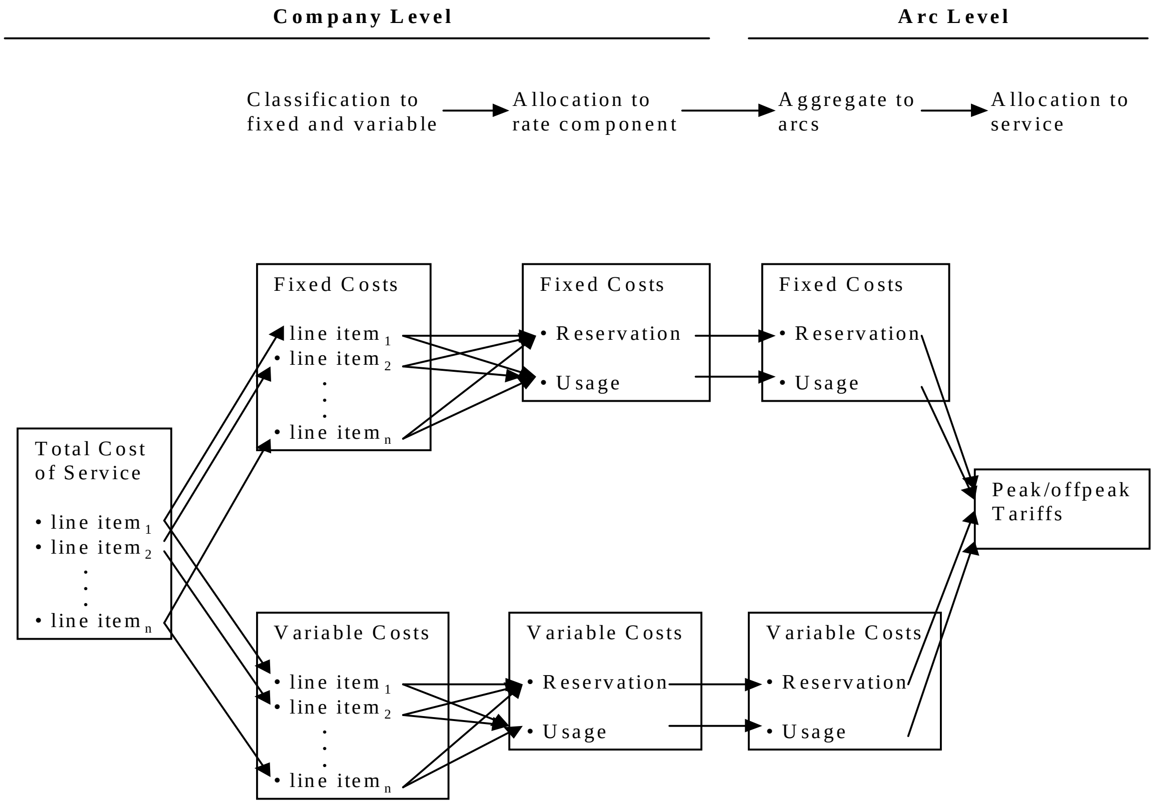


Figure 6-2. Processing Transportation Service Costs in the Ratemaking Process



TCOS = total cost-of-service (dollars[50])
TRR = total revenue requirement (dollars)
TNOE = total normal operating expenses (dollars)
REVC = revenue credits to cost-of-service (dollars) (Appendix E)
TRRB = total return on rate base (dollars)

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

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

Just and Reasonable Return. In order to compute the return portion of the cost-of-service, the determination of capital structure and rate base is necessary. Capital structure is important because it determines the cost of capital to the pipeline company. The weighted average cost of capital is applied to the rate base to determine the return component of the cost-of-service, as follows:

$$TRRB = WAROR * APRB \tag{90}$$

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)

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

$$PFEN = (PFES/TOTCAP) * PFER * APRB \tag{91}$$

$$CMEN = (CMES/TOTCAP) * CMER * APRB \tag{92}$$

$$LTDN = (LTDS/TOTCAP) * LTDR * APRB \tag{93}$$

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)
APRB = adjusted pipeline rate base (dollars)
CMEN = total return on common stock equity (dollars)
CMES = value of common stock equity (dollars)
CMER = common equity rate of return (fraction)
LTDN = total return on long-term debt (dollars)
LTDS = value of long-term debt (dollars)
LTDR = long-term debt rate (fraction)

The cost of capital (WAROR) is computed as the value-weighted average cost of capital for preferred stock, common stock equity, and long-term debt, as follows:

$$WAROR = (PFES*PFER + CMES*CMER + LTDS*LTDR)/TOTCAP \tag{94}$$

$$TOTCAP = PFES + CMES + LTDS \tag{95}$$

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)
TOTCAP = total capitalization (dollars)

The total rate base is computed as the sum of net plant in service, cash working capital, other working capital and transition expense balance minus accumulated deferred income taxes. That is,

$$APRB = NIS + CWC + OWC + TPEB - ADIT \tag{96}$$

where,

APRB = adjusted pipeline rate base (dollars)
NIS = net capital cost of plant in service (dollars)
CWC = cash working capital (dollars)
OWC = other working capital (dollars)
TPEB = transition expense balance (dollars)[51]
ADIT = accumulated deferred income taxes (dollars)

The net plant in service is the original capital cost plant in service minus the accumulated depreciation.

$$NIS = GPIS - ADDA \tag{97}$$

where,

NIS = net capital cost of plant in service (dollars)
GPIS = original capital cost of plant in service [gross plant in service (dollars)]
ADDA = accumulated depreciation, depletion, and amortization (dollars)

Total Normal Operating Expenses. Total normal operating expense line items include depreciation, taxes, administrative and general expenses, customer expenses, and operation and maintenance expenses. In the PTM, taxes are disaggregated further into Federal, State, and other taxes and tax credits to permit tax policy analysis. Operation and maintenance expenses also are disaggregated into several categories to enhance accuracy in forecasting expenses by function.

$$TNOE = DDA + TOTAX + TAG + TCE + TOM \tag{98}$$

where,

TNOE = total normal operating expenses (dollars)
DDA = depreciation, depletion, and amortization costs (dollars)
TOTAX = total Federal and State income tax liability (dollars)
TAG = total administrative and general expense (dollars)
TCE = total customer expense (dollars)[52]
TOM = total operations and maintenance expense (dollars)

Depreciation, depletion, and amortization costs, administrative and general expense, and customer expense are available directly from the financial data base.

Total taxes are computed as the sum of Federal and State income taxes and other taxes, less tax credits, as follows:

$$TOTAX = FSIT + OTTAX - FSITC \tag{99}$$

$$FSIT = FIT + SIT \tag{100}$$

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 (dollars)
FSITC = Federal and State investment tax credits (dollars)
FIT = Federal income tax (dollars)
SIT = State income tax (dollars)

[51]The transition expense balance is the remaining balance of approved but yet to be recovered transition costs associated with restructuring gas supply contracts for Order 636.

[52]Customer expense includes direct payroll distributions of salaries and wages associated with the following services: customer accounts, customer service, information, and sales.

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:

$$ATP = APRB*(PFER*PFES + CMER*CMES)/TOTCAP \qquad (101)$$

where,

ATP	=	after-tax profits (dollars)
APRB	=	adjusted pipeline rate base (dollars)
TOTCAP	=	total capitalization (dollars)
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)

and the Federal income taxes are

$$FIT = (FRATE*ATP\ /\ 1.- FRATE) \qquad (102)$$

where,

FIT	=	Federal income tax (dollars)
FRATE	=	Federal income tax rate (fraction) (Appendix E)
ATP	=	after-tax profits (dollars)

State income taxes are computed by multiplying the sum of taxable returns 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 are computed as follows:

$$SIT = SRATE * (FIT + ATP) \qquad (103)$$

where,

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

Total operations and maintenance expense consists of three major categories: supervision and engineering expenses, compressor station expenses, and other operations and maintenance expenses.[53] Compressor station expenses are disaggregated further into two categories: compressor station operating and maintenance labor expenses and compressor station operating and maintenance non-labor expenses. That is, total operating and maintenance expense (TOM) equals

$$TOM = SEOM + CSOML + CSOMN + OTOM \qquad (104)$$

where,

TOM	=	total operations and maintenance expense (dollars)
SEOM	=	supervision and engineering expense (dollars)
CSOML	=	compressor station operating and maintenance labor expense (dollars)
CSOMN	=	compressor station operating and maintenance non-labor expense (dollars)
OTOM	=	other operations and maintenance expense (dollars)

Revenue Credits. The revenue requirement is reduced (increased) by various revenue credits (expenses) to determine the total cost-of-service. These credits may relate to one-time expenditures that are outside the scope of the other cost

[53]Some expenses in this category apply only to transportation costs. Consequently, compressor-related and similar expenses will not be calculated for storage facilities.

categories. After the determination of the total cost of service, each line item is classified as a fixed or variable cost as described in Step 2.

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

The PTM classifies each line item of the cost of service (computed in Step 1) as a fixed and variable cost. 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:

$$R_{i,f} = ALL_f * R_i/100 \tag{105}$$

$$R_{i,v} = ALL_v * R_i/100 \tag{106}$$

where,

$R_{i,f}$	=	fixed cost portion of line item R_i (million dollars)
ALL_f	=	percentage of line item R_i representing fixed cost
R_i	=	total cost of line item i (million dollars)
$R_{i,v}$	=	variable cost portion of line item R_i (million 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.

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 usage fee. The reservation fee is a charge assessed based on the amount of the 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. For storage service the rate components are aggregated into one volumetric charge that is based on the amount of working gas capacity.[54]

The actual reservation and usage fees that pipelines are allowed to charge are regulated by the Federal Energy Regulatory Commission. 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, the more fixed costs are allocated to usage fees, the more costs are recovered based on throughput. Thus high load factor customers pay 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

[54]This simplified representation of one volumetric charge related to the working gas capacity is designed to include all the costs that in actual practice are recovered through reservation, inventory, injection, and withdrawal charges.

data subsequently are aggregated to the network arc, the composite rate design at the arc-level is the volumetric-weighted average of the pipelin 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.

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

Cost of Service Line Item	Total	Allocation Factors (percent) Fixed Cost	Variable Cost	Cost Component 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
Tax Credits	1,000	100	0	1,000	0
Administrative & General	50,000	90	10	45,000	5,000
Customer	2,000	100	0	2,000	0
Operations & Maintenance					
Supervision & Engineering	7,000	100	0	7,000	0
Compression Station/Labor	5,000	100	0	5,000	0
Compression Station/Non-labor	1,000	20	80	200	800
Other O & M	40,000	80	20	32,000	8,000
Revenue Requirement	227,000			213,200	13,800
Revenue Credits	25,000	100	0	25,000	0
Total Cost-of-Service	202,000			188,200	13,800

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.

The allocation of fixed costs to reservation and usage fees entails multiplying each fixed cost line item of the total cost of service by the corresponding fixed cost rate design classification factor. A similar process is carried out for variable costs. This procedure is illustrated in Tables 6-3a and 6-3b and is generalized in the equations following.

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

$$R_{i,f,r} = ALL_{f,r} * R_{i,f}/100 \quad (107)$$

$$R_{i,f,u} = ALL_{f,u} * R_{i,f}/100 \quad (108)$$

$$R_{i,v,r} = ALL_{v,r} * R_{i,v}/100 \quad (109)$$

$$R_{i,v,u} = ALL_{v,u} * R_{i,v}/100 \quad (110)$$

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

Cost of Service Line Item	Total	Allocation Factors (percent) Reservation	Usage	Cost Assigned to Rate Component Reservation	Usage
Total Return					
Preferred Stock	1,000	0	100	0	1,000
Common Stock	30,000	0	100	0	30,000
Long-Term Debt	29,000	100	0	29,000	0
Normal Operating Expenses					
Depreciation	30,000	100	0	30,000	0
Taxes					
Federal Tax	25,000	0	100	0	25,000
State Tax	5,000	0	100	0	5,000
Other Tax	1,000	100	0	1,000	0
Tax Credits	1,000	100	0	1,000	0
Administrative & General	45,000	100	0	45,000	0
Customer	2,000	100	0	2,000	0
Operations & Maintenance					
Supervision & Engineering	7,000	100	0	7,000	0
Compression Station/Labor	5,000	100	0	5,000	0
Compression Station/Non-labor	200	100	0	200	0
Other O & M	32,000	100	0	32,000	0
Revenue Requirement	213,200			152,200	61,000
Revenue Credits	25,000	100	0	25,000	0
Total Cost-of-Service	188,200			127,200	61,000

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

Cost of Service Line Item	Total	Allocation Factors (percent) Reservation	Usage	Cost Assigned to Rate Component 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
Tax Credits	0	0	100	0	0
Administrative & General	5,000	0	100	0	5,000
Customer	0	0	100	0	0
Operations & Maintenance					
Supervision & Engineering	0	0	100	0	0
Compression Station/Labor	0	0	100	0	0
Compression Station/Non-labor	800	0	100	0	800
Other O & M	8,000	0	100	0	8,000
Revenue Requirement	13,800			0	13,800
Revenue Credits	0	0	100	0	0
Total Cost-of-Service	13,800			0	13,800

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 fixed and variable costs allocated to reservation and usage components of the rates.

After ratemaking Steps 1, 2 and 3 are completed for each company, company-level costs are transformed to arc-level (node-level) rates for transportation (storage) services. This process, carried out for each arc and node in the NGTDM network, is accomplished in ratemaking Steps 4, 5 and 6 as presented below.

Step 4: Aggregation of Classified Cost of Service to Network Arcs and Nodes

As discussed above, for transportation services the PTM develops fixed and variable costs and allocates them to reservation and usage rate components at the pipeline company level. The PTM apportions these components to distinct segments of a pipeline path based on the share of the mileage-based capacity reservations on the segment. These pipeline path segments represent the portions of the physical pipeline system that fall within the transshipment nodes that define a network arc. The costs associated with each segment are mapped to the network arc by aggregating the cost information across all pipeline segments identified with an arc.[55] The capacity reservation shares (Appendix E, PS) used to apportion costs to pipeline segments are derived exogenously from the capacity reserved and distances associated with each segment and the capacity reserved and distances for the complete pipeline path. The shares do not change throughout the forecast.

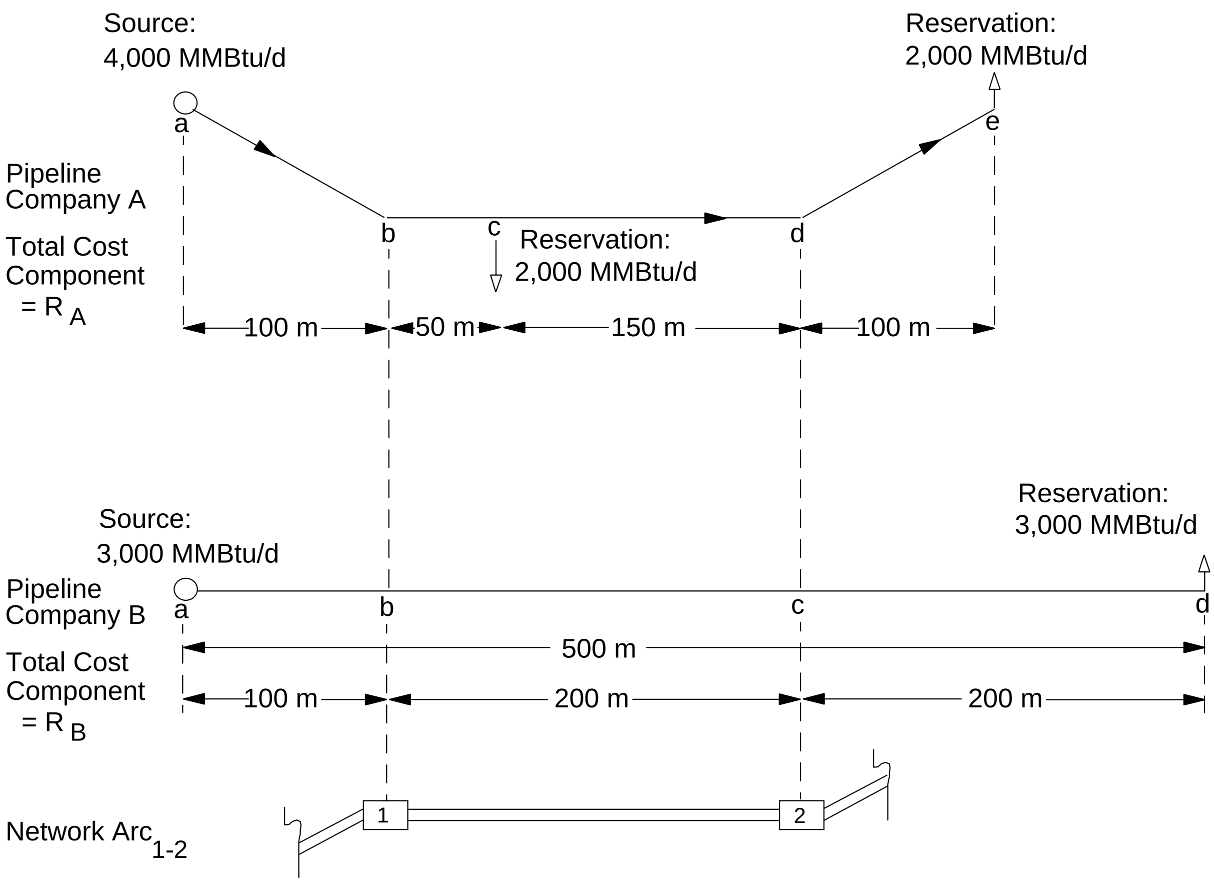
This procedure is illustrated for two hypothetical pipeline companies (Figure 6-3). In the example, it is assumed that the total costs to be distributed to distinct pipeline segments are R_A and R_B for Company A and Company B, respectively. Notice that Company A is defined by network a, b, c, d, e in the upper portion of Figure 6-3 and Company B is defined by network a, b, c, d in the middle half of the figure. Company A receives 4000 MMBtu/day at point a, discharges 2000 MMBtu/day at point c and ships the remaining 2000 MMBtu/day to point e. Company B ships 3,000 MMBtu along its entire route, from point a to point c. It is assumed further that segment b-d of Company A's pipeline path and segment b-c of Company B's pipeline path are to be mapped into the network arc defined by the transshipment nodes 1-2 at the bottom of Figure 6-3. Note that company A's segment b-d actually is composed of two segments: segment b-c and segment c-d.

The mileage-based capacity reservation (V) is determined as the capacity reserved in each pipeline segment multiplied by the length of the pipeline segment. For Company A the reservation on segment b-c is the quantity (4000*50) MMBtu-miles and the reservation on segment c-d is the quantity (2000*150) MMBtu-miles per day. For company B, the reservation on segment b-c is the quantity (3000*200) MMBtu-miles per day. The total reservation along the pipeline path for company A is the sum of the reservations on each segment, or 1,100,000 MMBtu-miles per day.[56]

[55]In the forecast years, arc-level costs include costs associated with generic companies representing pipeline capacity added subsequent to the base year. Generic companies are discussed in the section describing the forecast year updating process.

[56]Derived based on capacity reservations on arc a-b equal to (4000*100) MMBtu-miles per day, plus capacity reservations on arc b-c of (4000*50) MMBtu-miles per day, plus capacity reservations on arc c-d of (2000*150) MMBtu-miles per day and capacity reservations (2000*100) MMBtu-miles per day on arc d-e.

Figure 6-3. Example of Apportioning Pipeline Costs to Network Arcs



Once the reservations on the segments are determined, the pipeline costs are apportioned to each segment as follows. The share of cost (R_A) allocated to Company A's pipeline segment b-c is determined as the cost multiplied by the ratio of the reservations on segment b-c to the reservations on the total pipeline path, expressed as follows:

$$R_A^{b-c} = R_A * V_A^{b-c} / V_A^T \tag{111}$$

where,

R_A^{b-c} = portion of R_A allocated to Company A segment b-c
R_A = total component cost for Company A (dollars)
V_A^{b-c} = reservations on Company A segment b-c
V_A^T = total reservation on Company A pipeline path

In this example, V_A^{b-c} equals 200,000 MMBtu-miles per day and V_A^T equals 1,100,000 MMBtu-miles per day.

Similarly, the allocation of costs to Company A's segment c-d [$R_A^{c-d} = R_A*(3/11)$] and to Company B's segment b-c [$R_B^{b-c} = R_B*(6/15)$] are obtained. Finally, the costs are aggregated to the network arc by summing all distinct costs for Company A's segment b-c and segment c-d and Company B's segment b-c.

$$R_{1-2} = R_A^{b-c} + R_A^{c-d} + R_B^{b-c} \tag{112}$$

where,

$R_{1\text{-}2}$ = total costs allocated to arc 1-2
R_A^{b-c} = portion of R_A allocated to Company A segment b-c
R_A^{c-d} = portion of R_A allocated to Company A segment c-d
R_B^{b-c} = portion of R_B allocated to Company B segment b-c

Through this procedure, company-level fixed and variable costs are assigned to arcs on the NGTDM network and for each arc these costs have been assigned to a rate component. Thus the following variables are defined:

FCR_a = fixed costs assigned to the reservation component of the rate
VCR_a = variable costs assigned to the reservation component of the rate
FCU_a = fixed costs assigned to the usage component of the rate
VCU_a = variable costs assigned to the usage component of the rate
a = arc

Apportioning storage costs to network nodes is a more straightforward process because the costs are simply assigned to the nodes as a function of the share of storage capacity located in each region. Through the procedure provided in the following equations company-level fixed and variable costs are shared out and aggregated to nodes on the network.

$$FCS_n = FCS_n + (NS_{p,n} * SF_p) \tag{113}$$

$$VCS_n = VCS_n + (NS_{p,n} * SV_p) \tag{114}$$

where,

VCS_n = variable costs of storage (million dollars)
FCS_n = fixed costs of storage (million dollars)
$NS_{p,n}$ = share of company p gas storage capacity located at the node n [Appendix E, (fraction)]
SF_p = company p fixed costs for storage service (million dollars)
SV_p = company p variable costs for storage service (million dollars)
p = pipeline company index
n = node index

Step 5: Allocation of Arc-Level Transportation Costs to Services

The arc-level fixed and variable costs are allocated to firm and interruptible transportation services. In allocating these costs, a portion of the fixed costs are assigned to noncore customers. Historically, rate designs have placed some of the recovery of fixed costs at risk by assigning the recovery of these costs to noncore customers. Should the revenues obtained from interruptible service be less than those anticipated in the ratemaking process, the pipeline company would not recover all of its fixed costs. Variable costs are allocated based on total annual throughput for each type of service.

Derivation of Reservation Costs for Firm Transportation. Costs allocated to the firm transportation reservation fees consist of the firm transportation portion of the fixed and variable costs assigned to the reservation fee. This cost is derived by applying the allocation factors as follows:

$$RCFS_a = (FADFS_a * FCR_a) + (VADFS_a * VCR_a) \tag{115}$$

where,

$RCFS_a$ = reservation costs assigned to core customers (million dollars per year)
$FADFS_a$ = allocation factor for fixed costs recovered from firm service (ratio, set 1 in the PTM)
FCR_a = fixed costs assigned to the reservation component of the rate (million dollars per year)
$VADFS_a$ = allocation factor for variable costs recovered from firm service (ratio, set to 1 in the PTM)

VCR_a = variable costs assigned to the reservation component of the rate (million dollars per year)
a = arc

Derivation of Usage Costs for Firm Transportation. Costs allocated to the firm transportation usage fees consists of the firm transportation portion of the fixed and variable costs assigned to the usage fee. This cost is derived by applying the allocation factors as follows:

$$UCFS_a = (FADFS_a * FCU_a) + (VADFS_a * VCU_a) \tag{116}$$

where,

$UCFS_a$ = usage costs assigned to core customers (million dollars per year)
$FADFS_a$ = allocation factor for fixed costs recovered from firm service (ratio, set to 1 in the PTM)
FCU_a = fixed costs assigned to the usage component of the rate (million dollars per year)
$VADFS_a$ = allocation factor for variable costs recovered from firm service (ratio, set to 1 in the PTM)
VCU_a = variable costs assigned to the usage component of the rate (million dollars per year)
a = arc

Derivation of Fixed and Variable Costs Allocated to Interruptible Transportation. Costs allocated to interruptible transportation service consist of a portion of the fixed and variable costs assigned to the reservation and usage rate components. This cost is derived by applying the allocation factors as follows:

$$CIS_a = (FADIS_a * (FCU_a + FCR_a)) + (VADIS_a * (VCU_a + VCR_a)) \tag{117}$$

where,

CIS_a = costs assigned to noncore customers (million dollars per year)
$FADIS_a$ = allocation factor for fixed costs recovered from interruptible service (ratio, set to 0 in the PTM)
FCU_a = fixed costs assigned to the usage component of the rate (million dollars per year)
FCR_a = fixed costs assigned to the reservation component of the rate (million dollars per year)
$VADIS_a$ = allocation factor for variable costs recovered from interruptible service (ratio, set to 0 in the PTM)
VCU_a = variable costs assigned to the usage component of the rate (million dollars per year)
VCR_a = variable costs assigned to the reservation component of the rate (million dollars per year)
a = arc

The costs allocated to interruptible transportation service are not used to derive the maximum and minimum rates that may be charged for interruptible service. These costs are presented here to account fully for all costs that make up the total cost of service and to facilitate the discussion of the derivation of the costs allocated to firm transportation service. The computation of rates for peak and offpeak periods is presented in Step 6.

Step 6: Computation of Rates

The NGTDM pipeline network uses tariffs in the form of dollars per Mcf of throughput for peak and offpeak periods. The transportation tariffs associated with current capacity are derived from the following nonlinear tariff curve, which uses the base point (PNOD, QNOD) and an assumed positive price elasticity to set tariffs.

$$NGPIPE\_VARTAR = PNOD * (Q / QNOD) ** ALPHA\_PIPE \tag{118}$$

where,

for peak transmission tariffs:

PNOD = $TCOST_{i,j}$ *PKSHR_YR / (ADJ_PIP *QNOD)
QNOD = $PTCURPCAP_{i,j}$ * (PKSHR_YR *$PTPKUTZ_{i,j}$)

for offpeak transmission flows:

PNOD = $VCOST_{i,j}$ *(1.0 - PKSHR_YR) / (ADJ_PIP *QNOD)
QNOD = $PTCURPCAP_{i,j}$ *((1.-PKSHR_YR) *$PTOPUTZ_{i,j}$)

for offpeak transmission tariffs:

$$PNOD = TCOST_{i,j} *(1.0 - PKSHR\_YR) / (ADJ\_PIP*QNOD)$$

$$QNOD = PTCURPCAP_{i,j} *((1.-PKSHR\_YR) *PTOPUTZ_{i,j})$$

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 or net storage withdrawal (bcf)
ALPHA_PIPE =	Price elasticity for pipeline tariff curve
$VCOST_{i,j}$ =	Total variable cost of service for transportation (million 1987 dollars)
$TCOST_{i,j}$ =	Total cost of service for transportation (million 1987 dollars)
$PTPKUTZ_{i,j}$ =	Peak pipeline utilization (fraction)
$PTOPUTZ_{i,j}$ =	Offpeak pipeline utilization (fraction)
$PTCURPCAP_{i,j}$ =	Current pipeline capacity (bcf)
ADJ_PIP =	Pipeline tariff curve adjustment factor (fraction)
PKSHR_YR =	Portion of the year represented by the peak season (fraction)
r =	region
i,j =	regional source (i) and destination (j) link on arc a

Fixed and variables tariffs along Canadian import arcs are defined using input data. Fixed tariffs are obtained directly from the data (Appendix E, $ARC\_FIXTAR_{n,a,t}$), while variables tariffs are calculated based on pipeline utilization and a maximum expected tariff (CNMAXTAR). If the pipeline utilization along a Canadian arc is less than 50 percent, then the pipeline tariff is set low (50 percent of CNMAXTAR). If the Canadian pipeline utilization is between 50 and 90 percent, then the pipeline tariff is set to a level between 50 and 70 percent of CNMAXTAR. The sliding scale is determined using the corresponding utilization factor, as follows:

$$NGPIPE\_VARTAR_{i,j} = (CNMAXTAR * 0.5 * CANUTIL_{i,j}) + (CNMAXTAR * 0.25) \tag{119}$$

If the Canadian pipeline utilization is greater than 90 percent, then the pipeline tariff is set to between 70 and 100 percent of CNMAXTAR. This is accomplished again using Canadian pipeline utilization, as follows:

$$NGPIPE\_VARTAR_{i,j} = (CNMAXTAR * 3.0 * CANUTIL_{i,j}) - (CNMAXTAR * 2.0) \tag{120}$$

Note that no distinction is made at this time between peak and offpeak tariffs along Canadian import arcs.

Revenue Credit Option. A revenue credit algorithm has been designed and implemented as an option in the PTM. Its purpose is to capture the effects of capacity release on firm pipeline tariffs through the treatment of interruptible revenues. With this algorithm, a pipeline company[57] is allowed to transfer a portion of their incremental revenue from interruptible service to firm service. The incremental revenue of interruptible service is defined as the portion above expected revenue which is determined by using a conservative estimate of interruptible flow defined for the pipeline company. The portion transferred to firm service then becomes a credit to firm service, resulting in a reduction in the firm revenue requirements and, thus, firm tariffs. The amount of incremental revenue transferred from interruptible service to firm service, and ultimately used to adjust firm service tariffs, is held constant in real dollars throughout the forecast period.

Storage Service. Storage facilities are defined in the NGTDM network at regional nodes. In the base-year initialization phase, storage facility costs, capacities, inventories, and other data for existing companies are allocated

[57]According to regulation, revenue crediting can be adopted into the rate making process of an individual pipeline company. However, in the PTM module, revenue crediting is implemented at the arc level, instead.

to regional NGTDM network nodes using storage facility data in FERC and EIA data series.[58] An interstate pipeline company's total reported storage cost is allocated to NGTDM region nodes according to the regional distribution of natural gas storage capacity in the company's own storage facilities, as reported on Form EIA-191.[59] Because storage costs are related to base gas storage capacity, the cost allocation is based on the company's regional share of base gas storage capacity relative to its total base gas storage capacity. Regional interstate pipeline company-level costs are aggregated to the corresponding NGTDM region node (Equations 127 and 128).

The regional storage costs for interstate pipeline companies are converted to per-unit-capacity costs by dividing the aggregate regional cost by the aggregate regional base gas storage capacity. The interstate pipeline per-unit storage capacity cost obtained for each region is applied to the non-interstate (intrastate and third party owners) regional storage capacity to obtain their estimated storage costs. These costs are added to the NGTDM region aggregate interstate pipeline company costs (FCS and VCS) to obtain the total storage facility costs (FCST and VCST) at the region node.

Next, the node-level storage tariffs associated with current storage working capacity are derived from the following nonlinear tariff curve, which uses the base point (PNOD, QNOD) and an assumed positive price elasticity to set tariffs.

$$NGSTR\_VARTAR = PNOD' * (Q / QNOD') ** ALPHA\_STR \tag{121}$$

where,

for peak storage tariffs (net withdrawals):

PNOD' = $VSUM_r$ / (ADJ_STR *QNOD)
QNOD' = $PTCURPSTR_r$ *$PTSTUTZ_r$

NGSTR_VARTAR = PTM function to define storage tariffs (87$/mcf)
QNOD’ = Base point quantity (bcf)
PNOD’ = Base point price (87$/mcf)
Q = net storage withdrawal (bcf)
ALPHA_STR = Parameter for storage tariff equation for current capacity
$VSUM_r$ = VCST, Variable cost of service for storage (million 1987 dollars)
$PTSTUTZ_r$ = Storage utilization (fraction)
$PTCURPSTR_r$ = Current working storage capacity (bcf)
ADJ_STR = Storage tariff curve adjustment factor (fraction)

To account for regulatory oversight and to assist in stabilizing the tariffs, a check is performed each year to limit the annual increase in the storage tariff to a user specified escalation rate. This limit is imposed as shown in the following equation.

$$STAR_{n,t} = MIN(STAR_{n,t}, STAR_{n,t-1} * (1 + MAXESC)) \tag{122}$$

where,

$STAR_{n,t}$ = $NGSTR\_VARTAR_{n,t}$, storage tariff (1987 dollars per mcf)
$STAR_{n,t-1}$ = $NGSTR\_VARTAR_{n,t-1}$, storage tariff from previous year (1987 dollars per mcf)
MAXESC = maximum allowable annual escalation rate for tariffs [Appendix E, (fraction)]
n = node
t = forecast year

[58]FERC Form 2 provides total storage costs for interstate pipeline companies with storage facilities. Form EIA-191 provides injections, withdrawals, inventories, and base and working gas capacity by field/reservoir for storage facilities owned by all storage companies. The Form EIA-191 filings include information that allows facilities to be designated as owned by interstate pipeline and other firms.

[59]To distribute costs regionally, it is assumed that reported costs represent only costs associated with storage facilities owned by the company and do not include costs of storing gas in other facilities.

This method of computing storage tariffs does not conform strictly to industry practices; rather it conforms to the representation of storage in other modules of the NGTDM.

Construction of Capacity Expansion Cost (Pipeline/Storage) Tariff Curves

The primary criterion in determining when and where physical pipelines and storage facilities will need to be expanded is the need of customers purchasing firm service to receive gas on future peak days. A secondary criterion is that the costs associated with pipeline and storage expansion are kept to a minimum. In general, pipeline companies and local distribution companies (LDC) recognize that the high costs incurred in adding pipeline and storage capacity may lead to increased per-unit charges to customers purchasing firm service, which in the short-term may lead to slight decreases in consumption levels. In the long-term, increased delivery costs may lead to much more significant demand shifts when end-use capital purchasing decisions are affected.

The cost/tariff curves are constructed through a process comparable to the base-year initialization procedure described earlier. The PTM has an exogenous data input file of pipeline and storage capacity cost curves that relate capital cost to corresponding capacity expansion. Pipeline and storage capital cost data are developed from the incremental costs required to add an additional increment of capacity along a network arc or to a storage node in the NGTDM. These incremental costs reflect the capital costs associated with adding compressors, looping,[60] and other means of expanding pipeline capacity, or the capital costs associated with adding new or expanding existing natural gas storage fields. The PTM also obtains from an exogenous data base the operating costs, depreciation schedules, and other components of revenue requirements associated with pipeline or storage expansion. The exogenous data are defined by region and are based on historic industry averages.

Construction of the pipeline capacity (storage) tariff cost curves is comparable to the process in which base-year transportation (storage) tariffs are developed. However, instead of using the existing pipeline company data bases, the components of revenue requirements for the capacity expansion cost curves are obtained from a separate exogenous data base containing the capital and revenue requirements for capacity expansion projects. Using these data, together with the base-line initialization equations discussed above, the PTM develops the peak and offpeak tariffs for transportation and storage associated with each level of capacity expansion. The pipeline capacity (storage) expansion tariff curves are constructed in the base year and are used in all subsequent forecast years.[61]

Forecast Year Update Phase

The purpose of the forecast year update phase is to project, for each subsequent year of the forecast period, the line items of the cost-of-service discussed above that are used to develop rates. In each remaining year of the simulation, the PTM forecasts the pipeline company-level parameters required to determine the cost of capital, rate-base, operation and maintenance expense, and taxes. Additionally, arc-specific billing determinants are projected for the forecast year. These parameters are used to calculate the arc-specific (node-specific) rates using the procedure described in the base-year initialization phase. The forecasting relationships are discussed in detail below.

The PTM also accounts for revenues and volumetric flows for new capacity in the forecast year by assigning these parameters to arc- or region-specific generic pipeline or storage companies. These parameters are forecast at the arc-level in subsequent years. Generic pipeline and storage companies are discussed in more detail below.

After all the line items of the cost-of-service are forecasted, the PTM proceeds to: (1) classify line items of the cost of service as fixed and variable costs, (2) allocate fixed and variable costs to rate component (reservation and usage fee, volumetric charge) based on the rate design, (3) aggregate costs to the network arc/network node, (4) for transportation services, allocate costs to type of service (firm and interruptible), and (5) compute arc-specific (node-specific) rates.

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[60]Looping is the construction of a pipeline parallel to an existing line to increase the capacity of the system.

[61]The pipeline tariff is in dollars per MMBtu-mile and the storage tariff, including injection and inventory costs, is in dollars per MMBtu of working gas capacity.

Investment Costs for Generic Pipeline and Storage Companies

The PTM projects pipeline capacity expansion at the arc level and storage expansion at the regional level, as opposed to determining expansion for individual companies. The PTM creates arc-specific generic pipeline companies and regional, node-specific, generic storage facilities to incorporate the effects of capacity expansion on an arc or node. Thus, the PTM tracks costs attributable to capacity added during the forecast period separately from the costs attributable to facilities in service in the base year. The PTM uses an exogenous data base to obtain the capital costs which correspond to the level of capacity expansion provided by the Interstate Transmission Module (ITM) in the forecast year.[62] The exogenous data base contains costs in real dollars. These costs must be converted to nominal dollars in the forecast year using the GDP deflators provided by the NEMS macroeconomic model. Other line items of the cost-of-service for the generic companies are derived from historical industry averages and are provided by an exogenous data base. These costs too must be converted to nominal dollars and also must be scaled to reflect the size of expansion determined by the ITM.

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

$$CAPCSTN_a = ARCCC_a * (EXPQ_a/365) * MILES_a * 1{,}000{,}000 \qquad (123)$$

where,

CAPCSTN	=	total capital cost to expand capacity at a pipeline arc (dollars)
ARCCC	=	capital cost per unit of expansion (dollars-day per mcf-mile)
EXPQ	=	capacity expansion for an arc (bcf)
MILES	=	length of transportation arc in miles [Appendix E)
a	=	arc

Unit capital costs for expanding capacity are adjusted to reflect regional differences in costs, as shown below.

$$ARCCC_a = CCOST_a * (1 + CSTFAC_a) \qquad (124)$$

where,

$$CCOST_a = k0 * EXP(k1 * EXPFAC_a) \qquad (125)$$

$$EXPFAC_a = ((PTCURPCAP_a \,/\, CAP90_a) - 1.0) \qquad (126)$$

ARCCC	=	capital cost per unit of expansion (dollars-day per mcf-mile)
CCOST	=	capital cost to expand 1 unit of pipeline capacity [Appendix E, (dollars-day per mcf-mile)]
EXPFAC	=	expansion factor for pipeline capacity
PTCURPCAP	=	current pipeline capacity (bcf)
CAP90	=	base year pipeline capacity (bcf)
CSTFAC	=	factor to accommodate regional difference in cost [Appendix E, (fraction)]
k0	=	capital cost parameter [Appendix E, ALPHA_CCOST]
k1	=	capital cost parameter [Appendix E, BETA_CCOST]
a	=	arc

Similar to pipeline capacity expansion, capital costs for expanding storage at each node is derived below.

$$CAPCSTN_n = (CCOST_n + SLOPE_n * (STRFAC_n - FACTOR_n)) * EXPSTQ_n * 1{,}000{,}000) \qquad (127)$$

where,

[62]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.

and,

$$STRFAC_n = ((PTCURPSTR_n \ / \ STCAP90_n) - 1.0) \tag{128}$$

CAPCSTN = total capital cost to expand storage capacity (dollars)
STRFAC = expansion factor for storage capacity
PTCURPSTR = current storage capacity (bcf)
STCAP90 = base year storage capacity (bcf)
CCOST = capital cost per unit of expansion (dollars per Mcf)[Appendix E, STR_CCOST]
SLOPE = slope parameter for storage expansion cost curve [Appendix E, STRCC_SLOPE]
FACTOR = factor to accommodate regional difference in cost [Appendix E, STR_FACTOR]
EXPSTQ = capacity expansion for a storage node (bcf)
n = node

An upper bound limiting the amount of additional storage capacity that can be added at each node is defined as a function of the base year node capacity. The bounds are defined as follows:

$$EXPSTQ_n = (WGCT_n + WGCNT_n) * (1 + NODFACT_n) \tag{129}$$

where,

EXPSTQ = maximum allowable capacity expansion at a given storage node (bcf)
WGCT = jurisdictional working gas capacity in the base year (bcf)
WGCNT = non-jurisdictional working gas capacity in the base year (bcf)
NODFACT = Maximum growth in storage capacity throughout the forecast year from 1990
n = node

For pipeline capacity expansion, the peak day reservations are set equal to the daily capacity (the capacity provided by the ITM divided by 365 days per year). The annual flow through the pipeline is calculated as the capacity multiplied by a utilization factor provided by the ITM or assumed exogenously. For storage capacity expansion, the amount of gas withdrawn is set equal to the working gas capacity.

After the generic pipeline company transportation and storage volumes and cost-of-service are determined, the generic company is treated within the PTM as an additional arc-specific pipeline company and/or regional node-specific storage facility. Cost-of-service for the aggregate of all prior years' capacity expansion projects is projected to the forecast year according to the subsequent year's forecasting procedure discussed below. Company-level cost-of-service for the new incremental capacity in the forecast year are determined according to the base-year initialization procedure discussed above and added to the projected cost-of-service of the aggregate prior years' capacity.

Forecasting Cost-of-Service [63]

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 new construction 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

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

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 factor cost changes (e.g., wage rates), the extent 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 factor cost changes 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/storage facility costs, accounting algorithms, exogenous assumptions, and inputs from other NEMS modules. These forecasting algorithms may be classified into three distinct projected pipeline cost areas, as follows:

- The projection of existing and incremental rate base and capital costs
- The projection of capital-related components of the revenue requirement
- The projection of operations and maintenance expenses of the revenue requirements.

The empirically derived forecasting algorithms discussed below are determined for each pipeline company.

Projection of Rate Base and Cost of Capital

The approach for projecting rate base and capital costs is summarized in Table 6-4. Long-run marginal capital costs of pipeline companies are reflected in changes in the rate base. Once projected, the rate base is translated into capital-related components of the revenue requirements based on projections of the cost of capital, capitalization, and algorithms for depreciation and tax effects.

Rate-Base Components. The projected rate base in year t is computed as in the base year. That is, the rate base in year t is the net plant in service in year t plus working capital and transition expenses in year t.

$$PRB_t = GPIS_t - ADDA_{t-1} + CWC_t + OWC_t \tag{130}$$

where,

PRB	=	pipeline rate base before adjustment in dollars
GPIS	=	original capital cost of plant in service (gross plant in service) in dollars
ADDA	=	accumulated depletion, depreciation, and amortization in dollars
CWC	=	cash working capital in dollars
OWC	=	other working capital in dollars
t	=	forecast year

The variables of the rate-base equation are forecast by the following set of equations. First, gross plant in service in the forecast year is determined by the prior year's gross plant in service, new capacity expansion (as determined by the Capacity Expansion Module), current capital additions to existing plants for replacement and refurbishment, and cost associated with new facilities for complying with Order 636.[64] Gross plant in service is forecast as follows:

[64]New facilities transition cost will be added to original capital cost of plant in service, on an individual pipeline basis. See Appendix E (A191YRS, ANUM191, AGSRCOSTS, SHARE_GSR_F, GSRYRS, NEWCOST_PER) for default assumptions on costs and depreciation schedules.

$$GPIS_t = \begin{cases} GPIS_{t-1} + BLAE_t + PNEWFAC_t & \text{(existing pipe)} \\ GPIS_{t-1} + NCAE_t & \text{(generic pipe)} \end{cases} \tag{131}$$

where,

GPIS = original capital cost of plant in service (gross plant in service) in dollars
NCAE = new capacity expansion expenditures allowed in rate base within the forecast year in dollars
BLAE = capital expenditures associated with base year capacity (refurbishment/replacement expenditures) in dollars
PNEWFAC = cost of new facilities required to comply with Order 636 (nominal dollars)

Capital expenditures associated with base year capacity (refurbishment on existing pipeline/storage) are obtained by using three available options (BLAESWT = 0, 1, 2). The first option (used in *AEO98*) sets capital expenditures for pipeline refurbishment/replacement to zero. The second option sets refurbishment to be a proportion of the annual depreciation expense. The proportion is a function of the age of the plant. Option three allows the user to exogenously define total annual capital expenditures for refurbishment for the whole pipeline industry. The industry-wide expense is distributed to individual companies as a function of the gas plant in service. These options are defined as follows:

<u>option 1</u> (BLAESWT=0):

$$BLAE_t = 0 \tag{132}$$

<u>option 2</u> (BLAESWT=1):

$$BLAE_t = DDA_t * ADDA_t \,/\, GPIS_{t-1} \tag{133}$$

where,

BLAE = capital expenditures associated with base year capacity (refurbishment/ replacement expenditures) in dollars
DDA = depreciation, depletion and amortization costs in dollars
ADDA = accumulated depreciation, depletion, and amortization in dollars
GPIS = original capital cost of plant in service (gross plant in service) in dollars
t = forecast year

<u>option 3</u> (BLAESWT=2):

$$BLAE_t = BLAETOT * (GPIS_{t-1} \,/\, INDUSTRYGPIS_{t-1}) \tag{134}$$

where,

BLAE = capital expenditures associated with base year capacity (refurbishment/ replacement expenditures) in dollars
BLAETOT = user-defined total capital expenditure for refurbishment/replacement for the pipeline industry in dollars
GPIS = original capital cost of plant in service (gross plant in service) in dollars
INDUSTRYGPIS = total capital cost of plant in service (gross plant in service) for pipeline industry in dollars
t = forecast year

Accumulated depreciation, depletion, and amortization is given by:

$$ADDA_t = ADDA_{t-1} + DDA_t \tag{135}$$

where,

ADDA = accumulated depreciation, depletion, and amortization in dollars
DDA = depreciation, depletion, and amortization costs in dollars

A regression equation is used to define the annual depreciation, depletion, and amortization for existing pipelines, while an accounting algorithm is used for generic pipelines. For existing pipelines, this expense is forecast as follows:

$$\begin{aligned} DDA_t = & (1-\rho)*\beta_0 + \beta_1*NETPLT_t + \beta_2*DEPSHR_t \\ & + \rho*DDA_{t-1} - \rho*(\beta_1*NETPLT_{t-1} + \beta_2*DEPSHR_{t-1}) \end{aligned} \tag{136}$$

where,

Table 6-4. Approach to Projection of Rate Base and Capital Costs

Projection Component	Approach
1. Rate Base	
a. Gross plant in service	
I. Capacity expansion costs for generic pipeline/storage	Provided by the Capacity Expansion Module
II. Replacement/refurbishment costs for existing pipeline/storage	Accounting algorithm or user defined options
b. Accumulated Depreciation, Depletion & Amortization	Existing Pipelines: empirically estimated Generic Pipelines: accounting algorithm
c. Cash and other working capital	Empirically estimated
d. Transition expenses	Accounting algorithm with exogenous specification for recovery/absorption
e. Accumulated deferred income taxes	Existing Pipelines: empirically estimated Generic Pipelines: accounting algorithm
f. Depreciation, depletion, and amortization	Existing Pipelines: empirically estimated Generic Pipelines: accounting algorithm
2. Cost of Capital	
a. Long-term debt rate	Base year average rate, adjusted using projected bond yields
b. Preferred equity rate	Base year rate (fixed)
c. Common equity return	Incorporate changes in dividend/bond yields
3. Capital Structure	Held constant at base year values

DDA	=	depreciation, depletion, and amortization costs in dollars
β_0,β_1,β_2	=	coefficients estimated based on an empirical study (Appendix F, Table F3)
ρ	=	estimated auto-correlation coefficients (Appendix F, Table F3)
NETPLT	=	net capital cost of plant in service (dollars)
DEPSHR	=	ratio of accumulated depreciation, depletion, and amortization expenses to gross plant in service (a proxy for pipeline age)

A certain portion of the cost of new facilities required to comply with Order 636 can also be depreciated during the recovery period. Thus during this period, the depreciation, depletion, and amortization costs for existing pipeline are calculated as follows:

$$DDA_t = DDA_t + PNEWFAC / NEWCOST\_PER \tag{137}$$

where,

DDA	=	depreciation, depletion, and amortization costs in nominal dollars
PNEWFAC	=	cost of new facilities required to comply with Order 636 (nominal dollars)
NEWCOST_PER	=	period allowing recovery of new facility costs (Appendix E)

The net plant in service and the proxy for pipeline age are defined as follows:

$$\begin{aligned} NETPLT_t &= GPIS_{t-1} - ADDA_{t-1} \\ DEPSHR_t &= ADDA_{t-1} \; / \; GPIS_{t-1} \end{aligned} \tag{138}$$

where,

GPIS	=	original capital cost of plant in service (gross plant in service) in dollars
ADDA	=	accumulated depreciation, depletion, and amortization in dollars

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

$$DDA_t = \sum_{s=1991}^{t} (NCAE_s \; / \; 30) \tag{139}$$

where,

DDA_t	=	depreciation, depletion, and amortization costs in dollars
$NCAE_s$	=	new capacity expansion expenditures occurring in year s (in dollars)
s	=	the year new expansion occurred
30	=	30 years of plant life
t	=	forecast year

Cash working capital is set equal to zero, because historically it has been at or near zero. Thus,

$$CWC_t = 0 \tag{140}$$

where,

CWC	=	cash working capital in dollars

Other working capital consists of material and supplies, gas held in storage, and other components that vary by company. Other working capital is calculated as a function of gross plant in service, as follows:

$$\begin{aligned} OWC_t = {} & GPIS_t^{\beta 0} * GPIS_{t-1}^{-\rho * \beta 0} * e^{[\beta 1 \, * \, (MC\_PGDP_t \, - \, \rho * MC\_PGDP_{t-1})]} * \\ & e^{[\beta 2 \, * \, (TYEAR \, - \, \rho * (TYEAR \, - 1.0))]} * OWC_{t-1}^{\rho} * CONST \end{aligned} \tag{141}$$

where,

OWC	=	other working capital in dollars

GPIS = original capital cost of plant in service (gross plant in service) in dollars
$\beta 0$ = estimated coefficient on gross plant in service
ρ = estimated auto correlation coefficient
$\beta 1$ = estimated coefficient on price level
MC_PGDP_t = implicit GDP price deflator (from the Macroeconomic Activity Model)
$\beta 2$ = estimated coefficient on time trend
TYEAR = year in Julian units (i.e., 1995)
CONST = estimated constant term
t = forecast year
[Note: See Table F3 in Appendix F for derivation of coefficients and regression statistics]

The rate base is adjusted for accumulated deferred income taxes and other expenses as follows:

$$APRB_t = PRB_t - ADIT_t + TPEB \tag{142}$$

where,

APRB = adjusted pipeline rate base in dollars
PRB = pipeline rate base before adjustment in dollars
ADIT = accumulated deferred income taxes in dollars
TPEB = transition expense balance in dollars
t = forecast year

Accumulated deferred income taxes depend on income tax regulations in effect, differences in tax and book depreciation, and the time vintage of past construction. The relationship established for the existing pipelines is different from the generic pipelines. The accumulated deferred income taxes for existing pipeline/storage is derived as follows:

$$ADIT_t = \beta_0 + \beta_1 * ADIT_{t-1} + \beta_2 * NETPLT_t \tag{143}$$

where,

β_0,β_1,β_2 = coefficients estimated based on empirical study (Appendix F, Table F3)
ADIT = accumulated deferred income taxes in dollars
NETPLT = difference between original capital cost of plant in service and accumulated depreciation in previous period (net plant in service) in dollars
t = forecast year

Accumulated deferred income taxes for generic companies is calculated using an accounting algorithm. It is assumed that for rate making purposes, straight line depreciation (SLD) is used. However, for tax purposes, modified accelerated cost recovery system (MACRS) with a 15 ½ year schedule is used. ADIT is derived from the difference between two depreciation schedules and the tax rate. Selecting the formula used to calculate ADIT depends on the difference between two depreciation schedules and the book value of the asset (calculated using the MACRS depreciation schedule). The formula are as follows:

$$ADIT_t = \begin{cases} ADIT_{t-1} + (DEPRMACRS_t - DEPRSL_t) * FRATE & \text{if } DEPRMACRS > DEPRSL \\ ADIT_{t-1} & \text{if } DEPRMACRS < DEPRSL \text{ and } BOOKVL > 0 \\ ADIT_{t-1} - DEPRSL_t * FRATE & \text{if } BOOKVL = 0 \end{cases} \tag{144}$$

where,

ADIT = accumulated deferred income taxes in dollars
DEPRMACRS = annual depreciation expense using MACRS
DEPRSL = annual depreciation expense using 30 year straight line schedule
FRATE = federal tax rate (Appendix F, Table F3)
BOOKVL = book value of plant, which is calculated using straight line depreciation schedule

t = forecast year

and,

$$DEPRMACRS_t = \sum_{s=1991}^{t} NCAE_s * MACRS\_RATE_{t-s+1}$$

$$DEPRSL_t = \sum_{s=1991}^{t} NCAE_s \ / \ 30 \qquad (145)$$

where,

NCAE = new capacity expansion expenditures occurring in year s (in dollars)
MACRS_RATE = rate of depreciation by MACRS schedule (Appendix E)
s = the year new expansion occurred
t = forecast year

Cost of Capital. The capital-related components of the revenue requirement depend upon the size of the rate base and the cost of capital to the pipeline company. In turn, the company cost of capital depends upon the rates of return on debt and equity and the amounts of debt and equity in the overall capitalization.

Company cost of capital consists of long-term debt, preferred stock, and common equity. The rate of return variables for debt and equity will be related to forecast macroeconomic variables. For existing pipeline, it is assumed that the long-term debt rate will vary as a function of the difference in the long-term debt rate and the yield on AA utility bonds (provided by the Macroeconomic Activity Model) in the base year, as follows:

$$\begin{aligned} LTDR_{i,t} &= MC\_RMPUAANS_t \ / \ 100.0 \ + \ DLTDR_{i,b} \\ &= MC\_RMPUAANS_t \ / \ 100.0 \ + \ (LTDR_{i,b} \ - \ MC\_RMPUAANS_b \ /100.0) \end{aligned} \qquad (146)$$

where,

$LTDR_{i,t}$ = long-term debt rate [Appendix E -- PLTDR, (fraction)]
$MC\_RMPUAANS_t$ = AA utility bond index rate provided by the Macroeconomic Activity Model (percentage)
$DLTDR_{i,b}$ = difference in the long term debt rate and the yield on AA utility bond for pipeline company i in base year
i = pipeline company i
b = base year
t = forecast year

The rate of return on common equity for existing pipelines is considered to be a function of the long-term debt rate and the difference between the long-term debt rate and the rate of return on common equity in the base year. That is,

$$\begin{aligned} CMER_{i,t} &= LTDR_{i,t} \ + \ DCMER_{i,b} \\ &= LTDR_{i,t} \ + \ (CMER_{i,b} \ - \ LTDR_{i,b}) \end{aligned} \qquad (147)$$

where,

$CMER_{i,t}$ = common equity rate of return [Appendix E -- PCMER, (fraction)]
$LTDR_{i,t}$ = long-term debt rate [Appendix E -- PLTDR, (fraction)]
$DCMER_{i,b}$ = the difference between rate of return on common equity and on long-term debt in base year
i = pipeline company i
b = base year
t = forecast year

The rate of return on preferred stock for existing pipelines is also tied to the AA bond rate through the long term debt rate, as following:

$$PFER_{i,t} = LTDR_{i,t} \ + \ DPFER_{i,b} \qquad (148)$$

where,

$PFER_{i,t}$ = rate of return for preferred stock [Appendix E -- PPFER, (fraction)]
$LTDR_{i,t}$ = long-term debt rate [Appendix E -- PLTDR, (fraction)]
$DPFER_{i,b}$ = the difference between rate of return on preferred stock and rate of return on long-term debt[65]
i = pipeline company i
b = base year
t = forecast year

For generic pipelines, the rate of return on long term debt (LTDR) is defined as an industry average rate of return weighted by gross plant in service (GPIS) in the base year. In the forecast years, it is equal to the sum of the AA utility bond rate and a deviation constant calculated in the base year. The derivation is shown below:

$$\begin{aligned} LTDR_t &= \sum_i \left(LTDR_{i,t} * \frac{GPIS_{i,b}}{\sum_j GPIS_{j,b}}\right) \\ &= \sum_i (MC\_RMPUAANS_t \ / \ 100.0 + DLTDR_{i,b}) * \frac{GPIS_{i,b}}{\sum_j GPIS_{j,b}} \\ &= MC\_RMPUAANS_t/100.0 + \sum_i (DLTDR_{i,b}) * \frac{GPIS_{i,b}}{\sum_j GPIS_{j,b}} \\ &= MC\_RMPUAANS_t/100.0 + GLTDR0 \end{aligned} \tag{149}$$

where,
$LTDR_t$ = industry average long-term debt rate for generic pipeline (fraction)
$LTDR_{i,t}$ = long-term debt rate for existing pipeline company i [Appendix E -- PLTDR, (fraction)]
$MC\_RMPUAANS_t$ = AA utility bond index rate provided by the Macroeconomic Activity Model (percentage)
$DLTDR_{i,b}$ = the difference between the long term debt rate and the yield on AA utility bond for pipeline company i
GLTDR0 = deviation constant is the derived average difference between the rate of long term debt and the yield on AA utility bond in the base year
$GPIS_{i,t}$ = original capital cost of plant in service (gross plant in service) in dollars
i = existing pipeline company i
b = base year
t = forecast year

The rate of return on common equity (CMER) for generic pipelines is tied to the AA utility bond rate through the long-term debt rate (LTDR). CMER is equal to the sum of long term debt rate for generic pipeline and a deviation constant. The derivation is shown below:

$$\begin{aligned} CMER_t &= \sum_i \left(CMER_{i,t} * \frac{GPIS_{i,b}}{\sum_j GPIS_{j,b}}\right) \\ &= \sum_i (LTDR_{i,t} + DCMER_{i,b}) * \frac{GPIS_{i,b}}{\sum_j GPIS_{j,b}} \\ &= \sum_i \left(LTDR_{i,t} * \frac{GPIS_{i,b}}{\sum_j GPIS_{j,b}}\right) + \sum_i \left(DCMER_{i,b} * \frac{GPIS_{i,b}}{\sum_j GPIS_{j,b}}\right) \\ &= LTDR_t + GCMER0 \end{aligned} \tag{150}$$

where,

[65]The DPFER variable is assigned as 0.5% and kept constant for each pipeline throughout the entire forecast. This value represents analyst's judgement because attempts to derive it from historical data produced unrealistic results.

$CMER_t$ = industry average common equity rate for generic pipeline (fraction)
$CMER_{i,t}$ = rate of return on common equity for existing pipeline company i [Appendix E -- PCMER, (fraction)]
$LTDR_t$ = industry average long-term debt rate for generic pipeline (fraction)
$LTDR_{i,t}$ = long-term debt rate for existing pipeline company i [Appendix E -- PLTDR, (fraction)]
$DCMER_{i,b}$ = the difference between rate of return on common equity and rate of return on long-term debt for pipeline company i in base year
GCMER0 = deviation constant is the derived average difference between the rate of return on common equity and the yield on AA utility bond in base year
$GPIS_{i,t}$ = original capital cost of plant in service (gross plant in service) in dollars
i = pipeline company i
b = base year
t = forecast year

Similarly, the rate of return on preferred stock (PFER) is equal to the sum of the long term debt rate for generic pipelines and a deviation constant. It can be derived as shown below:

$$\begin{aligned} PFER_t &= \sum_i \left(PFER_{i,t} * \frac{GPIS_{i,b}}{\sum_j GPIS_{j,b}}\right) \\ &= \sum_i (LTDR_{i,t} + DPFER_{i,b}) * \frac{GPIS_{i,b}}{\sum_j GPIS_{j,b}} \\ &= LTDR_t + \sum_i \left(DPFER_{i,b} * \frac{GPIS_{i,b}}{\sum_j GPIS_{j,b}}\right) \\ &= LTDR_t + GPFER_0 \end{aligned} \tag{151}$$

where,
$PFER_t$ = average rate of preferred stock for generic pipelines (fraction)
$PFER_{i,t}$ = rate of return for preferred stock for the existing pipeline company i [Appendix E -- PPFER, (fraction)]
$LTDR_t$ = industry average long-term debt rate for generic pipeline (fraction)
$LTDR_{i,t}$ = long-term debt rate for existing pipeline company i [Appendix E -- PLTDR, (fraction)]
$DPFER_{i,b}$ = the difference between rate of return on preferred stock and rate of return on long-term debt for company i
GPFER0 = deviation constant is the derived average difference between the rate of return on preferred stock and the yield on AA utility bond in base year
$GPIS_{i,t}$ = original capital cost of plant in service (gross plant in service) in dollars
i = pipeline company i
b = base year
t = forecast year

For existing companies, the values of common stock, preferred stock and long term debt are assumed to be constant in real dollars; therefore, in nominal dollars these are increased by the inflation rate for the forecast period:

$$\begin{aligned} PFES_{i,t} &= PFES_{i,t-1} * GDPINFL_t \\ CMES_{i,t} &= CMES_{i,t-1} * GDPINFL_t \\ LTD_{i,t} &= LTD_{i,t-1} * GDPINFL_t \end{aligned} \tag{152}$$

where,
$PFES_{i,t}$ = value of preferred stock in nominal dollars
$CMES_{i,t}$ = value of common equity in nominal dollars

$LTD_{i,t}$ = long-term debt in nominal dollars
$GDPINFL_t$ = implicit GDP price inflator relative to previous year (from the Macroeconomic Activity Model)
i = pipeline company i
t = forecast year

The capital structure for generic pipelines is assumed constant. The three components of capital structure (GPFESTR, GCMESTR, and GLTDSTR) are defined as the average 1990 capital structure of the pipeline directly represented in the PTM (Appendix E -- PFES, CMES, LTD), and are used, along with the adjusted pipeline rate base, to determine the values of preferred stock, common stock, and long term debt:

$$\begin{aligned} PFES_t &= GPFESTR_t * APRB_t \\ CMES_t &= GCMESTR_t * APRB_t \\ LTD_t &= GLTDSTR_t * APRB_t \end{aligned} \tag{153}$$

where,
PFES = value of preferred stock in nominal dollars
CMES = value of common equity in nominal dollars
LTD = long-term debt in nominal dollars
GPFESTR = average historical ratio of preferred stock to total capital used as capital structure for generic pipeline (constant over forecast period)
GCMESTR = average historical ratio of common stock to total capital used as capital structure for generic pipeline (constant over forecast period)
GLTDSTR = average historical ratio of long term debt to total capital used as capital structure for generic pipeline (constant over forecast period)
APRB = adjusted pipeline rate base (dollars)
t = forecast year

Capital structure is the percent of total capitalization represented by each of the three capital components: long-term debt costs, preferred equity, and common equity. The proportions of total capitalization due to common stock, preferred stock, and long-term debt are considered fixed at the base-year values throughout the forecast. Assuming that the fractions of total capitalization remain the same over the forecast horizon,[66] the weighted average cost of capital in the forecast year is given by:

$$WAROR_t = [(PFER_t * PFES_t) + (CMER_t * CMES_t) + (LTDR_t * LTDS_t)] \;/\; TOTCAP_t \tag{154}$$

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 [Equation 95 (dollars)]
t = forecast year

[66]Changes in capital structure could be treated later as an enhancement to the PTM. This would involve consideration of, among other factors, sources and uses of funds, dividend payout policies, and regulatory caps on how much common equity is permitted in determining rates. It is not clear that this enhancement would offer large benefits to the forecast.

Projection of Capital-Related Components of the Revenue Requirements

The approach to the projection of capital-related components of the revenue requirements is summarized in Table 6-5. Given the rate-base and capitalization projections discussed above, the components of revenue requirements are relatively straightforward to project. The capital-related components of the revenue requirements include total return; Federal and State tax credits; Federal and State income taxes; other taxes; and depreciation, depletion, and amortization costs. These cost components are projected as follows:

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

$$TRRB_t = WAROR_t * APRB_t \tag{155}$$

where,

TRRB = total return on rate base (before taxes) in dollars
WAROR = weighted-average before-tax rate of return on capital (fraction)
APRB = adjusted pipeline rate base in dollars
t = forecast year

The return on rate base for existing companies is broken out into the three components as shown below.

$$PFEN_t = (PFES_t/TOTCAP_t) * PFER_t * APRB_t \tag{156}$$

$$CMEN_t = (CMES_t/TOTCAP_t) * CMER_t * APRB_t \tag{157}$$

$$LTDN_t = (LTDS_t/TOTCAP_t) * LTDR_t * APRB_t \tag{158}$$

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)
APRB = adjusted pipeline rate base (dollars)

Table 6-5. Approach to Projection of Revenue Requirements: Capital-Related Costs and Taxes

Projection Component	Approach
1. Rate Base-related Components	
a. Total return	Direct calculation from projected rate base and rates of return
b. Federal/State tax credits	Held constant in real terms at base year values
c. Federal/State income taxes	Accounting algorithms based on tax rates
2. Other Taxes	Held constant in real terms at base year values

CMEN = total return on common stock equity (dollars)
CMES = value of common stock equity (dollars)
CMER = common equity rate of return (fraction)
LTDN = total return on long-term debt (dollars)
LTDS = value of long-term debt (dollars)
LTDR = long-term debt rate (fraction)
t = forecast year

For generic companies the capital structure is assumed to be constant over the forecast period. Therefore, the return on rate base for generic companies (new expansion portion of pipeline/storage) is defined using a simpler format:

$$PFEN_t = (GPFESTR) * PFER_t * APRB_t \tag{159}$$

$$CMEN_t = (GCEMSTR) * CMER_t * APRB_t \tag{160}$$

$$LTDN_T = (GLTDSTR) * LTDR_t * APRB_t \tag{161}$$

where,

PFEN = total return on preferred stock (dollars)
CMEN = total return on common stock equity (dollars)
LTDN = total return on long-term debt (dollars)
GPFESTR = average historical ratio of preferred stock to total capital used as capital structure for generic pipeline (constant over forecast period)
GCMESTR = average historical ratio of common stock to total capital used as capital structure for generic pipeline (constant over forecast period)
GLTDSTR = average historical ratio of long term debt to total capital used as capital structure for generic pipeline (constant over forecast period)
PFER = coupon rate for preferred stock (fraction)
CMER = common equity rate of return (fraction)
LTDR = long-term debt rate (fraction)
APRB = adjusted pipeline rate base (dollars)
t = forecast year

Total taxes consists of Federal income taxes, State income taxes, and other taxes at average rates, minus tax credits for Federal and State income taxes. Federal income taxes and State income taxes are calculated in the same manner as in the base year (Equations 99-103) using average tax rates. The equation for total taxes is as follows:

$$TOTAX_t = FSIT_t + OTTAX_t - FSITC_t \tag{162}$$

where,

TOTAX = total Federal and State income tax liability (dollars)
FSIT = Federal and State income tax (dollars)
FSITC = Federal and State investment tax credits (dollars)
OTTAX = all other taxes assessed by Federal, State, or local governments except income taxes (dollars)
t = forecast year

Federal income tax credits are assumed to remain constant in real terms at the base year level throughout the forecast and therefore they are adjusted for inflation. Other taxes relate to 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 are determined as a function of the previous year's level times the inflation rate from the previous year.

$$OTTAX_t = OTTAX_{t-1} * (MC\_PGDP_t / MC\_PGDP_{t-1}) \tag{163}$$

where,

OTTAX = all other taxes assessed by Federal, State, or local governments except income taxes (dollars)
MC_PGDP = implicit GDP price deflator (from the Macroeconomic Activity Model)
t = forecast year

Projection of Normal Operating Expenses and Revenue Credits

The remaining projected components of the revenue requirements are normal operating expenses and revenue credits. Normal operating expenses are further disaggregated into depreciation, depletion, and amortization expenses, total taxes (previously estimated above), administrative and general expense, customer expenses, and total operations and maintenance expenses. The approach to the projection of these line items is summarized in Table 6-6. The projected costs are based on long-run marginal cost relationships in the pipeline industry which relate cost incurrence to external measures of industry size or activity and which relate unit costs to measurable changes in factor costs, the level and nature of the service, and technology. In some cases costs are assumed to be held constant because of limited resources available to develop data and develop the empirical estimates.

The total cost of service for a forecast year is as follows:

$$TCOS_t = TRRB_t + TNOE_t - REVC_t \tag{164}$$

where,

TCOS = total cost-of-service (dollars)
TRRB = total return on rate base [before taxes (dollars)]
TNOE = total normal operating expenses (dollars)
REVC = revenue credits to cost-of-service (dollars)
t = forecast year

Revenue credits to cost-of-service is determined as a function of the previous year's level times the inflation rate from the previous year, as follows:

$$REVC_t = REVC_{t-1} * (MC\_PGDP_t \ / \ MC\_PGDP_{t-1}) \tag{165}$$

where,

REVC = revenue credits to cost-of-service (dollars)
MC_PGDP = implicit GDP price deflator (from the Macroeconomic Activity Model)
t = forecast year

The revenue requirement consists of a just and reasonable return on the rate base plus normal operating expenses.

$$TRR_t = TRRB_t + TNOE_t \tag{166}$$

where,

TRR = total revenue requirement (dollars)
TRRB = total return on rate base [before taxes (dollars)]
TNOE = total normal operating expenses (dollars)
t = forecast year

The total normal operating expenses costs consist of the following components:

$$TNOE_t = DDA_t + TOTAX_t + TAG_t + TCE_t + TOM_t \tag{167}$$

where,

TNOE = total normal operating expenses (dollars)
TOTAX = total Federal and State income tax liability (dollars)
DDA = depreciation, depletion, and amortization costs (dollars)
TAG = total administrative and general expense (dollars)

TCE = total customer expense (dollars)
TOM = total operating and maintenance expense (dollars)
t = forecast year

Table 6-6. Approach to Projection of Revenue Credits and Normal Operating Expenses

Projection Component	Approach
1. Revenue Credits to Cost of Service	Held constant at base-year value adjusted for inflation
2. Depreciation, Depletion, and Amortization	Empirically estimated
3. Administrative & General - salaries, pension benefits, regulatory expenses, and other expenses	Empirically estimated
4. Customer Expense	Held constant at base-year value adjusted for inflation
5. Total Operating and Maintenance Expense	Empirically estimated

A regression equation is used to define the annual depreciation, depletion, and amortization for existing pipelines, while an accounting algorithm is used for generic pipelines. For existing pipelines, this expense is forecast as follows:

$$\begin{aligned} DDA_t = {} & (1-\rho)*\beta_0 + \beta_1*NETPLT_t + \beta_2*DEPSHR_t \\ & + \rho*DDA_{t-1} - \rho*(\beta_1*NETPLT_{t-1} + \beta_2*DEPSHR_{t-1}) \end{aligned} \tag{168}$$

where,

DDA = depreciation, depletion, and amortization costs in dollars
β_0,β_1,β_2 = coefficients estimated based on an empirical study (Appendix F, Table F3)
ρ = estimated auto-correlation coefficients (Appendix F, Table F3)
NETPLT = net capital cost of plant in service (dollars)
DEPSHR = ratio of accumulated depreciation, depletion, and amortization expenses to gross plant in service (a proxy for pipeline age)

A certain portion of the cost of new facilities required to comply with Order 636 can also be depreciated during the recovery period. During this period, the depreciation, depletion, and amortization costs for existing pipeline are calculated as:

$$DDA_t = DDA_t + PNEWFAC/NEWCOST\_PER \tag{169}$$

where,

DDA = depreciation, depletion, and amortization costs in nominal dollars
PNEWFAC = cost of new facilities required to comply with Order 636 (nominal dollars)
NEWCOST_PER = period allowing recovery of new facility costs (Appendix E)

The net plant in service and the proxy for pipeline age are defined as follows:

$$NETPLT_t = GPIS_{t-1} - ADDA_{t-1}$$
$$DEPSHR_t = ADDA_{t-1} \; / \; GPIS_{t-1} \tag{170}$$

where,

GPIS = original capital cost of plant in service (gross plant in service) in dollars
ADDA = accumulated depreciation, depletion, and amortization in dollars

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

$$DDA_t = \sum_{s=1991}^{t} (NCAE_s \; / \; 30) \tag{171}$$

where,

DDA_t = depreciation, depletion, and amortization costs in dollars
$NCAE_s$ = new capacity expansion expenditures occurring in year s (in dollars)
s = the year new expansion occurred
30 = 30 years of plant life
t = forecast year

For projection purposes, total customer expense is a function of last year's level times the inflation rate from the previous year.

$$TCE_t = TCE_{t-1} * (MC\_PGDP_t \; / \; MC\_PGDP_{t-1}) \tag{172}$$

where,

TCE = total customer expense (dollars)
MC_PGDP = implicit GDP price deflator (from the Macroeconomic Activity Model)
t = forecast year

Total administrative and general costs (TAG_t) are determined using an estimated equation and an efficiency adjustment term. The efficiency adjustment term is included to incorporate the observation that the efficiency of the natural gas pipeline system has been dramatically improved as a result of the increase in competition associated with open access.[67] The estimated equation used for the unadjusted TAG (Appendix F, Table F3) is determined as a function of gross plant in service, labor and rental cost indices, and some pipeline specific variables, as defined below:

$$TAG_{i,t}^{(unadj)} = e^{(\alpha_{1,i} * FD_i \, + \, \alpha_{2,i} * TF_{i,t})} * GPIS_{i,t-1}^{\beta_1} * W_t^{\beta_2} * PK_t^{(1-\beta_2)} \tag{173}$$

where,

$TAG_{i,t}^{(unadj)}$ = total administrative and general costs before adjusting for efficiency (1987 real dollars)
FD_i = pipeline specific dummy variable that represents pipeline specific unobserved effects (equals 1 if pipeline company i, 0 otherwise)
$TF_{i,t}$ = pipeline specific open access variable
= $TRNSHR_t * FD_i$, where, $TRNSHR_t$ is industry average share of gas transported for others. [$TRNSHR_t$ equals historical average shares during 1990 to 1994 (source: FERC Form 2), and is assumed to be 1.0 after 1994]
$GPIS_{i,t-1}$ = original capital cost of plant in service (gross plant in service at the beginning of the year) in dollars (used as a proxy for size of company i)
W_t = real labor cost index, all private sector
= MC_ECIWSP_t / MC_PGDP_t, where MC_ECIWSP_t is labor cost index and MC_PGDP_t is GDP price index from Macroeconomic Activity Model
PK_t = rental of office space for corporations ($RENTBLDG_t$)

[67]"Efficiency in the Natural Gas Industry," by Kevin Forbes, SAIC, January 31, 1995.

= rental cost index times rate of return (source: DRI)

$\alpha_{1,i}$, $\alpha_{2,i}$ = firm-specific coefficients estimated based on empirical study (Appendix F, Table F3)

β_1, β_2 = coefficients estimated based on empirical study (Appendix F, Table F3)

i = pipeline company index

t = forecast year

Next, the estimated TAG equation is used to determine total administrative and general costs which include the efficiency adjustment ($TAG_{i,t}^{(adj)}$). Similar methods are used for existing and generic pipelines to accomplish this. For both cases, the adjusted TAG equation is composed of two cost components: a discounted cost frontier and a discounted inefficiency measure. For generic pipelines, the inefficiency term is also multiplied by the GPIS (used as a proxy for size). The equations are presented below:

Existing pipeline:

$$TAG_{i,t}^{(adj)} = (1 - d_1)^{(t-1)} * TAG_{i,t}^{(frontier)} + (1 - d_2)^{(t-2)} * TAG\_IEFF\_E_{i,t} \quad (174)$$

where,

$TAG_{i,t}^{(adj)}$ = total administrative and general costs with efficiency adjustment for existing pipeline i in year t (1987 real dollars)

$TAG_{i,t}^{(frontier)}$ = cost frontier of total administrative and general costs for existing pipeline i in year t (1987 real dollars)

$TAG\_IEFF\_E_{i,t}$ = TAG inefficiency measurement for existing pipeline i in year t (see Endnote 2)

d_1 = discount rate of TAG cost frontier [Appendix E -- TAG_DCLE_CF, (fraction)]

d_2 = discount rate of TAG inefficiency for existing pipeline [Appendix E -- TAG_DCLE, (fraction)]

i = pipeline company index

t = forecast year

Generic pipeline:

$$TAG_{i,t}^{(adj)} = (1 - d_1)^{(t-1)} * TAG_{i,t}^{(frontier)} + (1 - d_2)^{(t-2)} * TAG\_IEFF\_G_{i,t} * GPIS_{i,t} \quad (175)$$

where,

$TAG_{i,t}^{(adj)}$ = total administrative and general costs with efficiency adjustment for generic pipeline i in year t (1987 real dollars)

$TAG_{i,t}^{(frontier)}$ = cost frontier of total administrative and general costs for generic pipeline i in year t (1987 real dollars)

$TAG\_IEFF\_G_i$ = TAG unit inefficiency factor (e.g., inefficiency per GPIS) for generic pipeline i (calculated in base year and kept constant in forecast years, see Endnote 2)

$GPIS_{i,t-1}$ = original capital cost of plant in service (gross plant in service at the beginning of the year) in dollars (used as a proxy for the size of company i)

d_1 = discount rate of TAG cost frontier [Appendix E -- TAG_DCLE_CF, (fraction)]

d_2 = discount rate of TAG inefficiency for generic pipeline [Appendix E -- TAG_DCLG, (fraction)]

i = pipeline company index

t = forecast year

The cost frontier for total administrative and general costs ($TAG_{i,t}^{(frontier)}$) is defined the same for both existing and generic pipelines: the coefficients and dummy variables of the most efficient pipeline company are substituted into the estimated equation ($TAG_{i,t}^{(unadj)}$). This defines the least cost for a company with the same size. The inefficiency term, however, is defined differently. For existing pipeline, the inefficiency measurement ($TAG\_IEFF\_E_{i,t}$) is defined as the difference between the unadjusted cost and the cost frontier (after discounting). Thus, the amount of inefficiency is calculated each year by subtracting the discounted cost frontier from the unadjusted costs. For generic pipelines, the inefficiency measurement term ($TAG\_IEFF\_G_{i,t}$) is the product of a unit inefficiency factor times a discount rate. The unit inefficiency factor is defined as the inefficiency per GPIS (used as a proxy for the size of expansion). This factor is calculated as the difference between the unadjusted pipeline TAG costs and the frontier TAG costs using the historical arc average data in the base year. The discount rate is applied to model the potential efficiency improvement in new generic pipelines.

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

$$TAG_{i,t} = TAG_{i,t}^{(adj)} * MC\_PGDP_t \tag{176}$$

where,

$TAG_{i,t}$ = total administrative and general costs with efficiency adjustment for generic pipeline i in year t (nominal dollars)
$TAG_{i,t}^{(adj)}$ = total administrative and general costs with efficiency adjustment for generic pipeline i in year t (1987 real dollars)
MC_PGDP = implicit GDP price deflator (from the Macroeconomic Activity Model)
t = forecast year

As with the TAG calculations, the total operation and maintenance costs (TOM_t) are determined using an estimated equation and an efficiency adjustment term. The estimated equation used for the unadjusted TOM (Appendix F, Table F3) is determined as a function of gross plant in service, labor and rental cost indices, and some pipeline specific variables, as defined below:

$$TOM_{i,t}^{(unadj)} = e^{(\alpha_{1,i} * FD_i + \alpha_{2,i} * TF_{i,t})} * GPIS_{i,t-1}^{\beta_1} * W_t^{\beta_2} * PK_t^{(1-\beta_2)} \tag{177}$$

where,

$TOM_{i,t}^{(unadj)}$ = total operation and maintenance costs before adjusting for efficiency (1987 real dollars)
FD_i = pipeline specific dummy variable that represents pipeline specific unobserved effects (equals 1 if pipeline company i, 0 otherwise)
$TF_{i,t}$ = pipeline specific open access variable
= $TRNSHR_t * FD_i$, where, $TRNSHR_t$ is industry average share of gas transported for others. [$TRNSHR_t$ equals historical average shares during 1990 to 1994 (source: FERC Form 2), and is assumed to be 1.0 after 1994]
$GPIS_{i,t-1}$ = original capital cost of plant in service (gross plant in service at the beginning of the year) in dollars (used as a proxy for size of company i)
W_t = real labor cost index, all private sector
= MC_ECIWSP_t / MC_PGDP_t, where MC_ECIWSP_t is labor cost index and MC_PGDP_t is GDP price index from Macroeconomic Activity Model
PK_t = the user cost of capital for compressor stations
$\alpha_{1,i}$, $\alpha_{2,i}$ = firm-specific coefficients estimated based on empirical study (Appendix F, Table F3)
β_1, β_2 = coefficients estimated based on empirical study (Appendix F, Table F3)
i = pipeline company index
t = forecast year

In the above equation, the user cost of capital for compressor stations is defined as the rental price of capital, represented as:

$$PK_t = \left(REALAA + PIPE\_DEPR - \frac{PIPE_t - PIPE_{t-1}}{PIPE_{t-1}} \right) * PIPE_t \tag{178}$$

where,

PK_t = the user cost of capital for compressor stations
PIPE_DEPR = assumed depreciation rate on compressor station equipment (= 0.10 annually, from PTARIFF)

$PIPE_t$ = Producer price index for compressor station equipment [initial values of PIPE are 1.133 (index of 1990) and 1.184 (index of 1991)][68]
REALAA = the real rate of AA utility bonds

Next, the estimated TOM equation is used to determine total operation and maintenance costs which include the efficiency adjustment ($TOM_{i,t}^{(adj)}$). Similar methods are used for existing and generic pipelines to accomplish this. For both cases, the adjusted TOM equation is composed of two cost components: a discounted cost frontier **and a** discounted inefficiency measure. For generic pipelines, the inefficiency term is also multiplied by the GPIS (used as a proxy for size). The equations are presented below:

Existing pipeline:

$$TOM_{i,t}^{(adj)} = (1 - d_1)^{(t-1)} * TOM_{i,t}^{(frontier)} + (1 - d_2)^{(t-2)} * TOM\_IEFF\_E_{i,t} \tag{179}$$

where,

$TOM_{i,t}^{(adj)}$ = total operation and maintenance costs with efficiency adjustment for existing pipeline i in year t (1987 real dollars)
$TOM_{i,t}^{(frontier)}$ = cost frontier of total operation and maintenance costs for existing pipeline i in year t (1987 real dollars)
$TOM\_IEFF\_E_{i,t}$ = TOM inefficiency measurement for existing pipeline i in year t (see Endnote 2)
d_1 = discount rate of TOM cost frontier [Appendix E -- TOM_DCLE_CF, (fraction)]
d_2 = discount rate of TOM inefficiency for existing pipeline [Appendix E -- TOM_DCLE, (fraction)]
i = pipeline company index
t = forecast year

Generic pipeline:

$$TOM_{i,t}^{(adj)} = (1 - d_1)^{(t-1)} * TOM_{i,t}^{(frontier)} + (1 - d_2)^{(t-2)} * TOM\_IEFF\_G_{i,t} * GPIS_{i,t-1} \tag{180}$$

where,

$TOM_{i,t}^{(adj)}$ = total operation and maintenance costs with efficiency adjustment for generic pipeline i in year t (1987 real dollar)
$TOM_{i,t}^{(frontier)}$ = cost frontier of total operation and maintenance costs for generic pipeline i in year t (1987 real dollars)
$TOM\_IEFF\_G_i$ = TOM unit inefficiency factor (e.g., inefficiency per GPIS) for generic pipeline i (calculated in base year and kept constant in forecast years, see Endnote 2)
$GPIS_{i,t-1}$ = original capital cost of plant in service (gross plant in service at the beginning of the year) in dollars (used as a proxy for size of company i)
d_1 = TOM_DCLE_CF: discount rate of TOM cost frontier [Appendix E -- TOM_DCLE_CF, (fraction)]
d_2 = discount rate of TOM inefficiency for generic pipeline [Appendix E -- TOM_DCLG, (fraction)]
i = pipeline company index
t = forecast year

The cost frontier for total operating and maintenance costs ($TOM_{i,t}^{(frontier)}$) is defined the same for both existing and generic pipelines: the coefficients and dummy variables of the most efficient pipeline company are substituted into the estimated equation ($TOM_{i,t}^{(unadj)}$). This defines the least cost for a company with the same size. The inefficiency term, however, is defined differently. For existing pipeline, the inefficiency measurement ($TOM\_IEFF\_E_{i,t}$) is defined as the difference between the unadjusted cost and the cost frontier (after discounting). Thus, the amount of inefficiency is calculated each year by subtracting the discounted cost frontier from the unadjusted costs. For generic pipelines, the

[68]Source of historical data: Bureau of Labor Statistics (1987=1.00).

inefficiency measurement term ($TOM\_IEFF\_G_{i,t}$) is the product of a unit inefficiency factor times a discount rate. The unit inefficiency factor is defined as the inefficiency per GPIS (used as a proxy for the size of expansion). This factor is calculated as the difference between the unadjusted pipeline TAG costs and the frontier TAG costs using the historical arc average data in the base year. The discount rate is applied to model the potential efficiency improvement in new generic pipelines.

Finally, the total operation and maintenance costs are converted to nominal dollar to be consistent with the convention in this module.

$$\mathrm{TOM}_{i,t} = \mathrm{TOM}_{i,t}^{(adj)} * \mathrm{MC\_PGDP}_t \tag{181}$$

where,

$TOM_{i,t}$	=	total operation and maintenance costs with efficiency adjustment for generic pipeline i in year t (nominal dollars)
$TOM_{i,t}^{(adj)}$	=	total operation and maintenance costs with efficiency adjustment for generic pipeline i in year t (1987 real dollar)
MC_PGDP	=	implicit GDP price deflator (from the Macroeconomic Activity Model)
t	=	forecast year

Computation of Rates for Forecast Years

Rates for the forecast years are computed using the procedures for the base-year initialization phase discussed above. These procedures include the following steps: (1) classify line items of the cost of service as fixed and variable costs, (2) allocate fixed and variable costs to rate component (reservation and usage fee, volumetric charge) based on the rate design, (3) aggregate costs to the network arc/network node, (4) for transportation services allocate costs to type of service (reservation and usage), and (5) compute arc-specific (node-specific) rates. Estimation of pipeline costs for forecast years was presented in the previous section. The transportation and storage tariffs during peak and offpeak periods are derived from the tariff curves below.

In the pipeline and storage functions (NGPIPE_VARTAR, NGSTR_VARTAR) used to define the variable tariff term, the tariff curves are segmented such that tariffs associated with *current capacity* and *capacity expansion* are represented by separate but adjacent equations. The same functional form is used for the *current capacity* segment of the tariff curves for both the pipeline arcs and storage nodes, however the base points (PNOD, QNOD) are defined using different *process-specific* parameters. Similarly, the functional forms for the *capacity expansion* segment of the tariff curves are the same for both the pipeline arcs and storage nodes (although different from the *current capacity* segment). They also use the same base points as defined for the corresponding *current capacity* segment. These relationships are presented below:

current capacity **segment:**

$$\mathrm{NGPIPE\_VARTAR} = \mathrm{PNOD} * (\mathrm{Q} \;/\; \mathrm{QNOD}) ** \mathrm{ALPHA\_PIPE} \tag{182}$$

$$\mathrm{NGSTR\_VARTAR} = \mathrm{PNOD}' * (\mathrm{Q} \;/\; \mathrm{QNOD}') ** \mathrm{ALPHA\_STR} \tag{183}$$

***capacity expansion* segment:**

$$\text{NGPIPE\_VARTAR} = \text{PNOD} + \text{PNOD} * (\text{ALPHA2/QNOD}) * ((\text{Q} / \text{QNOD}) ** (\text{ALPHA2} - 1.0)) * \text{EXPQij} \tag{184}$$

$$\text{NGSTR\_VARTAR} = \text{PNOD}' + \text{PNOD}' * (\text{ALPHA2\_STR} / \text{QNOD}') * ((\text{Q} / \text{QNOD}') ** (\text{ALPHA2\_STR} - 1.0)) * \text{EXPSTQr} \tag{185}$$

such that,

for peak transmission tariffs:

PNOD = $TCOST_{i,j}$ *PKSHR_YR / (ADJ_PIP *QNOD)
QNOD = $PTCURPCAP_{i,j}$ * (PKSHR_YR *$PTPKUTZ_{i,j}$)

for offpeak transmission flows:

PNOD = $VCOST_{i,j}$ *(1.0 - PKSHR_YR) / (ADJ_PIP *QNOD)
QNOD = $PTCURPCAP_{i,j}$ *((1.-PKSHR_YR) *$PTOPUTZ_{i,j}$)

for offpeak transmission tariffs:

PNOD = $TCOST_{i,j}$ *(1.0 - PKSHR_YR) / (ADJ_PIP*QNOD)
QNOD = $PTCURPCAP_{i,j}$ *((1.-PKSHR_YR) *$PTOPUTZ_{i,j}$)

for peak storage tariffs (net withdrawals):

PNOD' = $VSUM_r$ / (ADJ_STR *QNOD)
QNOD' = $PTCURPSTR_r$ *$PTSTUTZ_r$

where,

NGPIPE_VARTAR = PTM function to define pipeline tariffs (87$/mcf)
NGSTR_VARTAR = PTM function to define storage tariffs (87$/mcf)
PNOD', PNOD = Base point, price (87$/mcf)
QNOD', QNOD = Base point, quantity (bcf)
Q = Flow along pipeline arc or net storage withdrawal (bcf)
ALPHA_PIPE = Parameter for pipeline tariff equation for current capacity
ALPHA2 = Parameter for pipeline tariff equation for capacity expansion segment
ALPHA_STR = Parameter for storage tariff equation for current capacity
ALPHA2_STR = Parameter for storage tariff equation for capacity expansion segment
$EXPQ_{i,j}$ = Pipeline expansion level along pipeline i,j (bcf)
$EXPSTQ_r$ = Storage expansion level in region r (bcf)
$VCOST_{i,j}$ = Total variable cost of service (million 1987 dollars)
$TCOST_{i,j}$ = Total cost of service (million 1987 dollars)
$VSUM_r$ = Variable cost of service (million 1987 dollars)
$PTPKUTZ_{i,j}$ = Peak pipeline utilization (fraction)
$PTOPUTZ_{i,j}$ = Offpeak pipeline utilization (fraction)
$PTSTUTZ_r$ = Storage utilization (fraction)
$PTCURPCAP_{i,j}$ = Current pipeline capacity (bcf)
$PTCURPSTR_r$ = Current storage capacity (bcf)
ADJ_PIP = Pipeline tariff curve adjustment factor (fraction)
ADJ_STR = Storage tariff curve adjustment factor (fraction)
PKSHR_YR = Portion of the year represented by the peak season (fraction)
r = region
i,j = regional source (i) and destination (j) link on arc a

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 based on pipeline utilization and a maximum expected tariff (CNMAXTAR -- Appendix E, ARC_VARTAR*.25). If the pipeline utilization along a Canadian arc is less than 50 percent, then the pipeline tariff is set low (50 percent of CNMAXTAR). If the Canadian pipeline utilization is between 50 and 90 percent, then the pipeline tariff is set to a level between 50 and 70 percent of CNMAXTAR. The sliding scale is determined using the corresponding utilization factor, as follows:

$$NGPIPE\_VARTAR_{i,j} = (CNMAXTAR * 0.5 * CANUTIL_{i,j}) + (CNMAXTAR * 0.25) \tag{186}$$

If the Canadian pipeline utilization is greater than 90 percent, then the pipeline tariff is set to between 70 and 100 percent of CNMAXTAR. This is accomplished again using Canadian pipeline utilization, as follows:

$$NGPIPE\_VARTAR_{i,j} = (CNMAXTAR * 3.0 * CANUTIL_{i,j}) - (CNMAXTAR * 2.0) \tag{187}$$

Note that no distinction is made at this time between peak and offpeak tariffs along Canadian import arcs.

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.

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, AK_G)*. 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_EM)* are added to the average Alaskan natural gas wellhead price over the North and South regions, with the exception of the industrial sector which is estimated as a function of the world oil price. 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)*.[69] 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)*.[70] 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)*, cost sharing percentages *(DTM_BETA)*, bypass percentages *(I_BYPASS)*, 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, at current pipeline capacity times an assumed utilization rate *(PKUTZ, OPUTZ)*. To reflect recent regulatory changes related to

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

[70] 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 *(ARF, ARV, AFR, AFU, AVR, AVU)* to allocate each company's line item costs into the fixed and variable cost components of the reservation and usage fees
- Capacity reservation shares *(PS, currently assumed constant throughout the forecast)* used to allocate costs to portions of the physical pipeline system
- Share of a pipeline company's storage capacity located in a region *(TNS)*, used to allocate fixed and variable costs to network nodes
- Capacity expansion cost parameters and pipe mileage *(MILES)* used to derive total capital costs to expand pipeline capacity and storage capacity, respectively.
- Input coefficients *(TAG_IEFFADJ, TOM_IEFFADJ, TAG_DCLE_CF, TOM_DCLE_CF, TAG_DCLE, TAG_DCLG, TOM_DCLE, TOM_DCLG)* for efficiency components in the administrative and general and operation and maintenance calculations.

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. Approved transition costs are assumed to be consistent with FERC's revised cost estimate as published by the General Accounting Office in "Natural Gas: Costs, Benefits, and Concerns Related to FERC Order 636, Final Report," November 1993.

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, start 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 *(BGSCT, BGSCNT, BASET, WGCT, WGCNT, WORKT, 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, MAXUTZ)* 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 dry gas production 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 maximum levels, calculated as a factor *(MAXPRRFAC, MAXPRRNG)* times the expected production levels.

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, PER_ALOF, 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, PER_ALOF)
- 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_G, AK_RN, AK_CM)
- Alaskan pricing parameters
  (AK_RM, AK_CM, 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, MAXPRRNG)
- 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
  (ARF, AFR, AVR, ASF, ARV, AFU, AVU, ASV)
- Pipeline rate base, cost, and volume parameters
  (DDA, OTTAX, TAG, TCE, SEOM, CSOML, CSOMN, OTOM, CWC, OWC, ADIT, GPIS, ADDA, PFES, CMES, LTD, REVC, PCMER, PPFER, PLTDR, DCMER, DLTDR, AFM_PTAR_I, TRNSHR, RENTBLDG)
- Revenue requirement forecasting equation parameters
  (Table F3)
- Rate of return set for generic pipeline companies
  (PPFER, PCMER, PLTDR, DCMER, DLTDR)
- Federal and State income tax rates
  (FRATE, SRATE)
- Parameters for interstate pipeline transportation rates
  (PKSHR_YR, PTPKUTZ, PTOPUTZ, ADJ_PIP, ALPHA_PIPE, ALPHA2)
- Depreciation schedule
  (MAX_MACRS_YR, MACRS_RATE)
- Factor to accommodate region differences in cost
  (CSTFAC, FACTOR, NODFACT)
- Parameters for capital cost equations
  (ALPHA_CCOST, BETA_CCOST, CCOST, SLOPE)
- Canadian pipeline and storage tariff parameters
  (ARC_FIXTAR, ARC_VARTAR)
- Parameters for storage rates
  (PKSHR_YR, PTSTUTZ, ADJ_STR, 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 pipeline utilizations
  (PKUTZ, OPUTZ, MAXUTZ)
- Interregional planned pipeline capacity additions along primary and secondary arcs
  (PLANPCAP, SPLANPCAP, PER_YROPEN)
- Maximum storage utilization
  (PKUTZ)
- Existing storage capacity and planned additions
  (BGSCT, BGSCNT, BASET, WGCT, WGCNT, WORKT, 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, I_BYPASS, TECHEFF, DTM_BETA, MINMU_I, 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)
- Core and 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
- Natural gas supply activity and prices by NGTDM region
- 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 pipeline capacity utilization (entering and exiting a region) by NGTDM region and Census Division
- Natural gas underground storage and pipeline capacity by NGTDM region
- Unaccounted for natural gas[71]

[71]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, Feburary 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-M062/1 (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).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062/1 (Washington, DC, February 1995).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062/1 (Washington, DC, February 1994).

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

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

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Capacity Expansion Module (CEM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, Apr 30, 1993.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Pipeline Tariff Module (PTM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, Apr 30, 1993.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the Component Design Report Distributor Tariff Module (DTM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)." Boston, MA, Apr 30, 1993.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Final Review of the National Energy Modeling System (NEMS) Natural Gas Transmission and Distribution Model (NGTDM)." Boston, MA, Jan 4, 1995.

Archive Tapes: NEMS99—(Part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1999*, 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 2015, 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)

- *The Potential for Natural Gas in the United States* (National Petroleum Council, December, 1992)
  — Pipeline capacity expansion cost estimates
- Federal Offshore Statistics, OCS Report, MMS/0068
  — Offshore gas production and market values
- Canadian Energy Research Institute
  — Canadian natural gas wellhead price and production
- Alaska Department of Natural Resources
  — State of Alaska historical and projected oil and gas consumption.
- Information Resources, Inc., "Octane Week"
  — Federal vehicle natural gas (VNG) taxes
- 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-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-857, "Monthly Report of NaturalGas Purchases and Deliveries to Consumers"
  — Monthly natural gas price and volume data on deliveries to end users
- 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
- Federal Energy Regulatory Commission (FERC)
  — FERC Order 636 transition costs
- 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
- *Alternatives to Traditional Fuels*, DOE/EOA-0585.
  — State taxes for natural gas consumed in vehicles.
- *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

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
- Interstate Natural Gas Pipeline Data System (PIPENET)
  — Inter-regional pipeline capacity
  — Contract demand data.

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 convergences is realized across the network
  — PTM 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: 1014K bytes for input data storage; 662K bytes for source code storage; and 14415K 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 1998.

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).

Energy Information Administration, *Documentation of the Gas Analysis Modeling System*, DOE/EIA-M044(92) (Washington, DC, December 1991).

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

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).

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Energy Information Administration, *Model Methodology and Data Description of the Production of Onshore Lower-48 Oil and Gas Model*, DOE/EIA-M034(92) (Washington, DC, April 1992).

Energy Information Administration, *National Energy Modeling System, An Overview 1998*, DOE/EIA-0581(98) (Washington, DC, February 1998).

Energy Information Administration, *Natural Gas 1992: Issues and Trends* DOE/EIA-0560(92) (Washington, DC, March 1993).

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

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Energy Information Administration, *Natural Gas 1996: Issues and Trends* DOE/EIA-0560(96) (Washington, DC, December 1996).

Energy Information Administration, Office of Integrated Analysis and Forecasting, "Requirements for a National Energy Modeling System," (Working Paper) (Washington, DC, May 1992).

Forbes, Kevin, Science Applications International Corporation, "Efficiency in the Natural Gas Industry," Task 93-095 Deliverable under Contract No. DE-AC01-92-EI21944 for Natural Gas Analysis Branch of the Energy Information Administration, January 31, 1995.

Greene, William H., *Econometric Analysis* (New York: MacMillan, 1990).

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

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

Chapter 4 Equations	
EQ. #	**SUBROUTINE**
10,13	NGSET_NODEDMD, NGDOWN_TREE
11,14	NGSET_NODECDMD
12,15	NGSET_YEARCDMD
16,17	NGDOWN_TREE
18	NGSHR_CALC
19	NGDOWN_TREE
20	NGSET_MAXFLO*
21-24	NGSET_MAXPCAP
25-29	NGSET_MAXFLO*
30-32	NGSET_ACTPCAP
33-36	NGSET_SUPPR
37-38	NGSTEO_BENCHWPR
39-40	NGSET_ARCFEE
41-44	NGUP_TREE
45	NGSET_STORPR
46-47	NGUP_TREE
48	NGCHK_CONVNG
49	NGSET_SECPR
50	NGSET_BENCH, HNGSET_CGPR
51-59	NGSET_SECPR
* FUNCTION	

Chapter 5 Equations	
EQ. #	**SUBROUTINE**
60	NGDTM_FORECAST_DTARF
61	NGDTM_ICC
62-69	NGDTM_TCF1
70-71	NGDTM_CALCCOST*
72	NGDTM_TCF1
73-78	NGDTM_FORECAST_DTARF
79	NGDTM_TCF0
80-81	NGDTM_FORECAST_DTARF
82-83	NGDTM_FORECAST_TRNF
84-86	NGDTM_HISDIST
87	NGDTM_FORECAST_DTARF
* FUNCTION	

Chapter 6 Equations	
EQ #	**SUBROUTINE**
88-104	NGPA_CALCULATE_COST
105-110	NGPJ_TRNS_COST_OF_SERVICE
111-112	NGP4_BASE_YEAR_PIPELINE
113-114	NGP4_BASE_YEAR_PIPELINE, PTM6_FORECAST_PIPELINE
115-117	NGPD_ALLOCATE_ARC_LEVEL_COST
118-120,182,184,186-187	NGPIPE_VARTAR*
121-122,183,185	NGSTR_VARTAR*
123, 127	NGP9_EXPAND_GENERIC
123-129	NGP2_BASE_YEAR_INITIALIZATION
130	NGPA_CALCULATE_COST
131	NGPA_CALCULATE_COST, NGP7_FORECAST_COST
132-138	NGP7_FORECAST_COST
139	NGP9_EXPAND_GENERIC
140-141	NGP7_FORECAST_COST
142	NGPA_CALCULATE_COST
143-144	NGP7_FORECAST_COST
145	NGP7_FORECAST_COST, NGP9_EXPAND_GENERIC
146-162	NGPA_CALCULATE_COST
163	NGP7_FORECAST_COST
164	NGPA_CALCULATE_COST
165	NGP7_FORECAST_COST
166-167	NGPA_CALCULATE_COST
168-170	NGP7_FORECAST_COST
171	NGP9_EXPAND_GENERIC
172-173,175-176,178-181	NGP7_FORECAST_COST
173,177	YVALUE*
* FUNCTION	

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

Variable	File	Variable	File
A191START	RDESIGN	BLAEEFFC	NGPTAR
A191YRS	RDESIGN	BLAESWT	NGPTAR
ACTPCAP	NGCAN	BLAETOT	NGPTAR
ADDA	FORM2	CANEXP	NGCAN
ADDA	NGPTAR	CAN_XMAPCN	NGMAP
ADDYR	NGCAP	CAN_XMAPUS	NGMAP
ADIT	FORM2	CAPEXP	NGPTAR
ADIT	NGPTAR	CCOST	NGPTAR
ADIT90	NGPTAR	CMES	FORM2
ADIT_FD	NGPTAR	CMES	NGPTAR
ADIT_TEMP	NGPTAR	CNPER_YROPEN	NGCAP
ADJ_PIP	NGPTAR	CN_DMD	NGCAN
ADJ_STR	NGPTAR	CN_FIXSUP	NGCAN
ADW	NGHISAN	CON	NGHISMN
AFM_PTAR_I	NGPTAR	CONDEM	NGPTAR
AFR	ALLOCAT	CSOML	FORM2
AFU	ALLOCAT	CSOML	NGPTAR
AK_C	NGMISC	CSOMN	FORM2
AK_CM	NGMISC	CSOMN	NGPTAR
AK_CN	NGMISC	CSTFAC	NGPTAR
AK_D	NGMISC	CWC	FORM2
AK_E	NGMISC	CWC	NGPTAR
AK_EM	NGMISC	DCMER	NGPTAR
AK_F	NGMISC	DDA	FORM2
AK_G	NGMISC	DDA	NGPTAR
AK_PCTLSE	NGMISC	DDA_DEPSHR	NGPTAR
AK_PCTPIP	NGMISC	DDA_FD	NGPTAR
AK_PCTPLT	NGMISC	DDA_NETPLT	NGPTAR
AK_PCTSOUTH	NGMISC	DDA_RHO_E	NGPTAR
AK_RM	NGMISC	DEBTYR	NGDTAR
AK_RN	NGMISC	DEPSHR90	NGPTAR
ALPHA2_PIPE	NGPTAR	DEPSHR91	NGPTAR
ALPHA2_STR	NGPTAR	DLTDR	NGPTAR
ALPHA_CCOST	NGPTAR	DTAR_REFYR	NGDTAR
ALPHA_PIPE	NGPTAR	DTM_BETA	NGDTAR
ALPHA_STR	NGPTAR	EMMSUB_EL	NGMAP
ANGTS_TAR	NGMISC	EMMSUB_NG	NGMAP
ARC2P	NGPTAR	FACTOR	NGPTAR
ARC_2NODE	NGMAP	FLO_THRU_IN	NGCAN
ARC_FIXTAR	NGCAN	FRATE	RDESIGN
ARC_LOOP	NGMAP	FTAX	NGDTAR
ARC_VARTAR	NGCAN	GAMMAFAC	NGUSER
ARF	ALLOCAT	GDP_B87	NGMISC
ARV	ALLOCAT	GPIS	FORM2
ASF	ALLOCAT	GPIS	NGPTAR
ASV	ALLOCAT	GPIS89	NGPTAR
AVR	ALLOCAT	GSRSTART	RDESIGN
AVU	ALLOCAT	GSRYRS	RDESIGN
BASERADJ	RDESIGN	HAFLOW	NGMISC
BASET	NGPTAR	HCGPR	NGHISAN
BETA_CCOST	NGPTAR	HNETINJ	NGCAN
BGSCNT	NGPTAR	HNETINJ	NGHISMN
BGSCT	NGPTAR	HNETWTH	NGCAN

Variable	File
HNETWTH	NGHISMN
HPKSHR_FLOW	NGMISC
HPSUP	NGCAN
HQSUP	NGCAN
H_REALRMGBLUS	NGDTAR
H_RMPUAANS	NGDTAR
IEXPCT	RDESIGN
INTRAREG_TAR	NGDTAR
INTRAST_TAR	NGDTAR
I_BYPASS	NGDTAR
KCMER	NGPTAR
KLTDR	NGPTAR
LFAC_F	RDESIGN
LFAC_I	RDESIGN
LIMITFIRM	RDESIGN
LIMITINT	RDESIGN
LTD	FORM2
LTD	NGPTAR
MACRS_RATE	NGPTAR
MAPLNG_NG	NGMAP
MAP_PRDST	NGHISMN
MAP_STSUB	NGHISAN
MATRIX	RDESIGN
MAXCHNG	NGDTAR
MAXCYCLE	NGUSER
MAXESC	RDESIGN
MAXPRRFAC	NGMISC
MAXPRRNG	NGMISC
MAXUTZ	NGCAP
MAX_MACRS_YR	NGPTAR
MEX_XMAP	NGMAP
MILES	NGPTAR
MILE_FD	NGPTAR
MINMU_I	NGDTAR
MISC_GAS	NGHISAN
MISC_OIL	NGHISAN
MISC_ST	NGHISAN
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
NETPLT90	NGPTAR
NETPLT91	NGPTAR
NEWCOSTSTART	RDESIGN
NEWCOST_PER	RDESIGN
NG_CCAP	NGMISC
NG_CENMAP	NGMAP
NINJ_TOT	NGHISMN
NNETWITH	NGUSER
NOBLDYR	NGUSER
NODE_2ARC	NGMAP
NODE_ANGTS	NGMAP
NODE_SNGCOAL	NGMAP
NODFACT	NGPTAR
NPROC	NGMAP
NQPF_TOT	NGHISMN
NSUPLM_TOT	NGHISMN
NWTH_TOT	NGHISMN
OCSMAP	NGMAP
OPUTZ	NGCAP
OTOM	FORM2
OTOM	NGPTAR
OTTAX	FORM2
OTTAX	NGPTAR
OWC	FORM2
OWC	NGPTAR
OWC_FD	NGPTAR
OWC_TEMP	NGPTAR
P2ARCF	NGPTAR
P2ARCT	NGPTAR
PCMER	NGPTAR
PER_ALOF	NGHISAN
PER_YROPEN	NGCAP
PFES	FORM2
PFES	NGPTAR
PGRCOSTS	NGPTAR
PIPE	NGPTAR
PIPE_DEPR	NGPTAR
PKOPMON	NGMISC
PKSHR_CDMD	NGCAN
PKSHR_PROD	NGCAN
PKUTZ	NGCAP
PLANPCAP	NGCAN
PLANPCAP	NGCAP
PLTDR	NGPTAR
PMMMAP_NG	NGMAP
PNEWFAC	NGPTAR
PNUM191	NGPTAR
PPFER	NGPTAR
PRC	NGHISMN
PRESV	NGPTAR
PREV_PIPE	NGPTAR
PREV_RENTBLDG	NGPTAR
PROC_ORD	NGMAP
PS	NGPTAR
PSTRANDED	NGPTAR
PSUP_DELTA	NGUSER
PTACTPCAP	NGCAN
PTMDPCTFC	RDESIGN

Variable	File	Variable	File
PTMDPCTQ0	RDESIGN	SQIN	NGHISAN
PTPCAP_CUR	NGCAP	SQLP	NGHISAN
PW_CRG	NGMISC	SQLP	NGHISAN
Q23TO3	NGCAN	SQPF	NGHISAN
QLP_LHIS	NGHISMN	SQRS	NGHISAN
QOF_ALFD	NGHISAN	SQTR	NGHISAN
QOF_ALST	NGHISAN	SRATE	RDESIGN
QOF_CA	NGHISAN	SRVYR	NGMISC
QOF_LA	NGHISAN	STAX	NGDTAR
QOF_LAFD	NGHISAN	STDISCR	NGUSER
QOF_LAST	NGHISAN	STEOYRS	NGUSER
QOF_TX	NGHISAN	STINPUT_SCAL	NGUSER
QSUP_WT	NGUSER	STMAP_CAN	NGHISAN
RCREDIT_F	RDESIGN	STMAP_LNG	NGHISAN
RENTBLDG	NGPTAR	STMAP_MEX	NGHISAN
RETAIL_COST	NGDTAR	STOGPRSUP	NGUSER
REVC	NGPTAR	STOGWPRNG	NGUSER
ROF_CA	NGHISAN	STPHAS_YR	NGUSER
ROF_LA	NGHISAN	STPNGCM	NGUSER
ROF_TX	NGHISAN	STPNGEL	NGUSER
SAFLOW	NGMISC	STPNGRS	NGUSER
SARC_2NODE	NGMAP	STQGPTR	NGUSER
SBAL_ITM	NGHISAN	STQLPIN	NGUSER
SCALE_F_MIN	RDESIGN	STSCAL_DISCR	NGUSER
SCEN_DIV	NGHISAN	STSCAL_FPR	NGUSER
SCH_ID	NGHISAN	STSCAL_IPR	NGUSER
SDRY_PRD	NGHISAN	STSCAL_LPLT	NGUSER
SEOM	FORM2	STSCAL_NETSTR	NGUSER
SEOM	NGPTAR	STSCAL_PFUEL	NGUSER
SEXP	NGHISAN	STSCAL_WPR	NGUSER
SHARE_GSR_F	RDESIGN	SUPCRV	NGUSER
SIMP	NGHISAN	SUPPLM	NGHISAN
SIM_EX	NGHISAN	SUPSUB_NG	NGMAP
SITM_REG	NGHISAN	SUPSUB_OG	NGMAP
SLOPE	NGPTAR	SWT_COSTSHIFT	RDESIGN
SMKT_PRD	NGHISAN	TAG	FORM2
SNET_WTH	NGHISAN	TAG	NGPTAR
SNGCOAL	NGMISC	TAG_DCLE	NGPTAR
SNG_EM	NGHISAN	TAG_DCLE_CF	NGPTAR
SNG_OG	NGHISAN	TAG_DCLG	NGPTAR
SNODE_2ARC	NGMAP	TAG_EFF1	NGPTAR
SNUM_ID	NGHISAN	TAG_EFF2	NGPTAR
SPCM	NGHISAN	TAG_FD	NGPTAR
SPEU	NGHISAN	TAG_IEFFADJ	NGPTAR
SPEX	NGHISAN	TAG_TF	NGPTAR
SPIM	NGHISAN	TARCRV_ELAS	RDESIGN
SPIN	NGHISAN	TCE	FORM2
SPLANPCAP	NGCAP	TCE	NGPTAR
SPRS	NGHISAN	TCF_COEFF	NGDTAR
SPTR	NGHISAN	TCMES	NGPTAR
SPWH	NGHISAN	TECHEFF	NGDTAR
SQCM	NGHISAN	TFD1	NGDTAR
SQEU	NGHISAN	TFD2	NGDTAR

Variable	File
TFD2YR	NGDTAR
TGD	NGHISAN
TLTD	NGPTAR
TNS	NGPTAR
TOMEFFC	NGPTAR
TOMINC1	NGPTAR
TOMINC2	NGPTAR
TOMSWT	NGPTAR
TOM_DCLE	NGPTAR
TOM_DCLE_CF	NGPTAR
TOM_DCLG	NGPTAR
TOM_EFF1	NGPTAR
TOM_EFF2	NGPTAR
TOM_FD	NGPTAR
TOM_IEFFADJ	NGPTAR
TOM_TF	NGPTAR
TPFES	NGPTAR
TRNSHR	NGPTAR
TRN_DECL	NGDTAR
TST1	NGDTAR
TST2	NGDTAR
TST2YR	NGDTAR
WGCNT	NGPTAR
WGCT	NGPTAR
WHP_LHIS	NGHISMN
WORKT	NGPTAR
WT_DEBT	NGDTAR
YR_KERNRIVER_IN	NGPTAR

Appendix F

Derived Data

Table F1

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

Author: Tianchi Wang, SAIC, July 1995.

Source: *Natural Gas Annual* 1986, 1988, 1991, DOE/EIA-0131.
Annual Energy Review 1991 (Table 69, Appendix C).

Derivation: The method of Ordinary Least Squares (OLS) was used to estimate the parameters of the Alaskan natural gas consumption equation for each sector (except for electric generation), the industrial sector natural gas price equation, and the average wellhead price equation. These equations are defined as follows:

Residential Natural Gas Consumption

$\ln YR_t = AK\_C(1) + AK\_C(2) * \ln RN_t$
N = 24, R-Squared = 0.959, Durbin-Watson = 2.5

Variables:	AK_C(1)	AK_C(2)
Estimated Value:	5.871	0.852
t-statistic:	(29)	(17)

Commercial Natural Gas Consumption

$\ln YC_t = \alpha_c + ß_c * \ln CN_t$
N = 24, R-Squared = 0.579,
rho = 0.579 (t-3.2), Durbin-Watson = 1.5

Variables:	α_c	$ß_c$
Estimated Value:	9.0492	0.3708
t-statistic	(50)	(4.1)

After incorporating the first-order autocorrelation, 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:	3.8097	0.5790	0.3708	-0.2147

Industrial Natural Gas Consumption

$\ln YI_t = \alpha_i + ß_i * \ln T$
N = 24, R-Squared = 0.90
rho = 0.8086 (t-7.67), Durbin-Watson = 1.4

Variables:	α_i	$ß_i$
Estimated Value:	9.55	0.489
t-statistic:	(22)	(2.9)

After incorporating the first-order autocorrelation, 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:	1.8280	0.8086	0.4890	-0.3954

Average Natural Gas Wellhead Price

$WP_t = (AK\_F(1) * WP_{t-1}) + (AK\_F(2) * TC_t)$
N = 24, R-Squared = 0.72, Durbin-Watson = 1.85

Variables:	AK_F(1)	AK_F(2)
Estimated Value:	0.6964	0.002346
t-statistic:	(5.2)	(2.4)

Industrial Natural Gas Price
(Note: esimated with 2 less years of data than the equations above)

$IP_t = AK\_G(1) + AK\_G(2) * OP_t$
Durbin-Watson = 2.149, R-Squared = 0.288, N = 12

Variables:	AK_G(1)	AK_G(2)
Estimated Value:	1.0191	0.00645
t-statistic:	(9.997)	(2.009)

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
OP_t = total landed costs of crude oil imports (1987$/barrel) in current year. (WOPCUR)
YR_t = residential Alaskan natural gas consumption (MMcf) (QALK_NONU_F(1))
YC_t = commercial Alaskan natural gas consumption (MMcf) (QALK_NONU_F(2))
YI_t = industrial Alaskan natural gas consumption (MMcf) (QALK_NONU_F(3))
T = time trend variable having value 1, 2, 3,..., 23 starting from 1969 to 1991. In 2015, the T variable will take on the value of 47. (CNTYR+21)
TC_t = Total Alaskan natural gas consumption (MMcf) (AK_CONS_S + AK_CONS_N)
WP_t = average wellhead price (1987$/Mcf) in current year. (WPRCUR)
WP_{t-1} = average wellhead price (1987$/Mcf) lagged one year. (WPRLAG)
IP_t = industrial gas price (1987$/Mcf). (PALK_NONU_F(3))

Notes: Variables displayed in parentheses are used in the source code.

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).
AK_F	Parameters for average Alaskan natural gas wellhead price (Appendix E).
AK_G	Parameters for Alaskan industrial natural gas price (Appendix E).

Data used in estimating parameters in Tables F1 and F2

YEAR	YR	YC	YI	YE	PD	RN	CN	OP	WP	IP
1969	4573	11018	13653	6618	50.864	14.000	4.000	8.38	0.7508	1.08108
1970	6211	12519	14744	8198	111.576	15.000	4.000	8.41	0.7123	1.22507
1971	6893	14256	10628	10260	121.618	18.000	3.000	8.54	0.6469	1.72507
1972	8394	16011	12328	13085	125.596	21.000	3.000	8.30	0.3866	1.75258
1973	5024	12277	14985	15400	130.007	23.000	3.000	9.88	0.3632	1.74334
1974	4163	13106	13976	17117	128.935	22.000	4.000	27.88	0.3786	1.67038
1975	10393	14415	22388	19619	160.270	25.000	4.000	28.31	0.6098	1.64634
1976	10917	14191	26687	22204	166.072	28.000	4.000	25.77	0.7457	1.66348
1977	11282	14564	49302	23534	187.889	30.000	5.000	25.99	0.7156	1.80680
1978	12166	15208	77138	24431	203.088	33.000	5.000	24.16	0.8624	1.59204
1979	7313	15862	92733	28295	220.754	36.000	6.000	33.08	0.7939	1.60305
1980	7917	16513	69773	28763	230.588	37.000	6.000	47.27	1.0181	0.52999
1981	7904	16650	53083	29071	242.564	40.000	6.000	49.96	0.7858	0.45627
1982	10554	24232	77621	30988	264.364	48.000	7.000	40.04	0.7518	0.69212
1983	10434	24693	74641	31348	276.691	55.000	8.000	33.60	0.8372	0.76835
1984	11833	24654	72465	31582	286.280	63.000	10.000	31.74	0.8022	0.72527
1985	13256	20344	75676	34194	314.643	65.000	10.000	28.59	0.7839	0.75212
1986	12091	20874	60439	34409	300.635	66.000	11.000	14.45	0.5160	0.83591
1987	12256	20224	67467	30530	340.247	68.000	11.000	18.13	0.9400	0.74000
1988	12529	20842	67805	30841	355.398	68.612	11.649	14.01	1.2223	1.02984
1989	13589	21738	59341	32746	373.797	69.540	11.806	16.66	1.2546	0.99631
1990	14165	21622	76849	34366	381.431	70.808	11.921	19.21	1.2223	1.07174
1991	13562	20897	75637	31330	409.381	72.565	12.071	15.89	1.2650	1.00855
1992	14350	21299	80938	28953	411.593	74.268	12.204	15.03	1.1640	
1993	13858	20003	75795	28025	398.093	75.842	12.359	13.00	1.1430	

Table F2

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

Author: Tianchi Wang, SAIC, July 5, 1995.

Source: *Natural Gas Annual* (1985-1993), 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:

$$\log(RN_t) = 0.276 + 0.9437 * \log(RN_{t-1})$$

t = (3.7) (46)
R^2 = 0.99
DW = 1.504 (rho is not statistically significant)

This translates into the following forecast equation:

$$RN_t = 1.3178 * RN_{t-1}^{0.9437}$$

The number of commercial consumers, based on billing units, showed a strong relationship to the number of residential households and the number of commercial consumers in the last year, as follows:

$$CN_t = 0.1625 * RN_t$$

t = (31)
R^2 = 0.97
DW = 1.715
rho = 0.627 (t=3.3)

After incorporating the first-order autocorrelation, the forecast function becomes:

$$CN_t = 0.627 * CN_{t-1} + 0.16248 * RN_t - 0.10187 * RN_{t-1}$$

Notes: Documented in memo dated July 5, 1995 under SAIC Task 118.

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 PTM forecasting equations. Total working capital; total administrative and general expense; accumulated deferred income taxes; depreciation, depletion, and amortization expenses; and total operations and maintenance expense.

Author: Science Applications International Corporation

Source: Form FERC-2: Data collected for 1980 - 1991.

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 for each pipeline company or generic pipeline: total working capital; total operations and maintenance expense; total administrative and general expense; depreciation, depletion, and amortization expenses; and accumulated income taxes. These equations are defined as follows:

(1) Total Working Capital

$$OWC_t = GPIS_t^{\beta 0} * GPIS_{t-1}^{-\rho * \beta 0} * \exp\,[\beta 1 * (MC\_PGDP_t - \rho * MC\_PGDP_{t-1})] * \exp\,[\beta 2 * (TYEAR - \rho * (TYEAR - 1.0))] * OWC_{t-1}^{\rho} * OWC\_CONST$$

where,

(a) existing pipeline

β0, β1, β2	=	(1.92244, 1.99710, -0.170208)
ρ	=	0.602771
OWC_CONST	=	(1-ρ) * EXP(C+FDj)
FDj	=	firm dummy variable which is equal to 1, if j = i, or equal to 0, otherwise. (value of FDj see Table F3.1)
t-statistic	=	See Table F3.1
DW	=	1.65411
R-Squared	=	0.985791

(b) generic pipeline

β0, β1, β2	=	(1.76412, 1.94711, -0.159168)
ρ	=	0
OWC_CONST	=	294.161
t-statistic	=	3.12307, 26.9230, 1.70727, -3.31806
DW	=	1.93182
R-Squared	=	0.952241

(2) Total Administrative and General Expense

The following equation is used to calculate the TAG before adjustments for efficiency are made:

$$TAG_{i,t} = e^{(\alpha_{1,i} * FD_i + \alpha_{2,i} * TF_{i,t})} * GPIS_{i,t-1}^{\beta_1} * W_t^{\beta_2} * PK_t^{(1-\beta_2)}$$

input variables,

FD_i	=	pipeline specific dummy variable: equal to 1, if pipeline company i, 0 otherwise (values listed in Table F3.2b)
$TF_{i,t}$	=	pipeline specific open access variable: $TRNSHR_t * FD_i$ (values for $TRNSHR_t$ listed in Table F3.2a)
$GPIS_{i,t-1}$	=	original capital cost of plant in service (gross plant in service)
W_t	=	real labor cost index, all private sector [= MC_ECIWSP_t / MC_PGDP_t]
PK_t	=	rental of office space for corporations ($RENTBLDG_t$): equal to rental cost index times rate of return (values listed in Table F3.2a)
i	=	pipeline

resulting coefficients,

$\alpha_{1,i}$	=	FDj coefficients (values listed in Table F3.2b)
$\alpha_{2,i}$	=	TFj coefficients (values listed in Table F3.2b)
β_1	=	coefficient of ln(GPIS) (TAG_EFF1 value in Table F3.2b)
β_2	=	coefficient of labor cost (TAG_EFF2 value in Table F3.2b)

All Statistics are applied to transformed data with first order-autocorrelation correction in Log-linear regression function:

t-statistic	= See Table F3.2b
DW	= 1.94
Adjusted R-Squared	= 0.9998

The most efficient company is Trailblazer Pipeline (ID=6410), whose value of TAG represents the cost frontier in the industry.

(3) Accumulated Deferred Income Tax

(a) existing pipeline

$$ADIT_{i,t} = \beta_0 + \beta_1 * ADIT_{t-1} + \beta_2 * NETPLT_t$$

where,

β0,β1,β2	=	(FDj + POST86, 0.72988, 0.064099)
FDj	=	firm dummy variable which is equal to 1, if j = i, or equal to 0, otherwise. (value of FDj see Table F3.3)
POST86	=	0.129514E+7
i	=	pipeline
t-statistic	=	See Table F3.3
DW	=	1.85921
R-Squared	=	0.956792

(b) generic pipeline

Accumulated deferred income taxes for generic companies is calculated using an accounting algorithm. Straight Line Depreciation (SDL) is used for rate making purposes, while Modified Accelerated Cost Recovery System (MACRS) with a 15½ year schedule is used for tax purposes. The amount of depreciation using the MACRS and SDL schedules are derived as follows:

$$DEPRMACRS_t = \sum_{s=2}^{s=t} NCAE_s * MACRS\_RATE_{t-s+1}$$

$$DEPRSL_t = \sum_{s=2}^{s=t} NCAE_s/30$$

where,

MACRS_RATE	=	(5.00, 9.50, 8.55, 7.70, 6.93, 6.23, 5.90, 5.90, 5.91, 5.90, 5.91, 5.90, 5.91, 5.90, 5.91, 2.95)
FRATE	=	35 %

(4) Total Depreciation, Depletion, and Amortization

(a) existing pipeline

$$DDA_{i,t} = (1-\rho)*\beta_0 + \beta_1*NETPLT_t + \beta_2*DEPSHR_t + \rho*DDA_{t-1} - \rho*(\beta_1*NETPLT_{t-1} + \beta_2*DEPSHR_{t-1})$$

where,

β0,β1,β2	=	(FDj, β1,β2)
	=	(FDj, 0.037362, -0.315983E7)
FDj	=	firm dummy variable which is equal to 1, if j = i, or equal to 0, otherwise. (value of FDj see Table F3.4)
ρ	=	0.151232
i	=	pipeline
t-statistic	=	See Table F3.3
DW	=	1.77499
R-Squared	=	0.9634

(b) generic pipeline

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

(5) Total Operations and Maintenance Expense

The following equation is used to calculate the TOM before adjustments for efficiency are made:

$$TOM_{i,t} = e^{(\alpha_{1,i}*FD_i + \alpha_{2,i}*TF_{i,t})} * GPIS_{i,t-1}^{\beta_1} * W_t^{\beta_2} * PK_t^{(1-\beta_2)}$$

and,

$$PK_t = (REALAA + PIPE\_DEPR - \frac{PIPE_t - PIPE_{t-1}}{PIPE_{t-1}}) * PIPE_t$$

input variables,

FD_i	=	pipeline specific dummy variable: equal to 1, if pipeline company i, 0 otherwise (values listed in Table F3.2b)
$TF_{i,t}$	=	pipeline specific open access variable: $TRNSHR_t$ * FD_i (values for $TRNSHR_t$ listed in Table F3.2a)
$GPIS_{i,t-1}$	=	original capital cost of plant in service (gross plant in service)

W_t	=	real labor cost index, all private sector [= MC_ECIWSP_t / MC_PGDP_t]
PK_t	=	the user cost of capital for compressor stations
$PIPE_t$	=	producer price index for compressor stations: 1.133 (index of 1990) and 1.184 (index of 1991) [Source: Bureau of Labor Statistics, 1987=1.00.] [= $PIPE_{t-1}$ * (MC_WPI_t/MC_WPI_{t-1})]
PIPE_DEPR	=	assumed depreciation rate on compressor station equipment (= 0.10 annually, from PTARIFF)
REALAA	=	the real rate of AA utility bonds
i	=	pipeline

resulting coefficients,

$\alpha_{1,i}$	=	FDj coefficients (values listed in Table F3.4)
$\alpha_{2,i}$	=	TFj coefficients (values listed in Table F3.5)
β_1	=	coefficient of ln(GPIS) (TOM_EFF1 value listed in Table F3.5)
β_2	=	coefficient of labor cost (TOM_EFF2 value listed in Table F3.5)

All Statistics are applied to transformed data with first order-autocorrelation correction in Log-linear regression function:

t-statistic	= See Table F3.5
DW	= 1.81
Adjusted R-Squared	= 0.99996

The most efficient company is Trailblazer Pipeline (ID=6410), whose value of TOM represents the cost frontier in the industry.

Variables:

ADIT	=	accumulated deferred income taxes in dollars
DDA	=	depreciation, depletion, and amortization costs in dollars
DEPSHR	=	percentage of depreciation, derived from dividing accumulated depreciation by gross plant in service in previous period
FD	=	firm dummy variable which is equal to 1 if j=i, 0 otherwise (i=pipeline)
FRATE	=	federal tax rate
GPIS	=	original capital cost of plant in service (gross plant in service) in dollars
MACRS_RATE	=	rate of depreciation by MACRS schedule
MC_ECIWSPNS	=	price index of labor (from Macroeconomic Activity Model)
MC_PGDP	=	implicit GDP price deflator for year t (from the Macroeconomic Activity Model)
MC_WPI	=	wholesale cost index provided by Macroeconomic Activity Model
NETPLT	=	difference between original capital cost of plant in service and accumulated depreciation in previous period (net plant in service) in dollars
OWC	=	other working capital in dollars
OWC_CONST	=	estimated constant term
PIPE	=	producer price index for compressor station equipment
PIPE_DEPR	=	assumed depreciation rate on compressor station equipment
REALAA	=	the real rate of AA utility bonds
TAG	=	total administrative and general costs in real dollars
TF	=	pipeline specific open access variable ($TRNSHR_t$ * FD_i)
TOM	=	total operating and maintenance expense in real dollars
TRNSHR	=	industry average share of gas transported for others
TYEAR	=	year in Julian units (i.e., 1995)
W_t	=	real labor cost index, all private sector

Notes: None.

Units:

ADIT	=	nominal dollar
DDA	=	nominal dollar
DEPSHR	=	fraction
FRATE	=	fraction
GPIS	=	nominal dollar
MACRS_RATE	=	fraction
MC_ECIWSPNS	=	index
MC_PGDP	=	index
MC_WPI	=	index
NETPLT	=	nominal dollar
OWC	=	nominal dollar
PIPE	=	index
PIPE_DEPR	=	fraction
REALAA	=	rate
TAG	=	1987 real dollar (ultimately, converted to nominal dollar)
TOM	=	1987 real dollar (ultimately, converted to nominal dollar)
TRNSHR	=	fraction
TYEAR	=	Julian units (i.e., 1995)
W_t	=	index

Reference: (1) "Documentation of the Pipeline Tariff Model Econometric Equation" by Science Applications International Corporation, April 30, 1993.
(2) "Final Report, Documentation of Simplified PTM Algorithm," by Science Applications International Corporation, May 22, 1995.

Table F3.1. Summary Statistics for the Total Working Capital Equation with Dummy Variables

Coefficient	Estimated Value	Standard Error	t-statistic
C	312.686	86.8191	3.60157
LN_GPIS	1.92244	.069013	27.8560
GDP_INDX	1.99710	1.11522	1.79077
YEAR	-.170208	.044260	-3.84567
FD330	1.06750	.233223	4.57715
FD840	1.02271	.232931	4.39060
FD930	.957291	.231520	4.13481
FD1005	-.665842	.253675	-2.62479
FD1010	-1.14718	.248872	-4.60952
FD1075	-.317635	.234846	-1.35253
FD1450	1.54210	.241970	6.37310
FD1470	.970518E-02	.249324	.038926
FD1705	.350049	.234705	1.49144
FD1913	.257109	.235866	1.09006
FD2520	1.79581	.233402	7.69406
FD3240	.115678	.245968	.470296
FD3320	-.599203	.260134	-2.30344
FD3360	.737649	.235027	3.13856
FD3382	.396329	.230722	1.71778
FD3410	1.57254	.266284	5.90550
FD3450	1.02331	.253706	4.03345
FD3540	2.00584	.234659	8.54791
FD3620	-.955885	.266306	-3.58942
FD3775	-1.67645	.267098	-6.27652
FD3800	-1.79113	.257699	-6.95045
FD3835	.123892	.235964	.525046
FD4098	.764999	.267453	2.86031
FD4135	1.23531	.231506	5.33598
FD4160	.379134	.244188	1.55263
FD4875	-.037315	.230755	-.161708
FD5340	-.094529	.250759	-.376972
FD5715	.214417	.230721	.929338
FD5902	-.876017	.285765	-3.06552
FD6090	-1.58252	.277425	-5.70432
FD6210	.020513	.242916	.084444
FD6410	-1.14827	.246102	-4.66584
FD6420	-1.01856	.280325	-3.63351
FD6425	.357665	.236251	1.51392
FD6450	-.286970	.258668	-1.10941
FD6480	1.22267	.251145	4.86838
FD6630	-.589305	.241943	-2.43572
FD7000	.823061	.248338	3.31427
FD7010	1.89759	.334460	5.6736

Table F3.2a. Some Input Data for Calculating Total Administrative and General Expense Equation

Year	TRNSHR	RENTBLDG
1989	0.7550	0.1520
1990	0.8029	0.1600
1991	0.8367	0.1560
1992	0.8780	0.1500
1993	0.9200	0.1520
1994	0.9600	0.1630
1995	1.0000	0.1720
1996	1.0000	0.1780
1997	1.0000	0.1860
1998	1.0000	0.1960
1999	1.0000	0.2040
2000	1.0000	0.2100
2001	1.0000	0.2170
2002	1.0000	0.2250
2003	1.0000	0.2330
2004	1.0000	0.2400
2005	1.0000	0.2480
2006	1.0000	0.2570
2007	1.0000	0.2670
2008	1.0000	0.2760
2009	1.0000	0.2850
2010	1.0000	0.2940
2011	1.0000	0.3030
2012	1.0000	0.3130
2013	1.0000	0.3230
2014	1.0000	0.3340
2015	1.0000	0.3460

Sources: TRNSHR – FERC Form 2 for 1990-1994, and assumed to be 1.0 after 1994.
RENTBLDG – Data Resources Inc.

Table F3.2b. Total Administrative and General Expense Equation with Dummy Variables

Variable	Estimated Value	Standard Error	t-statistic
TAG_EFF1	.546521	.082891	6.59328
TAG_EFF2	.746612	.116822	6.39105
FD50	6.30018	1.71136	3.68138
FD330	6.30285	1.75090	3.59978
FD840	6.58232	1.76219	3.73530
FD930	6.28602	1.74518	3.60193
FD1005	6.80030	1.85334	3.66921
FD1010	5.85094	1.84181	3.17673
FD1075	6.48892	1.76860	3.66897
FD1450	5.99875	1.61533	3.71362
FD1470	6.88913	1.82922	3.76615
FD1705	6.68265	1.77822	3.75804
FD1913	5.90418	1.78470	3.30822
FD2050	4.96999	1.75473	2.83234
FD2520	6.56525	1.68432	3.89787
FD3240	6.81193	1.77880	3.82950
FD3320	6.89382	1.85650	3.71335
FD3360	6.26835	1.68926	3.71070
FD3382	5.95047	1.73896	3.42186
FD3410	4.91967	1.70103	2.89217
FD3450	5.89680	1.59192	3.70419
FD3540	6.42158	1.66719	3.85173
FD3620	7.26868	1.89742	3.83081
FD3775	5.33731	1.86108	2.86785
FD3800	6.87890	1.85380	3.71070
FD3835	6.55702	1.78981	3.66353
FD4098	3.56057	1.61480	2.20496
FD4135	6.00837	1.76093	3.41204
FD4160	6.72039	1.82418	3.68406
FD4875	6.13802	1.72427	3.55978
FD5340	6.84856	1.84478	3.71240
FD5715	4.73351	1.72216	2.74859
FD5902	7.01634	1.92765	3.63984
FD6090	6.80537	1.90209	3.57784
FD6210	6.73741	1.81721	3.70755
FD6410	4.11828	1.73453	2.37430
FD6420	7.09078	1.91477	3.70319
FD6425	6.36290	1.80033	3.53430
FD6450	6.05841	1.82361	3.32221
FD6480	3.91832	1.62231	2.41526
FD6630	7.08404	1.81856	3.89540

Variable	Estimated Value	Standard Error	t-statistic
FD7000	4.15445	1.69712	2.44794
TF50	.011031	.100409	.109860
TF330	.368245	.147138	2.50272
TF840	.028614	.088847	.322062
TF930	.148615	.090249	1.64671
TF1005	.148340	.090299	1.64276
TF1010	.065324	.113296	.576584
TF1075	-.148067	.080122	-1.84803
TF1450	-.084154	.112457	-.748322
TF1470	.395586	.114509	3.45464
TF1705	-.257853	.126443	-2.03929
TF1913	-.285061	.098021	-2.90817
TF2050	-.337730	.102031	-3.31009
TF2520	-.258312	.186565	-1.38457
TF3240	-1.69449	.692507	-2.44690
TF3320	-.068891	.100507	-.685436
TF3360	-.517070	.130362	-3.96641
TF3382	.057025	.270856	.210538
TF3410	1.43559	.380451	3.77338
TF3450	.279521	.774890	.360724
TF3540	-.140247	.067834	-2.06751
TF3620	.388410	.379806	1.02265
TF3775	-.171861	.111265	-1.54460
TF3800	.250739	.209853	1.19483
TF3835	-.229598	.117012	-1.96218
TF4098	-.763932E-02	.182092	-.041953
TF4135	.360972	.113808	3.17176
TF4160	-.268591	.135490	-1.98237
TF4875	-.745106	.197142	-3.77954
TF5340	-.274110	.101554	-2.69915
TF5715	.306619	.082403	3.72096
TF5902	-.047441	.093069	-.509738
TF6090	.253314	.124946	2.02739
TF6210	.424396E-02	.087744	.048367
TF6410	-.655675	.185596	-3.53280
TF6420	-.177991	.056635	-3.14278
TF6425	.310575	.213246	1.45641
TF6450	-.057026	.206198	-.276561
TF6480	.707801	.309742	2.28513
TF6630	-.134852	.110205	-1.22365
TF7000	-.235443	.097350	-2.41851

Table F3.3. Summary Statistics for Accumulated Deferred Income Tax Equation with Dummy Variables

Coefficient	Estimated Value	Standard Error	t-statistic
β1	.729880	.034326	21.2633
β2	.064099	.010285	6.23223
POST86	.129514E+07	597315.	2.16827
FD50	-.585536E+07	.421084E+07	-1.39054
FD330	.103331E+08	.432398E+07	2.38973
FD840	-.150482E+07	.398517E+07	-.377605
FD930	-.127081E+08	.577500E+07	-2.20054
FD1005	.792681E+08	.478025E+08	1.65824
FD1010	.500322E+07	.399926E+07	1.25104
FD1075	.866611E+07	.423324E+07	2.04716
FD1450	-.170162E+07	.138914E+07	-1.22495
FD1470	.288398E+08	.147628E+08	1.95354
FD1705	-261066.	.430122E+07	-.060696
FD1913	.107255E+07	.392570E+07	.273212
FD2050	-331096.	.252541E+07	-.131106
FD2520	100804.	.149690E+07	.067342
FD3240	-.386891E+07	.265839E+07	-1.45536
FD3320	.246935E+07	.143454E+08	.172135
FD3360	-655528.	.289783E+07	-.226214
FD3382	.134276E+07	.257215E+07	.522039
FD3410	-415096.	.279459E+07	-.148536
FD3450	746529.	.175377E+07	.425670
FD3540	-.253967E+07	.225567E+07	-1.12590
FD3620	-.155808E+07	.187475E+08	-.083108
FD3775	.229058E+08	.130580E+08	1.75416
FD3800	.376959E+08	.384250E+08	.981025
FD3835	.891349E+07	.766289E+07	1.16320
FD4098	-666686.	.131096E+07	-.508549
FD4135	-.790190E+07	.292055E+07	-2.70562
FD4160	.188337E+08	.957605E+07	1.96675
FD4875	.157189E+07	.105719E+08	.148685
FD5340	.115389E+07	.746511E+07	.154571
FD5715	766982.	.163080E+07	.470309
FD5902	.383549E+08	.382716E+08	1.00218
FD6090	.526591E+08	.443985E+08	1.18606
FD6210	-.139606E+07	.738119E+07	-.189137
FD6410	.222869E+07	.592477E+07	.376165
FD6420	.530083E+08	.214303E+08	2.47352
FD6425	-.166049E+07	.683077E+07	-.243089
FD6450	.257150E+08	.150151E+08	1.71262
FD6480	-555813.	569203.	-.976475
FD6630	-.244766E+08	.231915E+08	-1.05541
FD7000	-.156129E+07	.439756E+07	-.355035

Table F3.4. Summary Statistics for Depreciation, Depletion, and Amortization Equation with Dummy Variables

Coefficient	Estimated Value	Standard Error	t-statistic
β1	.037362	.215921E-02	17.3036
β2	-.315983E+07	.118222E+07	-2.67278
FD50	.524613E+07	835848.	6.27641
FD330	.172594E+07	.105781E+07	1.63161
FD840	.699559E+07	.100105E+07	6.98822
FD930	.563834E+07	.134644E+07	4.18759
FD1005	.971449E+07	.245244E+07	3.96115
FD1010	.363580E+08	.307654E+07	11.8178
FD1075	.920971E+07	.116537E+07	7.90282
FD1450	.242638E+07	785470.	3.08908
FD1470	.130872E+08	.161691E+07	8.09396
FD1705	.142000E+08	.125675E+07	11.2990
FD1913	.923499E+07	.130261E+07	7.08962
FD2050	.170989E+08	.253646E+07	6.74126
FD2520	.384055E+07	759960.	5.05362
FD3240	.584337E+07	.141660E+07	4.12492
FD3320	.307323E+08	.606948E+07	5.06341
FD3360	.380696E+07	.104426E+07	3.64560
FD3382	.637875E+07	881543.	7.23589
FD3410	.233743E+07	619300.	3.77430
FD3450	.231227E+07	634010.	3.64705
FD3540	.314533E+07	595989.	5.27751
FD3620	.369447E+08	.878650E+07	4.20471
FD3775	-.595437E+07	.114663E+08	-.519293
FD3800	.279146E+08	.498743E+07	5.59699
FD3835	.912853E+07	.202461E+07	4.50877
FD4098	.118440E+07	463369.	2.55605
FD4135	.155105E+08	.413476E+07	3.75123
FD4160	.122954E+08	.177809E+07	6.91496
FD4875	.789833E+07	.326112E+07	2.42197
FD5340	.282235E+08	.192597E+07	14.6542
FD5715	.897115E+07	.105040E+07	8.54073
FD5902	.817257E+08	.100491E+08	8.13266
FD6090	.455475E+08	.437448E+07	10.4121
FD6210	.176696E+08	.157079E+07	11.2489
FD6410	.266977E+07	.242852E+07	1.09934
FD6420	.620667E+08	.391804E+07	15.8413
FD6425	.111083E+08	.291027E+07	3.81694
FD6450	.202480E+08	.152389E+07	13.2870
FD6480	.496049E+07	839117.	5.91156
FD6630	.175537E+08	.288080E+07	6.09335
FD7000	.217175E+07	.209350E+07	1.03737

Table F3.5. Summary Statistics for Total Operations and Maintenance Expense Equation with Dummy Variables

Coefficient	Estimated Value	Standard Error	t-statistic
TOM_EFF1	.471373	.068874	6.84399
TOM_EFF2	.889413	.053922	16.4945
FD50	6.96331	1.30001	5.35634
FD330	7.57578	1.33699	5.66628
FD840	7.73947	1.34233	5.76570
FD930	7.41393	1.33069	5.57148
FD1005	8.36626	1.41871	5.89707
FD1010	7.66465	1.40895	5.43996
FD1075	8.03127	1.34883	5.95426
FD1450	7.11237	1.22266	5.81714
FD1470	8.38273	1.39905	5.99171
FD1705	7.67533	1.35517	5.66374
FD1913	8.27210	1.36329	6.06775
FD2050	7.99393	1.33608	5.98311
FD2520	7.34498	1.27522	5.75977
FD3240	6.84323	1.33042	5.14365
FD3320	8.28663	1.42266	5.82476
FD3360	7.35924	1.28387	5.73208
FD3382	6.90328	1.31986	5.23031
FD3410	7.37303	1.25586	5.87088
FD3450	6.91595	1.22364	5.65195
FD3540	7.45088	1.26369	5.89613
FD3620	8.26597	1.44693	5.71275
FD3775	5.47017	1.42607	3.83584
FD3800	8.55488	1.41678	6.03824
FD3835	7.10535	1.36952	5.18822
FD4098	4.97742	1.21899	4.08325
FD4135	6.66477	1.34207	4.96602
FD4160	8.67776	1.39450	6.22286
FD4875	6.97743	1.31890	5.29034
FD5340	7.99649	1.41132	5.66598
FD5715	6.99626	1.30970	5.34188
FD5902	8.13507	1.48410	5.48150
FD6090	8.61460	1.46708	5.87194
FD6210	8.15784	1.38849	5.87533
FD6410	5.19687	1.31866	3.94101
FD6420	8.31096	1.47041	5.65214
FD6425	8.16514	1.38047	5.91476
FD6450	7.85647	1.39139	5.64649
FD6480	5.75349	1.21779	4.72453
FD6630	8.14303	1.39281	5.84646
FD7000	5.28159	1.29356	4.08298
TF50	.020084	.068888	.291553
TF330	-.134264	.206530	-.650097
TF840	-.134700	.039999	-3.36756
TF930	.415624	.148109	2.80619
TF1005	.017809	.057366	.310443
TF1010	.061322	.072269	.848519
TF1075	-.261762	.098872	-2.64748
TF1450	.084376	.167036	.505136
TF1470	.366504	.103084	3.55539
TF1705	.052810	.047528	1.11113
TF1913	-1.18168	.140446	-8.41381
TF2050	-.322587	.055622	-5.79967
TF2520	-.250722	.063448	-3.95163
TF3240	-.073692	.315465	-.233597
TF3320	-.173362	.124727	-1.38993
TF3360	-.381712	.162348	-2.35119
TF3382	.065795	.140738	.467497
TF3410	-.386684	.093987	-4.11423
TF3450	.449951	.740135	.607931
TF3540	-.085064	.075943	-1.12011
TF3620	-.166116	.131860	-1.25979
TF3775	-.102120	.090072	-1.13376
TF3800	-.242226	.085042	-2.84832
TF3835	.565609	.194963	2.90111
TF4098	-.348827	.116545	-2.99307
TF4135	.460569	.105199	4.37809
TF4160	-.495938	.105004	-4.72306
TF4875	-.588361	.291423	-2.01892
TF5340	-.144959	.051680	-2.80494
TF5715	-.298722	.085840	-3.47999
TF5902	.238422	.179567	1.32776
TF6090	.249150	.271168	.918804
TF6210	-.089265	.052300	-1.70679
TF6410	-.962534	.103827	-9.27059
TF6420	-.198308	.057589	-3.44353
TF6425	-.457778	.275375	-1.66238
TF6450	-.147791	.070887	-2.08489
TF6480	-.134680	.060004	-2.24452
TF6630	-.415677	.177621	-2.34025
TF7000	-.629484	.191316	-3.29029

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, EI-823, 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. The PTM is represented by economic and regression equations (see Chapter 6 for details). 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 #
$R_{i,f}$	RF	105, 107, 108
$R_{i,v}$	RV	106, 109, 110
ALL_f	ARF(rd,i)	105
ALL_v	ARV(rd,i)	106
R_i	COST(1,i)	105, 106
$R_{i,f,r}$	RFR(i)	106
$R_{i,f,u}$	RFU(i)	108
$R_{i,v,r}$	RVR(i)	109
$R_{i,v,u}$	RVU(i)	110
$ALL_{f,r}$	AFR(rd,i)	107
$ALL_{f,u}$	AFU(rd,i)	108
$ALL_{v,r}$	AVR(rd,i)	109
$ALL_{v,u}$	AVU(rd,i)	110
R_A^{b-c}	Not used	111
R_A	RFR(18)	111
V_A^{b-c} / V_A^T	PS(P,AF,AT)	111
R_{1-2}	FCR,VCR,FCU,VCU	112
$INDUSTRYGPIS_{t-1}$	PLTOGPIS1	134
$GPIS_{t-1}$	PGPIS	131, 133, 134, 138
PNEWFAC	NEWCOST	137, 169
β0	OWC_BETA0	141
β1	OWC_BETA1	141
β2	OWC_BETA2	141
ρ	OWC_RHO	141
β0	ADIT_TEMP(1,3)+ADIT_FD	143
β1	ADIT_ADIT = ADIT_TEMP(1,1)	143
β2	ADIT_NETPLT = ADIT_TEMP(1,2)	143
β0	DDA_FD	136, 168
β1	DDA_NETPLT	136, 168
β2	DDA_DEPSHR	136, 168
ρ	DDA_RHO_E	136, 168
DDA_t	DDASL, DDA(P,T,CT)	138, 171

Table G-1. Cross Reference of PTM Variables Between Documentation, and Code (continued)

Documentation	Code Variable	Equation #
α_1 * FD_i	TAG_FD(T)	174
α_1 * $TF_{i,t}$	TAG_TF(T)	174
$GPIS_{i,t-1}$	X1	174
PK	RENTBLDG	174
β1	TAG_EFF1	174
β2	TAG_EFF2	174
α_1 * FD_i	TOM_FD(T)	177
α_1 * $TF_{i,t}$	TOM_TF(T)	177
$GPIS_{i,t-1}$	X1	177
PK	RENT	177
β1	TOM_EFF1	177
β2	TOM_EFF2	177
T - Pipeline type, t - year, rd - rate design index, i - node		