Model Documentation

Natural Gas Transmission and Distribution Model

of the National Energy Modeling System

Volume I

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For Further Information...

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This report documents the archived version of the NGTDM that was used to produce the natural gas forecasts presented in the *Annual Energy Outlook 1994*, (DOE/EIA-0383(94)). 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. This report represents Volume I of a two-volume set. Volume II will report 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. It is anticipated that Volume II will be available in December 1994.

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 1995.

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1. Introduction

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 by internally incorporating models of energy markets that had previously been analyzed off-line. In addition, greater structural detail in NEMS permits the analysis of a broader range of energy issues. The time horizon of NEMS is the midterm period, approximately 20 years in the future.[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. 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 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

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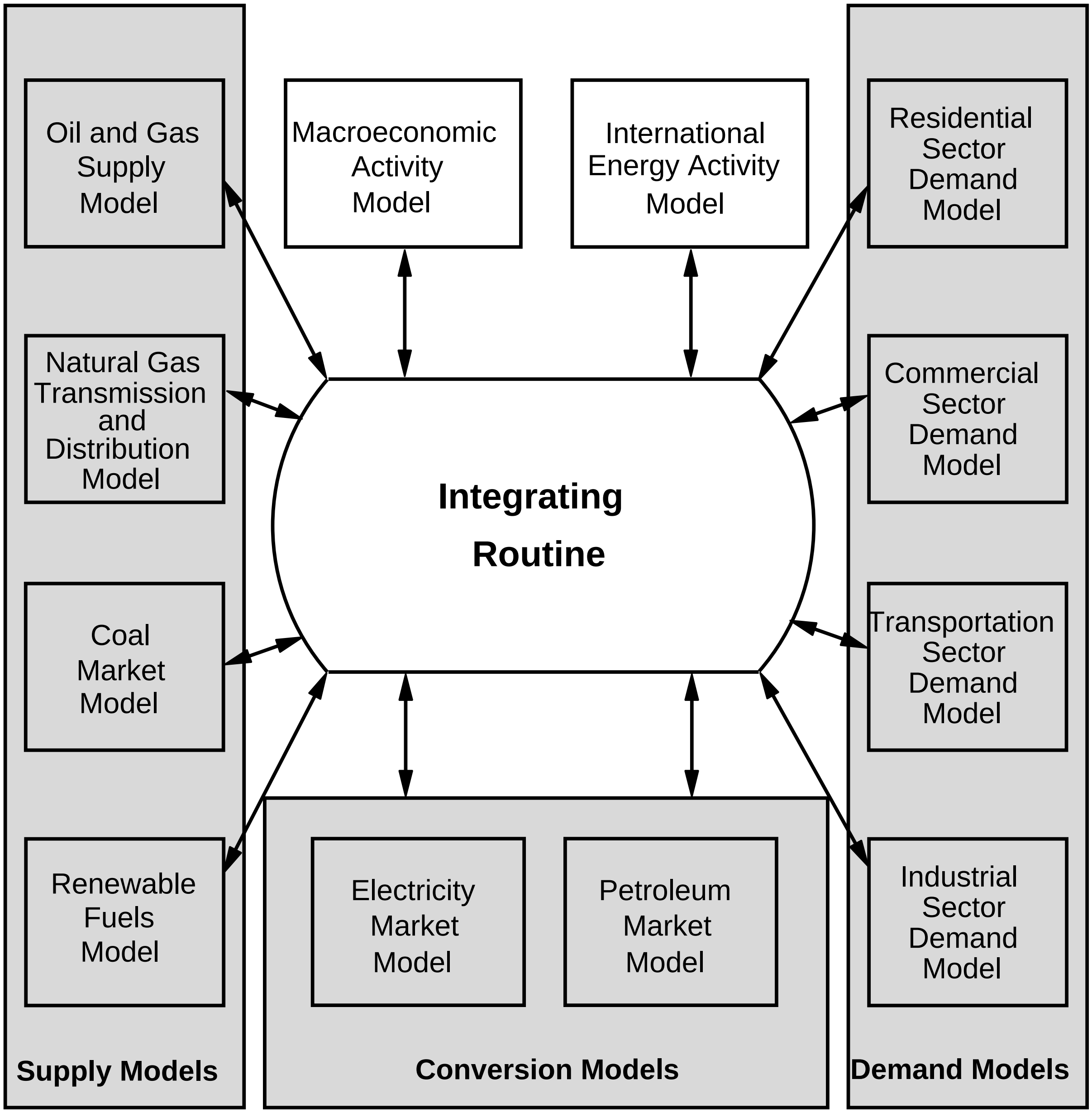
[1]For the *Annual Energy Outlook 1994* the NEMS was executed for each year from 1990 through 2010.

[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



, while a list of the associated model documentation reports is in Appendix K.

The NGTDM is the model within the NEMS that represents the transmission, distribution, and pricing of natural gas. The model also includes representations of the end-use demand for natural gas, the production of domestic natural gas, and the availability of natural gas traded on the international market based on information received from other NEMS models. The NGTDM determines the flow of natural gas in an aggregate, domestic pipeline network, connecting domestic and foreign supply regions with 12 demand regions. 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 capacity expansion requirements. There is an explicit representation of firm and interruptible markets for natural gas transmission and distribution services, and the key components of pipeline tariffs are represented in a pricing algorithm. Natural gas pricing and flow patterns are derived by obtaining a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The NGTDM consists of four modules: the Annual Flow Module, the Capacity Expansion Module, the Pipeline Tariff Module, and the Distributor Tariff Module. A model abstract is provided in Appendix A. Background information on current and potential future gas market developments, relevant to natural gas transmission and distribution modeling, is presented in Appendix C.

This report documents the archived version of the NGTDM that was used to produce the natural gas forecasts used in support of the *Annual Energy Outlook 1994*, DOE/EIA-0383(94). The purpose of this report is to provide a reference document for model analysts, users, and the public that defines the objectives of the model, describes its basic design, provides detail on the methodology employed, and describes the model inputs, outputs, and key assumptions. It is intended to fulfill the legal obligation of the EIA to provide adequate documentation in support of its models (Public Law 94-385, Section 57.b.2).

This report represents Volume I of a two-volume set. Volume II (available December, 1994) will report 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. Subsequent chapters of this report provide:

- An overview of the NGTDM (Chapter 2)
- A description of the interface between the NEMS and the NGTDM (Chapter 3)
- An overview of the solution methodology of the NGTDM (Chapter 4)
- The solution methodology for the Annual Flow Module (Chapter 5)
- The solution methodology for the Distributor Tariff Module (Chapter 6)
- The solution methodology for the Capacity Expansion Module (Chapter 7)
- The solution methodology for the Pipeline Tariff Module (Chapter 8)
- A description of model assumptions, inputs, and outputs (Chapter 9).

The archived version of the model is available from the National Energy Information Center (NEIC) and is identified as NEMS94 (part of the National Energy Modeling System archive package as archived for the *Annual Energy Outlook 1994*, DOE/EIA-0383(94)).

2. Overview

The purpose of this chapter is to provide a brief overview of the Natural Gas Transmission and Distribution Model (NGTDM) and its capabilities. The NGTDM is the component of the National Energy Modeling System (NEMS) that represents the mid-term natural gas market. The NGTDM models the Lower 48 States U.S. natural gas transmission and distribution network that links the suppliers (including importers) and consumers of natural gas, determining the regional market clearing natural gas end-use and supply (including border) prices. The demand regions modeled are the 12 NGTDM regions (Figure 2-1)

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

. These regions are based on 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. Forecasts are reported annually through 2010 for natural gas end-use prices in the residential, commercial, industrial, electric utility, and transportation sectors.

The model structure consists of four major components. The Annual Flow Module (AFM) 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. The Capacity Expansion Module (CEM) forecasts the development of new natural gas pipeline and storage facilities and sets maximum annual utilization rates based on a seasonal analysis of supply capabilities and demand requirements. The Pipeline Tariff Module (PTM) represents the development of firm/interruptible tariffs for transportation and storage services provided by interstate pipeline companies. The Distributor Tariff Module (DTM) represents the development of markups for distribution services provided by local distribution companies and for transmission services provided by intrastate pipeline companies. The modeling techniques employed are linear programs for the AFM and the CEM, an accounting algorithm for the PTM, and an empirical process based on historical data and competing fuel prices for the DTM.

The NGTDM provides a number of key modeling capabilities that were not available in its predecessor model, the Gas Analysis Modeling System (GAMS). These capabilities give the NGTDM the ability to:

- Represent interregional flows of gas and pipeline capacity constraints

- Represent regional supplies

- Represent different types of transmission service (firm and interruptible)

- Calculate emissions associated with pipeline fuel use

- Determine the amount and the location of additional pipeline and storage facilities on a regional basis

- Capture the economic tradeoffs between pipeline capacity additions and increases in regional storage capability

- Provide a peak/off-peak, or seasonal analysis capability in the area of capacity expansion

- Quantify capital investment in capacity expansion

- Distinguish customers by type of service (firm and interruptible) in end-use sectors.

These capabilities will be described in greater detail in the subsequent chapters of this report which describe the individual modules of the NGTDM.

Model 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. 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 National Energy Modeling System (NEMS) modules. The representations of the key features of the transmission and distribution network, which include interregional network capacities and transmission and distribution service pricing, are the focus of the various components of the NGTDM.

The need to model these specific characteristics of the natural gas industry stems from the structural changes that have taken place in the industry over the last 10 years. These changes include complete deregulation of the wellhead market, the unbundling of pipeline services, and the introduction of competitive forces related to pipeline expansion decisions, and transmission and distribution service pricing. Some of these changes have already had a large effect on the market, while other changes have recently been initiated and have yet to provide a significant impact on the prices and availability of services. A history of these developments is provided in Appendix C. Two key factors support the need to include an explicit representation of the transmission and distribution of natural gas within NEMS. The first is the substantial decline in wellhead prices which results in the acquisition cost of the commodity itself generally being less than half of the end-use price. The second is the ongoing evolution of the market. This ongoing evolution also supports the need for significant flexibility in how prices for transmission and distribution services are represented in the NGTDM and how the interregional flows respond to prices over time. Because of this, the NGTDM is a completely new system that provides, in addition to mid-term forecasts of end-use prices, forecasts of prices for, availability of, expansion of, and utilization of interstate natural gas pipeline services.

Prior to model development, a working paper was compiled by the EIA to establish the specific requirements for the overall NEMS, as well as for each of the component modules.[4] Requirements pertaining specifically to the NGTDM were based on: (1) recent analyses performed with EIA's IFFS/GAMS forecasting system, (2) limitations of GAMS, (3) the regulatory reform agenda of the Federal Energy Regulatory Commission (FERC), and (4) Department of Energy (DOE) policy initiatives as outlined in the National Energy Strategy.[5] These requirements, along with recommendations from a recent Model Quality Audit of the GAMS by the Office of Statistical Standards,[6] yielded a list of design guidelines for the NGTDM that support a broad array of desired analyses. Based on these guidelines, the NGTDM needed to:

- Represent pipeline capacity limitations exiting the major producing regions and entering the major market areas

- Employ a solution procedure based on an interregional trade equilibrium model that attempts to minimize simultaneously the global costs of supply and transportation subject to gas supplies available in each region, regional demand requirements, and pipeline capacity constraints

- Incorporate a transmission/storage capacity expansion/planning module that would recognize on-going, and planned/announced capacity expansion projects, as well as other capacity expansion needs throughout the forecast period

- Have the ability to determine endogenously market based rates for pipeline transportation services

- Have the ability to partition the natural gas market to apply either market based or cost based rates to specific segments of end-use sectors or to the market as a whole

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[4]Energy Information Administration, Office of Integrated Analysis and Forecasting, "Requirements for a National Energy Modeling System," December 12, 1991.

[5]*National Energy Strategy*, First Edition, 1991/1992 (Washington, DC, February 1991).

[6]Carpenter, Paul R., *Review of the Gas Analysis Modeling System* (Boston, MA: Incentives Research, Inc., August 1991).

- Employ a short-run supply curve that includes a direct representation of marginal sources of supply

- Represent Canadian and Mexican pipeline gas trade and liquefied natural gas trade

- Account for emissions of criteria pollutants that are emitted as a by-product of the natural gas transmission and distribution industry

- Account for capital investment requirements of storage and capacity expansion projects in the transmission and distribution sector.

During the development of the model methodology, a study was made of existing models and modeling techniques that might be used to meet the above requirements. Based on this study and the reports mentioned previously, it was determined that no model currently in existence could satisfy the NEMS requirements, and thus a new model was needed. The results of the study are presented in Appendix D.

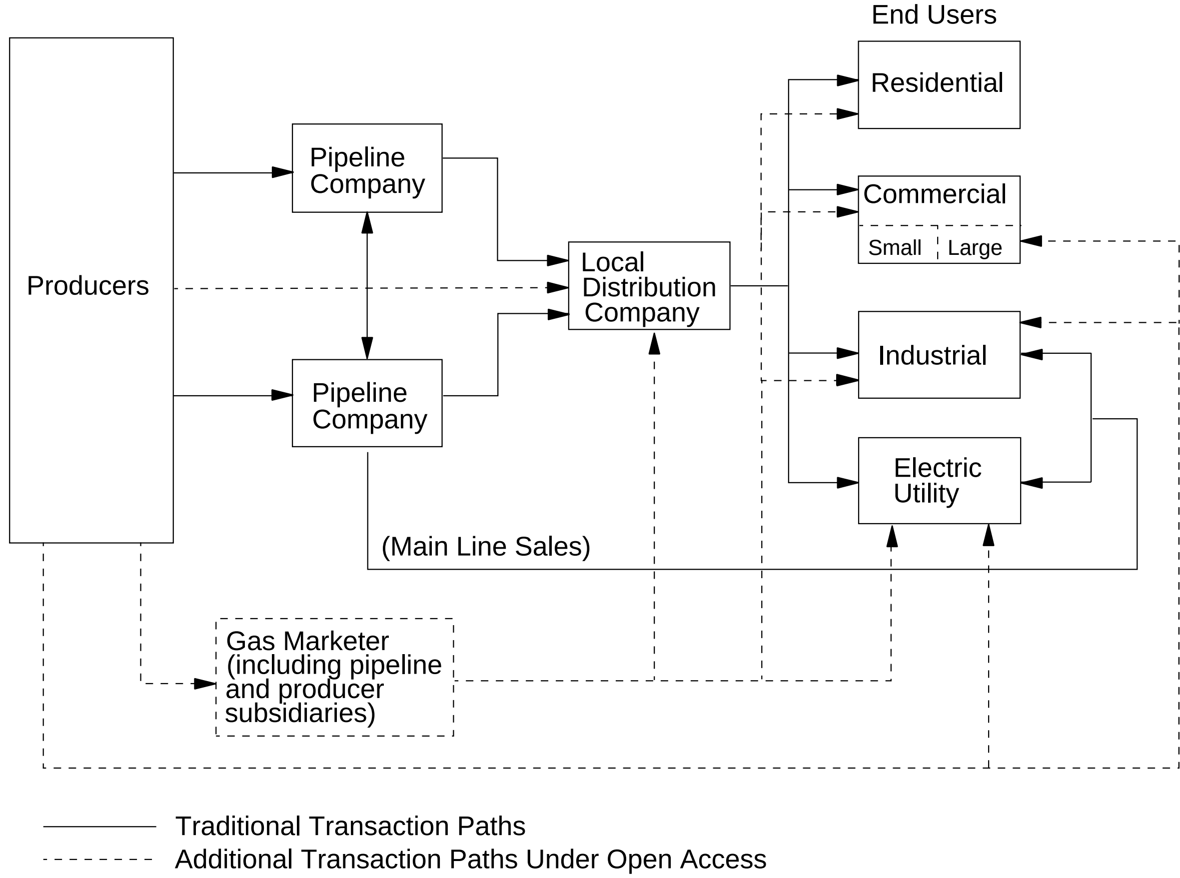
The following sections provide brief overviews of the four components of the NGTDM.

Annual Flow Module

The Natural Gas Annual Flow Module (AFM) is the main integrating module of the NGTDM. One of its major functions is to simulate the natural gas price determination process. The AFM brings together all major economic and technological factors that influence regional natural gas trade in the United States. The economic considerations include the demand for and the supply of natural gas, competition from substitute fuels and conservation options, and competition from imported natural gas.

The AFM integrates all components of the NGTDM (the AFM itself, the Capacity Expansion Module, the Pipeline Tariff Module and the Distributor Tariff Module). Through this integration process, the AFM derives average annual natural gas prices (wellhead, city gate, and end-use) that reflect an interregional trade market equilibrium among competing gas supplies, end-use sector consumption and transportation routes. End-use prices are derived for both firm and interruptible markets. Within NEMS the classification of customers that will purchase firm versus interruptible service is predetermined.

Figure 2-2. Principal Buyer/Seller Transaction Paths for Natural Gas Marketing



The historical evolution of the price determination process simulated by the AFM is depicted schematically in Figure 2-2 and described in greater detail in Appendix C. 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 employed, more pricing flexibility is being introduced, particularly in the interstate pipeline industry. 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.[7] These regional differences are evolving as new pipeline capacity is constructed to relieve the capacity constraints in the Northeast and on the West Coast, and to expand markets in the Midwest. As capacity changes take place, prices of services should adjust accordingly to reflect new market conditions.

[7]Energy Information Administration, *Capacity and Service on the Interstate Natural Gas Pipeline System, 1990: Regional Profiles and Analyses*, DOE/EIA-0551 (Washington, DC, May 1992).

Federal initiatives (most recently compiled in FERC Order No. 636) are reducing barriers to market entry and are encouraging the development of more competitive markets for pipeline 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. As the outcome is unknown at this point, the AFM is not designed to model any specific type of program. It is instead designed to simulate the overall impact of the movement towards market based pricing of transmission services.

The regional supply detail in the AFM, in conjunction with the AFM representation of pipeline capacity, supports analysis of regional shifts in supply and demand patterns. Regional differences in marginal sources of supply are also captured. Finally, the AFM addresses: transmission fuel consumption and losses; emissions associated with transmission fuel consumption; the evolution of a North American natural gas market; and capacity rationing (accomplished via the pricing of services).

Capacity Expansion Module

The primary purpose of the Capacity Expansion Module (CEM) is to simulate the decision-making process for expanding pipeline and/or storage capacity in the U.S. gas market. In simulating gas pipeline capacity expansion, the CEM: (1) determines the amount of pipeline and storage capacity to be added between or within regions in the NGTDM, and (2) establishes effective (or practical) maximum annual utilization rates for each of the interregional pipeline routes represented in the Annual Flow Module. Maximum utilization rates (or load factors) on pipeline routes are established to capture the impact of variations in seasonal demand on the maximum amount of gas which can practically flow between regions within a year. Pipeline and storage capacity additions are used in the Annual Flow Module (in combination with the maximum load factors) to set limits on annual interregional flows and to set working gas storage levels. These capacity additions are also used in the Pipeline Tariff Module when determining future storage rates and interregional pipeline tariffs.

The CEM was designed to address the guidelines that support a broad array of desired analyses and policy questions to be answered, such as:

- What impact will the increased demand for natural gas attributable to greater market penetration of new end-use gas technologies have on the utilization of the U.S. pipeline grid and requirements for new capacity? In what regions is capacity likely to be added?

- What might be the impact of a proactive natural gas policy on the utilization of pipeline capacity and the need for pipeline expansion?

- How will unbundling and the increasingly market-oriented pricing of gas supply and transmission services affect the differences between delivered prices for residential/commercial and industrial and electric utility gas users?

Regulation affecting the demand for gas and the supply of gas, such as emissions controls and tax credits, are modeled within the demand models of NEMS and the Oil and Gas Supply Model, respectively. The Pipeline Tariff Module and the Distributor Tariff Module provide tariffs to the CEM. Therefore, regulations affecting the setting of rates are specified within these two tariff modules, and are subsequently incorporated within the CEM. When the NGTDM is used to analyze the impact of new regulations which will increase or decrease expansion costs, these adjustments will be incorporated within the Pipeline Tariff Module, where the interstate tariffs associated with expanded pipeline or storage capacity are calculated, (e.g., incremental versus rolled-in rates for new capacity). Within the CEM, parameters can be set to capture the impact of changes in lead times associated with the regulatory approval process for pipeline and storage expansion.

The design of the CEM is consistent with the NEMS requirements for modeling natural gas pipeline capacity and capacity expansion: "The model will respond to external decisions (assumptions) about throughput capacity for natural gas facilities including the expansion of facilities (interstate pipelines, storage and import facilities), and maintenance and replacement of facilities, as well as the associated costs. The output reports will contain capacity requirements and utilization rates distinguished by region."[8]

Pipeline Tariff Module

The primary purpose of the Pipeline Tariff Module (PTM) is to compute tariffs for transportation and storage services provided by interstate pipeline companies. These tariffs are used within the Annual Flow Module to derive supply and end-use prices and within the Capacity Expansion Module to derive capacity additions. The tariffs are computed for individual pipeline companies, then aggregated to the major gas pipeline corridors or arcs (in the United States) specified in the NGTDM network, as described in Chapter 4. An accounting system is used to track costs and compute rates under various rate design and regulatory scenarios. Tariffs are computed for both firm and interruptible transportation and storage services. Transportation tariffs are computed for interregional arcs defined by the NGTDM network. These network tariffs represent an aggregation of the tariffs for individual pipeline companies supplying the network arc. Storage tariffs are defined at regional NGTDM network nodes, and, likewise, represent an aggregation of individual company storage tariffs. 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.

Since the tariffs determined by the PTM represent an aggregation of individual pipeline companies, the PTM is not designed to address the issue of analyzing competition within a regional pipeline corridor. 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 significant portion of the price of gas to end-users. 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) purchase firm transportation services, while the latter group (noncore customers) purchase interruptible services. Pipeline companies guarantee to their firm 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 PTM transportation and storage rates to firm customers are based on the average cost-of-service provided by the pipeline to all of its comparably situated firm customers.

The actual reservation and usage fees (tariffs) that pipelines are allowed to charge are 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. A fundamental decision in cost-based rate design is the apportionment of costs among customer classes. How costs are apportioned determines the extent of differences in the rates charged to different classes of customers and for different types of service. For example, the more fixed costs that are included in usage fees, the more interruptible customers share in paying pipeline costs. However, transferring a larger share of fixed costs to reservation fees leads to firm customers bearing a larger share of system costs. The PTM is designed to provide flexibility in allocating fixed and variable costs to firm and interruptible customers so that various policy initiatives may be examined.

Since requirements of interruptible customers generally are not taken into account in determining the peak-day delivery requirements of pipeline systems, the availability of capacity to serve these customers during peak consumption periods can be limited, and interruptions can occur. FERC sets maximum and minimum rates a pipeline is allowed to charge for interruptible service; thus, pipeline companies are allowed to offer discounts from the

[8]Energy Information Administration, *Requirements*, pp. 12-13.

maximum usage fee at their discretion provided they do not unduly discriminate among customers. Since rates may be discounted to the variable cost of moving gas, and the major portion of the pipeline costs are fixed costs, the pipelines have considerable discretion in setting rates. 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.

Fixed and variable cost allocation in the PTM rate base specification provides flexibility in modeling a pipeline company's response to recent FERC regulatory decisions to unbundle pipeline sales and transportation services, and to encourage market-based responses to competition. The cost allocation is specified at the pipeline company-level. After individual company revenue requirements are determined, they are aggregated across companies to the arc-level specified by the NGTDM network. The PTM estimates maximum and minimum interruptible transportation service rates which are used to determine interruptible service arc-level tariff bounds. These bounds constrain market-determined rates provided by the NGTDM to interruptible customers. The maximum rate computed by the PTM is the full cost-of-service rate (currently the 100-percent load factor rate). The minimum rate is the variable cost of transporting gas. The effective rate charged in the Annual Flow Module in capacity-constrained markets is based on marginal costs and, on occasion, exceeds the maximum rate computed by the PTM. A planned enhancement of the NGTDM involves imposing a limit on these interruptible rates.

Theoretically, the PTM could compute either incremental or rolled-in (average) rates for new capacity, thus allowing a more comprehensive analysis of the results of supply and demand shifts on capacities and flow patterns, as well as a more representative analysis of the pricing of natural gas transportation and distribution services.[9]

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. Although the distribution service performed by local distribution companies and the transportation service performed by intrastate carriers are distinct activities, separate distribution and intrastate markups are not determined. Rather, the DTM determines a volumetric charge which covers the cost of providing distribution or transportation services from the city gate to the end user. This charge represents the difference between the price to the customer and the price to the local distribution company (or intrastate carrier) at the city gate. Where end-use service is distinguished by service type (firm or interruptible), the DTM provides separate firm and interruptible distribution markups.

The DTM represents firm markups to the residential, commercial, industrial, and utility sector customers based on historical data. Transportation sector and interruptible service markups are based on the prices of competing fuels. 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.

Distribution markups represent a significant portion of the price of gas to customers. These customers include the residential, commercial, industrial, electric utility, and transportation (compressed natural gas vehicles) sectors. Each sector has different distribution service requirements. For example, residential, transportation and most commercial sector customers require guaranteed on-demand (firm) service because natural gas is their only fuel option. In contrast, portions of the industrial, electric utility, and commercial sectors may not rely solely on guaranteed service because they can either periodically terminate operations or switch to other fuels. Thus, commercial, industrial, and electric utility customers can elect to receive some gas supplies through a lower priority (and lower cost)

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[9]Throughout the report, reference will be made to the current formulation of the NGTDM where incremental rates will be used as a market test for capacity expansion, and where the AFM will use rolled-in rates in solving for flows and prices in the firm market and market-based rates for the interruptible market. However, the capability exists within the PTM to compute different types of rates allowing it, and thus the NGTDM, to respond to different rate design and regulatory scenarios.

interruptible (transportation) service. During periods of peak demand, services to these sectors can be interrupted in order to meet the natural gas requirements of firm service customers.

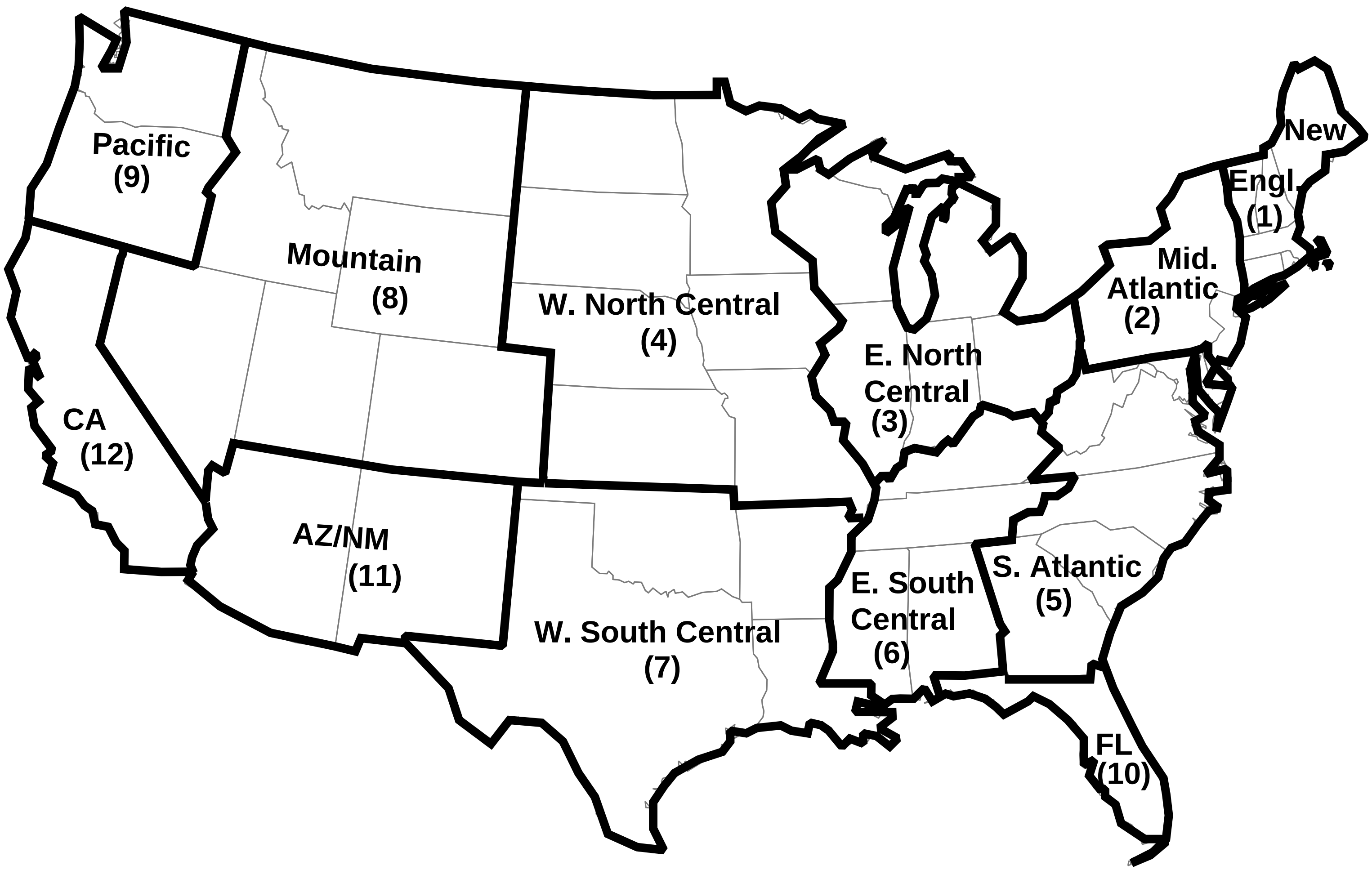
The actual rates that local distribution companies and intrastate carriers are allowed to charge are regulated by State authorities. State ratemaking traditionally allows (but does not necessarily guarantee) local distribution companies and intrastate carriers to recover their costs, including what the 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 explicitly determine cost-of-service distribution markups from revenue requirements because the availability of cost-specific data needed to determine revenue requirements is limited for local distribution companies and intrastate pipeline companies.[10] Instead, the markups are either determined from historical data or are based on the economic value of service as determined by the cost of competitive fuels. Firm service markups are based on historical data. Transportation sector and interruptible markups are based on value of service, which is determined largely by alternative fuel price relationships in fuel switchable markets.

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.

[10]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 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 Version I. This data collection may be considered for a future development effort.

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



3. 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 provided to the NGTDM from the Electricity Market Model (EMM) and from 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 the major fuel markets—crude oil and petroleum products, natural gas, coal, electricity, and imported energy—and iteratively solves for an annual supply/demand balance for each of the nine Census Divisions, accounting for the price responsiveness in both energy production and end-use demand, and for the interfuel substitution possibilities. NEMS solves for an equilibrium in each forecast year by iteratively operating a series of fuel supply and demand modules to compute the end-use prices and consumption of the fuels represented.[11] The end-use demand modules—for the residential, commercial, industrial, and transportation sectors—are detailed representations of the important features of each of these sectors. Using the delivered prices of each fuel, computed by the supply modules, the consumption modules evaluate the consumption of each fuel, taking into consideration the interfuel substitution possibilities, the existing stock of fuel and fuel conversion burning equipment, and the level of economic activity. Conversely, the fuel conversion and supply modules determine the end-use prices needed in order to supply the amount of fuel demanded by the customers, as determined by the demand modules. Each supply module considers the factors relevant to that particular fuel, for example: the resource base for oil and gas, the transportation costs for coal, or the refinery configurations for petroleum products. Electric utilities 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 determines the price and flow of dry natural gas supplied internationally from the contiguous U.S. border[12] or domestically from the wellhead (and indirectly from natural gas processing plants) to the domestic end-user.[13] 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. The primary data flows between the NGTDM and the other oil and gas models in NEMS, the Petroleum Market Model and the OGSM, are depicted in Figure 3-1.

[11]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, December 1993.

[12]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.

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

Figure 1 Primary Data Flows Between the Oil and Gas Modules of NEMS

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; and the OGSM provides the level of natural gas which would be produced (or imported) at the wellhead (or border crossing) 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.[14] 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 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,

[14]Special parameters are provided by OGSM for the construction of supply curves for domestic nonassociated natural gas production and by EMM for the construction of electric utility sector demand curves for natural gas which is competitive with residual fuel oil.

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 four primary components or modules: the Annual Flow Module, the Capacity Expansion Module, the Pipeline Tariff Module, and the Distributor Tariff Module. The Annual Flow Module is the central module of the NGTDM, since it is used to derive flows and prices of natural gas in conjunction with an annual natural gas market equilibrium. Conceptually the Annual Flow Module is a simplified representation of the natural gas transmission and distribution system, structured as a network composed of nodes and arcs. The other three primary components serve as satellite modules to the Annual Flow Module, providing parameters which define some of the characteristics of these nodes and arcs. 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 Capacity Expansion Module provides the Annual Flow Module with regional underground storage capacities and maximum annual flows allowed along each of the arcs in the network. The Pipeline and Distributor Tariff modules provide price parameters for establishing the tariffs to be charged along each of the interregional, intraregional, and distribution arcs. Data are also passed back to these satellite modules from the Annual Flow Module and between the satellite modules themselves.

The NGTDM is called once for each iteration of NEMS, but all modules are not run for every call. The Pipeline Tariff Module and the Capacity Expansion Module are executed once for each year, on the first iteration for each year and the last iteration for each year, respectively. The Annual Flow Module and the Distributor Tariff Module are executed for every NEMS iteration. The calling sequence of, and the interaction among, NGTDM modules is as follows for each year of execution of NEMS:

- First Iteration:

  The Pipeline Tariff Module determines tariffs for interstate pipeline company transportation and storage services, using a cost based simulation, and establishes tariff curves for pipeline and storage expansion.

- Each Iteration:

  The Distributor Tariff Module determines markups for intrastate transmission and distribution services based on historical data and alternate fuel prices. Next, the Annual Flow Module incorporates tariffs from the Pipeline Tariff Module and markups from the Distributor Tariff Module into a linear program that solves for interregional flows based on supply availability, demand requirements, and pipeline capacity constraints. The linear program determines a market equilibrium solution by maximizing consumer and producer surpluses, while minimizing supply and transportation costs, thus determining natural gas end-user and supply prices and domestic production. Pipeline capacity constraints for the first year (or years) of execution are determined from historical data. Subsequent year's constraints are taken from the previous year's Capacity Expansion Module results.

- Last Iteration:

  The Capacity Expansion Module incorporates the pipeline and storage expansion curves calculated in the Pipeline Tariff Module and expected future supply availability and consumption levels from other models in the NEMS. The Capacity Expansion Module represents two natural gas market seasons within a linear program structure to determine pipeline and storage capacity expansion for a future year, by minimizing the pipeline and storage expansion costs required to meet the expected consumption level of natural gas. The resulting seasonal flow patterns are used to approximate annual load patterns along pipelines, for use in the Annual Flow Module.

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, and associated production and Canadian import levels. In addition, the model provides a forecast of lease and plant fuel consumption, pipeline fuel use and the corresponding emissions, as well as pipeline and distributor tariffs, pipeline and storage capacity expansion, and interregional natural gas flows. Also, the capital investments associated with the expansion of pipeline and storage capacity are provided to the macroeconomic model of NEMS.

Natural Gas Demand Representation

Natural gas which is produced within the United States is consumed in lease and plant operations, delivered to consumers, exported internationally, and consumed as pipeline fuel. The consumption of gas as lease, plant, and pipeline fuel is determined within the NGTDM. Gas used in well, field, and lease operations is set equal to an exogenously specified percentage (Appendix F, Table F2) of dry gas production. Gas consumed in natural gas processing plants is similarly calculated, however, the percentages that are used are provided by the Petroleum Market Model. Pipeline fuel use depends on the amount and distance of gas transported and distributed in each region, as described in Chapter 5. The level of natural gas exports are currently determined exogenously to NEMS and passed to the NGTDM from the OGSM model. Exports are distinguished by six Canadian and three Mexican border crossing points, as well as for exports of liquefied natural gas to Japan from Alaska. 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,[15] and electric utility. 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 require guaranteed service and therefore are assumed to purchase firm service, which generally demands a higher rate. The noncore customers require a lower quality of transmission services and therefore, consume gas under a less certain and/or less continuous basis (i.e., their service may be interrupted). In the NGTDM, the core customers are assumed to purchase firm transmission services and the noncore customers are assumed to purchase interruptible transmission services. Therefore, these customers will be referred to in this document as either "firm" or "interruptible" customers.

Currently in NEMS, all of the natural gas consumed in the transportation, residential, and commercial sectors is classified as firm.[16] Within the industrial sector the interruptible segment includes the industrial boiler market and natural gas consumed within refineries. The interruptible market of the electric utility sector is further separated into two subclasses, depending on the alternative fuel a plant would burn should natural gas be unavailable or relatively uneconomic. The subclass of interruptible electricity generation plants that has the option of burning distillate fuel in lieu of natural gas is referred to as "competitive-with-distillate." The second subclass of interruptible plants can burn either natural gas or residual fuel oil and is therefore referred to as "competitive-with-residual fuel." The electric utility generating units defining each of the three customer classes modeled are as follows: (1) firm—gas steam units or gas combined cycle units, (2) competitive-with-distillate—dual-fired turbine units or gas turbine units, (3) competitive-with-residual—dual-fired steam plants (consuming both natural gas and residual fuel oil). Within the NGTDM, natural gas is exported to Mexico under firm transmission service and to Canada under interruptible transmission service.

For any given NEMS iteration within a 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 (set to zero if fixed consumption levels are required) as a basis for building a short-term demand curve. 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

[15]Natural gas burned in the transportation sector is defined as gas that is burned in compressed natural gas vehicles.

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

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 representation that the NGTDM requires. The demand curve representation and the regional mapping for the electric utility sector differ from the other NEMS sectors as described in the following sections.

Regional Representations of Demand

Nonutility[17] natural gas consumption levels are provided by the NEMS demand models for the nine Census divisions, the primary integrating regions represented in the NEMS. Alaska and Hawaii are included within the Pacific Census

[17]The "nonutility" sectors refer to the residential, commercial, industrial, and transportation demand sectors.

Figure 3-2. Electricity Market Model (EMM) Regions

Figure 5.1

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 3-2). Electricity generation in Alaska and Hawaii is handled separately. Within the EMM, the electric utility 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 nine 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 2-1).

As can be seen in Figure 3-2, 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. Therefore, electric utility demand 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 3-3)

Figure 3-3. NGTDM/EMM Regions

. For example, the South Atlantic NGTDM region (number 5) includes three NGTDM/EMM regions (also subregions of EMM regions 1, 3, or 9). Internally, the NGTDM represents electric utility consumption (and assigns prices) for each NGTDM/EMM region. 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 electric utility plants in each of the regions represented.

The consumption levels for each of the nonutility sectors are disaggregated from the 9 Census Divisions to the 12 NGTDM regions by applying historically based shares which are held constant throughout the forecast (Appendix F, Table F6). For the Pacific Division natural gas consumption estimates for Alaska are first subtracted to establish a consumption level for just the contiguous Pacific Division before the historical share is applied. The consumption of gas in Hawaii was considered to be negligible. Within the NGTDM, a relatively simple module (which is described later) was included for approximating the consumption of natural gas by each nonutility sector in Alaska. These estimates, combined with the consumption levels provided by the EMM for consumption by electric utilities in Alaska, are also used in the calculation of the production of natural gas in Alaska.

Nonutility 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 nonutility demand curves for the firm transmission service type for each sector and region is:

$$NGTDM\_CRVNONUFX_{s,r} = QBAS\_NONU\_F_{s,r} * (PRICE \ / \ NON \qquad (1)$$

where,

$NONU\_PR\_F_{s,r}$	=	end-use price to sector s in NGTDM region r in the previous NEMS iteration (dollars per Mcf)
$QBAS\_NONU\_F_{s,r}$	=	natural gas quantity which the NEMS demand models indicate would be consumed at price NONU_PR_F by sector s in NGTDM region r (Bcf)
$NONU\_ELAS\_F_{s}$	=	short-term price elasticity of demand for sector s (Appendix F, Table F36) Note: Demand curves can be represented with fixed consumption levels by setting elasticities equal to zero.
PRICE	=	end-use price at which demand is to be evaluated (dollars per Mcf)
$NGTDM\_CRVNONUFX_{s,r}$	=	estimate of the natural gas which would be consumed by sector s in region r at the price PRICE (Bcf)
s	=	nonutility sector (1-residential, 2-commercial, 3-industrial, 4-transportation)

The form of the nonutility demand curve for the interruptible transmission service type is identical, with the following variables substituted: NGTDM_CRVNONUIX, NONU_PR_I, QBAS_NONU_I, and NONU_ELAS_I.

Electric Utility Natural Gas Demand Curves

Natural gas demand by electric utilities is represented differently in the NGTDM from the nonutility demands because, for many powerplants, natural gas consumption depends primarily on the utilization of the plant by the electric utility (i.e. the dispatch order), which in turn is a function of the price of gas relative to the price of other fuels used by other powerplants operated by the electric utility. If the relative fuel prices to the electric utility sector require the dispatch order of the plants to change, the relative consumption level for gas used by electric utilities is likely to change as well. However, with the general exception of the competitive-with-residual plant types, the gas consumption level at electric utilities is unlikely to respond to changes in the gas price that do not affect the dispatch order. The representation of dispatch order is contained in the EMM, not in the NGTDM. Therefore, within the NGTDM, the firm and the competitive-with-distillate utility consumption levels are fixed at the values calculated by the EMM in the previous NEMS iteration.

In the EMM, natural gas consumption by plants classified as competitive-with-residual can change significantly in response to a different price even with no switch in the merit order. Consumption levels can change because these plants can switch between burning natural gas and burning residual fuel oil, which has historically been priced competitively with natural gas. A representation of the natural gas demand response within the EMM for the competitive-with-residual plant types is incorporated in the NGTDM. This representation will be relatively accurate within a range of natural gas prices which do not lead to a merit order change. Within the NGTDM, the competitive-with-residual plants either see the same price as the competitive-with-distillate plants or a lower price when it is deemed economically advantageous (i.e., the resulting price is at least as great as the minimum variable cost to supply the natural gas, but not high enough to result in a loss of market share to petroleum suppliers). To facilitate this determination, the EMM provides the NGTDM with additional parameters to anticipate more closely the demand response within the EMM to a change in the competitive-with-residual price.

Since the demand for natural gas in the competitive-with-residual class within the EMM is a function of the relative price of the two competing fuels, the demand curve to represent this customer class is specified within the NGTDM as a function of the price of natural gas relative to the price of residual fuel oil to electric utilities, as illustrated in Figure 3-4.

Figure 3-4. Electric Utility Natural Gas Demand Curve, Competitive-With-Residual Fuel Class

For a given demand for electricity and a given dispatch order for a region within the EMM, there is a maximum (GSHRMAX) and a minimum (GSHRMIN) level of natural gas which would be consumed by the competitive-with-residual class, (represented by the vertical lines in the figure). GRATMIN is the lowest price ratio which would result in a consumption level equal to GSHRMIN, and GRATMAX is the highest price ratio which would result in a consumption level equal to GSHRMAX. For each NGTDM/EMM region, the EMM provides these price/quantity pairs to the NGTDM based on the dispatch order from the current NEMS iteration. These are two of the four price/quantity pairs provided by the EMM, which the NGTDM connects to form a piece-wise linear demand curve for the competitive-with-residual class within the electric utility sector. The EMM also provides the quantity of gas (GSHRPAR) that would be consumed at the price ratio which represents parity (GRATPAR), and the quantity of gas that would be consumed at the natural gas price (converted to a price ratio in the NGTDM) which was sent to the EMM in the previous NEMS iteration (SHROLD and RATOLD). Within the NGTDM the residual fuel oil price to electric utilities (used in converting the price ratio into a natural gas price) is held constant at the level established in the previous NEMS iteration and is calculated as a quantity-weighted average of the low-sulfur and high-sulfur residual fuel prices (QRLELGR, QRHELGR).

Natural Gas Supply Interface

The primary categories of natural gas supply represented in the NGTDM for the contiguous Lower 48 States are nonassociated and associated-dissolved gas from onshore and offshore regions, pipeline imports from Mexico and Canada, liquefied natural gas imports, gas transported via the Alaskan Natural Gas Transportation System (ANGTS), synthetic natural gas produced from coal and from liquid hydrocarbons, and other supplemental supplies. The only supply categories from this list which are allowed to vary within the NGTDM in response to a change in the current year's natural gas price are synthetic natural gas produced from liquid hydrocarbons and nonassociated gas from onshore and offshore regions. 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 which varies with a change in the oil production in the current forecast year. The annual oil production level is determined in the Petroleum Market Model and can vary between each iteration of NEMS.

Within the OGSM, natural gas supply activities are modeled for the 13 supply regions (6 onshore, 3 offshore, and 3 Alaskan geographic areas) shown in Figure 3-5

Figure 3-5. Oil and Gas Supply Model (OGSM) Regions

. 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 (liquefied natural gas). Six Canadian and three Mexican border crossings demarcate the foreign pipeline interface between the OGSM and 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. The annual levels of liquefied natural gas imports are determined in the OGSM and are provided to the NGTDM at the beginning of each forecast year. Similarly the OGSM establishes the level of gas which will flow into the contiguous United States via the ANGTS.

Supplemental Gas Sources

Sources for synthetically produced natural gas are geographically specified in the NGTDM based on current plant locations. Synthetic gas from coal is exogenously specified, independent of the price of natural gas in the current forecast year. The Coal Module of NEMS sets the annual forecast of natural gas produced from the Great Plains Coal Gasification Plant in North Dakota, whereas a price responsive supply curve is incorporated within the NGTDM for synthetic gas production from liquid hydrocarbons (currently produced only in Illinois). Synthetic gas production from liquid hydrocarbons in Illinois is represented in the NGTDM using a statistically estimated function based on the associated region's market price:

$$VAL = SNGA1 * VALUE^{SNGA2} \tag{2}$$

where,

VAL	=	synthetic gas production from liquid hydrocarbons in Illinois (Bcf)
VALUE	=	firm service market price in the East North Central Census Division (which contains Illinois), (dollars per Mcf)
SNGA1, SNGA2	=	estimated parameters (Appendix G, Table G2)

The synthetic gas production level resulting from the above equation is limited to be no less than an exogenously specified minimum (Appendix F, Table F1) and not to increase by more than 50 percent above the level in the previous forecast year (Appendix F, Table F1). Synthetic gas production from liquid hydrocarbons in Hawaii is held constant throughout the forecast at an historically based level (Appendix F, Table F1), as is other supplemental supplies, which are disaggregated to regional levels using fixed historical shares[18] (Appendix F, Table F12).

Natural Gas Imports Via Pipeline

The OGSM provides most of the parameters used in the NGTDM for representing the imports of gas from Mexico and Canada into the United States by pipeline. Border crossing points are established at each NGTDM region with an international border. The annual import levels for gas from Mexico are generated exogenously and passed to the NGTDM via the OGSM. The OGSM also provides parameters for defining a national Canadian natural gas supply curve, an exogenous forecast for consumption of natural gas in Canada, and additional parameters for representing the transmission system for gas within Canada and to the U.S. border, including an exogenous forecast of the physical capacity of natural gas pipelines crossing the border into the United States. Within the NGTDM, this physical capacity limit is multiplied by an exogenously specified utilization rate to establish a maximum effective capacity limit for flow of gas from Canada into the United States. "Effective capacity" is defined as the maximum annual physically sustainable capacity of a pipeline times an assumed maximum likely utilization rate, based on the expected seasonal demand profiles of the customers being served.

The functional form of the Canadian natural gas supply curve is represented as follows:

$$\begin{aligned} CN\_PRODUC = {} & OGRESCAN_{2,y} * OGPRRCAN_{2,y} * \\ & (1 + OGELSCAN_{2,1} * \frac{CN\_WELPRC - CN\_WPRCL}{CN\_WPRCLAG} \end{aligned} \tag{3}$$

where,

CN_PRODUC	=	Canadian domestic natural gas production in year y (Bcf)
$OGRESCAN_{2,y}$	=	Canadian natural gas reserves in beginning-of-year y (from OGSM in Bcf)
$OGPRRCAN_{2,y}$	=	potential natural gas production-to-reserves ration in Canada in year y (from OGSM as fraction)
$OGELSCAN_{2,1}$	=	estimated short run price elasticity of extraction for Canada (from OGSM)
CN_WPRC	=	average Canadian wellhead price in year y (dollars per Mcf)
CN_WPRCLAG	=	average Canadian wellhead price in year y-1 (dollars per Mcf)

The amount of natural gas available to flow into the United States from Canada is calculated as:

$$\begin{aligned} TOT\_BRDQ = {} & CN\_PRODUC - \\ & \frac{OGCNCON_{2,y} - (CANFLO\_OUT + \sum_{i=1}^{6} OGQNGEXI}{1 - OGCNDMLOSS} \end{aligned} \tag{4}$$

where,

TOT_BRDQ	=	total gas available to flow into the United States from Canada (measured at the wellhead), (Bcf)
CN_PRODUC	=	Canadian domestic natural gas production in year y (Bcf)
$OGCNCON_{2,y}$	=	consumption of natural gas in Canada (from OGSM in Bcf)

[18]Other supplemental supplies include propane-air, refinery gas, coke oven gas, manufactured gas, biomass gas, and air injection for Btu stabilization.

CANFLO_OUT	=	gas flowing into Canada which was originally produced in Canada[19] (Bcf)
$OGQNGEXP_{i,y}$	=	exports of gas from the United States into Canada by border crossing i in year y (from OGSM in Bcf)
OGCNDMLOSS	=	percentage of gas produced in Canada to satisfy Canadian demand that is consumed in transit (from OGSM as fraction)
OGCNEXLOSS	=	percentage of gas produced in the United States to satisfy Canadian demand that is consumed in transit within Canada (from OGSM as fraction)

If the value of TOT_BRDQ exceeds the total effective capacity of the natural gas pipelines used to flow gas into the United States from Canada, then it is assumed that the share of TOT_BRDQ which will flow across each of the representative border crossings in the model (CN_FLOSHR) will be equivalent to that border crossing's share of the total effective capacity. Under most likely model scenarios this has been shown to be true. However, if available Canadian supplies are less than total effective pipeline capacity across the border, the allocation of TOT_BRDQ to each of the six border crossings is calculated as follows:

$$CN\_FLOSHR_i = (OGCNPARM1 * \frac{CN\_FLOLAG_i}{\sum_{i=1}^{6} CN\_FLOLAG_i}) + (1 - OGCNPARM1) * \frac{(CN\_BRDPRC_i - OGCNPM}{\sum_{i=1}^{6} (CN\_BRDPRC_i - OGCNP} \tag{5}$$

where,

CN_FLOSHR_i	=	the share of the gas available to flow from Canada into the United States to flow across border crossing i (fraction)
CN_FLOLAG_i	=	the amount of gas which flowed from Canada into the United States across border crossing i in the previous year (adjusted for pipeline additions in year y), (Bcf)
OGCNPARM1	=	parameter which reflects the importance of the historical flow pattern in the determination of actual allocation of gas (from OGSM, 0 < OGCNPARM1 < 1)
OGCNPARM2	=	parameter which reflects the responsiveness of the flow pattern to differentials in border prices netbacked to the wellhead (from OGSM, OGCNPARM2 = 1)
CN_BRDPRC_i	=	the market price at border crossing i (dollars per Mcf)
$OGCNPMARKUP_i$	=	assumed markup from the average Canadian wellhead price to border crossing i (from OGSM in dollars per Mcf)

If the resulting shares result in flow levels across some border crossings which exceed their maximum effective capacity level, then the "unflowable" portion is made available at border crossings with available pipeline capacity, and the values for the variable CN_FLOSHR are adjusted accordingly. These shares are ultimately used in the calculation of the Canadian wellhead price:

$$CN\_WELPRC = \sum_{i=1}^{6} CN\_FLOSHR_i * (CN\_BRDPRC_i - OGCNPMAR \tag{6}$$

where,

CN_WELPRC	=	Canadian wellhead price (dollars per Mcf)
CN_FLOSHR_i	=	the share of the gas available to flow from Canada into the United States to flow across border crossing i (fraction)
CN_BRDPRC_i	=	the market price at border crossing i (dollars per Mcf)

[19]In recent years, approximately 355 Bcf of gas flows into Minnesota from Canada on an annual basis only to be routed back to Canada through Michigan (and a very small amount through Montana). The amount of gas entering the United States that is not imported from Canada (and the percentage of this amount which travels back through Michigan) is set at a fixed historically based level throughout the forecast (Appendix F, Table F9).

$OGCNPMARKUP_i$	=	assumed markup from the average Canadian wellhead price to border crossing i (from OGSM in dollars per Mcf)

The system of equations which represents the pricing and flow of gas from Canada into the United States can not be solved in a top/down fashion, but requires an iterative process due to the interrelationships involved. Furthermore, the solution algorithm used within the NGTDM requires prespecified supply curves (or fixed supply levels) at each border crossing before solving. A short-term supply curve is generated for a single border crossing point, through the use of the equations shown above, by holding the border prices for the other crossing points at their solution values from the previous NEMS iteration.

Supply Curves for Domestic Dry Gas Production

Most of the parameters for generating short-term supply curves for dry natural gas production are provided to the NGTDM by the OGSM. 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 3-6).

Figure 6NGTDM/OGSM Regions

These supply curves are defined 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). Within the NGTDM, dry gas production is delineated by two categories, nonassociated and associated-dissolved production. Nonassociated 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.

Associated-Dissolved Gas Production

The production of associated-dissolved gas is established as a function of the level of crude oil production (an output of the Petroleum Market Model) and is assumed not to vary over the short-term with a change in the price of natural gas (except in as much as the oil production level might be indirectly impacted by a change in the gas price). The Petroleum Market Model forecasts domestic crude oil production by the 3 offshore and 6 onshore OGSM regions. Next, the NGTDM calculates associated-dissolved gas production for the 6 onshore regions, and then disaggregates the quantities into the 17 NGTDM/OGSM regions using historical based shares, as follows:

$$ADGPRDON_r = SHR\_AD17_r * AD\_FR\_OIL_{o,1} * (365.25 * RFQTDC \qquad (7)$$

where,

$ADGPRDON_r$	=	associated-dissolved gas production for NGTDM/OGSM region r (Bcf)
SHR_AD17_r	=	assumed share of the related OGSM region's associated-dissolved gas production which is in NGTDM/OGSM region r [Appendix F, Table F5 (fraction)]
$RFQTDCRD_{o,y}$	=	the crude oil production in the related OGSM region o in year y (from the Petroleum Market Model in millions of barrels per day)
$AD\_FR\_OIL_o$	=	estimated parameters associated with OGSM region o (Appendix G, Table G4)

The estimated equation for associated-dissolved gas in the Gulf of Mexico ($ADPRDOF_r$) is identical to the onshore equation once the SHR_AD17 term is removed. However, the functional form for the production of associated-dissolved gas off the coast of California is structurally different, as follows:

$$\begin{aligned} ADGPRDOF_r = {} & AD\_FR\_OIL_{r,1} * (365.25 * RFQTDCRD_{r,y})^{AD\_FR\_(} \\ & ADGLAG_r^{AD\_FR\_OIL_{r,3}} * (365.25 * RFQTDCRD_{r,y-1} \end{aligned} \qquad (8)$$

where,

$ADGPRDOF_r$	=	associated-dissolved gas production for the Pacific offshore region r in year y (Bcf)
$RFQTDCRD_{r,y}$	=	the crude oil production in the Pacific offshore region r in year y (from the Petroleum Market Model in millions of barrels per day)
$ADGLAG_r$	=	associated-dissolved gas production for the Pacific offshore region r in year y-1 (Bcf)
$AD\_FR\_OIL_r$	=	estimated parameters associated with the Pacific offshore region r (Appendix G, Table G4)

Total domestic production is the sum of nonassociated and associated-dissolved production.[20]

Optional Functional Forms for Nonassociated Gas Production Function

The NGTDM includes the option of selecting one of three different functional forms for the supply curve for nonassociated dry natural gas production (net of lease and plant fuel) in the domestic onshore and offshore regions. All three forms are constructed from a common key point (or price/quantity pair) which is based on an expected extraction rate, estimated in the OGSM. The "expected" or base production level from an onshore region is calculated as follows:

$$BASE\_Q_r = OGRESNGON_r * OGPRRNGON_r * PER \qquad (9)$$

where,

$BASE\_Q_r$	=	expected nonassociated production (net of lease and plant), NGTDM/OGSM region r (Bcf)
$OGRESNGON_{r,y}$	=	dry gas reserves at the beginning-of-year y in onshore NGTDM/OGSM region r (from OGSM in Bcf)
$OGPRRNGON_{r,y}$	=	expected extraction rate in year y from reserves in onshore NGTDM/OGSM region r (from OGSM as fraction)
PER	=	1 - $PCTLSE\_SUPL_r$ - $PCTPLT\_PADD_{p,y}$, a factor for netting lease and plant fuel out of dry gas production (fraction)
$PCTPLT\_PADD_{p,y}$	=	percent of dry gas production which is consumed in natural gas processing plant operations, for PADD[21] region p in year y (from the PMM as fraction)
$PCTLSE\_SUPL_r$	=	percent of dry gas production which is consumed in well, field, and lease operations [Appendix F, Table F2 (fraction)] Note: For the offshore regions $BASE\_Q_r$ = $OGRESNGOF_{r,y}$ * $OGPRRNGOF_{r,y}$.

The price (BASE_P) associated with BASE_Q is based on the average solved for wellhead price in the region over the previous two forecast years. The amount the production will vary from BASE_Q is a function of how different the wellhead price (at which the function is being evaluated) is from BASE_P. The calculation of the additional quantity of production (DEL_Q_r)[22] which would result at a given wellhead price (VALUE) is different under each of the three options.[23] Options one and two are presented below, with option 3 following.

[20]Within the FORTRAN code, the functions used to generate supply curves for total dry gas production include variables for associated-dissolved production, effectively shifting the nonassociated gas production curves to the right along the quantity axis to create a total production curve. (For convenience in the code, the synthetic production of gas from coal is similarly added to the total production curve.)

[21]Petroleum Administration for Defense Districts (PADD) are the regions modeled in the PMM. The PADD region which most overlaps the indicated NGTDM/OGSM region is used in this and other equations, as necessary.

[22]If DEL_Q_r is negative, the resulting production level will be less than $BASE\_Q_r$.

[23]A model user can select one of the three functional forms for the supply curves by setting the variable TYP_SUPCRV equal to either 1, 2, or 3, accordingly. For generating the forecast published in the *Annual Energy Outlook 1994*, option 3 was selected.

Option 1:

$$DEL\_Q_r = BASE\_Q_r * OGELSNGON_{r,y} * (VALUE - BASE\_P_r)/BAS \tag{10}$$

where,

OGELSNGON$_r$ = estimated short-term price elasticity (from OGSM), for offshore regions the variable OGELSNGOF$_r$ is used

Option 2:

$$DEL\_Q_r = BASE\_Q_r * ELAS * (VALUE - BASE\_P_r)/BASE\_P_r \tag{11}$$

where,

If VALUE $\geq$ BASE_P$_r$

ELAS = PARM_SUPCRV2$_1$, (user specified short-term price elasticity, assumed to be less than one, Appendix F, Table F37)

If VALUE < BASE_P$_r$

ELAS = PARM_SUPCRV2$_2$, (user specified short-term price elasticity, assumed to be greater than one, Appendix F, Table F37)

Option 1 is symmetric for price increases and decreases. Option 2 assumes production responds more strongly to price declines than to increases. The justification for incorporating a different elasticity above and below the "expected" production level on the supply curve is that producers have a vested interest in selling close to their planned for or expected production level. Much lower than anticipated gas sales do not allow the producer the necessary cash flow to stay in business. In such cases, prices would be lowered enough to increase sales and resulting revenues. However, there are practical upper limits on the rates of extraction from reserves, causing an upward push on the price when there are market pressures to produce at elevated extraction rates.

Option 3 is a combination of Options 1 and 2. In a close range around the base point (plus or minus an assumed percentage —PARM_SUPCRV3$_1$— of the base quantity), the short-term wellhead price elasticity (PARM_SUPCRV3$_2$) does not change from one side of the base point to the other (as in Option 1), but is assumed to be highly inelastic. Outside of this range, the short-term price elasticities are set to the same values used under Option 2. However, these segments of the curve are shifted (left, below the base price, and right, above the base price) to intersect the end points of the segment of the curve running through the base point, as follows:

Option 3:

$$DEL\_Q_r = (BASE\_Q_r * PARM) + (1 + PARM) * BASE\_Q_r * ELAS * \tag{12}$$

where,

If VALUE is within the range BASE_P$_r$ ± (BASE_P$_r$ * PARM_SUPCRV3$_1$ / PARM_SUPCRV3$_2$)

PARM = 0.

ELAS = PARM_SUPCRV3$_2$

If VALUE is greater than BASE_P$_r$ + (BASE_P$_r$ * PARM_SUPCRV3$_1$ / PARM_SUPCRV3$_2$)

PARM = + PARM_SUPCRV3$_1$

ELAS = PARM_SUPCRV2$_2$

If VALUE is less than BASE_P$_r$ - (BASE_P$_r$ * PARM_SUPCRV3$_1$ / PARM_SUPCRV3$_2$)

PARM = - PARM_SUPCRV3$_1$

ELAS = PARM_SUPCRV2$_1$

The assumed values for all of the parameters and elasticities shown above are presented in Appendix F, Table F37.

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Figure 3-8. Nonassociated Gas Supply Curve Options

$NGPRD\_L48 = BASE\_Q_r + DEL\_Q_r + (ADGP$

(res): $QALK\_NONU\_F_d = EXP(AK\_C_1) * WOPLAG^{AK\_C_2} * AK\_R$ (15)

(com): $QALK\_NONU\_F_d = EXP(AK\_D_1) * WOPLAG^{AK\_D_2} * AK\_C$ (16)

where,

$QALK\_NONU\_F_d$	=	consumption of natural gas by residential (d=1) or commercial (d=2) customers in Alaska (Bcf)
WOPLAG	=	landed cost of crude oil in the previous forecast year [the 1989 value used in forecast year 1990 is a data input, Appendix G, Table G1.1] (dollars per barrel)
AK_C	=	estimated parameters for residential consumption equation (Appendix G, Table G1)
AK_D	=	estimated parameters for commercial consumption equation (Appendix G, Table G1)
AK_RN_y	=	number of residential customers (exogenously specified, Appendix G, Table G1)
AK_CN_y	=	number of commercial customers (exogenously specified, Appendix G, Table G1)

The consumption of gas by Alaskan industrial customers is a function of the landed cost of crude oil imports and time:

(ind): $QALK\_NONU\_F_d = (\; AK\_E_1 + (AK\_E_2 * WOPCUR) + (AK\_$ (17)

where,

$QALK\_NONU\_F_d$	=	consumption of natural gas by industrial customers (d=3), (Bcf)
WOPCUR	=	average national landed cost of crude oil in the current forecast year [the 1989 value used in forecast year 1990 is a data input, Appendix G, Table G1.1] (dollars per barrel)
AK_E	=	estimated parameters for industrial consumption equation (Appendix G, Table G1)
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, 6 for 1995, etc.)

The use of natural gas in compressed natural gas vehicles in Alaska is assumed to be negligible.

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 F, Table F10). 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:

(S. AK): $AK\_PROD_{r=1} = (EXPJAP + AK\_CONS\_S) \;/\; (1 - AK\_PCTLS$
$AK\_PCTPIP_{r=1})$ (18)

(N. AK): $AK\_PROD_{r=2} = AK\_CONS\_N \;/\; (1 - AK\_PCTLSE_{r=2} - AK\_I$ (19)

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_PCTLSE_r	=	assumed percent of gas production which is consumed in lease operations in region r (fraction)
AK_PCTPLT_r	=	assumed percent of gas production which is consumed in plant operations in region r (fraction)

AK_PCTPIP_r = assumed percent of gas production which is consumed as pipeline fuel in region r (fraction)

The variables for AK_PCTLSE, AK_PCTPLT, and AK_PCTPIP are based on historical percentages (Appendix F, Table F7) 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 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 corresponding to the North and South regions (not accounting for the impact should ANGTS be connected) is calculated as:

$$AK\_WPRC = AK\_F_1 + (AK\_F_2 * WPRLAG) + (AK\_F_3 * (AK\_PROD \tag{20}$$

where,

AK_WPRC = average Alaskan natural gas wellhead price (dollars per Mcf)
AK_PROD_r = dry gas production in Alaskan region r (1=South; 2= North) (Bcf)
$WPRLAG$ = average national landed cost of crude oil in previous forecast year (dollars per Mcf)
AK_F = estimated parameters (Appendix G, Table G1)

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. 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 F, Table F8). The Alaskan industrial sector price is calculated as:

$$PALK\_NONU\_F_s = AK\_G_1 + (AK\_G_2 * WOPCUR) \tag{21}$$

where,

$PALK\_NONU\_F_d$ = price of natural gas to Alaskan industrial customers (d=3), (dollars per Mcf)
$WOPCUR$ = landed price of crude oil in current forecast year (dollars per barrel)
AK_G = estimated parameters (Appendix G, Table G1)

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.

Figure 3-1. Primary Data Flows Between Oil and Gas Models of NEMS

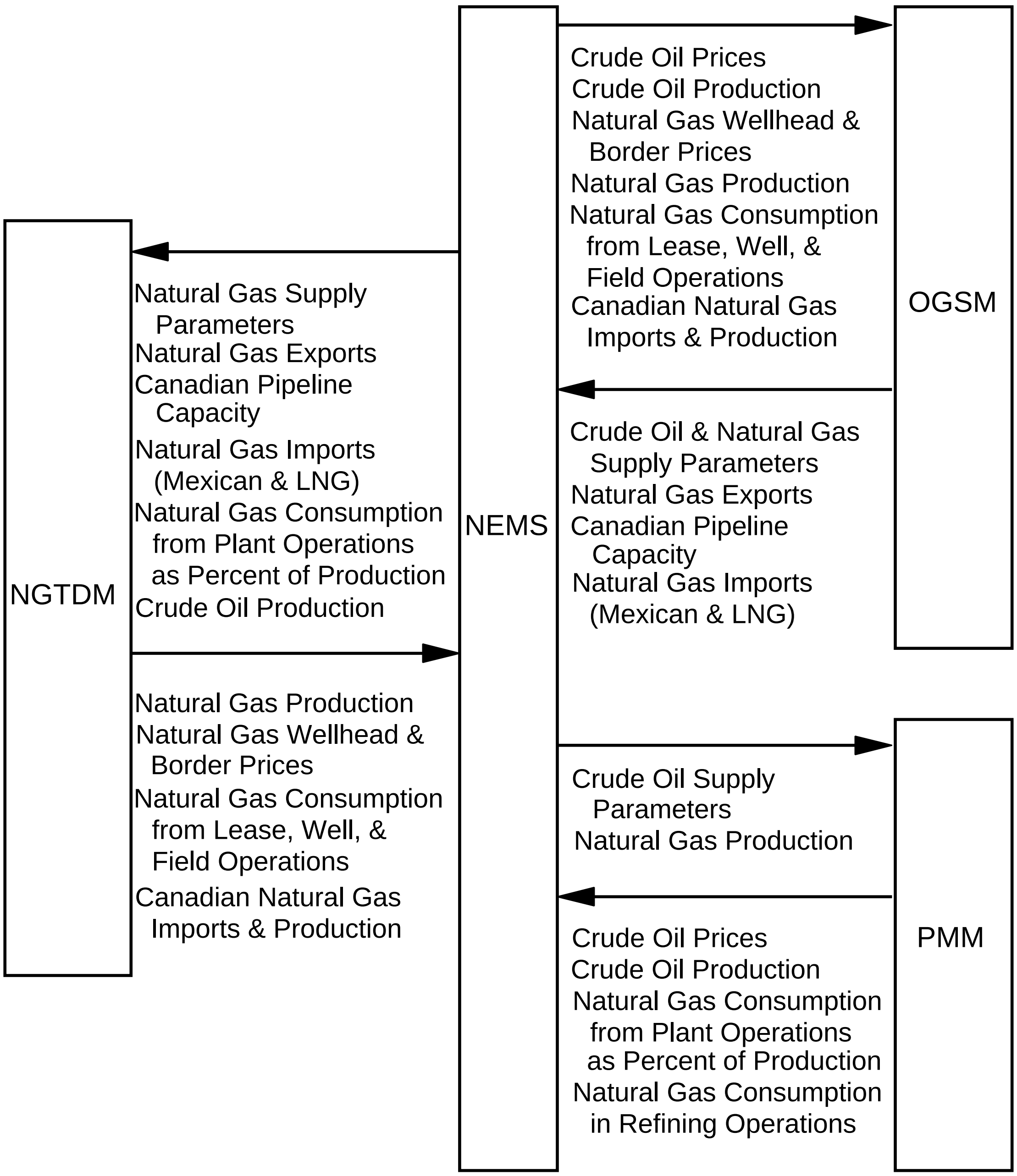


Figure 3-2. Electricity Market Model (EMM) Regions

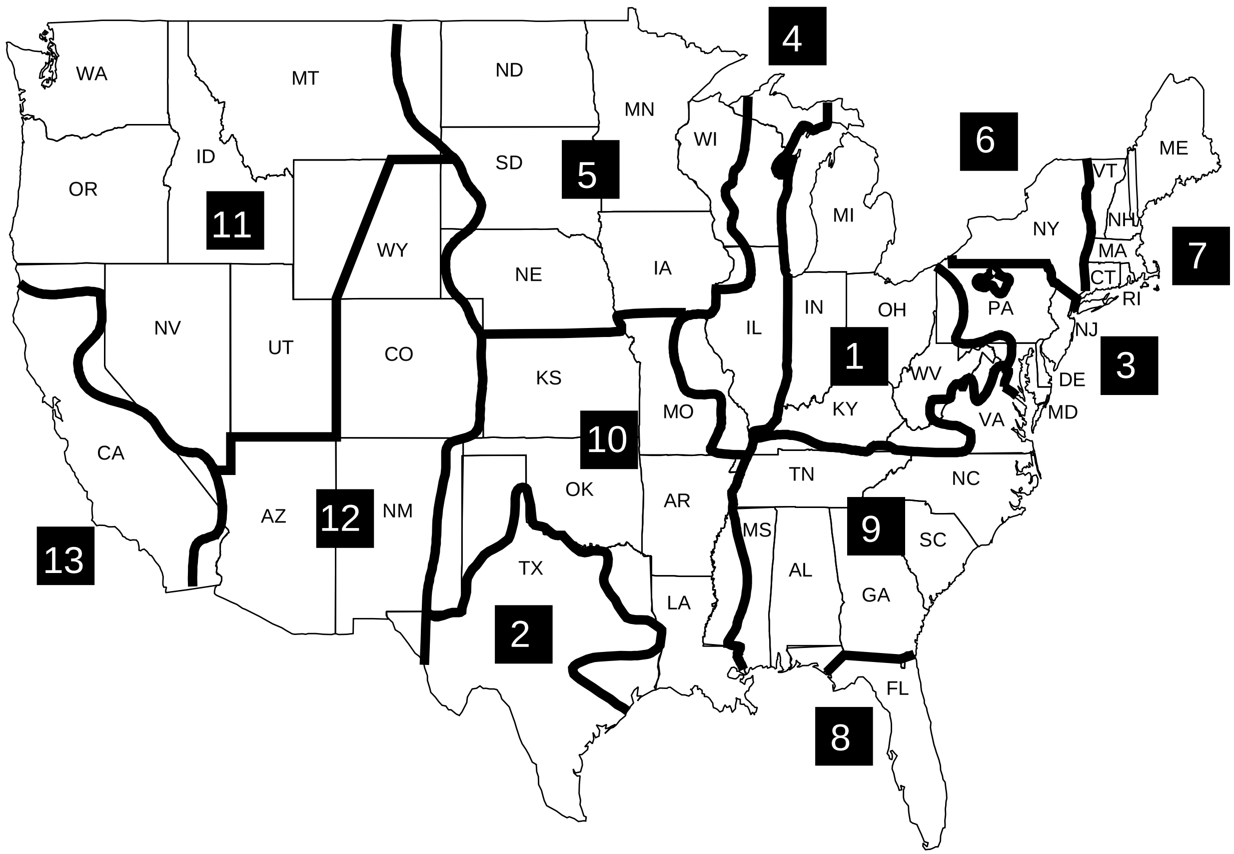
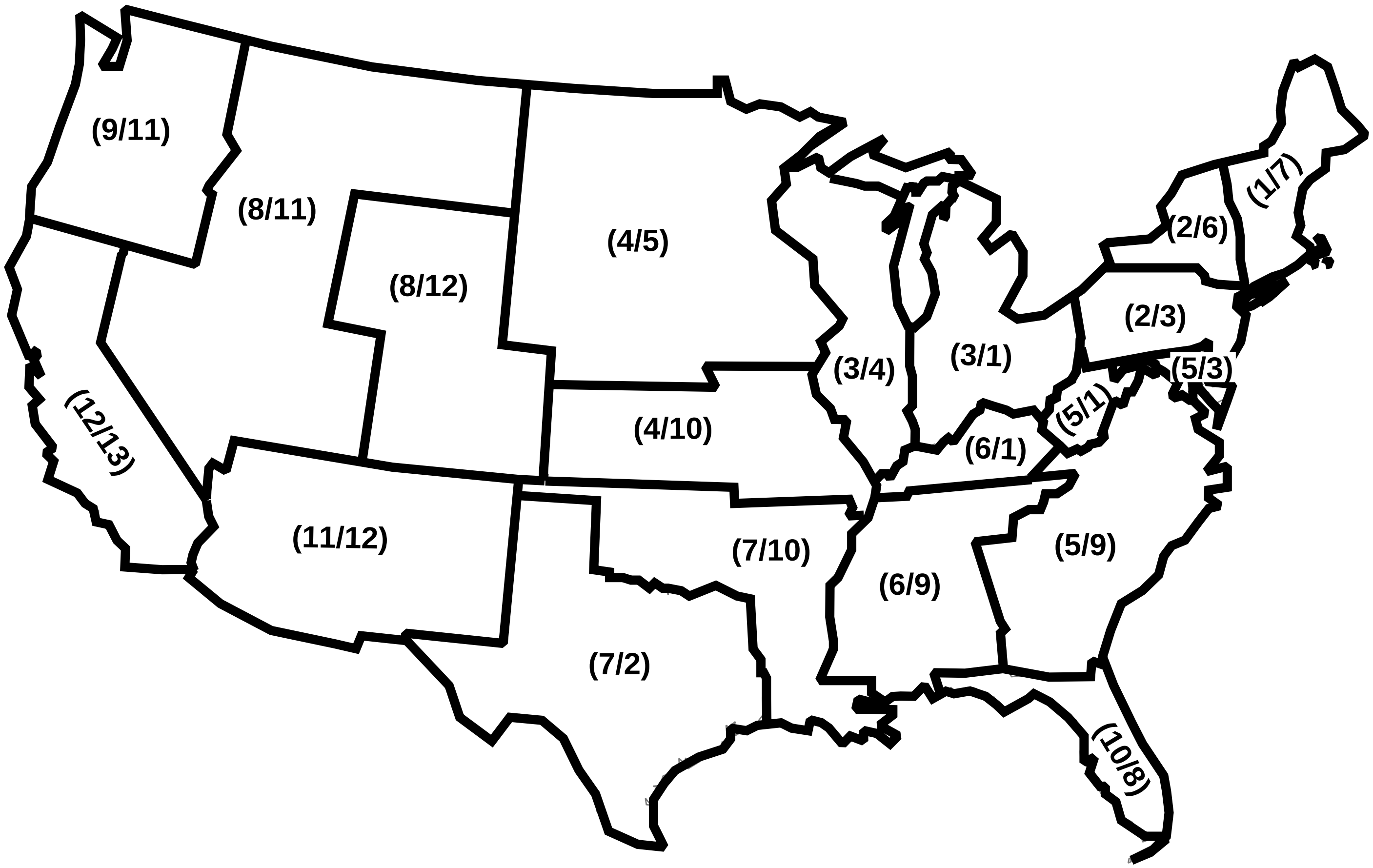


Figure 3-3. Natural Gas Transmission and Distribution Model/Electricity Market Model (NGTDM/EMM) Regions



(NGTDM Region Number/EMM Region Number)

Figure 3-4. Example NGTDM Electric Utility Demand Curve, Competitive With Residual Fuel Oil Class

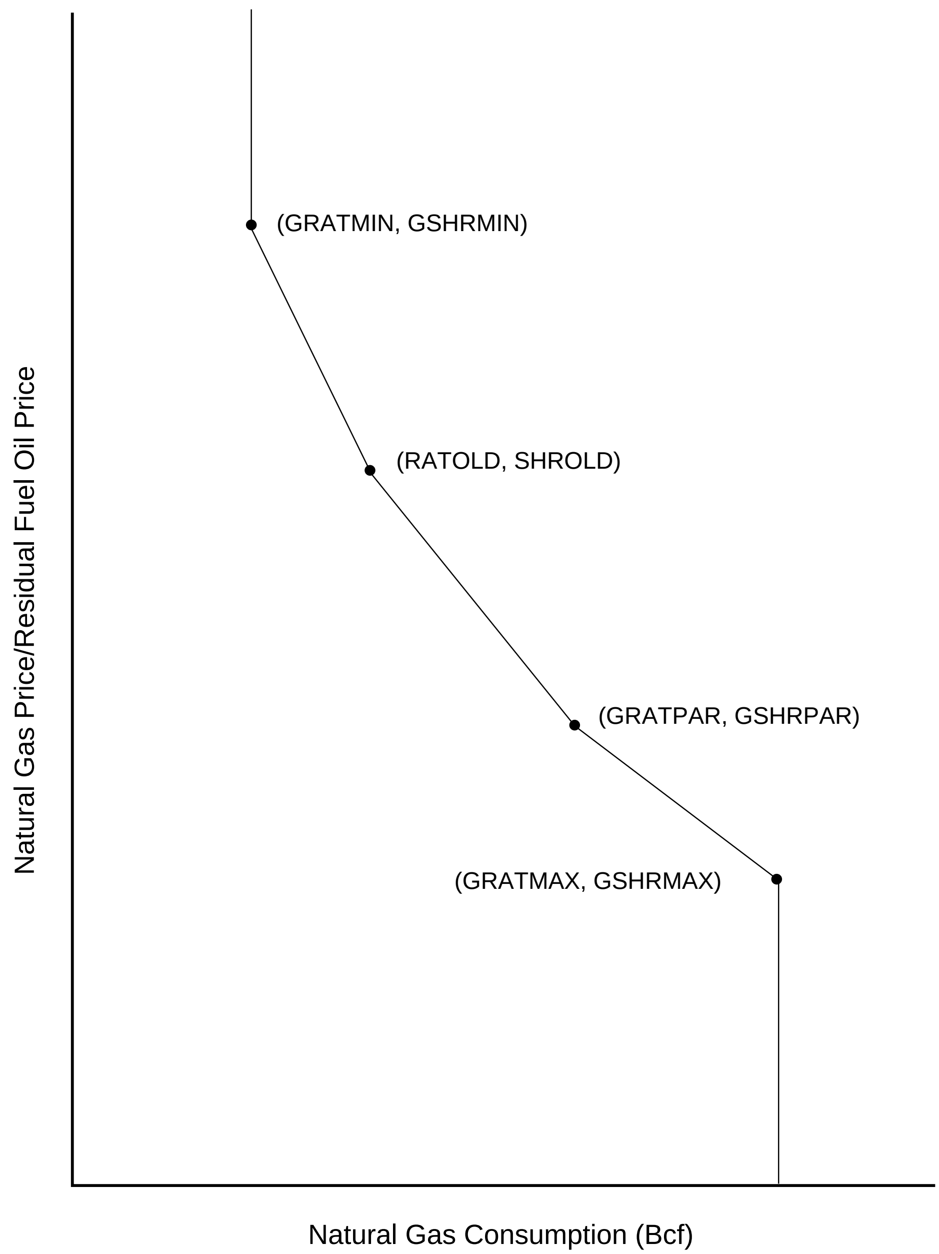


Figure 3-5. Oil and Gas Supply Model (OGSM) Regions

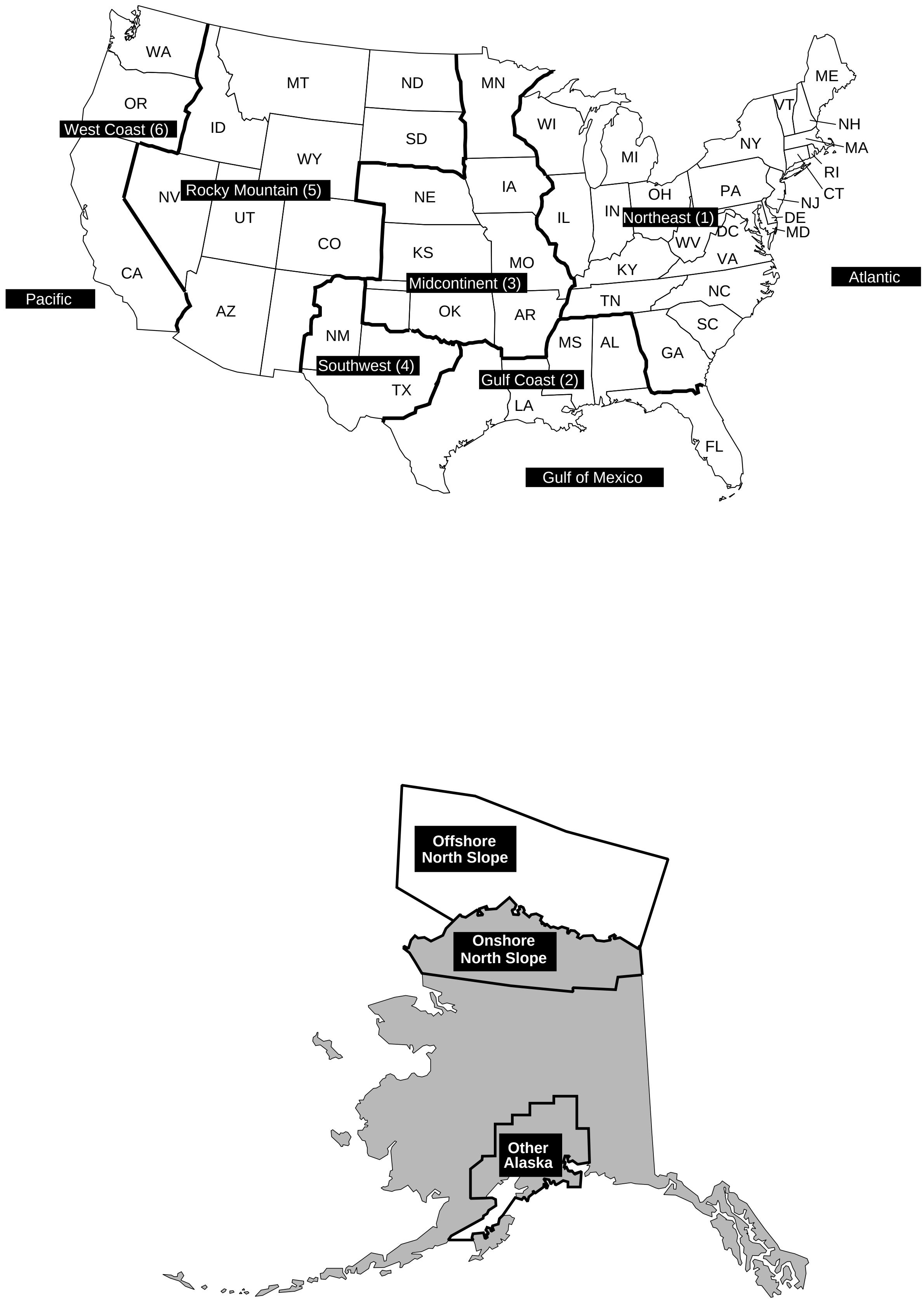
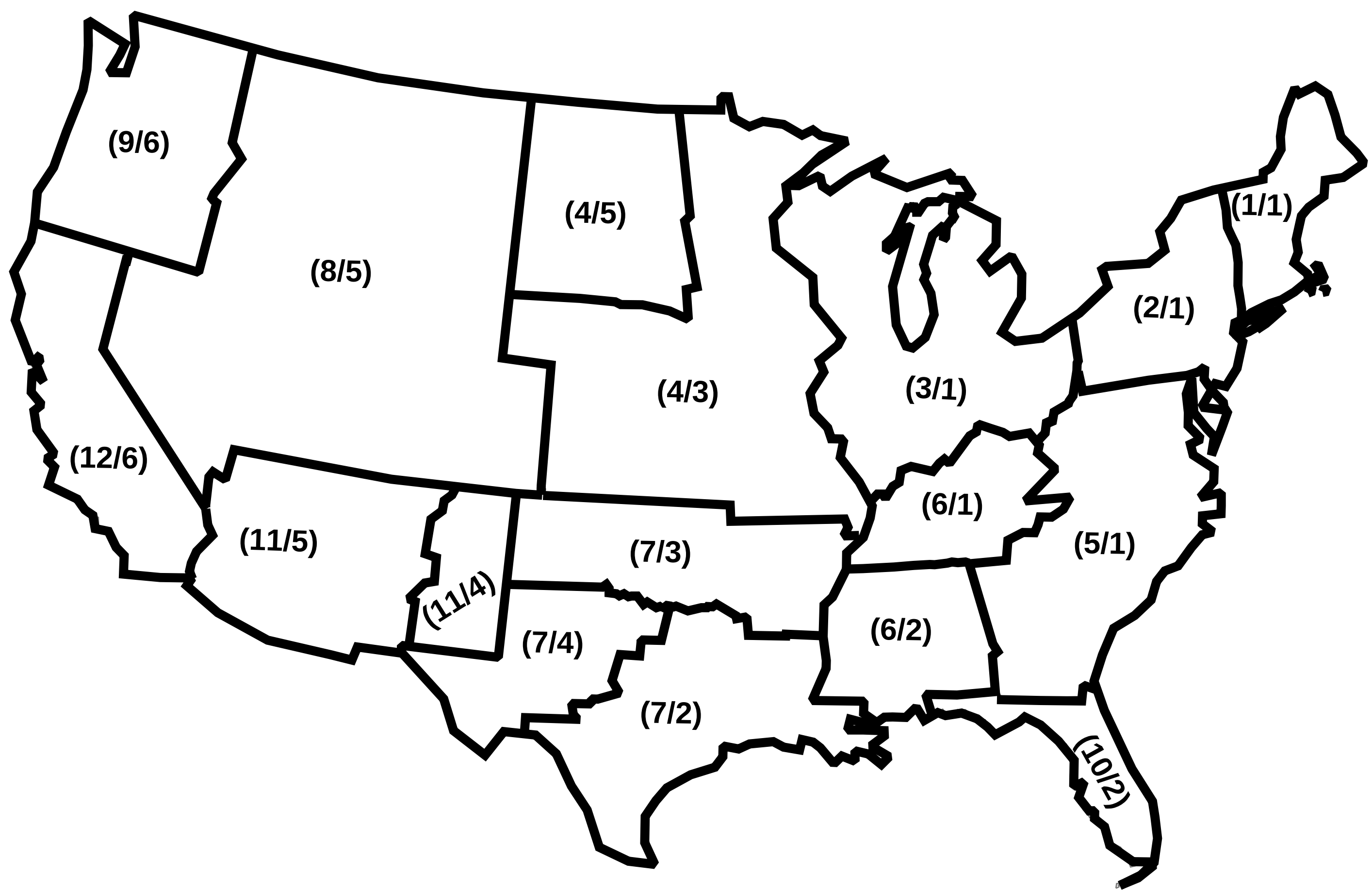
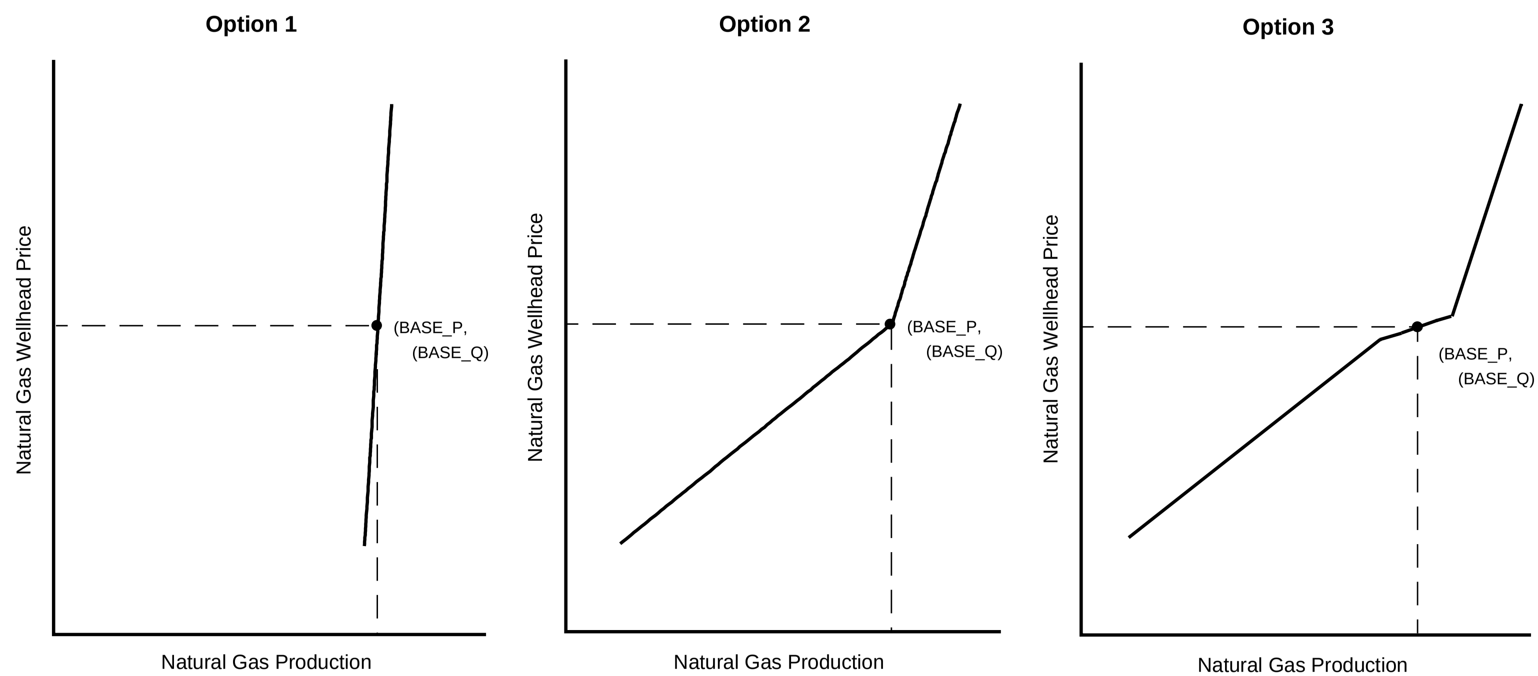


Figure 3-6. Natural Gas Transmission and Distribution Model/Oil and Gas Supply Model (NGTDM/OGSM) Regions



(NGTDM Region Number/OGSM Region Number)

Figure 3-7. Nonassociated Natural Gas Supply Curve Options



4. Overview of Solution Methodology

The previous chapter described the function of the NGTDM within the NEMS. This chapter will present the methodologies used to represent the natural gas transmission and distribution industries, as well as an overview of the NGTDM model structure and solution methodologies. 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 4-1)

Figure 4-1. Natural Gas Transmission and Distribution Network

simulates the interregional flow of gas in the contiguous United States. 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. 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.[24] Bidirectional flows can also be the result of directional flow shifts within a single pipeline system due to seasonal variations in flows.

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).

[24]Historically, one out of each pair of bidirectional arcs in Figure 4-1 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, 11 to 7, 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. Minimum flows constraints are established for these arcs at historically observed flow levels.

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Figure 4-2. Transshipment Node

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 utility, and transportation), including separate arcs to each electric utility subregion. Arcs are also established from nodes at the international borders to represent exports. Each transshipment node has one or more arcs flowing in from each supply source represented. These supply points may represent onshore or offshore production, liquefied natural gas imports, synthetic natural gas production, gas produced in Alaska and transported via the Alaska Natural Gas Transportation System, or Canadian or Mexican imports in the region. In addition, each onshore supply region also includes any synthetic natural gas produced from coal, as well as other supplemental supplies. Finally, annual underground storage injections and withdrawals (as determined within the Capacity Expansion Module) are accounted for at each transshipment node.

Once all of the types of end-use destinations and supply sources are defined for 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, the transshipment nodes at the Canadian border may only have Canadian supply defined going into the node. Additionally, 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 4-1. 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 3-4 and 3-7 in Chapter 3)

Table 4-1. 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)	P(2/1)
3	R, C, I, T, U(3/1), U(3/4)	P(3/1), SNG
4	R, C, I, T, U(4/5), U(4/10)	P(4/3), P(4/5)
5	R, C, I, T, U(5/1), U(5/3), U(5/9)	P(5/1), LNG Cove Pt Maryland, LNG Elba Island Georgia, Atlantic Offshore
6	R, C, I, T, U(6/1), U(6/9)	P(6/1), P(6/2)
7	R, C, I, T, U(7/2), U(7/10)	P(7/2), P(7/3), P(7/4), LNG Lake Charles Louisiana, Offshore Louisiana, Gulf of Mexico
8	R, C, I, T, U(8/11), U(8/12)	P(8/5)
9	R, C, I, T, U(9/11)	P(9/6)
10	R, C, I, T, U(10/8)	P(10/2)
11	R, C, I, T, U(11/12)	P(11/4), P(11/5)
12	R, C, I, T, U(12/13)	P(12/6), Pacific Offshore
13	Canadian Exports	Canadian Imports
14	Canadian Exports	Canadian Imports
15	Canadian Exports	Canadian Imports
16	Canadian Exports	Canadian Imports
17	Canadian Exports	Canadian Imports
18	Canadian Exports	Canadian Imports, Alaskan Supply
19	Mexican Exports	Mexican Imports
20	Mexican Exports	Mexican Imports
21	Mexican Exports	Mexican Imports

R - Residential demand; C - Commercial demand; I - Industrial demand; T - Transportation demand
U(n1/n2) - Electric Utility demand in NGTDM/EMM region (n1/n2) as shown in Figure 3-3
P(n1/n2) - Production in NGTDM/OGSM region (n1/n2) as shown in Figure 3-6
SNG - Synthetic Natural Gas from liquid hydrocarbons
LNG - Liquified Natural Gas

.

As described in earlier chapters, there are significant differences in market structure and dynamics between the firm and interruptible service markets. The basic network structure separately represents the flow of gas within the firm and interruptible transmission service markets within the Annual Flow Module. Conceptually this can be thought of as two parallel networks, with three areas of overlap. First, the interruptible and firm market flows along each arc are interrelated and their sum is constrained to the pipeline capacity available along the arc. Second, the firm and interruptible service networks share common supply sources. At each supply source there is a single price regardless of whether the supplies are used to meet firm service demand or interruptible service demand (or both), because it is assumed that the supply component of the market will remain fully competitive. Third, the quantity of net injections into underground storage in the interruptible market is equal to the net withdrawals from storage within the firm market in the same region. The actual levels of underground storage injections and withdrawals associated with the firm and interruptible service markets are determined within the Capacity Expansion Module (since it contains a seasonal representation) and used within the Annual Flow Module.

Specifications of a Network Arc

Each arc of the network has parameters (inputs) and model variables (outputs) associated with it (Figure 4-3)

Figure 4-3. Network Parameters and Variables

. The parameters that define an arc are the pipeline direction, available capacity, the tariffs, the percentage of gas which travels on the arc that is lost or used (in power compressor stations) along the way, and a mileage indicator. In the case of bidirectional arcs, the arc with the lower flow rate is identified as a "bidirectional" arc for special handling.

Once a model solution has been reached (i.e., the quantity of the natural gas flow along each interregional arc is determined), pipeline fuel use associated with interregional transfers (from transshipment node to transshipment node) can be computed for each arc by multiplying the percentage loss of gas (given by the efficiency parameter) by the flow along the arc. In turn, the emissions (carbon, carbon monoxide, carbon dioxide, sulfur oxides, nitrogen oxides, volatile organic compounds, and methane) associated with the consumption of pipeline fuel can be estimated. (Details are given in Chapter 5.)

For the firm market the pipeline tariff (indicated as "TAR" in subsequent equations) represents two parameters: a usage fee and the revenue the pipeline is collecting from customers who have reserved capacity on the pipeline. Since the NGTDM does not explicitly represent the capacity reserved on a pipeline, this revenue is allocated over the amount of gas that is expected to flow on the arc rather than the amount of space reserved. Therefore, the reservation fee (the per-unit fee for reserving capacity on a pipeline) is not explicitly calculated. It is instead approximated as the total revenue from reservation fees divided by the amount of gas expected to flow. Thus, the total pipeline tariff for the firm market is the sum of the usage fee and this approximation of the reservation fee. For the interruptible market, the tariff parameter is simply a per-unit usage fee (as specified by the Pipeline Tariff Module). It is not necessary for the firm and interruptible usage fees to be equal.

For the arcs from the transshipment nodes to the end-use sectors, the parameters defined are capacities, tariffs, and percentage of gas used in compressor stations. The tariffs represent the sum of several charges or adjustments, including interstate pipeline tariffs in the region, intrastate pipeline tariffs, and distributor markups when applicable. The model variable associated with each of these arcs is the flow along the arc, which is equal to the amount of demand satisfied plus gas consumed in compressor stations. For arcs from supply points to transshipment nodes, the parameters are again capacities, tariffs, and compressor station usage. In this case the tariffs represent gathering charges. Although capacity limits can be set for the arcs to and from end-use and supply arcs, respectively, the current version of the model does not impose such limits on the flows along these arcs.

In an effort to represent potential interruptions in service to the interruptible market, a "relief valve" was put in the system. The interruptible market has the option of meeting all of the interruptible demand requirements through a highly priced "backstop" supply source, which is made directly available at the end-user nodes. Backstop supply is designed to be used only in the event that pipeline capacity (existing plus capacity to be built for the firm service market) is not sufficient to meet the interruptible demand requirements. Backstop supply displaces demand for interruptible service which would be expected not to materialize in the Annual Flow Module due to fuel switching or generally lower consumption levels in response to higher gas prices. The incorporation of backstop supply is a modeling tool and is not intended to represent a real supply source.

Note that any of the above parameters, supplies, or demands may be set equal to 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 2010. 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 four components or modules, the Capacity Expansion Module and the Pipeline Tariff Module are executed only once per forecast year. The Annual Flow Module and the Distributor Tariff Module are executed every iteration of each forecast year. A process diagram of the NGTDM is provided in Figure 4-4,

Figure 4-4. NGTDM Process Diagram

showing the general calling sequence.

The primary function of the Capacity Expansion Module is to forecast interregional pipeline and underground storage expansions and basic seasonal load profiles. Using this information from the Capacity Expansion Module and other data, the Pipeline Tariff Module uses an accounting process to derive interregional and intraregional pipeline tariffs for firm and interruptible transmission service to be used in the Annual Flow Module and the Capacity Expansion Module. The Distributor Tariff Module provides distributor tariffs for use in the Annual Flow Module and the Capacity Expansion Module. The Distributor Tariff Module must be called each iteration because some of the distributor tariffs are based on alternate fuel prices (e.g., residual fuel oil) which may change from iteration to iteration. Finally, using the information provided by other NGTDM modules and other NEMS models, the Annual Flow Module solves for natural gas prices and quantities which reflect a market in equilibrium for the current forecast year. A brief summary of each of the NGTDM modules follows.

The Annual Flow Module

The Annual Flow Module (AFM) is considered the central module within the NGTDM, with the Capacity Expansion Module, Pipeline Tariff Module, and Distributor Tariff Module (in addition to other NEMS models) providing it with critical information. Its objective is to determine the market equilibrium associated with natural gas supplies, demands, and transportation costs, thereby generating supply and end-use prices and production levels for use by other NEMS models. Formulated as a linear program, the AFM determines a market equilibrium by maximizing the sum of consumer and producer surplus, while minimizing transmission and distribution charges, subject to system constraints. As the name indicates, it has been designed to represent annual flows (as opposed to seasonal) from supply points to demand points traveling along a pipeline network. As defined above, the network in the AFM represents firm and interruptible markets separately along parallel networks, connected only at the supply points and through capacity constraints along the network arcs.

To accomplish its goal, the AFM uses regional price curves to represent regional supplies and demands. These curves represent linear approximations of the price response that can be expected from the more detailed NEMS models that provide the parameters used to build the curves. Each year the Oil and Gas Supply Model provides the parameters to build the supply curves, and each iteration the demand models provide the parameters to build the demand curves.

The Capacity Expansion Module, Pipeline Tariff Module, and Distributor Tariff Module also provide data required by the AFM. The Capacity Expansion Module provides pipeline capacity additions, pipeline utilizations for firm flows and total flows, and net storage withdrawal levels for firm and interruptible markets. The Pipeline Tariff

Module calculates interregional and intraregional pipeline tariffs for both firm and interruptible service. Similarly, the Distributor Tariff Module provides the AFM with markups for local distribution and intrastate transportation services.

The AFM also provides data to two of the other three NGTDM modules. It provides the Pipeline Tariff Module and the Capacity Expansion Module with annual firm flow results. The Capacity Expansion Module uses these flows to estimate minimum flows for its capacity expansion forecasts and the Pipeline Tariff Module uses them to convert the reservation costs for firm service into unitized tariffs. The AFM also provides the Pipeline Tariff Module with realized tariffs (see Chapter 5) along each arc in the network providing interruptible service.

The Capacity Expansion Module

The Capacity Expansion Module (CEM) is the only module in the NGTDM that includes a seasonal representation of the natural gas market. In each NEMS forecast year, the CEM determines incremental pipeline and storage capacity required to satisfy expected firm service demands in a future year based on an analysis of the expected supply, storage, and transportation requirements. The peak and off-peak seasons are analyzed, concurrently within the CEM, to determine pipeline and storage capacity needs. The storage decision affects the need for pipeline capacity upstream and influences the relative utilization of the pipeline between the peak and off-peak seasons. A brief description of the seasonal network used in the CEM is presented next, followed by an overview of the model solution methodology.

Seasonal Network Representation in the Capacity Expansion Module

The basic network structure defined for the CEM is nearly identical to the general NGTDM network described above, with the exception that a two-period (peak and off-peak) representation of the annual market is now being modeled. The "peak period" is defined as the months in the year with distinctly higher levels of natural gas consumption on a national basis.[25] As in the Annual Flow Module, interregional flows to satisfy firm transmission service are handled separately from the flows to satisfy interruptible service, both in the peak and off-peak periods.

Structurally the Capacity Expansion Module consists of four parallel networks. Each network represents the flow of gas either during the peak period under firm service, the off-peak period under firm service, the peak period under interruptible service, or the off-peak period under interruptible service. Interaction between the two periods occurs primarily through the use of storage. Arcs are established from each off-peak firm and interruptible transshipment node to the storage point in the region to represent storage injections. Likewise, arcs are established from each storage point into the associated transshipment nodes in both the firm and interruptible peak period networks. These arcs represent storage withdrawals in the peak period to satisfy firm or interruptible demand. An additional link between the two periods occurs due to the existence of annual supply sources as opposed to separate peak and off-peak supply. Thus, supply from each supply source in a region is available to both the peak and off-peak transshipment node in the region, and arcs are established to allow these flows. An illustration of the two-period network is shown in Figure 4-5

[25]The data inputs to the Capacity Expansion Module define the months designated as peak versus offpeak. Currently the data in the Capacity Expansion Module reflect a peak period from December through April. Due to a lag in the reporting of monthly consumption data, November falsely appears to be a "nonpeak" month. This should be corrected in the future once a method is developed for generating adjusted monthly consumption data.

Figure 4-5. Example Two-Period Network for a base network with three transhipment nodes. For simplicity, the example does not show the further disaggregation of the network into its firm and interruptible components.

Overview of the CEM Solution Methodology

The functional requirement for the CEM is to make natural gas pipeline and storage capacity expansion decisions and to estimate corresponding pipeline and storage utilization levels based on assumptions similar to those used by the natural gas industry. The CEM has been designed as a seasonal natural gas transportation model, with storage serving as a link between supplies and seasonal demands. As with the Annual Flow Module, both firm and interruptible services are also represented. Formulated as a linear program, the objective is to minimize production and transportation costs, as well as costs associated with pipeline and storage expansion decisions. Although the basic network structure, its parameters (inputs), and its model variables (outputs) have been designed to be similar to that in the Annual Flow Module, some elements had to be defined as seasonal.

The CEM is executed within the NGTDM once at the end of each forecast year to determine the pipeline and storage expansion which will come on line "n" years in the future. Capacity is expanded to meet firm transmission service demands[26] that are expected to occur in that year. The parameter "n" represents the average number of years in which the decision to expand capacity cannot be reversed due to contractual obligations. The results generated by the CEM during the current forecast year do not affect the current forecast year's market solution, but are used in the Annual Flow Module and the Pipeline Tariff Module when the NGTDM determines a natural gas market equilibrium solution for the n^{th} year in the future.

The data inputs for the CEM from the NEMS system include macroeconomic parameters from the Macroeconomic Activity Model of NEMS, as well as expected values for natural gas consumption levels in future years. The NEMS Integration Routine provides the CEM with estimates of future consumption levels for nonutility natural gas, while the Electricity Market Model estimates future electric utility consumption based on existing and planned electricity generation plant capacities. Parameters are provided by the Oil and Gas Supply Model to the CEM for estimating potential future supply levels. In addition, minimum interregional firm service flow constraints (based on Annual Flow Module solution values in the previous forecast year) are set in the CEM to represent the inertia of firm service customers from annually switching pipeline routes used in transporting their natural gas (e.g., due to long-term contract commitments).

The CEM uses the same regions and end-use sectors defined within the Annual Flow Module. However, the Annual Flow Module is an annual model; whereas, the CEM requires a seasonal analysis to represent more accurately the decision to expand pipeline and/or storage capacity to meet peak-day firm service demands. The CEM includes a methodology for converting from annual to seasonal (peak and off-peak) consumption levels, as well as a means for capturing firm peak-day requirements in the capacity expansion decision. The factors for estimating seasonal load patterns are historically based model inputs which are held constant throughout the forecast in the current model. Future model enhancements may allow for the representation of structural changes in seasonal consumption patterns (e.g., demand side management, changing building structures, and/or technological innovations).

Dry gas production is represented in the CEM with a price responsive equation (or curve) developed from inputs from the Oil and Gas Supply Model. Although the supply representation within the CEM reflects annual levels, the formulation allows for upper bounds to be set on the level of supply available within the peak or off-peak period from each supply source (formulated as the annual supply times the percentage of the year represented by the given period). Furthermore, the seasonal variation in wellhead prices is accounted for by including a positive adjustment "tariff" on the arcs connecting a supply source to the peak period network and a negative adjustment factor on the arcs to the offpeak period network.

The foreign natural gas module of the Oil and Gas Supply Model sets pipeline capacity limits on the pipelines that cross the Canadian border at the six border crossings specified in the Annual Flow Module. These capacities are used to establish capacity expansion requirements for the connecting pipe on the U.S. side of the border, and as a basis for setting the potential flow of gas across the border within the CEM.

Storage is used to satisfy peak season consumption by injecting gas into storage in the off-peak period and withdrawing the gas during the peak season. Thus, storage is considered a supply source in the peak period, and a demand requirement in the off-peak period. This limits the amount of off-peak capacity that is available on an interruptible basis for consumption in the period.

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[26]Note: Because the process of establishing new contracts for firm service is complex, local distribution companies (the primary firm service customers) commit to firm service contracts on approximately 3-year planning cycles, based on expected demands over the time period covered. Therefore, the CEM planning horizon ensures that adequate capacity is available for local distribution company customers over a three-year planning horizon beyond the year the capacity will come online.

The Pipeline Tariff Module provides interregional pipeline tariffs and storage charges associated with existing and incremental expansion of regional pipeline and storage facilities. This information is sent to the CEM in the form of storage and pipeline "capacity supply curves." These "capacity supply curves" are based on exogenously specified capital cost curves for expansion and on macroeconomic parameters from the NEMS Macroeconomic Activity Model.

If the CEM determines that pipeline (or storage) capacity will be added, the Pipeline Tariff Module will in turn adjust the associated revenue requirements (and resulting tariff parameters) for the year in which the new capacity is scheduled to come on-line to account for the expansion costs. In addition, the pipeline capacities and seasonal utilization patterns established in the CEM are used in defining maximum annual interregional flow constraints in the Annual Flow Module, reflecting the impact of the variation in seasonal demand on pipeline loads. The available storage capacity is used as a basis for setting storage injections and withdrawals in the Annual Flow Module. The Pipeline Tariff Module also uses the levels of storage and pipeline capacity expansion established in the CEM when determining the associated capital expenditures (an input to the Macroeconomic Activity Model of the NEMS).

The Pipeline Tariff Module

The Pipeline Tariff Module (PTM) is executed within the NGTDM once each forecast year to calculate pipeline and storage tariffs for the Annual Flow Module and the Capacity Expansion Module. The tariffs calculated within the PTM are computed for individual pipeline companies and are then aggregated as required. An accounting system is used to track costs and compute rates under various rate design and regulatory scenarios. Tariffs are computed for both storage and firm and interruptible transportation services. Transportation tariffs are computed for interregional arcs defined by the NGTDM network. These network tariffs represent an aggregation of the tariffs for individual pipeline companies supplying the network arc. Storage tariffs are defined at regional NGTDM network transhipment nodes, and likewise, represent an aggregation of individual storage company tariffs. These tariffs are for transmission services only and do not include the price of gas.

More specifically, the PTM computes (1) reservation costs assigned to firm transportation service customers, (2) usage fees for firm transportation service, (3) minimum transportation rate for interruptible service, (4) maximum transportation rate for interruptible service, and (5) rates for storage service. For fully regulated services, cost-of-service based revenue requirements are computed by the PTM and are used within the Annual Flow Module to price transportation services. Where markets are competitive or are loosely regulated (i.e., interruptible transportation), the Annual Flow Module uses a marginal pricing structure which incorporates maximum and minimum rates for service, set by the PTM in determining the actual rate charged. The resulting rate should be within the bounds of the minimum and maximum rates computed by the PTM.[27]

The impacts of the capacity expansion decisions made in the Capacity Expansion Module are reflected in the pipeline tariffs computed by the PTM. The Capacity Expansion Module determines the location and quantities of additional pipeline capacity and storage facilities at the aggregate level represented by the NGTDM network. Interregional pipeline or regional annual storage capacity expansion requirements are passed by the Capacity Expansion Module to the PTM. Also, since capacity expansion decisions need to take into account the marginal changes in pipeline tariffs in response to increased capital requirements, the PTM initially establishes tariffs (reservation fee) associated with a series of incremental expansions. Many of the calculations of components of the revenue requirements require the use of macroeconomic variables that are provided by the NEMS Macroeconomic Activity Model.

The Distributor Tariff Module

[27]The NGTDM compares the effective tariff (i.e., the difference between the price at two adjoining nodes) to ascertain if the limit was violated. Currently the model does not have a correcting mechanism if the constraint is violated and simply reports the occurrence in a report. A more proper response mechanism will be employed in subsequent versions of the model.

The Distributor Tariff Module (DTM) determines markups for distribution and intrastate transportation services provided by local distribution companies and intrastate pipeline companies. Empirically derived or value-of-service estimated volumetric charges are determined by the DTM and are used within the Annual Flow Module as markups for local distribution and intrastate transportation services. The markups represent an incremental charge added by local distribution companies and intrastate pipeline companies and passed to the end user. The markups are determined for distribution arcs from each NGTDM transshipment node to each end-use sector. For interruptible service customers in the Annual Flow Module, these markups are generally reevaluated once the linear program has solved.

Depending on the end-use sector, the markups either represent historical data or the value of service as determined from alternative fuel prices. Historical data are used to develop markups to firm gas markets while value of service (or alternative fuel prices) are used to develop markups for the transportation sector and for interruptible service. Since alternative fuel prices are used as a basis for estimating interruptible markups, the DTM is executed during each NGTDM iteration so that these markups more accurately reflect the actual alternative fuel prices. For the electric utility sector, markups are computed for the three classes of customers in each NGTDM/EMM region.

Figure 4-1. Natural Gas Transmission and Distribution Model Network

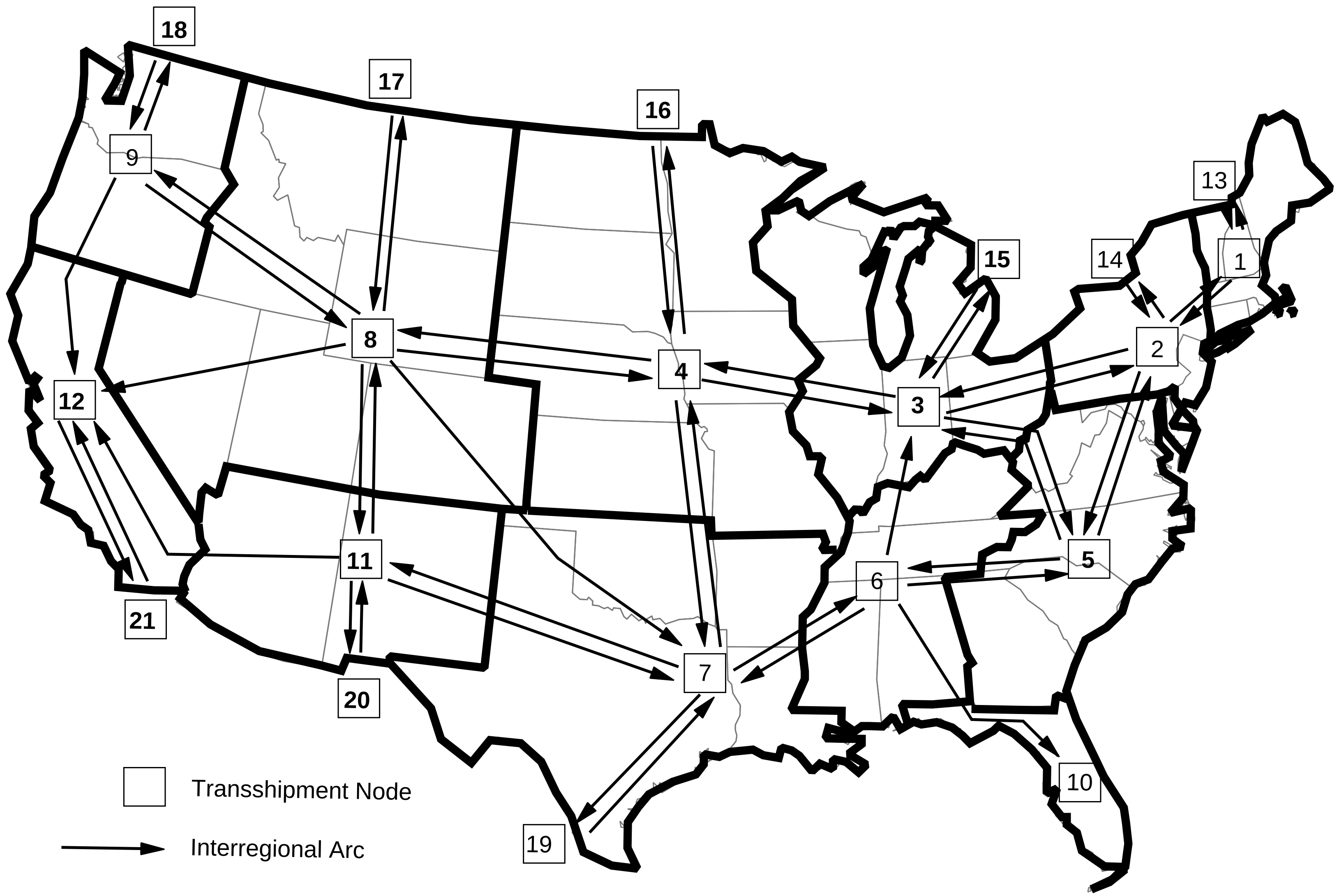
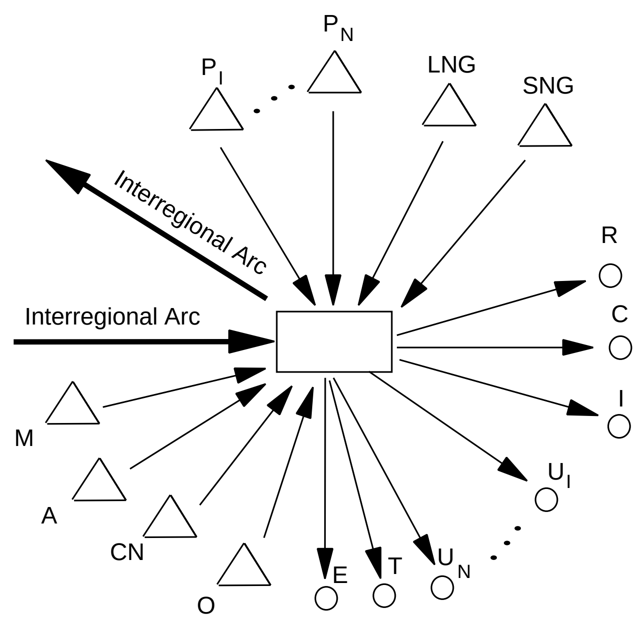


Figure 4-2. Transshipment Node



- Transshipment Node

- Supply Point

- Demand Point

P_i	-	Production in NGTDM/OGSM Region i
LNG	-	Liquefied Natural Gas
SNG	-	Synthetic Natural Gas
O	-	Offshore Supplies
CN	-	Canadian Supplies
A	-	Alaskan Supplies
M	-	Mexican Supplies
R	-	Residential Demand
C	-	Commercial Demand
I	-	Industrial Demand
U_i	-	Electric Utility Demand in NGTDM/EMM Region i
T	-	Transportation Demand
E	-	Exports

Figure 4-3. Network Parameters and Variables

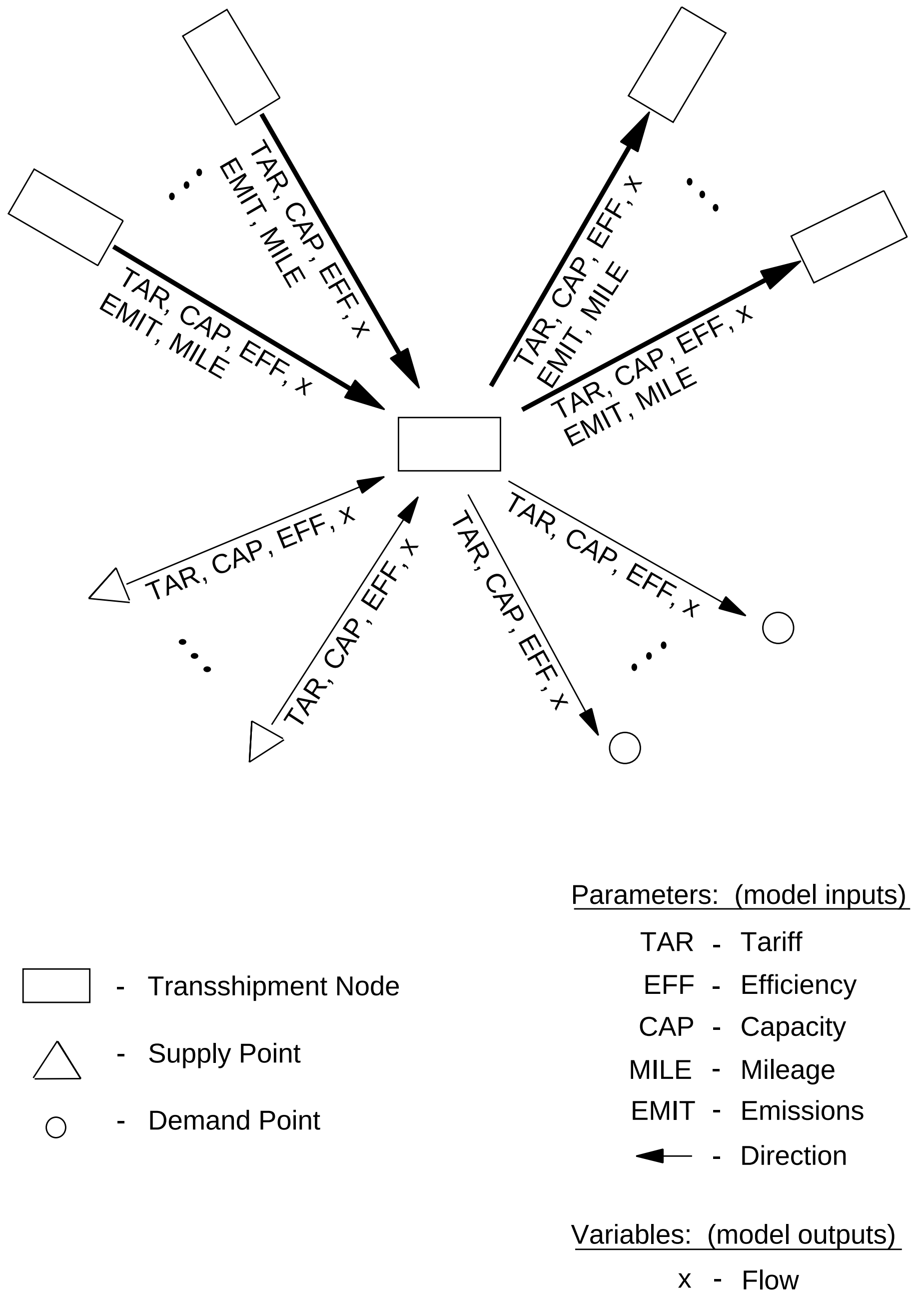


Figure 4-4. NGTDM Process Diagram

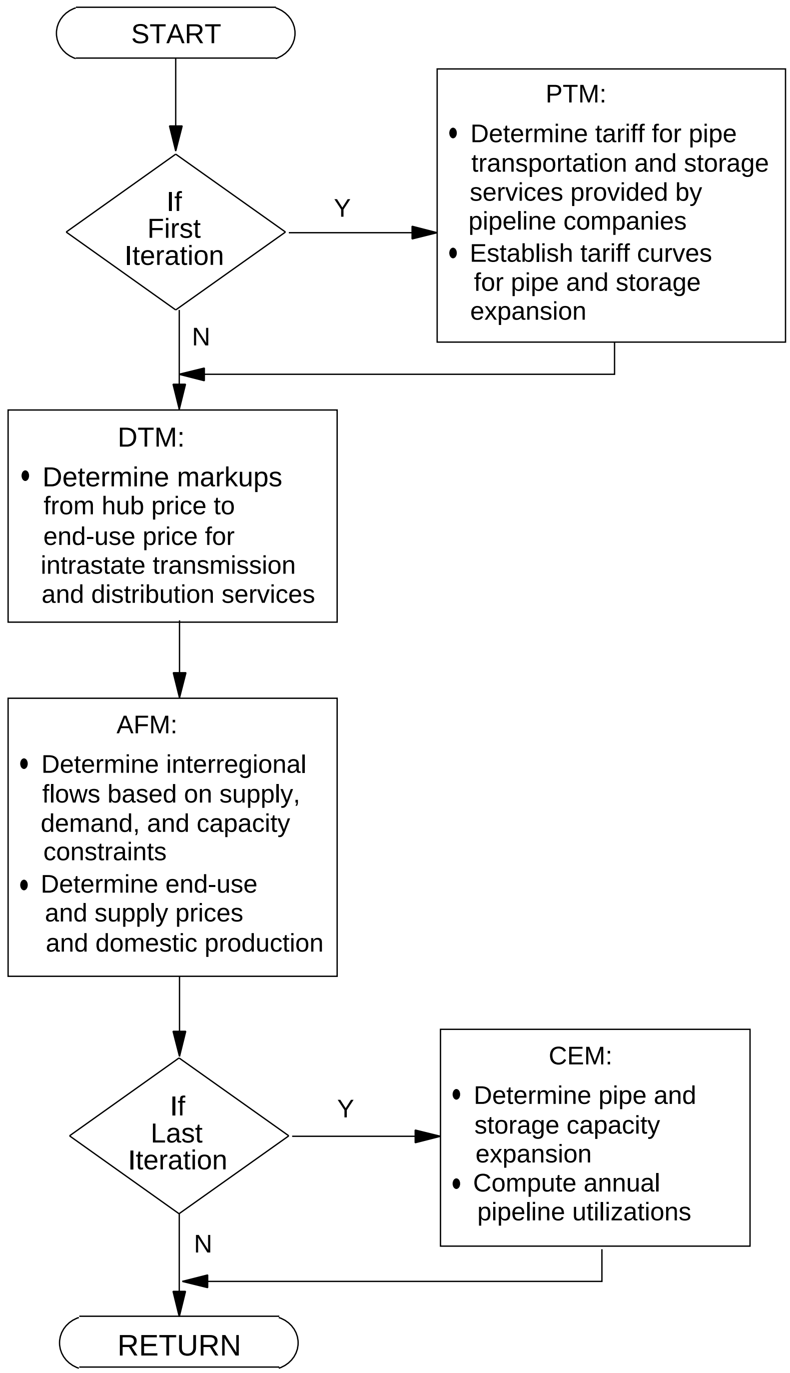
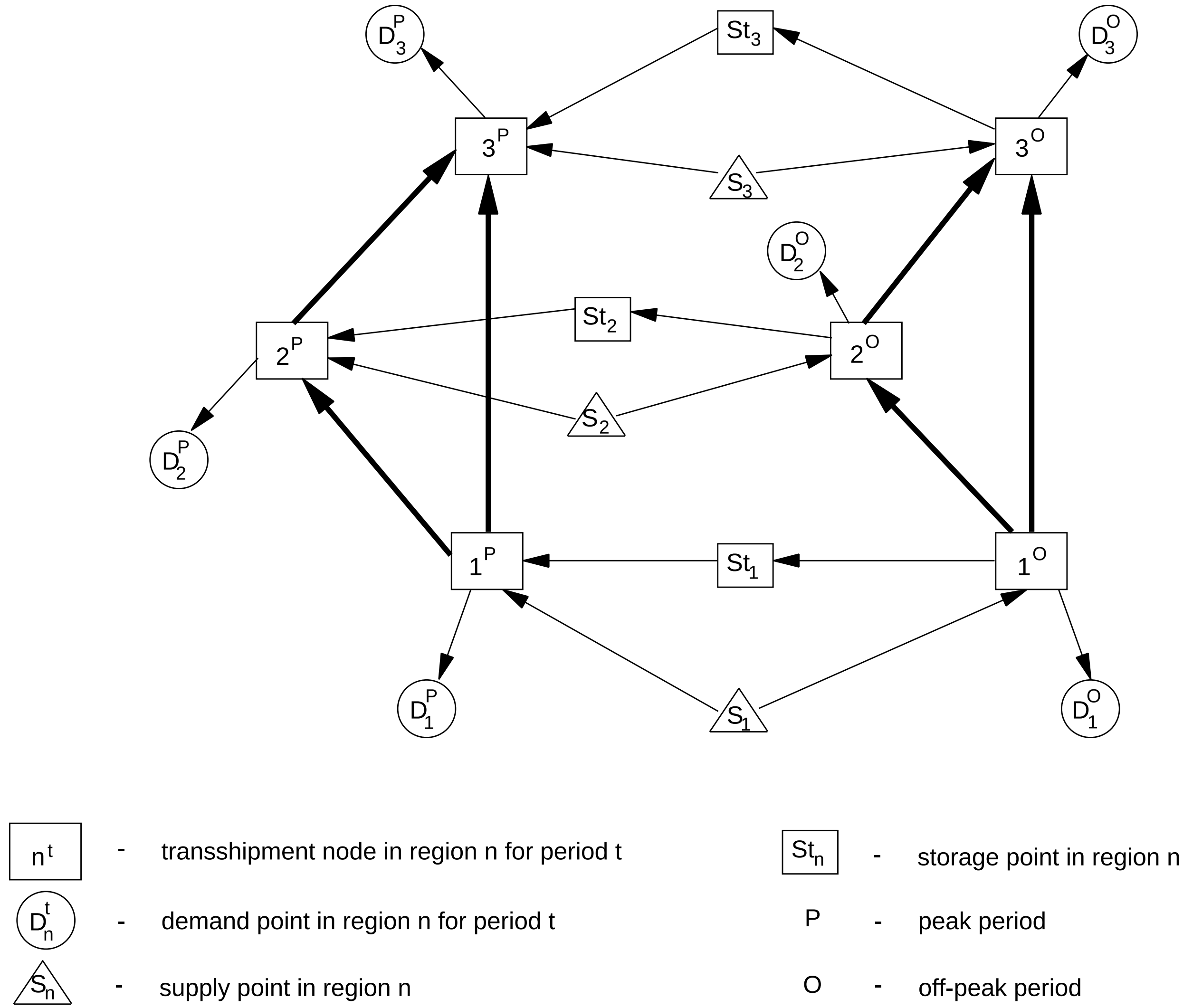


Figure 4-5. **Example Two-Period Network**



5. Annual Flow Module Solution Methodology

As a key component in the NGTDM, the Annual Flow Module (AFM) determines the market equilibrium between supply and demand of natural gas. 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 limitations, and mass balances. Structurally, the AFM consists of a network of regions connected by a parallel system of pipelines designed to service two types of customers, firm and interruptible. Supplies are defined as total regional supplies available to both parallel networks, while demands are defined separately as firm or interruptible regional demands. Because of the characteristics of these two markets, pipeline tariffs are rated differently along the same arc. To achieve market equilibrium, the AFM has been formulated as a linear program which maximizes consumer plus producer surpluses.[28] Supply and demand prices and quantities, as well as resulting flow patterns, are obtained from the linear programming solution and sent to other NGTDM modules or other NEMS models. A simple system diagram of the information flowing to and from the AFM is presented in Figure 5-1

[28]Adapted from the Project Independence Evaluation System (PIES) model.

Figure 1 Annual Flow Module System Diagram

. A brief explanation of how supplies and demands are represented in the AFM, how the linear program has been formulated for the AFM, and how the AFM results are processed for the other NGTDM modules and NEMS models is presented below.

Network Characteristics in the AFM

As described earlier, the AFM network consists of two parallel networks (firm and interruptible service), each containing 12 regions (or nodes), 6 Canadian border crossing nodes, and 3 Mexican border crossing nodes. Net storage withdrawals are represented at 10 of the 12 regional nodes for both firm and interruptible services. Arcs connecting the nodes are characterized by pipeline efficiencies, pipeline tariffs, minimum flows, and maximum utilizations. The efficiencies are exogenously defined (Appendix F, Table F19) and represent reduction in flows due to pipeline fuel consumption. Pipeline tariffs (defined in the Pipeline Tariff Module) represent fees for moving gas along pipelines. Pipeline tariffs in the firm market include reservation and usage fees while pipeline tariffs in the interruptible market are composed solely of usage fees. Minimum flows are defined for each arc in order to maintain continuity in flows from one model year to the next. Maximum pipeline utilizations (defined in the Capacity Expansion Module) are defined to maintain consistency between capacity expansion decisions and flow patterns. Finally, a designated percentage of the pipeline capacity is not allowed to be used, to represent the capacity that would not be released, and is held as a safety margin under normal weather conditions (Appendix F, Table F41).

Supply and Demand Representations

Supply and demand are represented as price curves in each region in the AFM network. These curves represent estimates of short term responses that can be expected from the NEMS models that provide the AFM with regional supply and demand levels. Demand is defined separately for firm and interruptible service, while supply is defined as total supply available (in most cases) to either network. The supply and demand types are addressed below.

Supply in the AFM includes production sources (onshore, offshore, and Alaska), imports (Canadian and Mexican by pipeline, and as liquefied natural gas), synthetic natural gas (from liquids and coal), and other supplemental supply. Of these, the liquefied natural gas, Mexican imports, Alaska production, and other supplemental supply categories are considered to be constant (or fixed). Supplies with fixed levels are assumed to be available only to the firm network, while supplies with variable levels are available to either network.

Some supply quantities are provided directly by the Oil and Gas Supply Model and/or other NEMS models, while others are determined within the NGTDM, as described in Chapter 4. Onshore and offshore production and Canadian imports are determined within the NGTDM based on parameters provided by the Oil and Gas Supply Model, whereas the Oil Gas Supply Model establishes the level of natural gas flowing into the contiguous United States via the Alaskan Natural Gas Transportation System (ANGTS), as well as the liquefied natural gas quantities imported through the four gasification terminals modeled by the NGTDM. Synthetic natural gas from liquids in Illinois is determined by the NGTDM (as a function of the associated region's market price), with synthetic natural gas from Hawaii held constant throughout the forecast. Natural gas from coal in North Dakota is provided by the Coal Market Model. Finally, other supplemental supplies are set to historical levels by the NGTDM and held constant throughout the forecast. Table 4-1 provides more detail on the regional representation of natural gas supply in the NGTDM.

Another type of supply (or pseudo supply) available is backstop supply; however, it is undesirable for the system to use this supply source. Backstop supply is designed to be used only if the system has insufficient supply or pipeline capacity to meet a minimum level of demand. If it is used, a high price is sent to the demand models which, in turn, are expected to respond by sending lower demand levels. It is priced high[29] in order to prevent it from becoming economically attractive.

Demand includes end-use sector demands as well as exports (Canadian and Mexican). As mentioned above, end-use sector demands are defined for both firm and interruptible services. Although demands for both types of service are represented by demand curves, firm demands are kept nearly constant while interruptible demands are allowed to vary more depending on sector type. Export demands are set exogenously in the Oil and Gas Supply Model and specified to be interruptible.

AFM Linear Program Formulation

A linear programming algorithm has been developed to determine the least cost approach to achieving an equilibrium between the supply and demand for natural gas in the AFM. Equilibrium occurs when the "price" at which consumers are willing to purchase a product is equal to the "price" at which producers together with transporters are willing to supply the product to the end-user. Economically, this is the point where the sum of consumers' surplus and producers' surplus is maximized.[30] The methodology employed in solving the natural gas supply and demand equilibrium assumes that marginal costs are the basis for determining market-clearing prices throughout the forecast period.[31] The problem is based on a transmission and distribution system composed of two parallel networks. These two networks serve as a means of distinguishing between firm and interruptible transmission and distribution services, and are interconnected only at supply points and through capacity constraints. This section defines the linear programming methodology used to establish a market equilibrium in the AFM, from which supply and end-use prices are obtained. First, the representation of consumer plus producer surplus used in the objective function is derived, then a general description of the entire formulation is presented, followed by the explicit mathematical equations.

Derivation of the Representation of Consumer and Producer Surplus

The objective of the linear program designed for the AFM is to determine a market equilibrium between the supply and demand of natural gas. As mentioned above, this occurs when the sum of consumers' surplus and producers' surplus has been maximized. Figure 5-2

[29]The backstop supply price is a user input, currently defaulted at $20.00 (1987$/MCF).

[30]Adapted from the Project Independence Evaluation System (PIES) model.

[31]Although marginal cost pricing is currently inconsistent with past and most current practices which use average cost pricing, a number of recent events point to a trend toward marginal pricing in the gas industry. How broadly and how rapidly marginal cost pricing is adopted throughout the natural gas industry is largely a function of implementation of recent FERC rulemaking, the level of activity in capacity release markets, and changes in State-level regulations.

Figure 2 Supply and Demand Curves

illustrates this sum as the area under the demand curve (A+B+C) minus the area under the supply curve (C) to the left of the point of market equilibrium (P,Q). This section describes the computation of the area under the supply and demand curves that are used in the objective function equation.

A method for determining the area under the demand curve is established by first representing the demand curves as step functions, as shown in Figure 5-3.

Figure 3 Approximation of Area Under the Demand Curve

A base quantity and price are given and n steps on either side of the base point are defined. Toward this end, let (QDEM0,PDEM0) represent a known point (the base point) on the curve and an estimate of where the model will solve. The parameters $UDEM_{-k}$ and $UDEM_k$ are defined as the incremental quantities represented by each step on the curve (i.e., the length of each step on the demand curve), and $PDEM_{-k}$ and $PDEM_k$ represent the corresponding actual prices. Note that the subscript k identifies the k^{th} step on the curve to the right of the point (QDEM0,PDEM0), and the subscript -k corresponds to the k^{th} step on the curve to the left of (QDEM0,PDEM0).

If ydem is defined as the total deviation from the base point, then introduce the set of model variables $ydem_k$ and $ydem_{-k}$ which are used to define ydem. Each variable represents a portion of the length of the specified step, such that:

$$0 \leq ydem_k \leq UDEM_k$$
$$0 \leq ydem_{-k} \leq UDEM_{-k}$$

and,

$$ydem = \sum_{k=1}^{n} ydem_k - \sum_{k=1}^{n} ydem_{-k} \tag{22}$$

In order for ydem to represent the distance either to the right or left of the initial point (QDEM0,PDEM0), the following conditions must hold. If ydem is greater than zero, then each $ydem_{-k}$ is at the lower bound of zero; and, if ydem is less than zero, then each $ydem_k$ is equal to zero. If ydem is equal to zero, then each $ydem_k$ and $ydem_{-k}$ is equal to zero, and the model solved at (QDEM0,PDEM0).

In short, the demand curve is represented as a step function by defining an initial point on the curve (PDEM0,QDEM0), n $ydem_k$ variables, n $ydem_{-k}$ variables, and the corresponding prices.

Given the above conditions for the relationship between $ydem_k$ and $ydem_{-k}$, the area under the demand curve is approximated by:

$$\sum_{k=1}^{n} (PDEM_k * ydem_k - PDEM_{-k} * ydem_{-k}) + C \tag{23}$$

where,

C	=	the area under the demand curve from 0 to QDEM0
$\Sigma\ PDEM_k * ydem_k$	=	the area under the demand curve from QDEM0 to step k
$\Sigma\ PDEM_{-k} * ydem_{-k}$	=	the area under the demand curve from step -k to QDEM0

Note that C is a constant since the demand curve and QDEM0 are given. The variable ydem represents the distance either to the right or left of the initial point (QDEM0,PDEM0), and the equation approximates the integral evaluated from zero to that point.

The area under the demand curve as calculated in the above equation is incorporated in the objective function of the linear program with some modifications. First, the model is formulated as a minimization problem requiring the signs of the coefficients on the equation representing the area under the demand curve to change. Second, since the inclusion of a constant in the objective function does not change the model solution, the C term is excluded from the objective function. As a result, the following term becomes a part of the objective function:

$$\sum_{k=1}^{n} (PDEM_{-k} * ydem_{-k} - PDEM_k * ydem_k) \tag{24}$$

When the area to the right of QDEM0 (ydem greater than zero)[32] is being calculated, the following properties must hold:

(1) At most one $ydem_k$ is not equal to zero or $UDEM_k$.

(2) If $ydem_k$ is not equal to one of its limits, then $ydem_j$, for all j less than k, is equal to its upper limit $UDEM_j$; and $ydem_j$, for all j greater than k, is equal to its lower limit of zero.

At optimality, the conditions listed above for ydem can be shown to hold.[33] If the optimal quantity satisfied is on step k of the demand curve, i.e., $ydem_k$ is not at either of its bounds, then $ydem_j$, for j less than k must be at its upper bound ($UDEM_j$), because it will always be more beneficial to bring in more of quantity $ydem_j$ than to bring in any of $ydem_k$ since the coefficient of $ydem_j$ is negative and $PDEM_j$ greater than $PDEM_k$. Similarly, $ydem_j$ for j greater than k will be zero because it will not be beneficial to bring in any of $ydem_j$ before bringing in all of $ydem_k$ since the coefficient of $ydem_j$ is negative and $PDEM_j$ is less than $PDEM_k$. Furthermore, $ydem_{-j}$ for all j will be zero because it will not be beneficial to bring in any of $ydem_{-j}$ since its coefficient is positive.

Likewise, if the optimal quantity satisfied corresponds to step -k (some quantity must be subtracted from the base demand), where $ydem_{-k}$ is not at either of its bounds, then $ydem_{-j}$, for j less than k, must be at its upper bound ($UDEM_{-j}$), because it will always be more beneficial to subtract more of quantity $ydem_{-j}$ than to subtract any $ydem_{-k}$, since the coefficient of $ydem_{-j}$ is positive and $PDEM_{-j}$ is less than $PDEM_{-k}$. Similarly, $ydem_{-j}$, for j greater than k, will be zero because it will not be beneficial to subtract any of $ydem_{-j}$ before subtracting all of $ydem_{-k}$, since the coefficient of $ydem_{-j}$ is positive and $PDEM_{-j}$ is greater than $PDEM_{-k}$. Furthermore, $ydem_j$ for all j will be zero even though the coefficient of $ydem_j$ is negative. This can be deduced by observing that if the quantity at $ydem_j$ were above zero, the increase in quantity would have to be negated by increasing $ydem_{-k}$, which has a higher price, thus causing the objective function to rise.

Supply Curves

As with the demand curves, the area under the supply curve can be estimated by first representing the supply curves as step functions and then summing the area under the steps on each curve. This is accomplished in a manner similar to the methodology used for demand curves; however, the base point (QSUP0,PSUP0) is assumed to be at QSUP0 equals zero. Thus, the ysup is represented only by $ysup_k$ and the supply term in the objective function becomes $\Sigma\ PSUP_k * ysup_k$.

General Description of the AFM Linear Program Formulation

The objective of the linear program designed for the AFM is to determine a market equilibrium between the supply and demand of natural gas. Since the network consists of multiple supply sources, multiple demand points, and transshipment arcs, transportation costs also must be included. Thus, system equilibrium will occur when the sum of <u>all</u> the consumers' surplus, <u>all</u> the producers' surplus, and <u>all</u> the transportation costs (negative) is maximized. After translating this into a cost minimization problem, the follow objective function results.

minimize { transportation costs - (Σ (consumer surplus) + Σ (producer surplus)) }

where,

Σ (consumer surplus) + Σ (producer surplus) =
(the area under the demand curve to the left of equilibrium)-
(the area under the supply curve to the left of equilibrium)

[32]The analogous properties hold for the left of QDEM0 (ydem less than zero).
[33]See page B-16 in the PIES model documentation for a complete description.

Capacity flow constraints are defined for each interregional arc in the overall network. Two types of constraints have been defined. One limits total annual flows along an arc and the other serves to limit annual firm service flows along the arc. The total flow constraint is an inequality constraint defined to ensure that total flow (firm plus interruptible) along an arc does not exceed the maximum allowable annual flow along the pipeline. The maximum allowable flow is defined as the maximum physical capacity (adjusted for normal weather representation) times the maximum total utilization (defined by the Capacity Expansion Module) for that arc. Similarly, the firm flow constraint is an inequality constraint defined to ensure that firm flow along an arc does not exceed the maximum allowable annual firm flow along the pipeline. The maximum allowable firm flow is defined as the maximum physical capacity (adjusted for normal weather representation) times the maximum firm utilization (defined by the Capacity Expansion Module) for that arc. The resulting constraints are given below for each interregional arc.

For each interregional arc i,j:

> (flow on the arc to satisfy the firm market) + (flow along an arc to satisfy the interruptible market) ≤ ((physical capacity on the arc) * (1 - weather adjustment factor for normal weather) * (annual capacity utilization factor for total flow))

> (flow on the arc to satisfy the firm market) ≤ ((physical capacity on the arc) * (1 - weather adjustment factor for normal weather) * (annual capacity utilization factor for firm flow))

A mass balance constraint exists for each transshipment node in each parallel network. These constraints ensure that the total input to a node equals the total output from the node (including net storage withdrawals). In general, gas flowing into a transshipment node comes from other transshipment nodes, supply points, and (in some cases) storage, while gas flowing from a transshipment node goes to demand points, other transshipment nodes, and (in some cases) storage. Storage flows in the AFM are assumed to be constant for a particular year (defined by the Capacity Expansion Module) and are represented as net withdrawals (i.e., natural gas flowing out of storage to a node minus natural gas flowing into storage from a node). Net withdrawals are defined separately for the firm and interruptible networks. A general transshipment node mass balance constraint is listed below for both networks.

For each firm service transshipment node i:

> (flow into a transshipment node from another firm service transshipment node) + (flow into a transshipment node from supply points in the region) + (net storage withdrawals corresponding to firm service) - (losses) = (flow out of the transshipment node to other firm service transshipment nodes) + (flow out of the transshipment node to firm service demand points in the region)

For each interruptible service transshipment node i:

> (flow into a transshipment node from another interruptible service transshipment node) + (flow into a transshipment node from supply points in the region) + (net storage withdrawals corresponding to interruptible service) - (losses) = (flow out of the transshipment node to other interruptible service transshipment nodes) + (flow out of the transshipment node to interruptible service demand points in the region)

A mass balance constraint also is included for each firm service and interruptible service demand point. This constraint ensures that the quantity allocated to an end-use point equals the quantity demanded at that point. Demands in the AFM can vary by region and are defined by demand cost curves. It is the linear approximations to these curves that are used to represent demands in the linear programming problem. Although these curves allow demands to drop to levels below base level demands in an effort to achieve a market equilibrium, supply or pipeline utilization limits may prevent some regional demands from being met. In order to prevent the linear program from going infeasible, a highly priced backstop supply is available at each demand point. If backstop supply is needed, high prices result and the other NEMS models will respond with lower demands. General transshipment node mass balance constraints are listed below for both parallel networks.

(flow out of a transshipment node to firm service demand points in the region) + (flow from a backstop supply point to firm service demand points in the region) - (losses) = (quantity consumed at that node for firm service)

(flow out of a transshipment node to interruptible service demand points in the region) + (flow from a backstop supply point to interruptible service demand points in the region) - (losses) = (quantity consumed at that node for interruptible service)

Each supply point also has a mass balance constraint represented. Since gas may flow from a supply point to a transshipment node (in the same region) in either the firm or interruptible network, this constraint ensures that the total quantity flowing from the supply point equals the amount supplied. The constraint states that total supply is equal to the portion of supply flowing to the firm network plus the portion of supply flowing to the interruptible network. The general constraint is presented below.

(quantity supplied from the supply curve) = (flow from the supply point to a transshipment node to satisfy the firm market) + (flow from the supply point to the transshipment node to satisfy the interruptible market)

Due to the nature of a linear program, an optimal solution will not allow flow to occur simultaneously on a primary arc from Region A to Region B and on its bidirectional arc from Region B to Region A because such a situation would incur higher transportation costs (as compared with a case where flows occur only in one direction and represent net flows). Since an arc in the network may represent an aggregation of some pipelines flowing one direction and other pipelines flowing the opposite direction, flows along bidirectional arcs need to be explicitly represented. This is accomplished by setting minimum flows along the bidirectional arcs in both the firm and interruptible networks equal to historically observed levels (Appendix F, Table F20). The general equations are present below.

(flow along the bidirectional arc to satisfy the firm market) ≥ (minimum firm flow requirement for the arc)

(flow along the bidirectional arc to satisfy the interruptible market) ≥ (minimum interruptible flow requirement for the arc)

Minimum levels are also needed for flows along primary arcs within the firm network. These minimum flows help to generate some continuity in flow patterns (which may not always occur in a linear programming environment) that are generally associated with firm contract demands. These minimum levels are a percentage (Appendix F, Table F32) of flows resulting from last year's solution,[34] and are defined as lower bounds on the flow variables. The general bound equation follows.

(flow along the primary arc to satisfy the firm market) ≥ (minimum firm flow requirement for the arc)

Nominal minimum flows are also defined for flows along primary arcs in the interruptible network. As with the firm network, the minimum flows are set equal to a percentage (Appendix F, Table F32) of the flows resulting from last year's solution, and are defined as lower bounds on the flow variables. This is represented in the following bound equation.

(flow along the primary arc to satisfy the interruptible market) ≥ (minimum interruptible flow requirement for the arc)

Finally, a number of bound constraints are needed to completely describe the step functions for the supply and demand curves. These bounds serve to define the lengths of each of the steps on the linearized curves.

[34]In the first forecast year, minimum flows are assigned as a percentage of historically derived flows for 1990 (Appendix F, Table F20).

Mathematical Specification of the AFM Linear Program Formulation

This section presents the set of equations which completely defines the linear programming formulation for the AFM. This set consists of an objective function, flow constraints, mass balance constraints, and bounds on model variables.

The objective function has been defined as the market equilibrium between natural gas supplies and demands, including relevant transportation costs and backstop supply. This has been translated into the following objective function equation.

$$
\begin{aligned}
\underset{x,ysup,ydem,qzz}{\text{minimize}}\ & \sum_{i,j} TAR^{F}_{i,j} * x^{F}_{i,j} + \sum_{i,j} TAR^{I}_{i,j} * x^{I}_{i,j} + \sum_{s,i} TAR^{F}_{s,i} * x^{F}_{s,i} + \sum_{s,i} TAR^{I}_{s,i} * x^{I}_{s,i} \\
& + \sum_{i,d} TAR^{F}_{i,d} * x^{F}_{i,d} + \sum_{i,d} TAR^{I}_{i,d} * x^{I}_{i,d} + \sum_{i,d} PZZ^{F}_{i,d} * qzz^{F}_{i,d} + \sum_{i,d} PZZ^{I}_{i,d} * qzz^{I}_{i,d} \\
& + \sum_{s,i} \sum_{k=1}^{c} (PSUP_{s,i,k} * ysup_{s,i,k}) \\
& - \sum_{i,d} \sum_{k=1}^{n} (PDEM^{F}_{i,d,k} * ydem^{F}_{i,d,k} - PDEM^{F}_{i,d,-k} * ydem^{F}_{i,d,-k}) \\
& - \sum_{i,d} \sum_{k=1}^{n} (PDEM^{I}_{i,d,k} * ydem^{I}_{i,d,k} - PDEM^{I}_{i,d,-k} * ydem^{I}_{i,d,-k})
\end{aligned} \tag{25}
$$

where,

the subscripted indices are:

i,j, and m	=	transshipment node
d	=	demand point
s	=	supply point
st	=	storage point
k	=	step on the curve
c	=	number of steps on the supply curve
n	=	number of steps represented to the left or right of the initial demand point (QDEM0,PDEM0)
i,j	=	arc connecting transshipment nodes i and j
i,d	=	arc from transshipment node i to demand point d
s,i	=	arc from supply point s to transshipment node i
st,i	=	arc from transshipment node i to storage point st
i,st	=	arc from transshipment node i to storage point st

the superscripted indices are:

F	=	firm
I	=	interruptible

the parameters are:

TAR	=	per unit reservation fee and usage fee (dollars per Mcf)
EFF	=	efficiencies (fraction)
PCAPMAX	=	physical capacity (Bcf)
WTHRXCAP	=	weather factor for normal weather (fraction)
AUTILZ	=	pipeline utilization (from Capacity Expansion Module as fraction)
MINF	=	minimum flow requirement (Bcf)
PZZ	=	price of backstop supply

		(set to an arbitrarily high value), (dollars per Mcf)
PSUP	=	prices on the supply steps (dollars per Mcf)
PDEM	=	prices on the demand steps (dollars per Mcf)
QDEM0	=	base demand level (Bcf)
QSTR	=	net withdrawals from storage (Bcf)
UDEM	=	size of demand step (Bcf)
USUP	=	size of supply step (Bcf)
LSUP	=	minimum supply level (Bcf)

the variables are:

$x_{i,j}$	=	flow from i to j (Bcf)
$ydem_{i,d,k}$	=	for demand point (i,d), amount of corresponding demand step taken (Bcf)
$ysup_{s,i,k}$	=	for supply point (s,i), the amount of supply step k taken (Bcf)
$qzz_{i,d}$	=	amount of backstop supply used for demand point (i,d), (Bcf)

Capacity Constraint Along Each Arc i,j:

$$x_{i,j}^{F} + x_{i,j}^{I} \le PCAPMAX_{i,j} * (1 - WTHRXCAP_{i,j}) * AUTILZ_{i,j}^{T} \tag{26}$$

$$x_{i,j}^{F} \le PCAPMAX_{i,j} * (1 - WTHRXCAP_{i,j}) * AUTILZ_{i,j}^{F} \tag{27}$$

Mass Balance Constraints at Each Transshipment Node (m):

$$\sum_i x_{i,m}^{F} * EFF_{i,m} + \sum_s x_{s,m}^{F} * EFF_{s,m} + QSTR_{st}^{F} * EFF_{st,m} = \sum_d x_{m,d}^{F} + \sum_i x_{m,}^{F} \tag{28}$$

$$\sum_i x_{i,m}^{I} * EFF_{i,m} + \sum_s x_{s,m}^{I} * EFF_{s,m} + QSTR_{st}^{I} * EFF_{st,m} = \sum_d x_{m,d}^{I} + \sum_i x_{m,}^{I} \tag{29}$$

Mass Balance Constraints at Each Demand Point (i,d):

$$x_{i,d}^{F} * EFF_{i,d} + qzz_{i,d}^{F} = QDEM0_{i,d}^{F} + \sum_{k=1}^{n} (ydem_{i,d,k}^{F} - ydem_{i,d,-k}^{F}) \tag{30}$$

$$x_{i,d}^{I} * EFF_{i,d} + qzz_{i,d}^{I} = QDEM0_{i,d}^{I} + \sum_{k=1}^{n} (ydem_{i,d,k}^{I} - ydem_{i,d,-k}^{I}) \tag{31}$$

Mass Balance Constraint at Each Supply Point (s,i):

$$\sum_{k=1}^{c} ysup_{s,i,k} = x_{s,i}^{F} + x_{s,i}^{I} \tag{32}$$

Minimum Bounds on Flows Along Bidirectional Arcs (i,j):

$$x_{i,j}^{F} => MINF_{i,j}^{F} \tag{33}$$

Minimum Bounds on Flows Along Primary Arcs (i,j):

$$x_{i,j}^{F} \Rightarrow MINF_{i,j}^{F} \tag{34}$$

$$x_{i,j}^{I} \Rightarrow MINF_{i,j}^{I} \tag{35}$$

The following bound constraints also must be defined for the steps on the supply and demand curves:

$$\begin{aligned}
0 \leq\ & ydem^{F}_{i,d,k} && \leq UDEM^{F}_{i,d,k} \\
0 \leq\ & ydem^{F}_{i,d,-k} && \leq UDEM^{F}_{i,d,-k} \\
0 \leq\ & ydem^{I}_{i,d,k} && \leq UDEM^{I}_{i,d,k} \\
0 \leq\ & ydem^{I}_{i,d,-k} && \leq UDEM^{I}_{i,d,-k} \\
LSUP_{s,i,k} \leq\ & ysup^{I}_{s,i,k} && \leq USUP_{s,i,k}
\end{aligned}$$

For the most part LSUP is zero, except on the first step of the supply curve where a minimum supply level may be defined.

Thus, the above equations mathematically specify the linear program objective function and the model constraints. The linear programming solution is obtained using a commercial software package designed to solve these problems.

Processing of AFM Results

The primary purpose of the AFM is to provide other models within NEMS with natural gas end-use and supply prices and quantities which correspond to a market equilibrium between natural gas supply and demand. The AFM also has the responsibility to provide NEMS with resulting pipeline fuel consumption, lease and plant consumption, and emissions levels associated with the network results, as well as realized tariffs for the interruptible market for the Pipeline Tariff Module to process. All of this information is obtained by solving the AFM regional transmission and distribution network problem defined by the linear program. Since the AFM solves at a regional level which differs somewhat from the NEMS Census divisions and other model region definitions (as described in Chapter 3), the AFM results must be processed into the regions required by the receiving models prior to being passed to NEMS.

Supply Prices and Quantities

The AFM provides wellhead prices and quantities for onshore, offshore, Alaska, and Canadian production, for Canadian, Mexican, and liquefied natural gas imports (at the border crossing), and for synthetic natural gas and other supplemental supplies. With the exception of Canadian import and wellhead prices, these values are obtained directly from the linear programming solution with little or no processing required (i.e., to translate information from one regional representation to another). Some of these results are passed to the Oil and Gas Supply Model, the Petroleum Market Model and the Coal Market Model for processing, while others are passed to NEMS for convergence and reporting purposes.

To determine Canadian import and wellhead prices, a netback pricing routine is used. For Canadian import prices, this involves taking the price at the node nearest to the border crossing node and reducing it by the tariff along the arc connecting the two nodes. For example, since Canadian imports from border crossing node 13 go into node 1 on the AFM network (see network defined in Chapter 4), the Canadian import price at node 13 is the node price at node 1 minus the tariff along arc 13 -> 1. Similarly, Canadian wellhead prices are determined by first taking each of the Canadian imports prices (at the border crossing) and subtracting the corresponding Canadian markups from the wellhead, and then taking a quantity weighted average of the results (adjusted for losses).

End-Use Prices

The AFM provides regional end-use prices for the Electricity Market Model (utility sector) and the other NEMS demand models (nonutility sectors). For the nonutility sectors, prices correspond to firm and interruptible service at the Census Division level. However, for the utility sector, prices are determined for three types of customers (firm service segment, segment competitive with residual oil, and segment competitive with distillate oil) at two different regional levels (the Census Division level and the NGTDM/EMM subregion level).

With the exception of firm transportation prices, firm and interruptible nonutility prices are easily determined from the AFM linear programming solution. Once retrieved from the linear programming solution, the prices are aggregated into Census Division level results (using a simple quantity weighted averaging technique) and converted into the appropriate units. Natural gas to the firm transportation sector is priced to be competitive with motor gasoline (see Chapter 6 for details).

Utility prices are sent to the Electricity Market Model at the NGTDM/EMM subregion level and to NEMS (for convergence and reports) at the Census Division level. The Electricity Market Model requires prices to be reported for all three market segments, while NEMS requires prices for the competitive markets be combined into an average competitive (interruptible) price. In contrast to the nonutility sectors, different methodologies are used to determine the utility prices to each of the three market segments. Utility prices to firm customers are taken directly from the AFM linear programming results, processed to represent the appropriate regions (NGTDM/EMM subregions for the Electricity Market Model and Census Divisions for NEMS), and converted into the proper units. Utility prices to the competitive (residual and distillate) segments are calculated based on their corresponding competitive fuel price (see Chapter 6 for details). Next, a quantity weighted averaging routine is used to combine the two competitive segments into a single average end-use price to send to NEMS.

Pipeline Fuel Consumption and Associated Emissions

For each arc of the network, pipeline fuel consumption is calculated by multiplying the flow on the arc by the percentage (specified as a fraction) lost due to pipeline fuel use. This percentage lost is 1 minus the efficiency specified along the arc as a data input. The pipeline fuel use along each arc of the network must be translated to fuel use by NGTDM region. This disaggregation is accomplished by multiplying the fuel use on each arc by regional shares based on the mileage of pipe in a given region (Appendix F, Table F39). A similar loss factor is applied along each intraregional arc to account for losses accrued in the distribution process.

Pipeline fuel consumption is used as a basis for calculating the emissions which result from pipeline compressor engine use. Both reciprocating engines and gas turbines are used to power compressors. The latter engines outnumber the former by a factor of approximately 3.3, primarily because they accommodate higher capacity flows at a greater efficiency. However, the reciprocating engines allow for greater variation in flows and are able to send flows in both directions along the pipe. According to estimates by Argonne National Laboratory (presented in the *NES Environmental Analysis Model (NESEAM): ANL Technical Memorandum*, Section "Natural Gas" of the Appendix C), 77 percent of the engines used for pipeline transportation are gas turbines and 23 percent are reciprocating piston compression engines.

The NGTDM quantifies eight types of pollutants discharged by the combustion of natural gas at gas pipeline compressor stations: total carbon, nitrogen oxides, sulfur oxides, carbon monoxide, carbon dioxide, methane, volatile organic compounds, and particulate. Since data on particulate emissions are not available and particulate emission levels are assumed to be small, estimates for particulate emissions are not included. Estimates for the discharge levels of the other pollutants are calculated as functions of the pipeline fuel consumption. In the last five years, pipeline fuel consumed by the compressor stations represents about 3.6 percent of the annual amount of gas delivered to consumers. Natural gas pipeline emissions by NGTDM region are calculated as the product of the annual pipeline fuel consumption in the region times an emissions factor, as follows:

$$EMNT_{r,p,y} = QGPTR_{r,y} * EMISRAT_{p} / (CFNGC * 2205.0) \tag{36}$$

where,

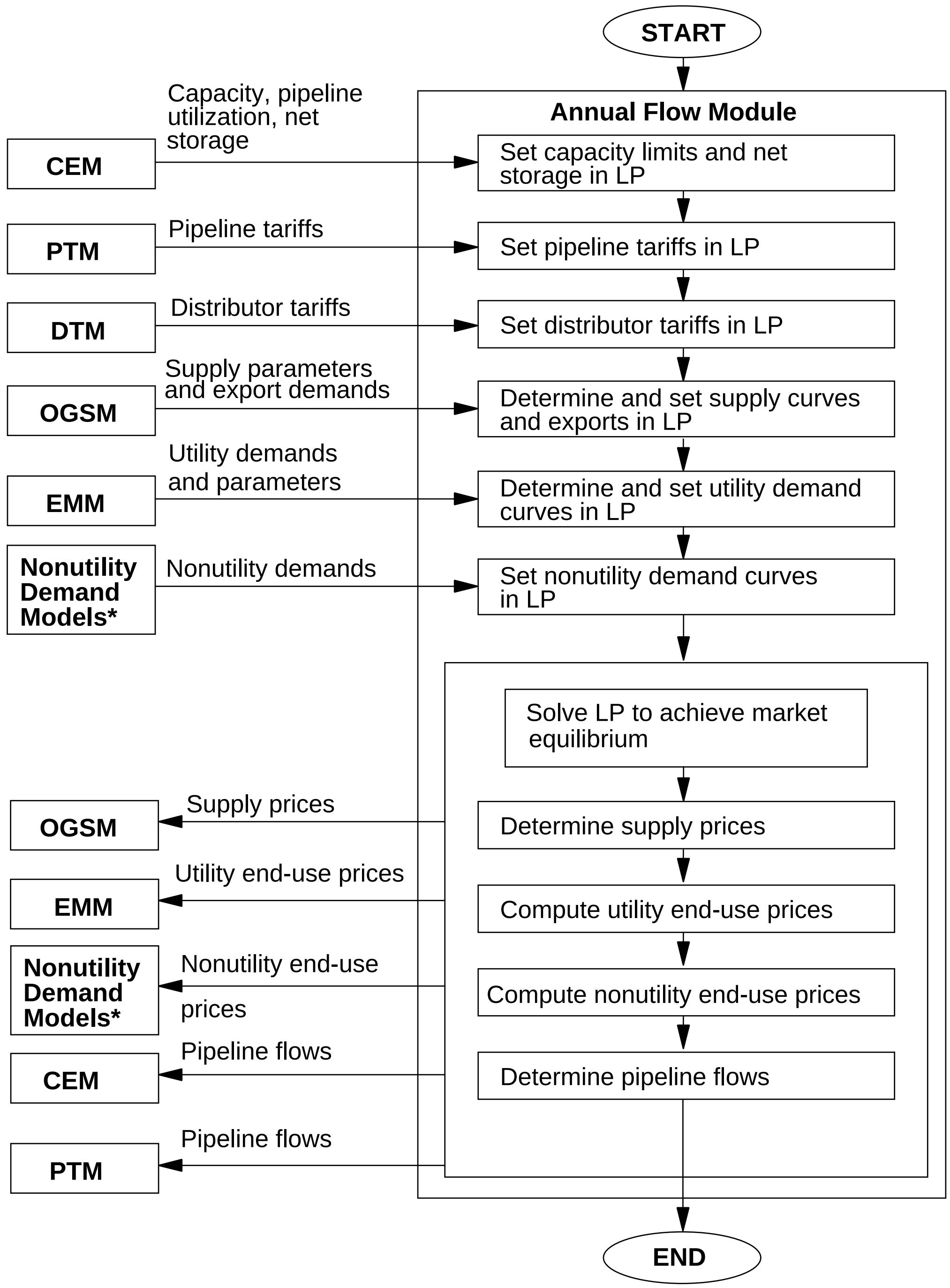
p	=	subscript that designates any of the eight types of pollutants discussed above (1-total carbon, 2-carbon monoxide, 3-carbon dioxide, 4-sulfur oxides, 5-nitrogen oxides, 6-volatile organic compounds, 7-methane, 8-particulates)
$QGPTR_{r,y}$	=	annual pipeline fuel consumption in year y for Census Division r (Trillion BTU)
$EMISRAT_p$	=	emissions factor (Appendix F, Table F25) (lb/MMCF)
$CFNGC$	=	Conversion factor (Trillion BTU/BCF)
$EMNT_{r,p,y}$	=	natural gas pipeline annual emissions, in thousand metric tons (MMT) in Census Division r and year y.

The constant 2205.0 in the equation converts the result in pounds to metric tons.

Realized Pipeline Tariff

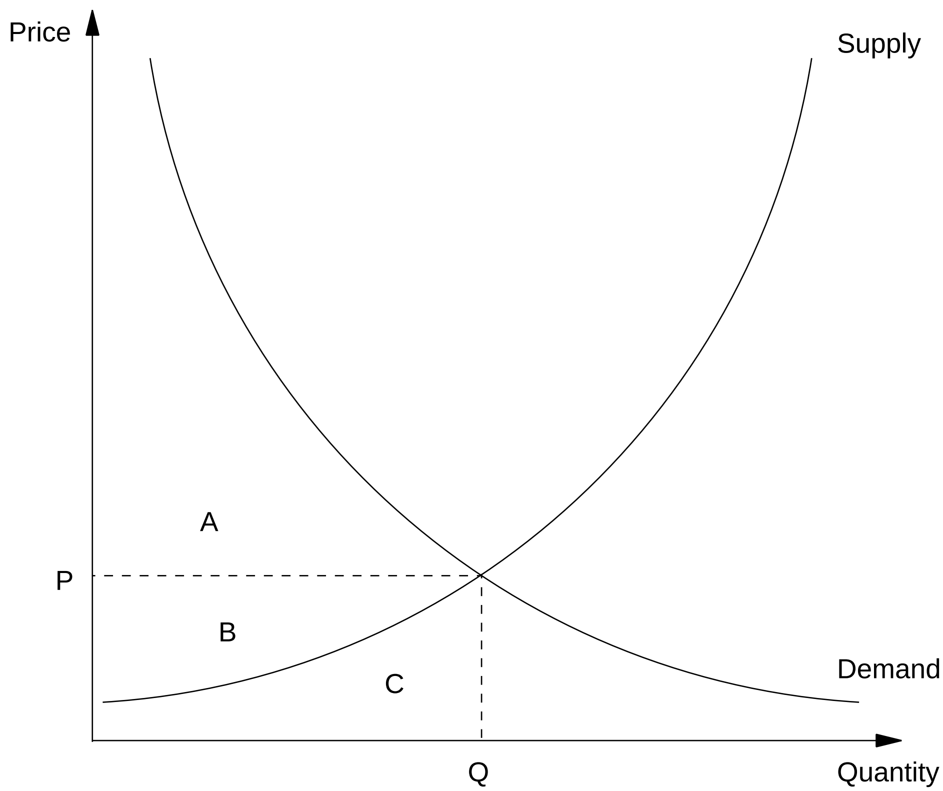
The Pipeline Tariff Module provides the AFM with a minimum and maximum usage fee, as well as an estimated usage fee for use in the model for transporting gas between regions under interruptible service. Once the linear program is solved, the realized tariff along each arc in the network equals the difference between the market clearing prices at the two connected transshipment nodes. If the natural gas flow along the arc is less than its capacity limit, the realized tariff equals the usage fee assigned when the linear program was formulated. If the flow along the arc is at its limit, the realized tariff will be greater than (or possibly equal to) the usage fee originally specified and could exceed its maximum allowed level. A check is made to identify any realized tariff greater than its allowed maximum. If one or more arcs are identified as having tariffs greater than the maximum, the tariff is adjusted to this maximum and sent back to the Pipeline Tariff Module for processing next year.

Figure 5-1. Annual Flow Module System Diagram



*Residential Demand Model, Commerical Demand Model, Industrial Demand Model, and Transportation Demand Model

Figure 5-2. Supply and Demand Curves



Area A: Consumers' Surplus

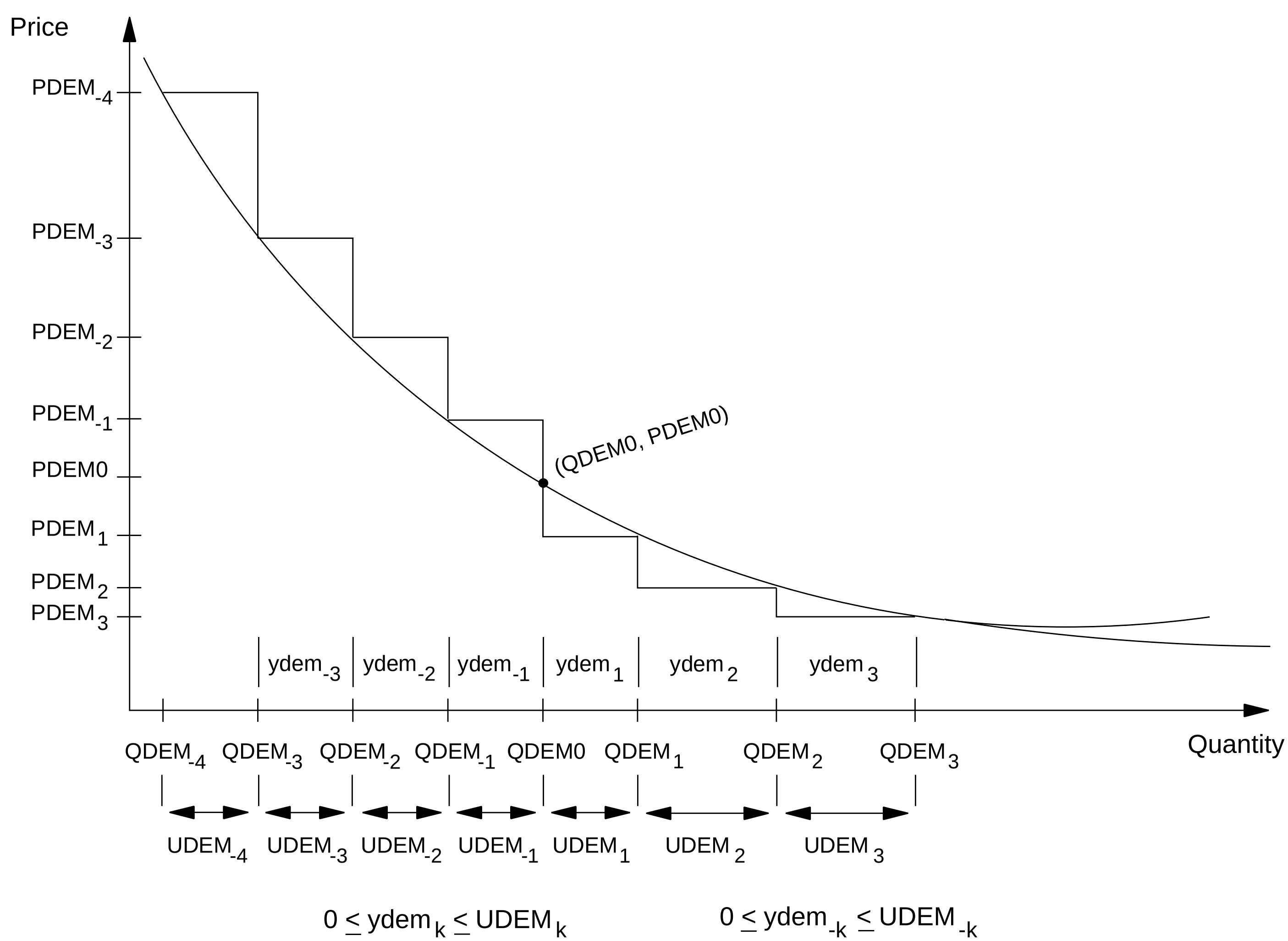
Area B: Producers' Surplus

Area C: Total Cost to the Producers

P: Price at Market Equilibrium

Q: Quantity at Market Equilibrium

Figure 5-3. Approximation of Area Under the Demand Curve



6. 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). The DTM develops markups that are applied to regional hub prices[35] to derive end-use prices that reflect the various pricing strategies employed by intrastate carriers and distributors. Markups are determined separately for the residential, commercial, industrial, electric utility, and transportation (compressed natural gas vehicles) sectors. Markups for the industrial and electric utility sectors are distinguished further by the type of service—interruptible and firm. It is assumed that residential and commercial sectors receive all of their natural gas under firm service agreements.

The purpose of the DTM is to determine firm and interruptible (where applicable) markups for each end-use sector.[36] Firm service markups for the residential, commercial, industrial, and electric utility sectors are based on the cost of providing service to the end user. The firm service markups to these sectors are derived from historical data. Historical markups are used because publicly available data are insufficient to develop a cost-based accounting methodology similar to the approach used for interstate pipeline tariffs in the Pipeline Tariff Module.

Firm service provided to the transportation sector (compressed natural gas vehicle customers) is priced using a methodology incorporating cost components and competing fuel prices. The price for compressed natural gas to vehicles is based on the regional hub price of natural gas, the cost of dispensing natural gas, applicable motor fuel taxes, and the cost of motor gasoline. In general, the price of compressed natural gas is derived by discounting the motor gasoline price with a floor price set equal to the sum of the cost of the delivery of compressed natural gas to the service station, the cost of dispensing the fuel, and applicable motor fuel taxes.

DTM estimates of interruptible markups are based on the value of service. In contrast to firm service markups, interruptible service markups reflect choices end-use sectors make among competing fuel sources. The value of interruptible service to each end-use sector depends on the sector's ability to switch among alternative fuels or to reduce or eliminate natural gas requirements during periods of peak demand. Thus, the value of interruptible service to a sector is constrained by the value of alternative fuel choices. Consequently, interruptible rates are determined largely by alternative fuel price relationships in fuel switchable markets. Alternative fuel prices used in the DTM are output values from other NEMS models in the previous NEMS iteration. A detailed discussion of how the DTM determines markups and end-user prices for each end-use sector is presented in subsequent sections of this chapter.

Residential, Commercial, and Firm Industrial Markups and End-Use Pricing

Residential, commercial, and firm industrial end-use prices are comprised of four components: (1) the regional hub price of natural gas, (2) the firm tariff for intraregional movements of natural gas on the interstate network, (3) a markup covering the costs of distribution and intrastate pipeline services, and (4) a benchmark factor. The latter three components are consolidated into a markup. The "cost of distribution" for each sector is set to reflect that a portion of the customers represented may bypass the local distribution company. In establishing the final end-use price, both the markup and the supply price at the hub are adjusted for an efficiency representing fuel use for the services required to move natural gas from the regional hub to the end user. The primary equation for determining end-use prices is provided below:

$$NONU\_PR\_F_{i,j} = (NG\_AVGPR\_F_{j} + NONU\_DTAR\_F_{i,j}) \ / \ NEFF\_ \qquad (37)$$

[35]The hub price is equal to the market clearing price of all supplies at the transhipment node in the region in which the gas is consumed.

[36]The DTM determines distributor markups separately for each end-use sector. This modularity of design makes it easier to revise the pricing structure to accommodate future market changes or increased availability of data.

where,

NONU_PR_F	=	end-use price for firm service provided to nonutility sectors (dollars per Mcf)
NG_AVGPR_F	=	hub price for firm service [from Annual Flow Module solution matrix (dollars per Mcf)]
NONU_DTAR_F	=	markup for firm service provided to nonutility sectors, before adjusting for pipeline fuel use (dollars per Mcf)
NEFF_PIPE	=	efficiency for services provided to transporting natural gas from the regional hub to end-use customers [Appendix F, Table F19 (fraction)]
i	=	end-use sector index
j	=	region index.

The firm service markup is comprised of three separate cost components as presented in the following equation:

$$NONU\_DTAR\_F_{i,j} = DIST_{i,j} + PTAR\_F_{i,j} + BENCHF_{i,j} \tag{38}$$

where,

NONU_DTAR_F	=	markup for firm service provided to nonutility sectors, before adjusting for pipeline fuel use (dollars per Mcf)
DIST	=	markup for firm distributor and intrastate pipeline services [Appendix F, Table F21 (dollars per Mcf)]
PTAR_F	=	markup for intraregional firm service provided by interstate pipelines [from the Pipeline Tariff Module (dollars per Mcf)]
BENCHF	=	benchmark factor (dollars per Mcf)
i	=	end-use sector index
j	=	region index.

The benchmark factor is derived internally from differences in historical end-use prices and the end-use prices derived by the NGTDM for the years historical data is available, and is primarily used to calibrate the model against actual historical data. For the first iteration of the first model forecast year (1990) of the simulation, the DTM sets the benchmark factors to zero. For subsequent iterations and years of the historical period (1990 through 1991), the benchmark algorithm computes benchmark factors. The benchmark factors for the residential sector are computed using the following equation:

$$BENCHF_{i=1,j} = HPGFRSGR_{j,t} - NONU\_PR\_F_{i=1,j} \tag{39}$$

where,

$BENCHF_{i=1}$	=	benchmark factor for the residential sector (dollars per Mcf)
HPGFRSGR	=	historical natural gas end-use price for the residential sector [Appendix E, Table E8 (dollars per Mcf)]
$NONU\_PR\_F_{i=1}$	=	end-use price for firm service provided to the residential sector (dollars per Mcf)
t	=	model year index
i	=	end-use sector index (i=1 for residential sector)
j	=	region index.

[Note: A similar equation is used for the commercial and industrial sectors with HPGFRSGR replaced with HPGFCMGR or HPGFINGR, respectively, and with the index i set to 2 or 3.]

When the model converges for the base year, the benchmark factors from the last iteration for 1990 are assigned to the array BENCHF90. After the historical period (i.e., model year 1991) is completed, the benchmark algorithm sets the benchmark factors equal to the average of the 1990 benchmark factor and the benchmark factor computed for the last benchmark year (1991). The average benchmark factor is held constant for all the forecast years. Computation of the average benchmark factor is shown below:

$$BENCHF_{i,j} = (BENCHF_{i,j} + BENCHF90_{i,j}) \; / \; 2 \qquad (40)$$

where,

BENCHF	=	benchmark factor derived for the last year historical data is available (dollars per Mcf)
BENCHF90	=	benchmark factor for 1990 (dollars per Mcf)
i	=	sector index
j	=	region index.

Before completing the processing of the end-use prices, the DTM checks the prices against a minimum threshold price of $0.00001 per Mcf. The purpose of this check is to pass back a nonzero price to the NEMS Integrating Module in situations where there is no demand for a sector in a region. Should the end-use price be very small, the price is reset to the last price that is available (either from a previous iteration, model year, or historical period) for the sector and region.

Transportation Sector Markups and End-Use Prices

The transportation sector includes the use of compressed natural gas as a vehicle fuel. The price of natural gas used for pipeline fuel is not included in the price of natural gas delivered to the transportation sector. Pipeline fuel is priced at the market clearing price of gas supplies at the transhipment node at the origin of the arc on which the natural gas is transported. Two price methodologies are available for deriving end-use prices for compressed natural gas (CNG). The first methodology (called the historical markup method) uses an endogenously derived markup and holds this markup constant throughout the forecast. The second methodology (called the competitive price method) develops a markup for CNG using an algorithm that takes into consideration cost components of supplying and dispensing CNG and the price of motor gasoline to commercial customers. The DTM offers the flexibility to transition to the competitive price methodology in a user specified forecast year. The DTM can also phase in the competitive price methodology over a period of years specified by the user. This capability was incorporated to reflect the gradual phaseout of special marketing programs many local distribution companies have implemented. These two pricing methodologies and the phase-in method are presented below.

In the historical markup method, the price of CNG is a function of the firm service hub price, an historical markup, and an efficiency as shown in the following equation:

$$NONU\_PR\_F_{i=4,j} = (NG\_AVGPR\_F_j + NONU\_DTAR\_F_{i=4,j}) \; / \; NE \qquad (41)$$

where,

$NONU\_PR\_F_{i=4}$	=	end-use price for firm service provided to the transportation sector (dollars per Mcf)
NG_AVGPR_F	=	hub price for firm service [from Annual Flow Module solution matrix (dollars per Mcf)]
$NONU\_DTAR\_F_{i=4}$	=	markup for firm service provided to the transportation sector, before adjusting for pipeline fuel use (dollars per Mcf)
$NEFF\_PIPE_{i=4}$	=	efficiency for services provided in transporting natural gas from the regional hub to compressed natural gas vehicle customers [Appendix F, Table F19 (fraction)]
i	=	end-use sector index (i=4 for transportation sector)
j	=	region index.

The transportation sector markup (NONU_DTAR_F) is held constant throughout the period the historical markup method is used and is set equal to the difference between the regional historical price of CNG and the regional hub price of firm natural gas supplies as determined within the Annual Flow Module for the last year that historical data are available to the NGTDM (1991). This derivation is shown in the following equation:

$$NONU\_DTAR\_F_{i=4,j} = HPGFTRGR_{j,h} * NEFF\_PIPE_{i=4,j} - NG\_ \qquad (42)$$

where,

$NONU\_DTAR\_F_{i=4}$	=	markup for firm service provided to the transportation sector, before adjusting for pipeline fuel use (dollars per Mcf)
HPGFTRGR	=	historical natural gas end-use price for the transportation sector [Appendix E, Table E8 (dollars per Mcf)]
$NEFF\_PIPE_{i=4}$	=	efficiency for services provided in transporting natural gas from the regional hub to compressed natural gas vehicle customers [Appendix F, Table F19 (fraction)]
NG_AVGPR_F	=	hub price for firm service [from Annual Flow Module solution matrix (dollars per Mcf)]
i	=	end-use sector index (i=4 for transportation sector)
j	=	region index
h	=	index for last year historical data is available.

Under the competitive price method, the price of CNG is set equal to the competing fuel price (the price of motor gasoline to the commercial sector) times a user-specified discount factor, as long as the implied markup allows for basic cost recovery. The implied markup (the competitive fuel price markup) is derived from the competing fuel price and the firm price of natural gas at the regional hub as follows:

$$NONU\_DTAR\_F_{i=4,j} = PTAR\_F_{j,j} + PERDISC * (AFP * NEFF\_ \quad PTAR\_F_{j,j})) \tag{43}$$

where,

$NONU\_DTAR\_F_{i=4}$	=	markup for firm service provided to the transportation sector, before adjusting for pipeline fuel use (dollars per Mcf)
PTAR_F	=	markup for intraregional firm service provided by interstate pipelines [from the Pipeline Tariff Module (dollars per Mcf)]
PERDISC	=	discount [Appendix F, Table F27 (fraction)]
AFP	=	alternative fuel price [commercial motor gasoline price (dollars per Mcf)]
$NEFF\_PIPE_{i=4}$	=	efficiency for services provided in transporting natural gas from the regional hub to compressed natural gas vehicle customers [Appendix F, Table F19 (fraction)]
NG_AVGPR_F	=	hub price for firm service [from Annual Flow Module solution matrix (dollars per Mcf)]
i	=	end-use sector index (i=4 for transportation sector)
j	=	region index.

The minimum allowed markup (or cost-based markup) for CNG ia based on (1) the cost of moving the natural gas from the hub to the service station, (2) the cost of dispensing the CNG, and (3) applicable federal and State motor fuel taxes. These three costs are summed to derive a markup floor (or minimum markup) for the CNG as shown in the following equation:

$$NONU\_DTAR\_F_{i=4,j} = PTAR\_F_{j,j} + TFLOOR_j + STAX_j + FTA \tag{44}$$

where,

$NONU\_DTAR\_F_{i=4}$	=	markup for firm service provided to the transportation sector, before adjusting for pipeline fuel use (dollars per Mcf) [assigned to variable DTAR_CHK]
PTAR_F	=	markup for intraregional firm service provided by interstate pipelines [from the Pipeline Tariff Module (dollars per Mcf)]
TFLOOR	=	cost of dispensing CNG [Appendix F, Table F27 (dollars per Mcf)]
STAX	=	State motor vehicle fuel tax applied to CNG [Appendix F, Table F27 (dollars per Mcf)]
FTAX	=	Federal motor vehicle fuel tax applied to CNG [Appendix F, Table F27 (dollars per Mcf)]

i	=	end-use sector index (i=4 for transportation sector)
j	=	region index.

The final competitive CNG markup is set equal to the greater of (1) the cost-based markup or (2) the competitive fuel price markup.

In years when the model is making the transition from the historical markup to the competitive markup, a composite markup is derived by applying weights to the two markups. The weight applied to the historical markup is derived in the equation below:

$$BETA = 1 - (CURIYR - STPHASE)/(EPHASE - STPHASE) \tag{45}$$

where,

BETA	=	markup weight (fraction)
CURIYR	=	current model year (1=1990, 2=1991,,, 26=2010)
STPHASE	=	year that transition begins (STPHASE=2, for 1991)
EPHASE	=	year that transition ends (EPHASE=7, for 1996).

In deriving the composite markup, the BETA weight is applied to the competitive markup and a weight equal to (1.0-BETA) is applied to the historical markup.

Similar to the other sectors, the transportation price is checked against a minimum price ($0.00001 per Mcf). The purpose of this check is to pass nonzero prices to the NEMS Integrating Routine in situations where there is no natural gas demand by a sector in a region. Should the end-use price be very small, the price is reset to the last price that is available (either from a previous iteration, model year, or historical period) for the sector and region.

Interruptible Industrial Sector Markups and End-Use Prices

Industrial customers are engaged in processes that create or change raw or unfinished materials into another form or product. Some industrial processes depend on a secure supply of clean burning fuel and, consequently, require firm natural gas service.[37] Other industrial processes are not limited to natural gas as the sole energy source but can switch to alternative fuels depending on the availability and cost of competing fuels. These processes may lend themselves to interruptible gas service. In contrast to the residential and commercial sectors, some industrial customers have sufficiently large volume purchases of natural gas to enable them to negotiate gas contracts with suppliers offering the lowest prices. These natural gas purchasers can either bypass the local distribution company and contract directly with the producer (in which case the industrial customer may contract with the local distribution company for the transport of the fuel) or negotiate with the local distribution company for a more competitive natural gas price. Thus, markups for the industrial sector tend to be site specific and are affected by the customer's market power, as determined by the volume of gas purchased, the type of service required, the ability to switch to alternative fuels, and the potential to bypass the local distribution company. This section of the chapter presents the derivation of the markups that are applied to interruptible industrial customers.

In contrast to industrial consumers who require firm service, industries that can switch among fuels for their energy requirements can negotiate with local distribution companies and producers to keep the cost of their fuel choices within a narrow competitive range. Thus, local distribution company markups for interruptible service are significantly less than firm service markups and tend to be structured to keep the total cost of purchased gas competitive with alternate fuels.[38] Consequently, interruptible service markups are estimated from the value of service to the sector as determined by the alternative fuel prices. The markup, however, is never lower than the variable costs of service in the short run. The interruptible markup to the industrial sector is the difference between

[37]For example, the cooking and glass industries.
[38]When the city-gate price exceeds the equivalent cost of the alternative fuel, natural gas is no longer the fuel of choice.

a user-specified portion (PERDISC) of the alternative fuel price and the natural gas city-gate price in the NGTDM region, as follows:

$$NONU\_DTAR\_I_{i=3,j} = (PERDISC * AFP) - NG\_AVGPR\_I_j \tag{46}$$

where,

$NONU\_DTAR\_I_{i=3}$	=	markup for interruptible service provided to the industrial sector, before adjusting for pipeline fuel use (dollars per Mcf)
PTAR_I	=	markup for intraregional interruptible service provided by interstate pipelines [from the Pipeline Tariff Module (dollars per Mcf)]
PERDISC	=	discount factor for industrial interruptible service customers [Appendix F, Table F28 (fraction)]
AFP	=	average industrial alternative fuel price (dollars per Mcf)
NG_AVGPR_I	=	hub price for interruptible service [from Annual Flow Module solution matrix (dollars per Mcf)]
i	=	end-use sector index (i=3 for industrial sector)
j	=	region index.

The interruptible markup is constrained by maximum and minimum values. The maximum value is set equal to the industrial sector firm distribution markup. The minimum value is a user-specified minimum threshold value [equal to the sum of $PTAR\_I_{j,j}$ + IFLOOR (Appendix F, Table F28)], representing the variable cost of service. When the estimated interruptible markup exceeds the firm markup, it is set equal to the firm markup. Correspondingly, when the estimated markup is less than the minimum threshold markup, it is set equal to the minimum threshold markup.

The alternative fuel price is the volume-weighted average price of the fuels that the manufacturing industries can consume. These include distillate fuel oil, residual fuel oil, coal and liquefied petroleum gas as identified in EIA's *Manufacturing Fuel-Switching Capability 1988*.[39] The regional shares for each switchable fuel (or the composition of the market basket) are derived from the Census region data in the EIA publication. It is assumed that the Census region shares apply to each NGTDM subregion within the Census region. The alternative fuel price in forecast year t and NGTDM region j is calculated as follows:

$$\begin{aligned} AFP = (&W\_RESID_j * PRSIN_{j,t} + W\_DIST_j * PDSIN_{j,t} + W\_CC \\ &W\_LPG_j * PLGIN_{j,t}) * CFNGN \end{aligned} \tag{47}$$

where,

AFP	=	average industrial alternative fuel price (dollars per Mcf)
W_RESID	=	percent of "switchable" industrial capacity in region j that is switchable to residual fuel oil [Appendix F, Table F22 (fraction)]
PRSIN	=	price of residual fuel oil to the industrial sector (dollars per MMBtu)
W_DIST	=	percent of "switchable" industrial capacity in region j that is switchable to distillate fuel oil [Appendix F, Table F22 (fraction)]
PDSIN	=	price of distillate fuel oil to the industrial sector (dollars per MMBtu)
W_COAL	=	percent of "switchable" industrial capacity in region j that is switchable to coal [Appendix F, Table F22 (fraction)]
PCLIN	=	price of coal to the industrial sector (dollars per MMBtu)
W_LPG	=	percent of "switchable" industrial capacity in region j that is switchable to liquefied petroleum gas [Appendix F, Table F22 (fraction)]
PLGIN	=	price of liquefied petroleum gas to the industrial sector (dollars per MMBtu)
CFNGN	=	conversion factor (MMBtu/Mcf)

[39]Energy Information Administration, *Manufacturing Fuel-Switching Capability*, 1988, DOE/EIA-0515(88) (Washington, DC, September 1991).

j	=	region index
t	=	year index.

The weighting factors are held constant throughout the forecast period.

Electric Utility Sector Markups and End-Use Prices

Electric utilities balance the mix of their generating capacity against generation cost and fuel availability. To meet demand, utilities provide a mix of electric generation technology to satisfy their generation requirements while minimizing generation costs. A large portion of this technology depends on a single energy source--coal-fired steam turbine power plants, for example. However, a significant portion of the technology is dual-fired which can switch between different fuels depending upon the cost and availability of alternative fuels.

Utilities respond to seasonal changes in fuel cost and availability by switching their dual-fired capability to lower cost fuels and by increasing the utilization of lower cost generating capacity. Thus during winter months when space heating demand for natural gas is at peak levels, utilities switch from natural gas to distillate and residual fuel oils, among others, to supply a portion of their generating capacity. For example, in the Central Atlantic Region the share of natural gas-based electric generation, on average, declines from 10 percent during summer months to 3 percent in winter months. During the same period, the share of fuel oil-based electric generation, on average, increases by 6 percent.[40]

Since the bulk of the electric generating technology using natural gas is switchable to other fuels, the electric utility sector contracts predominantly for interruptible service. Some electric generation technologies, however, use natural gas as their sole energy source, so a portion of the utility sector's requirements also is for firm service.[41]

The utility markups are based on a characterization of electric generation technology drawn from various EIA data surveys.[42] In addition to technology type, the data surveys provide historical information on natural gas consumption volumes and end-use prices. For modeling purposes, utility natural gas demand is distinguished by three service types: firm service, interruptible service to utilities where gas competes with residual fuel oil, and interruptible service to utilities where gas competes with distillate fuel oil. Each service type is characterized by electric generation technology as follows:

- Firm service—dedicated gas steam and gas combined cycle generating units
- Competitive-with-residual fuel oil—dual-fired steam generating units that are primarily switchable to residual fuel oil
- Competitive-with-distillate fuel oil—gas-only[43] and dual-fired turbines.

Firm Service Markup

The firm service markup to the electric utility sector from the regional firm service hub is comprised of two components: (1) a markup for intraregional services provided by interstate pipelines and (2) a benchmark factor to calibrate the model to historical data. The benchmark factor must at least cover a user-specified minimum distribution fee (URFLOOR, Appendix F, Table F29). The equation for the firm service markup is shown below:

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[40]Energy Information Administration, "Effects of Interruptible Natural Gas Service: Winter 1989-1990," Office of Oil and Gas, July 1991.

[41]Texas is the only State in which a significant portion of electric utility natural gas contracts are for firm service.

[42]The EIA surveys include Forms EIA-767, "Steam-Electric Plant Operation and Power Plant Design Report," EIA-860, "Annual Electric Generator Report," EIA-759, "Monthly Power Plant Report," and FERC Form 423, "Monthly Report on Cost and Quality of Fuels for Electric Plants."

[43]Gas-only turbines are competitive with distillate fuel oil since these generating units may be displaced by distillate-fired units.

$$UTIL\_DTAR\_F_{j,n} = PTAR\_F_{j,j} + UBENCH_k \tag{48}$$

where,

UTIL_DTAR_F	=	markup for firm service provided to electric utilities, includes intrastate pipeline services and distributor services before adjusting for pipeline fuel use (dollars per Mcf)
PTAR_F	=	markup for intraregional firm service provided by interstate pipelines [from the Pipeline Tariff Module (dollars per Mcf)]
UBENCH	=	benchmark factor (dollars per Mcf)
j	=	NGTDM gas region index
n	=	Electricity Market Model region index
k	=	region index (NGTDM/EMM).

[Note: A factor (TILT) for shifting distribution costs between end-use service categories is also added to UTIL_DTAR_F, but is currently set to zero (Appendix F, Table F29).]

Benchmark factors for historical years are derived from differences in historical prices and model generated prices for the historical period as shown below:

$$UBENCH_k = HPGFELGR_{k,t} - UTIL\_PR\_F_{j,n} \tag{49}$$

where,

UBENCH	=	benchmark factor (dollars per Mcf)
HPGFELGR	=	historical natural gas end-use price for the firm service to electric utilities [Appendix E, Table E17 (dollars per Mcf)]
UTIL_PR_F	=	end-use price for firm service to electric utilities, from the Annual Flow Module solution matrix (dollars per Mcf)
k	=	region index (NGTDM/EMM)
t	=	model year index
j	=	NGTDM region index
n	=	Electricity Market Module region index.

After the historical period is completed, the maximum regional benchmark factor to be used in the forecast period is set equal to the average of the benchmark factors for the last 2 years that historical data are available (1990 and 1991). The minimum benchmark factor in a region is equivalent to the minimum distribution fee (URFLOOR). Over the next UBENYRD years (Appendix F, Table F29), the applied benchmark factor in a region is scaled down from its maximum level to its minimum level plus a percentage (UBENPER, Appendix F, Table F29) of the difference between the maximum and the minimum levels.

Similar to the other sectors, the firm electric utility price is checked against a minimum price ($0.00001 per Mcf). The purpose of this check is to pass back a nonzero price to the NEMS Integrating Routine in situations where there is no demand for firm natural gas service by electric utilities in a region. Should the end-use price be very small, the price is set to the last price that is available (either from a previous iteration, model year, or historical period) for the sector and region.

Competitive-with-Residual Fuel Oil Markup

Natural gas priced competitive-with-residual fuel oil is marketed to dual-fired electric generating units that are switchable to residual fuel oil. The markup for this category is based on the value of service to the sector as determined by the competing residual fuel oil price. The alternative fuel price used in deriving the markup for natural gas prices is set equal to the quantity weighted average price of high and low sulfur residual fuel oil delivered to electric utilities. If the total quantity of residual fuel oil delivered to electric utilities in a region is small (less than 1000 MMBtu) the alternative fuel price is set equal to either the high or low sulfur residual fuel oil price. The price chosen is based on fuel quality with the largest quantity consumed in the region. The markup is derived from the following equation:

$$UTIL\_DTAR\_IR_{j,n} = PR\_MIN * UEFF\_PIPE_{j,k} - NG\_AVGPR\_I \quad (50)$$

where,

UTIL_DTAR_IR	=	markup for interruptible service provided to electric utilities switchable to residual fuel oil (dollars per Mcf)
PR_MIN	=	minimum price of natural gas (dollars per Mcf)
UEFF_PIPE	=	efficiency for services provided in transporting natural gas from the regional hub to end-use customers [Appendix F, Table F19 (fraction)]
NG_AVGPR_I	=	hub price for interruptible service [from Annual Flow Module solution matrix (dollars per Mcf)]
j	=	NGTDM region index
n	=	Electricity Market Module region index.

The price PR_MIN is set equal to (1) a discounted alternative fuel price or (2) the interruptible natural gas price solved for in the Annual Flow Module, whichever is the greater price. The discounted alternative fuel price is the product of the alternative fuel price times a discount factor. The discount factor is lesser of the gas to residual oil price ratio provided by the Electricity Market Module (GRATMAX) or the gas to residual fuel oil price ratio exogenously specified by the user [NGRATMAX, (Appendix F, Table F23)]. The interruptible natural gas price solved for in The Annual Flow Module will equal the interruptible hub price (NG_AVGPR_I) in region j plus the markup for interregional service provided by interstate pipelines ($PTAR\_I_{jj}$) plus the minimum distribution fee (UDFLOOR). This algorithm will maximize the use of natural gas in markets where natural gas competes with residual fuel oil subject to the condition that full cost recovery takes place.

Competitive-with-Distillate Fuel Oil Markup

Natural gas priced competitive-with-distillate fuel oil is marketed to gas turbines and dual-fired turbines that are switchable to distillate fuel oil. This markup is based on the value of service to the sector as determined by the alternative distillate fuel oil price. The markup is defined as the difference between the product of a discount factor for region j [UDPD1, (Appendix F, Table F23)] multiplied by the price of distillate fuel oil to electric utilities in the region and the interruptible natural gas price at the regional hub ($PTAR\_I_{jj}$).

The competitive-with-distillate fuel oil markup for services is constrained by maximum and minimum values. If the markup derived from the discounted alternative fuel price exceeds the firm service electric utility markup, the value is set equal to the electric utility sector firm distribution markup minus a user specified discount (UDFLOOR, currently set at $0.10 in 1987 dollars per Mcf). If the markup derived from the discounted alternative fuel price is less than a minimum markup, the markup is set to the minimum. The minimum markup is the greater of either the competitive-with-residual fuel oil markup or a user-specified minimum threshold markup that equals the sum of the interregional pipeline tariff and UDFLOOR.

Figure 7-1. Capacity Expansion Module System Diagram

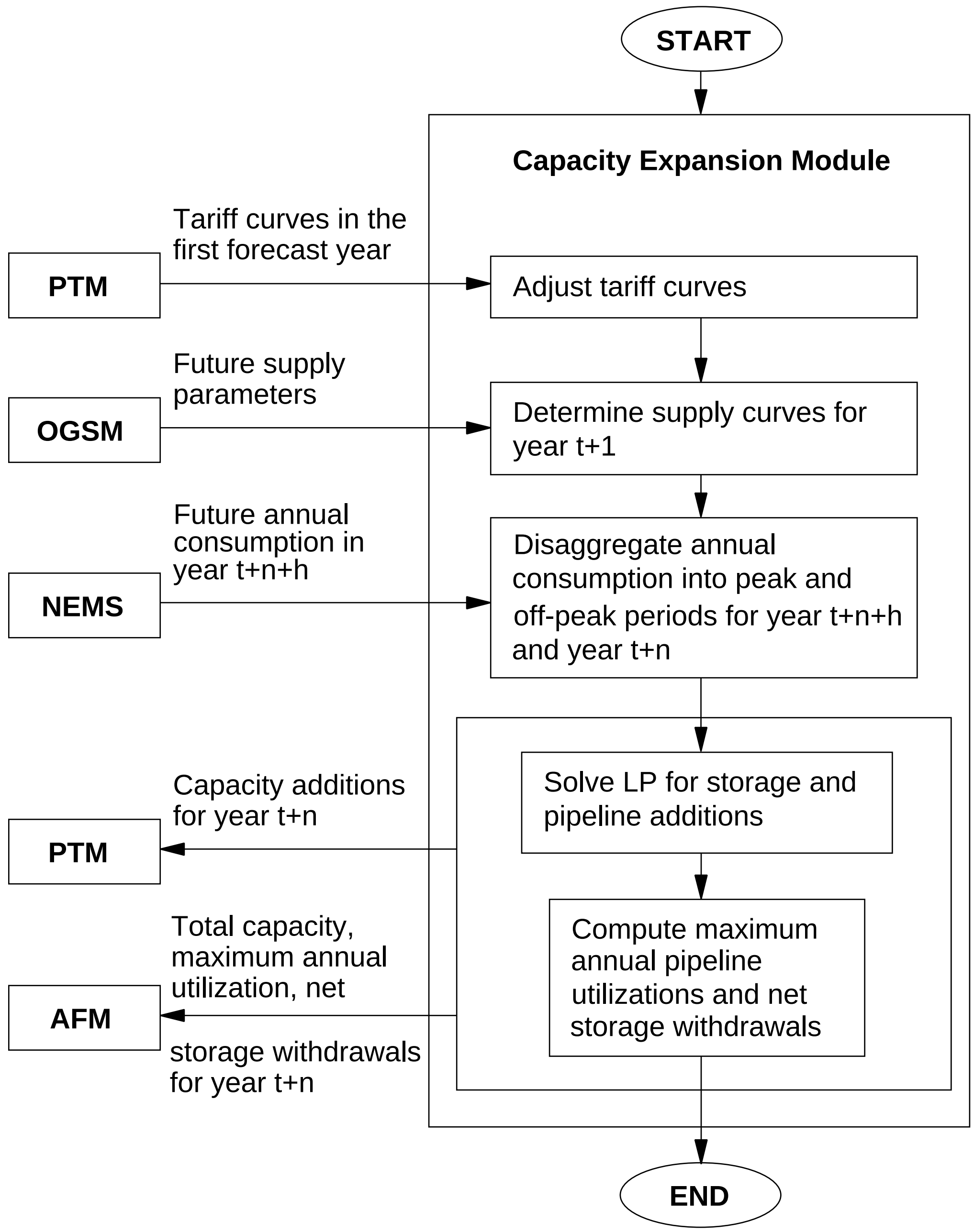
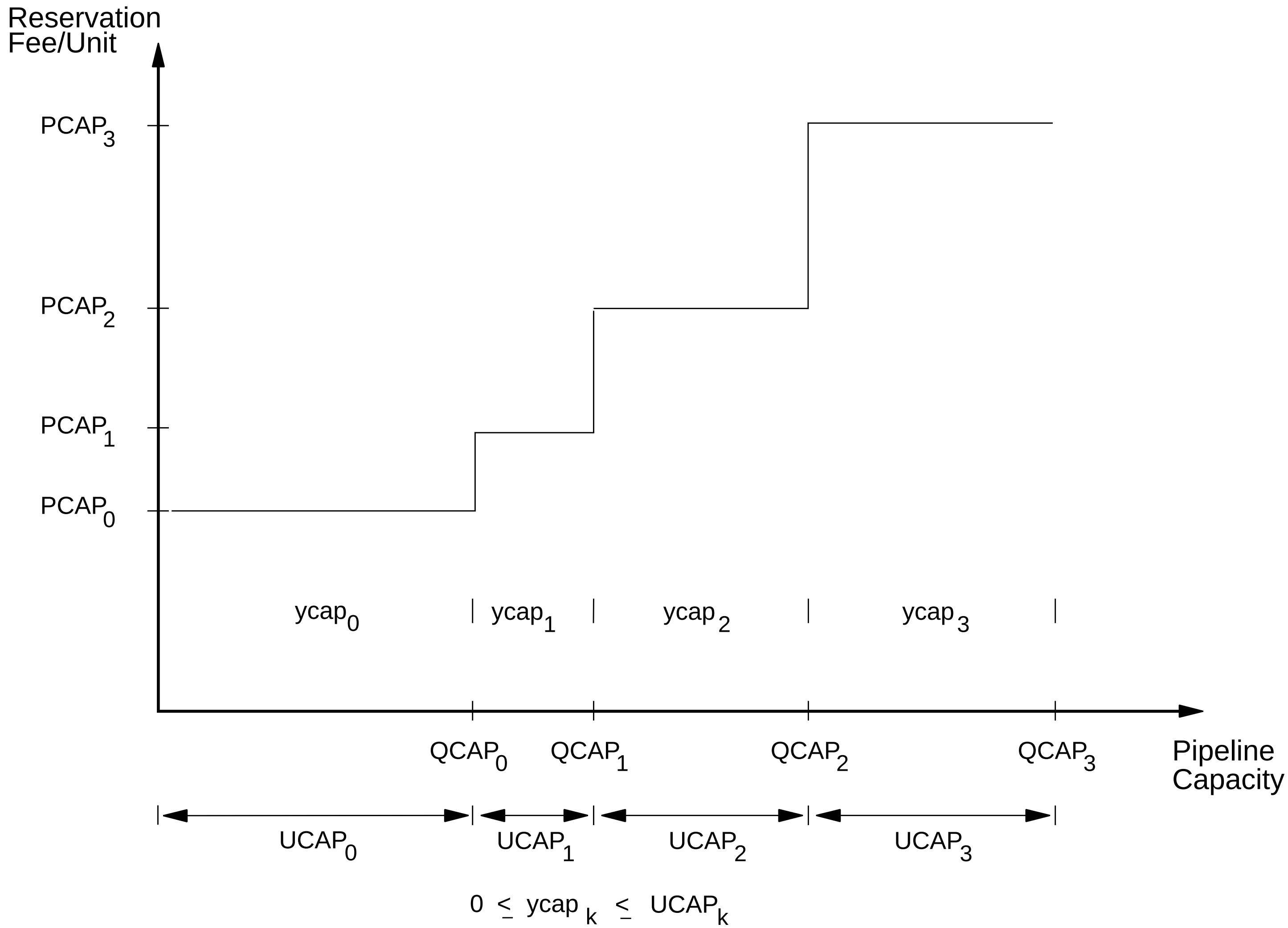
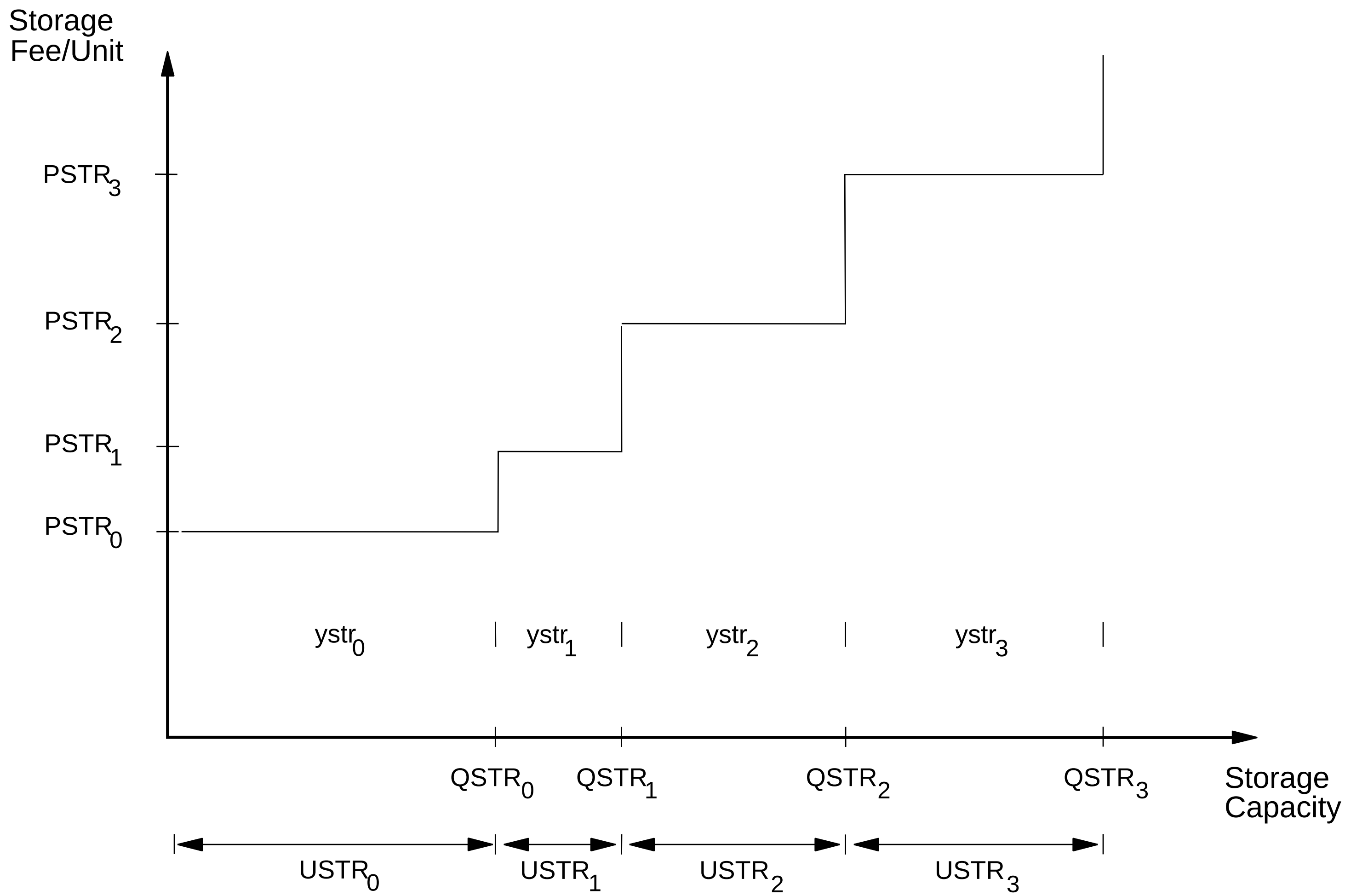


Figure 7-2. Pipeline Capacity Price Curve



Note: $PCAP_0$ is currently set to zero.

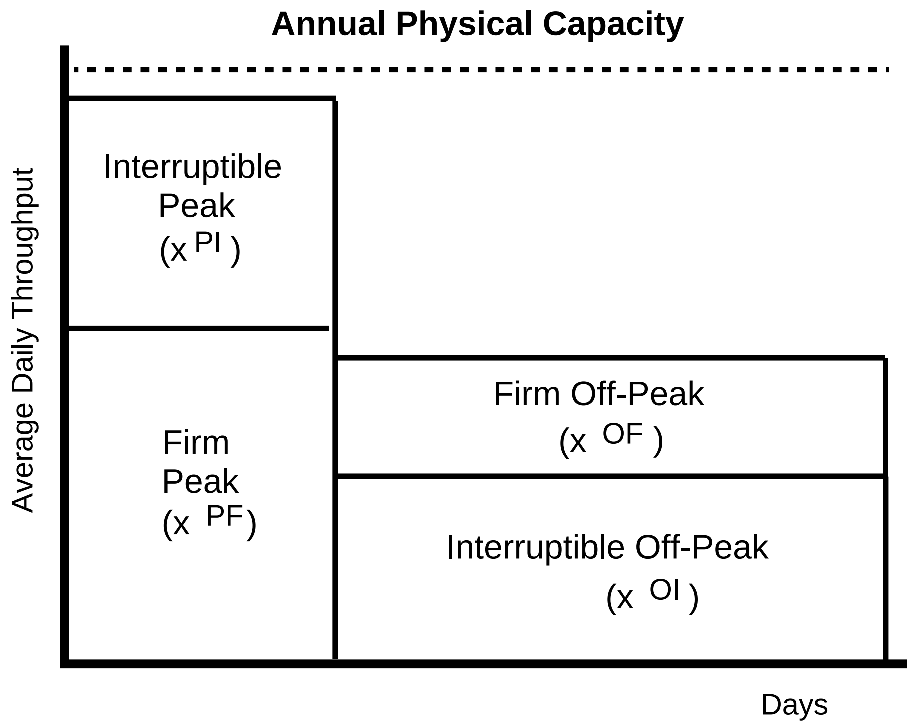
Figure 7-3. Storage Capacity Price Curve



$0 \leq ystr_k \leq USTR_k$

Note: $PSTR_0$ is currently set to zero.

Figure 7-4. Example of a Seasonal Flow Pattern Along an Arc



7. Capacity Expansion Module Solution Methodology

The Capacity Expansion Module (CEM) is a component of the Natural Gas Transmission and Distribution Model (NGTDM). Its function is to determine future interstate pipeline and storage capacity expansion requirements, firm and total pipeline utilization estimates, and firm and interruptible net storage withdrawal levels for use by the Annual Flow Module and/or the Pipeline Tariff Module. A flow diagram illustrating the general structure of the CEM is provided in Figure 7-1.

Figure 7-1. Capacity Expansion Module Flow Diagram

These results are determined based on an equilibrium between expected changes in gas consumption levels and supply availability corresponding to a CEM forecast year (represented as the Annual Flow Module model year "t" plus look-ahead years "n").[44] Like the Annual Flow Module, it is structured as a transportation network servicing both firm and interruptible customers; however, it bases its capacity and storage utilization/expansion decisions on seasonal firm service loads, thus accounting for peak period and off-peak period consumption requirements. This two-period network structure allows for a more accurate representation of the capacity build decisions and storage requirements, as well as a mechanism for setting maximum utilization levels for the Annual Flow Module. It is important to note that without the total market (firm and interruptible) being represented in the CEM, natural gas production levels cannot be properly represented and maximum utilization levels cannot be properly determined.

Formulated as a linear program, the CEM determines the capacity expansion and flow decisions which correspond to the least cost solution for achieving an equilibrium between expected supply and demand levels for natural gas. It is designed to determine pipeline and storage expansion and utilization levels that correspond to satisfying firm and interruptible demands represented in both the peak and off-peak periods. Price curves for storage and pipeline expansion are employed to represent the costs associated with expansion options. The decision to expand capacity in the model is based on the criterion that peak period firm service requirements for design weather conditions[45] must be met. Thus, when current capacity levels are fully utilized, the model simultaneously determines the relative difference in price to the consumer among the following activities: (1) adding more pipeline capacity, (2) adding more storage capacity to enable the transfer of gas to a firm customer in the peak period, (3) adding no more pipeline or storage capacity but taking an alternate route, and/or (4) temporary interruptions of supplies to some interruptible customers. Given that the price to the consumer is a combination of the wellhead price, the transportation charge, and the storage fee, the availability of supply and its relative regional price are included in this determination. The location and amount of pipeline and/or storage capacity expansion determined by the CEM serve to satisfy the Nation's expected firm service requirements for the lowest price to the consumer.

For this model to operate properly, a number of parameters are derived. Some are derived from data passed from other NEMS models, such as supply curve coefficients and expected firm and interruptible consumption levels. Others are based on the results from other NGTDM modules, such as the price (or tariff) curves for interregional pipeline and storage capacity expansion provided by the Pipeline Tariff Module. Finally, some of the parameters for the CEM are based on exogenously determined relationships and are assigned directly within the module.

The following sections present the CEM in more detail. The methodologies used to represent supply, demand, pipeline capacity price curves, and storage capacity price curves used in the CEM are presented first. Then, a general description of the CEM linear program is presented, followed by a mathematical specification. Finally, the methodology used to calculate the maximum pipeline utilizations used by the Annual Flow Module is provided. The variables for which the CEM solves are: (1) the flows along each arc (including flows associated with storage), (2) the incremental pipeline capacity expansion required for each arc, and (3) the storage capacity expansion required for each region.

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[44] The look-ahead year n is an input parameter that represents the minimum planning horizon for constructing new pipeline and storage capacity in the CEM.

[45] Design weather is defined as the pattern of temperatures which results in degree days which are a certain percent colder than normal. Firm service customers (primarily local distribution companies) use demand estimates under design weather conditions for assessing their future need for firm pipeline transportation service.

Supply Representation

As with the Annual Flow Module, natural gas supply sources have been classified into the following basic categories: onshore and offshore dry gas production, Canadian and Mexican imports, liquefied natural gas imports, Alaskan gas transported via the Alaskan Natural Gas Transportation System, synthetic natural gas, and other supplemental supplies. Of these categories, all except onshore, offshore, and synthetic natural gas production are considered to be constant (or fixed) supplies within the CEM each year. The approach used to represent variable[46] supply sources is similar to that used in the Annual Flow Module. When a supply source is designated as fixed, the annual production is split into peak and offpeak levels based on assumed shares (SUP_PKSHR, Appendix F, Table F30). When a supply source is designated as variable, the portion of the annual production which can be used in either period is capped at assumed percentages of the annual production (SUP_PUTILZ and SUP_OUTILZ, Appendix F, Table F30).

Dry Gas Production

Both onshore and offshore dry gas production levels are a function of regional beginning-of-year natural gas reserve levels and expected production-to-reserves ratios, with functional forms identical to those used in the Annual Flow Module. The parameters defining these supply curves (provided by the Oil and Gas Supply Model) correspond to production levels for the year following the Annual Flow Module forecast year (current model year plus 1) and, therefore, serve as an approximation for supplies available to the CEM in the CEM forecast year (defined as current model year plus n). As in the Annual Flow Module, maximum and minimum supply levels are represented for each region. The minimum supply is calculated as a percentage of the resulting Annual Flow Module production in the Annual Flow Module forecast year, as shown in equation 21 of Chapter 3. The maximum supply is determined to be a specified percentage (PARM_MAXPR, Appendix F, Table F11) above the product of the reserves and the production-to-reserves ratio.

Natural Gas Pipeline Imports

Imports from Mexico and Canada for each CEM forecast year are represented in the CEM for each border crossing node. Mexican imports are represented as constant supply available to the firm network only. These imports are provided directly by the Oil and Gas Supply Model as annual supplies. The CEM then uses exogenously defined values (Appendix F, Table F30) to split these annual numbers into seasonal supply levels (peak and off-peak splits). Canadian imports are determined from Canadian pipeline capacities and utilizations. Canadian pipeline capacities are provided by the Oil and Gas Supply Model, while utilizations are defined by the NGTDM. Utilizations correspond to firm and interruptible networks and are composed of two categories: seasonal and annual. Seasonal utilizations (Appendix F, Table F34) are exogenously defined for the NGTDM and kept constant throughout the model. Annual utilizations, however, are calculated by the CEM in the previous forecast year and are based on imports resulting in that year. The Canadian produced natural gas which passes through the United States on its way to Canadian markets (as described in Chapter 3) is split into peak and offpeak levels based on assumed shares (CANFLO_PFSHR, Appendix F, Table F30). Both Mexican and Canadian imports are represented as fixed supplies each year in the CEM.

Liquefied Natural Gas Imports and the Alaskan Natural Gas Transportation System

The levels of liquefied natural gas imports into the four designated entry points, and the level of gas entering the United States via the Alaskan Natural Gas Transportation System, are provided to the CEM, as well as the Annual Flow Module, by the Oil and Gas Supply Model. For both of these sources, the level of supply assumed in the CEM for a future forecast year, is the level of supply the Annual Flow Module will actually see in that forecast year, (i.e., the CEM operates under perfect foresight with regard to these two supply categories).

For the *Annual Energy Outlook 1994,* the liquefied natural gas imports were specified exogenously. However, the Oil and Gas Supply Model includes an option for these imports to be specified endogenously. In such a case, the solution price from the Annual Flow Module at the nearest associated market node is provided to the Oil and Gas Supply Model at the end of each forecast year. This price is used as a basis for deciding whether or not the capacity at the associated gasification plant will be

[46] The production levels for variable supply sources are endogenously determined within the CEM as a function of the natural gas price.

expanded. The Oil and Gas Supply Model assumes that any added capacity will not be available for use until at least "n" years (as defined in the CEM) after the decision is made to expand. The decision to build is not reversed, even if the price in intervening years falls below the originally required threshold price. The utilization rates for the gasification plant capacities are set exogenously. Because of the lead time for these builds, the Oil and Gas Supply Model is able to provide the CEM with the import levels for liquefied natural gas for "n" years beyond the current forecast year.

Within the Oil and Gas Supply Model, the initial build (for those segments not already in existence) and the potential expansion decisions for the Alaskan Natural Gas Transportation System is structurally identical to the method used for endogenously forecasting the expansion of liquefied natural gas gasification facilities. Therefore, the representation of the Alaska Natural Gas Transportation System in the CEM likewise is similar to the approach taken for representing liquefied natural gas imports in the CEM. Natural gas supplied by Alaska Natural Gas Transportation System is provided by the Oil and Gas Supply Model based on the border price at the U.S./Canadian border adjoining the Pacific Census Division. The Oil and Gas Supply Model assumes that the final pipeline connection (and any subsequent expansions) of the Alaska Natural Gas Transportation System will be completed at least "n" years after the referenced border price is high enough to recover costs for the completion of the project.

Associated-Dissolved Gas, Synthetic Natural Gas, and Other Supply Sources

Three supply categories remain: associated-dissolved gas from oil, synthetic natural gas from coal, and other supplemental supplies. Associated-dissolved gas production is represented as a constant supply in both the Annual Flow Module and the CEM, and is determined from the average daily crude oil production levels provided by the Petroleum Market Model. However, due to the lack of a foresight value for crude oil production, the level of associated-dissolved production set within the Annual Flow Module is used in the CEM. Similarly, synthetic production of natural gas from coal for each model year is provided by the Coal Market Module and is represented as a constant supply within the Annual Flow Module[47] and, therefore, also within the CEM. Since both of these supply categories correspond to current year levels, they serve as an approximation for synthetic natural gas from coal and associated-dissolved gas available to the CEM in the CEM forecast year (defined as Annual Flow Module forecast year plus n). Synthetic natural gas produced from liquid hydrocarbons is treated as a variable supply type within the CEM. The quantity of synthetic natural gas produced is calculated as a function of the market price for natural gas, with the same functional form and constraints used in the Annual Flow Module. Finally, since other supplemental supplies are assumed to remain constant throughout the forecast in the Annual Flow Module, they also are assumed constant in the CEM (Appendix F, Table F12).

Demand Representation

Demands within the CEM include end-use consumption, export demands, and pipeline fuel consumption. As with the Annual Flow Module, end-use and export demands for forecast years beyond the current model year are defined by other models within NEMS, while pipeline fuel is accounted for through exogenously defined pipeline efficiencies (Appendix F, Table F19). End-use consumption levels are provided on an annual basis by region (Census or NGTDM/EMM) and type of service (firm or interruptible[48]), and are considered to be fixed demands in the CEM. Similarly, export demand forecasts are provided on an annual basis for each border crossing node and are defined to be fixed; however, Canadian exports are assumed to service interruptible customers only while Mexican exports service only firm customers.

Since the CEM is a seasonal model, each of the annual levels must be separated into peak and off-peak consumption. The CEM contains exogenously specified percentages for disaggregating these annual consumption levels into peak and off-peak periods. These shares (Appendix F, Tables F3 and F4 for consumption, Table F30 for exports) have been estimated using historical monthly consumption data reported by sector and region, combined with annual estimates of firm and interruptible service demands. Historically observed heating degree days have been included in the residential and commercial sector estimates so that the resulting shares reflect normal weather patterns (average monthly heating degree days). A future model enhancement may be to establish these peak/off-peak shares endogenously. For example, seasonal shifts in the demand for electricity (as represented within the Electricity Market Model) could be used as a basis for endogenously determining shifts in seasonal demands for

[47] Each forecast year, the Coal Market Module of NEMS estimates the amount of natural gas which will be produced from coal. The current system does not provide a mechanism for estimating these levels beyond the current forecast year. Such an enhancement will be considered in the future.

[48] For the electric utility sector, the interruptible service class is further subdivided into "competitive with distillate" and "competitive with residual fuel oil," as described in Chapter 3.

natural gas by the electric utility sector. Likewise, seasonal shares for the nonutility sectors could be specified at a more disaggregate level, such as by type of end-use (e.g., space heating).

The forecast years and regions representing end-use sector consumption in the CEM differ from one sector to another. For the industrial, transportation, and utility sectors, forecast consumption levels correspond to "n" years beyond the current model year, while residential and commercial consumption levels correspond to "n+h" years beyond the current model year. The "n" represents the number of years required to construct a pipeline and the "h" corresponds to the planning horizon used by a local distribution company when assessing capacity requirements.[49] As for regional representation, the Electricity Market Model provides utility consumption forecasts for the NGTDM/EMM regions defined in Chapter 3, while the NEMS system provides nonutility consumption forecasts by Census Divisions. As in the Annual Flow Module, estimates of Alaskan natural gas consumption are generated in the CEM in order to derive separate consumption levels for the Pacific Contiguous Division. Similarly, consumption levels within three of the Census Divisions are further subdivided to form separate NGTDM regions using the same fixed historically derived shares as are used in the Annual Flow Module. These splits include: Florida split from the rest of the South Atlantic Division, California split from the rest of the Pacific Contiguous Division, and Arizona and New Mexico split from the rest of the Mountain Division.

Pipeline Capacity Price Curve

Initial pipeline capacity price curves are developed by the Pipeline Tariff Module at the beginning of the forecast. These curves are based on estimates of capital costs of expansion and parameters (such as interest rates) from the NEMS macroeconomic model. (See Chapter 8 for a complete description of how these tariffs are calculated.) Each cost curve represents the per unit reservation charge on a particular interregional arc (PCAP) based on the annual physical capacity (design day capacity[50] times 365). The base quantity (initial step) represents the existing pipeline capacity. The corresponding price is the base year reservation charge (i.e., the demand charge) expressed on a per unit basis. Subsequent steps represent incremental expansion and the corresponding incremental tariff. It is assumed that the price curve is nondecreasing. To keep the curve increasing when additional capacity is expected to result in declining prices (such as when incremental capacity expansion is the result of added compression), the step on the curve associated with this additional capacity is held at the price associated with the previous step, i.e., the step representing the level of capacity without the addition. A generic pipeline capacity price curve is presented in Figure 7-2.

[49] These variables were defined as follows in the *Annual Energy Outlook 1994*: n=2, h=3.

[50] A pipeline's design day capacity (or certificated capacity) represents a level of service that can be maintained over an extended period of time and may not represent the maximum throughput capability of the system on any given day.

Figure 7-2. Pipeline Capacity Price Curve

In forecast year t, the CEM determines the capacity expansion for year t+n (the CEM forecast year). Therefore, each year the CEM must adjust the price curves based on capacity expansion which was determined in the previous CEM forecast year, and set to come on-line in year t+n-1. Specifically, the quantity associated with the base step on the curve will be adjusted to equal the capacity which will exist on the arc at the end of year t+n-1, where t is the current model year and n is the number of years beyond the current model year for which the CEM is determining expansion. Note that adjustments to the curve have already been made in previous CEM forecasts to reflect expansion in any of the intervening years to year t+n-1. The associated base level tariff is set to zero because the majority of the costs associated with existing capacity are sunk costs.[51]

Storage Capacity Price Curve

Initial working gas storage capacity price curves are determined by the Pipeline Tariff Module at the beginning of the forecast. These curves are based on estimates of capital costs of expansion, costs of holding base gas in storage, and parameters (such as interest rates) from the NEMS macroeconomic model. (See Chapter 8 for a complete description of how these tariffs are calculated.) Each cost curve represents the storage charge per unit (PSTR) as a function of the annual working gas capacity for a particular region. This storage charge is exclusive of any transportation costs to move gas to or from storage areas. The base quantity (initial step) represents the existing working gas storage capacity (Appendix F, Table F33). The corresponding price is the initial storage charge per unit. Subsequent steps represent incremental expansion and the corresponding incremental charge. The final step on the curve represents an upper limit on working gas storage capacity expansion due to known physical limits in a region (Appendix F, Table F26) or other nonprice dependent factors. A generic working gas storage capacity price curve is presented in Figure 7-3.

[51]After initial testing of the model, it was determined that the base tariff should be set to zero to prevent the model from overbuilding in the early years of the forecast. During this period, large regional supply price differentials make it economic to build new capacity to access competitively priced supplies while leaving existing capacity highly underutilized. Regulation of pipeline construction activities and the potential for discounting existing rates deter the construction of new capacity at the expense of existing capacity. A future improvement to the CEM will set the base tariff to the variable cost.

Figure 7-3. Storage Capacity Price Curve

Each year the CEM must adjust these working gas storage price curves based on the current capacity levels, similar to the adjustment made to the pipeline capacity price curves. Specifically, the quantity associated with the base step on the curve is adjusted to equal the working gas storage capacity which exists in the region at the end of year t+n-1, where t is the current model year and n is the number of years beyond the current model year for which the CEM is determining expansion. Since in model year t the capacity expansion for year t+n is being determined, the base step includes working gas capacity for current year t as well as the capacity expansions defined in years t+1,t+2,...,t+n-1. The associated base level tariff is determined as a quantity-weighted average of the tariff associated with the existing capacity and the tariffs for each of the previously determined expansions for years t+1, t+2,..., t+n-1, as well as the original base storage capacity in model year t.

Linear Program Formulation

A linear programming (LP) framework is used in the CEM as the basis for determining expansion requirements for pipeline and storage facilities. As described in Chapter 4, the CEM structure is based on a natural gas transmission and distribution system composed of four parallel networks interconnected at the supply points and the storage points. These networks serve to represent the seasonal nature (peak and off-peak) and types of service (firm and interruptible) associated with the natural gas market. Thus, peak firm, peak interruptible, off-peak firm, and off-peak interruptible service are modeled by the four networks. The CEM LP is solved in two phases: The first phase establishes pipeline and storage capacity expansion requirements, and the second establishes final firm, interruptible, peak and off-peak flows. This section defines the linear program methodology used to determine the expansion requirements necessary to enable gas to flow along the networks to meet expected gas consumption, while minimizing delivered costs. Also included is a description of how all of these pieces are used to determine the pipeline and storage capacity expansion requirements.

General Description of the Linear Program Formulation

The objective of the linear program designed for the CEM is to minimize the cost of supplying and transporting natural gas to the end-user, subject to operational and supply constraints, with the requirement to satisfy all firm service demand under design weather conditions. This section gives a general description and justification of the linear programming formulation (objective function and constraints), and a subsequent section includes the explicit mathematical equations representing the formulation.

The objective function has been formulated to minimize costs. These costs include the costs of supplies, transportation along the existing network, and costs of additional pipeline and storage capacity. The objective function can be represented as follows:

> minimize {transportation costs + supply costs + pipeline expansion costs + storage expansion costs + backstop supply costs}

A mass balance constraint is included for each transshipment node. This constraint ensures that the total input to the node equals the total output from the node. In general, gas flowing into a transshipment node comes from other transshipment nodes, supply points, and (in some cases) storage, while gas flowing from a transshipment node goes to demand points, other transshipment nodes, and (in some cases) storage. Flows into and out of storage have been defined to be network dependent because gas generally is injected into storage in the off-peak period and used to satisfy firm customer demand during the peak period. (Peak interruptible customers also may draw from storage if it is not needed for firm customers.) Therefore, in the linear program formulation, gas flows into a regional storage point from transshipment nodes (in the same region) on the off-peak firm and interruptible service networks, and flows out of the same storage point to transshipment nodes (again in the same region) on the peak firm and interruptible service networks. A general transshipment node mass balance constraint is listed below for each of the four parallel networks.

For each peak period firm service network transshipment node:

> (flow into the transshipment node from other peak period firm service network transshipment nodes) + (flow into the transshipment node from supply points in the region) + (flow into the transshipment node from storage in the region) - (losses) = (flow out of the transshipment node to peak period firm demand points in the region) + (flow out of the transshipment node to other peak period firm service network transshipment nodes)

For each peak period interruptible service network transshipment node:

> (flow into the transshipment node from other peak period interruptible service network transshipment nodes) + (flow into the transshipment node from supply points in the region) + (flow into the transshipment node from storage in the region) - (losses) = (flow out of the transshipment node to peak period interruptible demand points in the region) + (flow out of the transshipment node to other peak period interruptible service network transshipment nodes)

For each off-peak period firm service network transshipment node:

> (flow into the transshipment node from other off-peak period firm service network transshipment nodes) + (flow into the transshipment node from supply points in the region) - (losses) = (flow out of the transshipment node to storage in the region) + (flow out of the transshipment node to off-peak period firm demand points in the region) + (flow out of the transshipment node to other off-peak period firm service network transshipment nodes)

For each off-peak period interruptible service network transshipment node:

> (flow into the transshipment node from other off-peak period interruptible service network transshipment nodes) + (flow into the transshipment node from supply points in the region) - (losses) = (flow out of the transshipment node to storage in the region) + (flow out of the transshipment node to off-peak period interruptible demand points in the region) + (flow out of the transshipment node to other off-peak period interruptible service network transshipment nodes)

A mass balance constraint also is included for each storage point. This constraint ensures that the total gas input into storage equals the total gas output from storage. As mentioned above, gas flows to storage from the off-peak period firm and interruptible service networks, and gas flows out of storage to the peak period firm and interruptible service networks. The flow comes from and goes to the transshipment node corresponding to the same region as the storage point. A mass balance constraint for storage is presented below.

For each storage point:

> (flow of gas into a storage point from the off-peak period firm service network transshipment node) + (flow of gas into a storage point from the off-peak period interruptible service network transshipment node) - (losses) = (flow of gas out of the storage point to the peak period firm service network transshipment node) + (flow of gas out of the storage point to the peak period interruptible service network transshipment node)

Each demand point also has a mass balance constraint represented. This constraint ensures that the quantity allocated to the end-use point equals the expected consumption level associated with that point. All expected firm demand (peak and off-peak) must be satisfied; however, pipeline and storage facilities can only be built to meet peak firm service demands. It is assumed that the resulting capacity levels will be sufficient to accommodate flows to satisfy firm off-peak period requirements. Since new facilities are not built for the satisfaction of interruptible demand, a backstop supply is a modeling structure introduced to represent the portion of the interruptible demand for natural gas which cannot be satisfied by conventional supply sources and must be interrupted. A general transshipment node mass balance constraint is listed below for each of the four parallel networks.

For each peak period firm demand point:

> (flow from a peak period firm service network transshipment node in a region to a peak period firm demand point in the region) - (losses) = (quantity consumed at that peak period firm demand point)

For each peak period interruptible demand point:

> (flow from a peak period interruptible service network transshipment node in a region to a peak period interruptible demand point in the region) + (backstop supply) - (losses) = (quantity consumed at that peak period interruptible demand point)

For each off-peak period firm demand point:

> (flow from an off-peak period firm service network transshipment node in a region to an off-peak period firm demand point in the region) - (losses) = (quantity consumed at that off-peak period firm demand point)

For each off-peak period interruptible demand point:

> (flow from an off-peak period interruptible service network transshipment node in a region to an off-peak period interruptible demand point in the region) + (backstop supply) - (losses) = (quantity consumed at that off-peak period interruptible demand point)

Supply utilization constraints are included for each supply point. Since gas may flow from a supply point to a transshipment node (in the same region) in any of the four parallel networks, these supply constraints ensure that the flows (including losses) do not exceed the total amount supplied at that point. The constraints also ensure that the quantity flowing from the supply point has been properly split between the peak and off-peak period during any one year, thus generating a peak supply constraint and an off-peak supply constraint. The peak supply constraint states that, for any supply type and any supply level, a specified portion (Appendix F, Table F30) of the annual supply flow must be used to supply peak demands. Similarly, the off-peak supply constraint states that a specified portion of the annual supply flow must be used to supply off-peak demands. The latter constraint is defined slightly differently for onshore and offshore dry gas production: the supply quantity supplied to the off-peak networks must be less than or equal to a specified portion of the total annual dry gas production level. The constraints are as follows.

For each supply point:

> (flow from the supply point to a peak period firm service network transshipment node) + (flow from the supply point to a peak period interruptible service network transshipment node) = (peak share of total supply) * (total annual quantity supplied from the supply curve)

For each onshore and offshore supply point:

> (flow from the supply point to an off-peak period firm service network transshipment node) + (flow from the supply point to an off-peak period interruptible service network transshipment node) þ (off-peak share of total supply) * (total annual quantity supplied from the supply curve)

For each supply point excluding onshore and offshore supplies:

> (flow from the supply point to an off-peak period firm service network transshipment node) + (flow from the supply point to an off-peak period interruptible service network transshipment node) = (off-peak share of total supply) * (total annual quantity supplied from the supply curve)

A constraint (referred to as the alpha constraint) has been established to prevent backstop prices from translating back through the network from the demand points when backstop supply is required. This constraint has been developed to support the requirements that firm peak period demand must be satisfied first, and that capacity expansion can only be made to satisfy firm peak period demand. In the effort to satisfy peak firm demands, some interruptible demands may not be able to be met by conventional supply sources (i.e., must be interrupted). Since all demands in the CEM are considered to be constant and, therefore, must be met before the model can produce an optimal solution, high priced backstop supply (a fabricated supply source) has been made available to interruptible end-use customers to model an interruption in service without producing an infeasible solution. Due to the structure of the linear program, without the alpha constraint these high prices would translate back through the network and potentially cause the CEM to make decisions that were not economical. The alpha constraint states that the total interruptible flows from a node to the end-use demand points must be less than or equal to total interruptible end-use demands. Since this constraint must be binding[52] in order to prevent the backstop prices from translating back through the system, the right hand side is represented as: alpha times total interruptible end-use demands. The alpha factor (ranges from 0.0 to 1.0) starts at 1.0 and is reduced systematically until the constraint becomes binding. Each time alpha is changed, the CEM linear program matrix is solved and evaluated. The alpha constraint is presented below.

> (flow out of the transshipment node to peak period interruptible demand points in all lower 48 regions) + (flow out of the transshipment node to off-peak period interruptible demand points in all lower 48 regions) - losses þ (alpha factor) * ((total quantity consumed at the peak period interruptible lower 48 demand point) + (total quantity consumed at the off-peak period interruptible lower 48 demand point))

A more efficient methodology for determining the proper alpha was recently proposed, but has not been implemented due to time constraints. The following is a summary of this proposed methodology. First, alpha is set equal to 1.0 and the CEM is solved. If the alpha constraint is not binding at this point, a new alpha is determined: alpha equals the fraction of total interruptible demand that was not met by backstop supplies (minus a tolerance of .01). This new approach should reduce the number of times the CEM needs to be solved and evaluated.

Capacity expansion and flow constraints are defined for each interregional arc in the overall network. These constraints ensure that pipeline capacity is built, as necessary, to satisfy only firm peak period demand, and that the total flows along the interregional arcs are less than or equal to the available capacities (base[53] plus added capacity). Within these constraints seasonal maximum arc utilization rates are used to capture the variation in load patterns and operational limitations

[52] Binding means that the left side of the equation equals the right side.

[53] Recall from previous sections that capacity expansion levels are being determined for year t+n; therefore, the base capacity refers to the capacity existing at the end of the year t+n-1.

throughout the season. Constraints have been established for firm peak period flows, total peak period flows, and total off-peak period flows for each interregional arc in the network. In general, maximum seasonal pipeline utilizations are set equal to the fraction of the year the season represents times an assumed maximum utilization rate for the type of service represented (Appendix F, Table F34) times a factor representing the percentage of the pipe reserved to account for the potential of abnormal weather (Appendix F, Table F40).

It is the firm peak period capacity constraint that ensures that no pipeline capacity is built beyond what is needed to satisfy peak period firm service requirements. It states that total peak firm flow along an arc must **equal** total capacity (base plus added capacity) times a maximum peak firm arc utilization rate. It is the equality requirement that does not allow new capacity to be built unless peak firm demands require additional quantities to flow along the specific arc(s). The peak total (firm and interruptible) period capacity constraint has been established as an **inequality** constraint to ensure that the flows to satisfy interruptible peak period service are **less than or equal to** the remaining peak season effective capacity (i.e., total capacity times the maximum peak season utilization rate) once the firm service requirements have been met. In addition, an off-peak period capacity constraint (also as an inequality constraint) has been developed to ensure that the total off-peak season flows on the arc are less than or equal to the off-peak season effective capacity (i.e., total capacity times the maximum off-peak season utilization rate). The resulting constraints are given below for each interregional arc.

For each peak firm interregional arc:

> (flow along the arc to satisfy firm peak period service requirements) = (level of base capacity used + level of pipeline capacity expansion) * (peak period interregional arc maximum utilization rate for firm service)

For each peak firm and interruptible interregional arc:

> (flow along the arc to satisfy interruptible peak period service requirements) + (flow along the arc to satisfy firm peak period service requirements) þ (base capacity + level of pipeline capacity expansion) * (peak period interregional arc maximum utilization rate)

For each off-peak firm and interruptible interregional arc:

> (flow along the arc to satisfy interruptible off-peak period service requirements) + (flow along the arc to satisfy firm off-peak period service requirements) þ (base capacity + level of pipeline capacity expansion) * (off-peak period interregional arc maximum utilization rate)

Storage expansion and flow constraints are defined for each node in the lower 48-State portion of the network. These constraints ensure that storage capacity is built, as necessary, to satisfy peak firm service requirements and that the flows from storage are less than or equal to the total available storage capacity (base[54] plus added capacity). Constraints have been established for firm peak period flows and total peak period flows from storage locations at each node. Storage utilization rates (Appendix F, Table F31) have been used to define the maximum storage levels used for peak firm service and total peak storage. The peak firm constraint has been established as an equality constraint to ensure that no storage capacity is built beyond what is needed to satisfy peak period firm service requirements. The total peak constraint has been established as an inequality constraint to ensure that the flows to satisfy interruptible service are less than or equal to the effective storage capacity remaining after the firm service requirements have been met. The resulting constraints are given below.

For each storage point:

> (flow from the storage point to the peak period firm service network transshipment node) = ((level base storage capacity used) + (storage capacity expansion)) * (peak period maximum storage utilization rate for firm service)

For each storage point:

> (flow from the storage point to the peak period interruptible service network transshipment node) + (flow from the storage point to satisfy firm service requirements) þ ((base storage capacity) + (storage capacity expansion)) * (peak period maximum storage utilization rate for total peak service)

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[54] Recall from previous sections that storage capacity expansion levels represent working gas capacities and are being determined for year t+n; therefore, the base storage refers to the working gas storage capacity existing at the end of the year t+n-1.

Similar to the AFM, minimum flows have been defined for the CEM firm networks, (in the form of lower bounds on the flow variables). These minimum flows are defined to be a fraction of the resulting firm flows in the Annual Flow Module in the current model year plus an estimated utilization of the new capacity added between the current model year (t) and the beginning of the CEM forecast year (t+n). As in the Annual Flow Module, this fraction is exogenously specified (Appendix F, Table F32) and is intended to represent the level of flexibility firm customers exhibit in changing their selected routes for transporting natural gas from year-to-year, even if relative costs would indicate a change would be prudent (e.g., flexibility would be lessened due to the existence of long-term contracts). Finally, maximum utilization rates are used to split the minimum firm flow into peak and off-peak minimum firm flows, as described below.

For each interregional arc on the peak firm network:

peak firm flow þ (minimum flow fraction) * (estimated firm flow) * (peak period share of firm flow)

For each interregional arc on the off-peak firm network:

off-peak firm flow þ (minimum flow fraction) * (estimated firm flow) * (off-peak period share of firm flow)

Additional constraints are represented as lower and/or upper bounds on the flow variables. These include lower bounds set for flows along all arcs (and networks) with bidirectional flows,[55] as well as upper and lower bounds set on all flows into (off-peak firm and interruptible) and out of (peak firm and interruptible) storage. Finally, a number of bound constraints are needed to completely describe the step functions for the supply, capacity expansion, and storage expansion curves. These bounds serve to define the lengths of each of the steps on the curves.

Thus, the linear program solves for the level and location of storage and pipeline capacity expansion, as well as the associated peak and off-peak flows. Note that the amount of capacity expansion is a continuous function. Although, for a given pipeline company, capacity may be added only through discrete projects, the arcs in the CEM represent aggregates of pipeline companies. Taken together these companies can add capacity in virtually any desired quantity through combinations of additional compressor capacity, looping, or other means.

Mathematical Specification of the Linear Programming Formulation

This section presents the set of equations which establishes the linear programming formulation for the CEM. This set is comprised of an objective function, flow constraints, and bounds on model variables.

$$\begin{aligned}\underset{x,ysup,ycap,ystr,qzz}{\text{minimize}} \; & \sum_{i,j} TAR^{F}_{i,j}\,(x^{PF}_{i,j} + x^{OF}_{i,j}) + \sum_{i,j} TAR^{I}_{i,j}\,(x^{PI}_{i,j} + x^{OI}_{i,j}) + \sum_{s,i} TAR^{P}_{s,i}\,(x^{PF}_{s,i} + x^{PI}_{s,i}) \\ & + \sum_{s,i} TAR^{O}_{s,i}\,(x^{OF}_{s,i} + x^{OI}_{s,i}) + \sum_{i,d} TAR^{PF}_{i,d}\,x^{PF}_{i,d} + \sum_{i,d} TAR^{PI}_{i,d}\,x^{PI}_{i,d} + \sum_{i,d} TAR^{OF}_{i,d}\,x^{OF}_{i,d} \\ & + \sum_{i,d} TAR^{OI}_{i,d}\,x^{OI}_{i,d} + \sum_{s,i}\sum_{k=1}^{c} PSUP_{s,i,k}\,ysup_{s,i,k} + \sum_{i,j}\sum_{k=0}^{c} PCAP_{i,j,k}\,ycap_{i,j,k} \\ & + \sum_{st,i}\sum_{k=0}^{c} PSTR_{st,i,k}\,ystr_{st,i,k} + \sum_{i,d} PZZ^{PI}_{i,d}\,qzz^{PI}_{i,d} + \sum_{i,d} PZZ^{OI}_{i,d}\,qzz^{OI}_{i,d}\end{aligned} \qquad (51)$$

where,

[55] The minimum flows for bidirectional arcs, by both firm and interruptible service categories, that are established in the Annual Flow Module are multiplied by assumed peak shares (Appendix F, Table F38) to set comparable minimum flows in the CEM.

the subscripted indices are:

i,j, and m	=	transshipment node
d	=	demand type
s	=	supply type
st	=	storage
k	=	step on the curve
c	=	number of steps on the curve
i,j	=	arc connecting transshipment nodes i and j
i,d	=	arc from transshipment node i to demand point d
s,i	=	arc from supply point s to transshipment node i
st,i	=	arc from transshipment node i to storage point st
i,st	=	arc from transshipment node i to storage point st

the superscripted indices are:

P	=	peak period
O	=	off-peak period
F	=	firm
I	=	interruptible

the parameters are:

TAR	=	tariff (pipeline usage from node to node, gathering charge from supply point to node, or distributor charge from node to end-use point), (dollars per Mcf)
EFF	=	efficiencies (fraction)
U	=	maximum allowable utilization of an arc in the season (fraction)
UP	=	maximum percentage of supply available for demand type (fraction)
UST	=	maximum percentage of storage available to demand type (fraction)
QDEM0	=	quantity demanded (Bcf)
ESTFLOW	=	flow from Annual Flow Module in year t, plus estimated utilization of capacity added after year t through year t+n (Bcf)
SHR	=	period share of total flow (fraction)
MINBIFLO	=	minimum flow for bidirectional arcs (Bcf)
MNSTR	=	minimum flow allowed into or out of storage for specified network (Bcf)
MXSTR	=	maximum flow allowed into or out of storage for specified network (Bcf)
ALPHA	=	factor used to bind the alpha constraint (fraction)
DMD	=	total demand for a demand type (Bcf)
PCTMFLO	=	percent minimum flow requirement (fraction)
PSUP	=	prices on the supply steps (dollars per Mcf)
PCAP	=	prices on the pipeline capacity steps (dollars per Mcf)
PSTR	=	prices on the storage capacity steps (dollars per Mcf)
PZZ	=	price of backstop supply (dollars per Mcf)
LSUP	=	lower bound on supply step (Bcf)
USUP	=	size of supply step (Bcf)
UCAP	=	size of pipeline capacity step (Bcf)
USTR	=	size of storage capacity step (Bcf)

the variables are:

$x_{i,j}$	=	flow from i to j (Bcf)
$ysup_{s,i,k}$	=	for supply point (s,i), the amount of supply step k taken (Bcf)
$ycap_{i,j,k}$	=	for arc i,j, the amount of pipeline capacity step k built (Bcf)
$ycap_{i,j,0}$	=	for arc i,j, the amount of base pipeline capacity taken (Bcf)
$ystr_{st,i,k}$	=	for storage point (st,i), the amount of storage capacity step k built (Bcf)
$ystr_{st,i,0}$	=	for storage point (st,i), the amount of base capacity taken (Bcf)
$qzz_{i,d}$	=	amount of backstop supply used for demand point (i,d), (Bcf)

Mass Balance Constraints at Each Transshipment Node (m):

$$ {}_{\substack{i\\ i\ m}} x^{PF}_{i,m}\ EFF^{P}_{i,m} \quad {}_{s} x^{PF}_{s,m}\ EFF^{P}_{s,m} \quad {}_{st} x^{PF}_{st,m}\ EFF^{P}_{st,m} \quad {}_{d} x^{PF}_{m,d} \quad {}_{\substack{i\\ i\ m}} x^{PF}_{m,i} \qquad (52) $$

$$ {}_{\substack{i\\ i\ m}} x^{PI}_{i,m}\ I \qquad (53) $$

$$ {}_{\substack{i\\ i\ m}} x^{OF}_{i,m}\ EFF^{O}_{i,m} \quad {}_{s} x^{OF}_{s,m}\ EFF^{O}_{s,m} \quad {}_{st} x^{OF}_{m,st} \quad {}_{d} x^{OF}_{m,d} \quad {}_{\substack{i\\ i\ m}} x^{OF}_{m,i} \qquad (54) $$

$$ {}_{\substack{i\\ i\ m}} x^{OI}_{i,m}\ EFF^{O}_{i,m} \qquad (55) $$

Mass Balance Constraints at Each Storage Point (st,i):

$$ (x^{OF}_{i,st} \quad x^{OI}_{i,st})\ EFF^{O}_{i,st} \quad x^{PF}_{st,i} \quad x^{PI}_{st,i} \qquad (56) $$

Mass Balance Constraints for Demand Points (i,d):

$$ x^{PF}_{i,d}\ EFF^{P}_{i,d} \quad QDEM0^{PF}_{i,d} \qquad (57) $$

$$ x^{PI}_{i,d}\ EFF^{P}_{i,d} \quad qzz^{PI}_{i,d} \quad QDEM0^{PI}_{i,d} \qquad (58) $$

$$ x^{OF}_{i,d}\ EFF^{O}_{i,d} \quad QDEM0^{OF}_{i,d} \qquad (59) $$

$$ x^{OI}_{i,d}\ EFF^{O}_{i,d} \quad qzz^{OI}_{i,d} \quad QDEM0^{OI}_{i,d} \qquad (60) $$

Supply Utilization Constraints at Each Supply Point (s,i):

$$ x^{PF}_{s,i} \quad x^{PI}_{s,i} \quad {}^{c}_{k\ 1} ysup_{s,i,k}\ UP^{P}_{s,i} \qquad (61) $$

For onshore and offshore supply types only,

$$ x^{OF}_{s,i} \quad x^{OI}_{s,i} \quad {}^{c}_{k\ 1} ysup_{s,i,k}\ UP^{O}_{s,i} \qquad (62) $$

For all supply types other than onshore and offshore,

$$ x^{OF}_{s,i} \quad x^{OI}_{s,i} \quad {}^{c}_{k\ 1} ysup_{s,i,k}\ UP^{O}_{s,i} \qquad (63) $$

Alpha Constraint:

$$ {}_{i,d} (\ x^{PI}_{i,d} \quad x^{OI}_{i,d}\ ) \quad ALPHA \quad {}_{i,d} \left(\frac{DMD^{PI}_{i,d}}{EFF^{P}_{i,d}} \quad \frac{DMD^{OI}_{i,d}}{EFF^{O}_{i,d}} \right) \qquad (64) $$

Pipeline Capacity Constraints for Each Arc (i,j):

$$ x^{PF}_{i,j} \quad U^{PF}_{i,j}\ (ycap_{i,j,0} \quad {}^{c}_{k\ 1} ycap_{i,j,k}) \qquad (65) $$

$$ x^{PI}_{i,j} \quad x^{PF}_{i,j} \quad U^{P}_{i,j}\ (ycap_{i,j,0} \quad {}^{c}_{k\ 1} ycap_{i,j,k}) \qquad (66) $$

$$ x^{OF}_{i,j} \quad x^{OI}_{i,j} \quad U^{O}_{i,j}\ (ycap_{i,j,0} \quad {}^{c}_{k\ 1} ycap_{i,j,k}) \qquad (67) $$

Storage Capacity Constraint for Each Region (st,i):

$$x^{PF}_{st,i} \quad UST^{PF}_{st,i} \quad (ystr_{st,i,0} \quad \mathop{}^{c}_{k\;1} ystr_{st,i,k}) \qquad (68)$$

$$x^{PI}_{st,i} \quad x^{PF}_{st,i} \quad UST^{P}_{st,i} \quad (ystr_{st,i} \qquad (69)$$

Minimum Bounds on Peak and Off-peak Firm Flows for each Arc (i,j):

$$x^{PF}_{i,j} \quad PCTMFLO^{F}_{i,j} \quad ESTFLOW^{F}_{i,j} \quad SHR^{PF}_{i,j} \qquad (70)$$

$$x^{OF}_{i,j} \quad PCTMFLO^{F}_{i,j} \qquad (71)$$

Other bound constraints set minimum flows along bidirectional arcs, as well as minimum and maximum flows into and out of storage:

$x_{i,j}^{xx}$ þ MINBIFLO	for each bidirectional flow arc (i,j), and each network (xx = PF, PI, OF, OI)
$MNSTR_{st,i}^{xx}$ þ $x_{st,i}^{xx}$ þ $MXSTR_{st,i}^{xx}$	for each flow (xx = PF, PI, OF, OI) into and out of storage (st,i)

The following bound constraints also are defined for the steps on the supply, capacity expansion, and storage expansion curves:

$LSUP_{s,i,k}$	þ $ysup_{s,i,k}$	þ $USUP_{s,i,k}$	for each supply point (s,i), and k=1,2,...,n.
0	þ $ycap_{i,j,k}$	þ $UCAP_{i,j,k}$	for each arc i,j, and k=0,1,2,...,n.
0	þ $ystr_{st,i,k}$	þ $USTR_{st,i,k}$	for each storage point (st,i), and k=0,1,2,...,n.

For the most part LSUP is zero, except on the first step of the supply curve where a minimum supply level may be defined.

Thus, the above equations and bounds mathematically specify the linear program objective function and the key model constraints. A commercial software package[56] designed to solve linear programming problems is utilized to modify and solve the linear program matrix, and to access the resulting solution.

Implementation of the Linear Program Within the CEM

The CEM linear program solves for the level and location of pipeline and storage capacity expansion, as well as the corresponding peak and off-peak flows associated with firm and interruptible service. To provide this information, the linear program matrix is solved in two phases—the first establishes the pipeline and storage expansion levels, and the second establishes the final flows. Within each phase, the alpha factor (see equation 14) is systematically varied (starting at 1.0) until the alpha constraint is properly binding. This iterative method for setting alpha is described briefly below, followed by an explanation of the differences between the two solution phases.

As mentioned above, constant interruptible demands may need to be interrupted in order for all constant firm demands to be met. If this situation exists, supply and/or pipeline capacity is no longer available and backstop supply is needed to meet interruptible demands. Because of the nature of a linear program, the high prices associated with backstop supply flow back through the network and potentially cause the CEM to make decisions that may not be economical. Therefore, the goal of the alpha constraint is to prevent these high prices from filtering back through the network, without changing the level of demands that were initially interrupted. This is achieved by systematically reducing the alpha factor in the alpha constraint from 1.0 until the constraint is first binding. This process is performed in both phases.

In the first phase of the CEM, the linear program is defined according to the equations above, and iteratively solved until the alpha constraint is properly binding. From this solution, pipeline and storage capacity expansions and peak firm flows are established. However, base capacity on some pipeline arcs may not be fully utilized because of insufficient peak firm demand requirements. Likewise, some base storage capacity may not be fully utilized due to peak firm demand requirements. This underutilization, in turn, restricts the amount of off-peak and interruptible flows that can occur along the underutilized

[56] All of the linear programming problems within the NEMS will be solved using the Optimization and Modeling Library (OML), a product of Ketron Management Science, a Division of Bionetics Corporation.

arcs, and into/out of underutilized storage facilities. This occurrence is dictated by the pipeline and storage capacity constraints. The second phase serves to remove this connection between peak firm flows and other flows, while still maintaining the peak firm flow levels resulting in the first phase.

In the second phase, the peak period capacity constraints (equations 66 and 69) must be represented such that interruptible volumes can flow along the unused capacity. To accomplish this, pipeline and storage capacities ($ycap_{i,j}$ and $ystr_{st,i}$) are held constant and set equal to the solution levels (YCAP and YSTR) from the first CEM phase (base utilization plus added capacity). This is represented with the changes in the equation from 'ycap' to 'YCAP' and from 'ystr' to 'YSTR.' Also, a constant term is added to the constraint that identifies the unused base capacity which may used for interruptible flows only. The corresponding equations are presented below.

Pipeline Capacity Constraint for Peak Period Flows on Arc (i,j):

$$x_{i,j}^{PI} + x_{i,j}^{PF} \le U_{i,j}^{P} \left(YCAP0_{i,j} + \sum_{k=1}^{c} YCAP_{i,j,k}\right) + U_{i,j}^{P} \left(QCAP0_{i,j} - YCAP0_{i,j}\right) \quad (72)$$

Storage Capacity Constraint for Peak Period Flows in Each Region (st,i):

$$x_{st,i}^{PI} + x_{st,i}^{PF} \le UST_{st,i}^{P} \left(YSTR0_{st,i} + \sum_{k=1}^{c} YSTR_{st,i,k}\right) + UST_{i,j}^{P} \left(QSTR0_{st,i} - YSTR0_{st,}\right) \quad (73)$$

where,

$x_{i,j}$	=	flow from i to j (Bcf)
U	=	maximum allowable utilization of an arc in the season (fraction)
QCAP0	=	base pipeline capacity (capacity level existing at the end of year t+n-1) (Bcf)
YCAP	=	actual pipeline capacity added (Bcf)
YCAP0	=	base pipeline capacity utilized (Bcf)
$x_{st,i}$	=	flow from storage (st) to node (i) (Bcf)
UST	=	maximum percentage of storage available (fraction)
QSTR0	=	base storage capacity (capacity level existing at the end of year t+n-1), (Bcf)
YSTR	=	actual storage capacity added (Bcf)
YSTR0	=	base storage capacity utilized (Bcf)

With the completion of the second phase, the CEM has generated pipeline and storage capacity expansion results, as well as seasonal flows corresponding to firm and interruptible markets. The capacities are used directly in the Annual Flow Module, while the flows are used to generate annual pipeline capacity utilization factors for use in the Annual Flow Module. The procedure to generate annual capacity utilization factors is presented in the next section.

Processing of CEM Results

The primary purpose of the CEM is to provide the Annual Flow Module and Pipeline Tariff Module each year with a forecast of physical pipeline capacity and working gas storage capacity for forecast year t+n, and to determine maximum pipeline capacity utilizations corresponding to annual firm and total interregional flows (to be used in the maximum annual flow constraints within the Annual Flow Module). Capacity expansion results are used to determine the forecasted capacity levels, while firm and total flows are used to determine pipeline utilizations. These calculations are presented below.

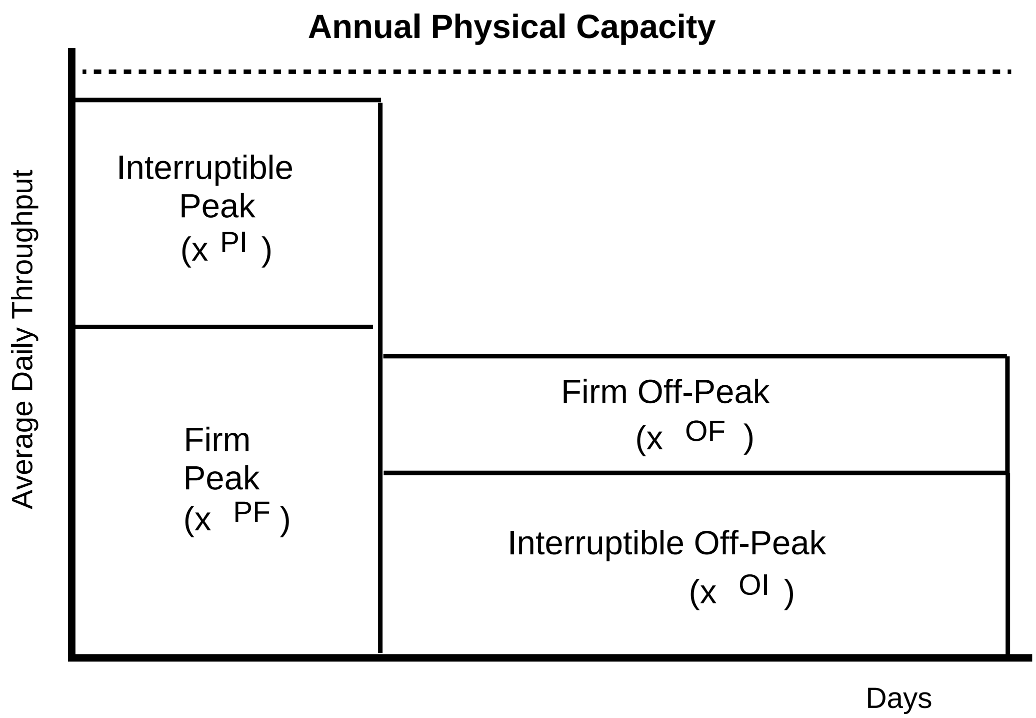
Pipeline and storage capacity expansion levels for forecast year t+n are generated by solving the CEM linear program, and are used to determine forecasted capacities. Physical pipeline capacity along the interregional arc from transshipment node i to node j is calculated as the base capacity (including planned expansions -- Appendix F, Table F42) plus the corresponding level of expansion in year t+n.

$$PhyCap_{i,j} = QCAP0_{i,j} + \sum_{k=1}^{n} ycap_{i,j,k} \quad (74)$$

Likewise, regional working gas storage for year t+n is calculated as base working gas (including planned expansions, Appendix F, Table F33) plus the corresponding level of expansion in year t+n.

$$StrCap_{st,i} = QSTR0_{st,i} + \sum_{k=1}^{n} ystr_{st,i,k} \tag{75}$$

Figure 7-4. Example of a Seasonal Flow Pattern Along an Arc



Since loads on a pipeline tend to be variable throughout a year (with full utilization more prevalent during the peak season and lower utilization during the off-peak season), the purpose of the maximum annual flow constraints in the Annual Flow Module is to better represent seasonal flows on an annual basis. This is accomplished by using the seasonal flow patterns resulting in the CEM and translating them into annual pipeline utilizations. The CEM calculates both firm and total annual pipeline utilizations to be used with the maximum annual flow constraints for both firm and total flows in the Annual Flow Module. A graphical depiction of the load curve that represents seasonal flows is presented in Figure 7-4.

Firm annual utilizations are a function of peak firm flows, off-peak firm flows, and peak firm utilization rates. Peak firm utilization rates (Appendix F, Table F34) define the maximum portion of total physical annual capacity available to the peak firm network along a specific arc, and are used in conjunction with other utilizations to establish arc-specific load duration curves represented in the CEM. Assuming that the resulting peak firm flow reflects full utilization of the capacity available to the firm market during the peak season, an equivalent maximum annual capacity available to the firm market can be calculated by dividing the peak firm flow by the peak firm utilization. Next, dividing the total firm flow (peak and off-peak) by this maximum annual firm capacity produces maximum firm annual utilizations used by the Annual Flow Module. The following equations result.

For the firm service market, along each arc i,j:

$AUTILZ_{i,j}^{F}$ = ((the flow along the arc to satisfy peak period firm service requirements) + (the flow along the arc to satisfy off-peak period firm service requirements)) / (equivalent annual firm capacity)

given, equivalent annual firm capacity = (the flow along the arc to satisfy peak period firm service requirements) / (peak firm utilization rate)

$$
\begin{aligned}
AUTILZ_{i,j}^{F} & \quad \frac{(x_{i,j}^{PF} \quad x_{i,j}^{OF})}{ECAP_{i,j}^{F}} \\
ECAP_{i,j}^{F} & \quad \frac{x_{i,j}^{PF}}{UTILZ_{i,j}^{PF}}
\end{aligned}
\tag{76}
$$

where,

$AUTILZ_{i,j}^{F}$	=	annual firm capacity utilization rate along arc i,j (fraction)
$x_{i,j}^{PF}$	=	peak firm flow along arc i,j (Bcf)
$x_{i,j}^{OF}$	=	off-peak firm flow along arc i,j (Bcf)
$ECAP_{i,j}^{F}$	=	equivalent capacity available to firm market along arc i,j (Bcf)
$UTILZ_{i,j}^{PF}$	=	peak firm capacity utilization rate along arc i,j (fraction)

Likewise, total capacity utilization rates are a function of peak firm flows, off-peak firm flows, peak interruptible flows, off-peak interruptible flows, and peak utilization rates. Peak utilization rates (Appendix F, Table F34) define the maximum portion of total physical annual capacity available in the peak period along a specific arc, and are used in conjunction with other utilizations to establish arc-specific load duration curves represented in the CEM. Assuming that the resulting peak flows reflect full utilization of the capacity available during the peak season, an equivalent maximum annual capacity available to the natural gas market can be calculated by dividing the total peak flow by the peak utilization. Next, dividing the total flow (peak and off-peak, firm and interruptible) by this maximum annual capacity produces maximum annual total utilizations used by the Annual Flow Module. The following equations result.

For the total natural gas market, along each arc i,j:

$AUTILZ_{i,j}^{T}$ = ((the flow along the arc to satisfy peak period firm service requirements) + (the flow along the arc to satisfy off-peak period firm service requirements) + (the flow along the arc to satisfy peak period interruptible service requirements) + (the flow along the arc to satisfy off-peak period interruptible service requirements)) / (equivalent total annual capacity)

given, equivalent total annual capacity = ((the flow along the arc to satisfy peak period firm service requirements) + (the flow along the arc to satisfy peak period interruptible service requirements) / (peak utilization rate)

$$
\begin{aligned}
AUTILZ_{i,j}^{T} & \quad \frac{(x_{i,j}^{PF} \quad x_{i,j}^{OF} \quad x_{i,j}^{PI} \quad x_{i,j}^{OI})}{ECAP_{i,j}^{T}} \\
ECAP_{i,j}^{T} & \quad \frac{(x_{i,j}^{PF} \quad x_{i,j}^{PI})}{UTILZ_{i,j}^{P}}
\end{aligned}
\tag{77}
$$

where,

$AUTILZ_{i,j}^{T}$	=	total annual capacity utilization rate along arc i,j (fraction)
$x_{i,j}^{PF}$	=	peak firm flow along arc i,j (Bcf)
$x_{i,j}^{OF}$	=	off-peak firm flow along arc i,j (Bcf)
$x_{i,j}^{PI}$	=	peak interruptible flow along arc i,j (Bcf)
$x_{i,j}^{OI}$	=	off-peak interruptible flow along arc i,j (Bcf)
$ECAP_{i,j}^{T}$	=	equivalent total annual capacity available to the natural gas market along arc i,j (Bcf)
$UTILZ_{i,j}^{P}$	=	peak capacity utilization rate along arc i,j (fraction)

Contingencies have been written into the code to ensure that the total utilization remains greater than the firm, and that the total utilization is above a minimum threshold utilization.

8. 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, for fully regulated services, the rates developed by the methodology are used as actual costs for transportation and storage services. Where interruptible services are more loosely regulated or where markets are deemed competitive, the methodology computes maximum and minimum rates for service. The minimum rate is used as a lower bound on the price of services. The actual price charged for these more loosely regulated services or the "market clearing price" is determined by the Annual Flow Module. Under current regulatory policy, the maximum price computed by the methodology (the 100-percent load factor rate) will act as a cap on the market clearing price. This "price cap" will not be enforced if deregulation of service is assumed or if Federal Energy Regulatory Commission provides for alternative pricing/cost recovery mechanisms.

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 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 (firm and interruptible),[57] 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 (1) transportation rates for the Annual Flow Module, (2) storage rates for the Annual Flow Module, (3) transportation rates for the Capacity Expansion Module to determine pipeline capacity expansion, and (4) storage rates for the Capacity Expansion Module to determine storage capacity expansion. A general overview of the

[57]This step is not carried out for storage service because no distinction is made between firm and interruptible storage services.

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

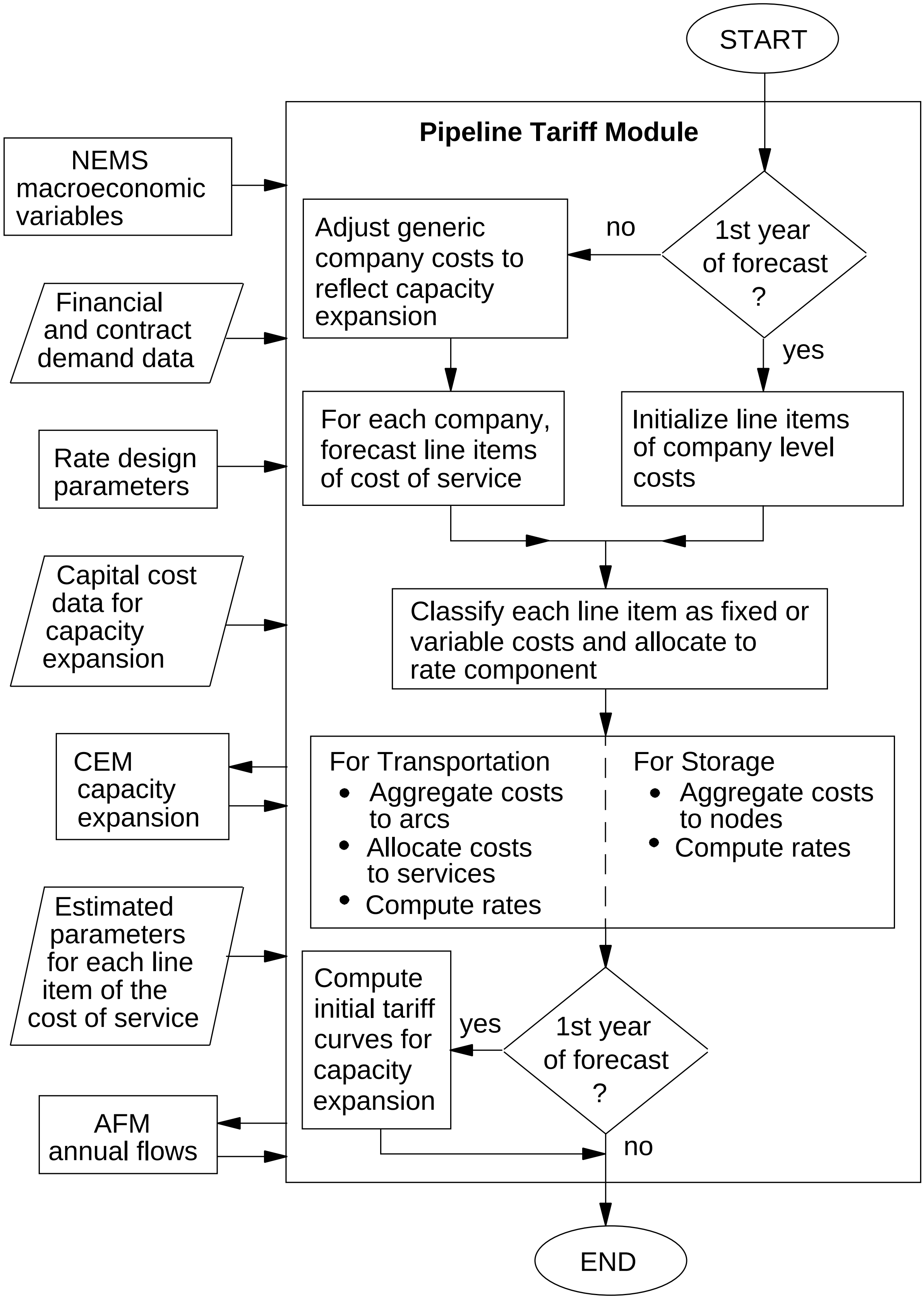
- Aggregate Costs to Network Arcs and Nodes

- Allocate Costs to Services
  - Derive Allocation Determinants
  - Derive Costs by Type of Service

- Compute Rates for Services
  - Derive Billing Determinants
  - Derive Unit Fees

methodology for deriving rates is presented in the box on the next page, while the PTM system diagram is presented in Figure 8-1.

Figure 8-1. Pipeline Tariff Module System Diagram



Base-Year Initialization Phase

The purpose of the base-year initialization phase is to provide, for the base year of the NEMS forecast horizon, 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 allocation and billing determinants. These determinants 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 three separate processes that occur during the base-year initialization phase: (1) the computation of the cost of service and rates for services, (2) the construction of capacity expansion cost/tariff curves, and (3) manipulations required to pass the rates to the Annual Flow Module and curves to the Capacity Expansion Module.

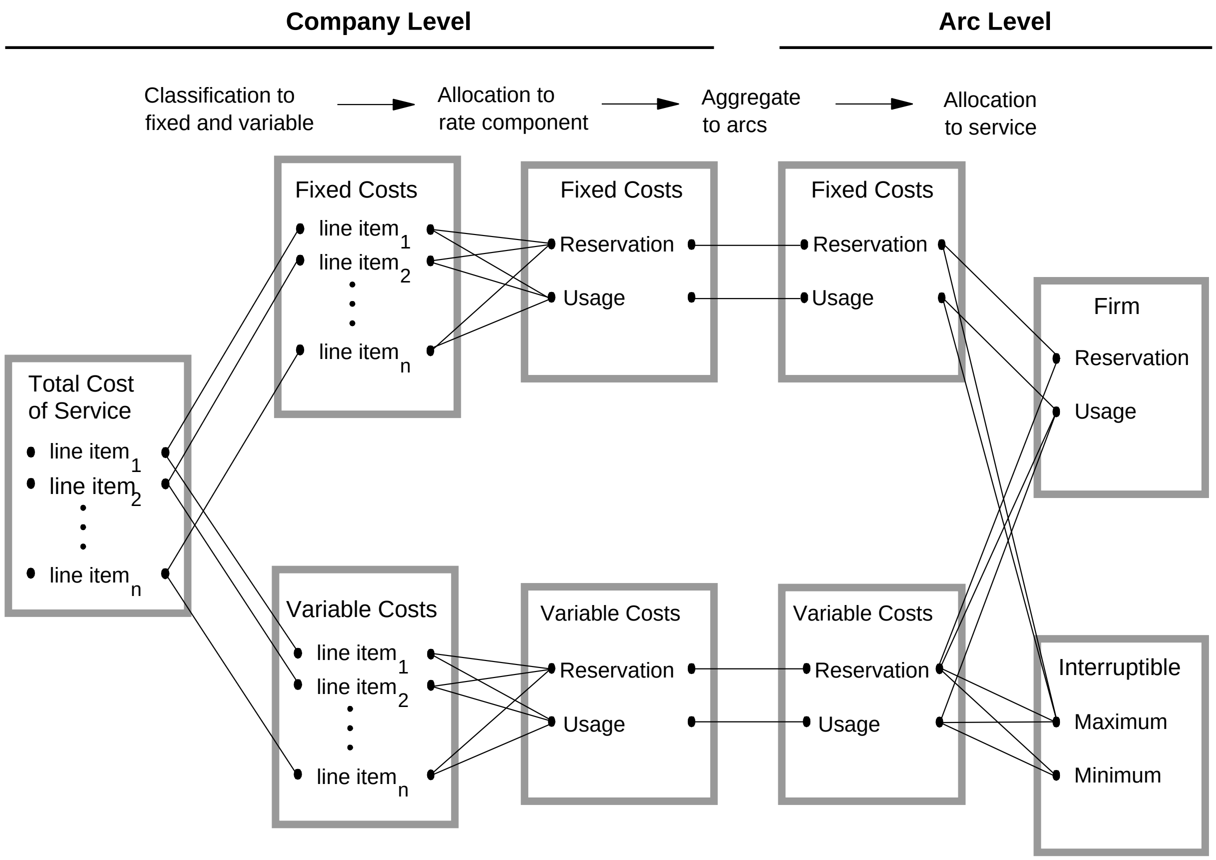
The computation of base-year cost of service and rates for services involves six distinct procedures as outlined in the box below. Each of these procedures is discussed in detail below.

In order to facilitate capacity expansion decisions in the Capacity Expansion Module, the PTM constructs cost/tariff curves which relate incremental 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.

Prior to passing the rates to the Annual Flow Module and Capacity Expansion Module, the PTM rates must be adjusted to maintain consistency among the three modules. PTM rates which are in nominal dollars must be converted to real dollars for use in the Annual Flow Module and Capacity Expansion Module.

Computation of Rates

Figure 8-2. Processing Transportation Service Costs in the Ratemaking Process



An overview of the processing of costs in the PTM ratemaking procedure is illustrated in Figure 8-2. 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 components based on rate design. The fourth step is to transform the costs from the company level to the network (arc and 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:

$$TCOS = TRR - REVC \tag{78}$$

$$TRR = TRRB + TNOE \tag{79}$$

where,

TCOS = total cost-of-service (dollars[58])
TRR = total revenue requirement (dollars)
TNOE = total normal operating expenses (dollars)
REVC = revenue credits to cost-of-service (dollars)
TRRB = total return on rate base (dollars)

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

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:

$$TRRB = WAROR * APRB \tag{80}$$

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.

$$PFEN = (PFES/TOTCAP) * PFER * APRB \tag{81}$$

$$CEMN = (CMES/TOTCAP) * CMER * APRB \tag{82}$$

$$LTDN = (LTDS/TOTCAP) * LTDR * APRB \tag{83}$$

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)

[58]All costs discussed in this chapter are in nominal 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:

$$WAROR = (PFES*PFER + CMES*CMER + LTDS*LTDR)/TC \tag{84}$$

$$TOTCAP = PFES + CMES + LTDS \tag{85}$$

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,

$$APRB = NIS + CWC + OWC + TPEB - ADIT \tag{86}$$

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)[59]
ADIT = accumulated deferred income taxes (dollars)

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

$$NIS = GPIS - ADDA \tag{87}$$

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

[59]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.

and maintenance expenses also are disaggregated into several categories to enhance accuracy in forecasting expenses by function.

$$TNOE = DDA + TOTAX + TAG + TCE + TOM \tag{88}$$

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)[60]
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:

$$TOTAX = FSIT + OTTAX - FSITC \tag{89}$$

$$FSIT = FIT + SIT \tag{90}$$

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)

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:

$$ATP = APRB*(PFER*PFES + CMER*CMES)/TOTCAP \tag{91}$$

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

$$FIT = (FRATE*ATP \;/\; 1.- FRATE) \tag{92}$$

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

where,

FIT = Federal income tax (dollars)
FRATE = Federal income tax rate (fraction)
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:

$$SIT = SRATE * (FIT + ATP) \tag{93}$$

where,

SIT = State income tax (dollars)
SRATE = average State income tax rate (fraction)
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.[61] Compressor station expenses are disaggregated further into two categories: compressor station operating and maintenance labor expenses and compressor station operating and maintenance nonlabor expenses. That is, total operating and maintenance expense (TOM) equals

$$TOM = SEOM + CSOML + CSOMN + OTOM \tag{94}$$

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 nonlabor 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 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:

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

$$R_{i,f} = ALL_f * R_i / 100 \tag{95}$$

$$R_{i,v} = ALL_v * R_i / 100 \tag{96}$$

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
$1 = ALL_f + ALL_v$

An example of this procedure is illustrated in Table 8-1.

Table 8-1. 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/Nonlabor	1,000	20	80	200	800
Other O & M	40,000	80	20	32,000	8,000
Revenue Requirement	225,000			211,200	13,800
Revenue Credits	25,000	100	0	25,000	0
Total Cost-of-Service	200,000			186,200	13,800

9. Model Assumptions, Inputs, and Outputs

This last chapter summarizes the 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 solutions. The first type can be derived based on historical data (past event), and the second type is based on an unknown source or not yet established data, but can be assumed based on experience and/or an event that is likely to occur (expert or analyst judgment). The discussion of the assumed values based on analyst judgment is beyond the scope of this report, and additional information on these data choices will be provided in the Model Development Report, Volume II (available December, 1994), which discusses the model performance and results of sensitivity testing. All model input assumptions derived from the known sources or analyst judgment are provided in Appendix F.

The assumptions summarized in this section are referred to in Chapters 3 - 8. They are used by NGTDM equations as their starting values, coefficients, factors, shares, bounds, or user specified parameters. Six general categories of data assumptions related to the classification of market services, demand, service pricing, pipeline tariffs and regulation, pipeline capacity and utilization, and supply have been defined. These assumptions are summarized below:

Market Service Classification

Non-utility sector demands for natural gas have been classified as either firm or interruptible service customers as follows. Natural gas consumed by residential, commercial, and transportation end-use sectors is assumed to be transported under firm transportation rates. Natural gas consumed by industrial end users is transported under both firm and interruptible transportation service arrangements: transportation rates for natural gas consumed in industrial boilers and in refineries are assumed to be interruptible, while natural gas for all other industrial uses is assumed to be transported under firm transportation rates.

Electric utility natural gas demand is classified as either (1) firm, (2) interruptible, priced competitive with distillate fuel oil, or (3) interruptible, priced competitive with residual fuel oil. The classification is based on the type of utility boiler. The electric utility generating units defining each of the three customer classes modeled are as follows: (1) firm — gas steam units or gas combined cycle units, (2) competitive-with-distillate — dual-fired turbine units or gas turbine units, (3) competitive-with-residual — dual-fired steam plants (consuming both natural gas and residual fuel oil).

Demand

The regional representations of natural gas demand curves for the nonutility sectors assumes that the share of nonutility gas consumption in an NGTDM region is held constant throughout the forecast period and is equal to the average historical levels from 1985 to 1990 (Table F6). Further, the user can specify values for the short-term price elasticity of these demand curves by sector (Equation 1 and Table F36).

Likewise, when developing the Alaskan Natural Gas Module, the Alaskan consumption is disaggregated into South and North Alaska in order to compute the natural gas production forecasts in these regions (Equations 5, 6). This methodology assumes that the value of gas consumption in South Alaska as a percent of total Alaskan gas demand is based on average historical data (Table F10), and the lease fuel, plant fuel, and pipeline fuel consumption as average percentages of total dry production in Alaska (Table F7). Also, when computing Alaskan end-use gas prices by different sectors (Equation 7), fixed markups derived from historical data (Table F8) are added to the average

Alaskan natural gas wellhead price. It is assumed that percentages and markups are constant throughout the forecast period.

The lease fuel consumption is computed from an historically derived percentage of dry gas production in each NGTDM/OGSM region (Table F2).

In the Capacity Expansion Module, the seasonal demand representations are calculated using the exogenously specified percentages to disaggregate the annual consumption in any year into peak and off-peak consumption. These peak and off-peak shares (Tables F3 and F4 for consumption, Table F30 for exports) by market types and sectors are estimated based on historical monthly natural gas consumption. These shares are constant throughout the forecast.

Pipeline fuel use is derived by NGTDM region using the efficiencies associated with each arc and exogenously specified shares which allocated fuel use to regions based on the mileage in a given region (Table F39). It is assumed that these shares are constant through the forecast. The NGTDM estimates ambient emissions from the pipeline fuel consumption. These emissions are a function of pipeline fuel use and emissions coefficients (Equation 36). An average emission coefficient vector was derived for each emission type represented in NEMS, using coefficients for different types of compressors and the 1990 national composition of compressor capacity (e.g. 23 percent reciprocating engine and 77 percent gas turbines). It is assumed that emission control technologies currently used on the compressors and the national composition of the compressor capacity do not change over the forecast. Thus, the emission factors are kept constant throughout the forecast period (Table F25).

Pricing of Services

Firm transportation rates for pipeline services are calculated assuming the cost of new pipeline capacity is rolled into the existing rate base. It is assumed that (1) prudency reviews restrict price increases for firm transportation services to less then 5 percent per year and (2) the effective maximum interstate pipeline markup is capped at the rate reflecting a 70 percent pipeline capacity utilization level.

Using parameters such as efficiencies for compressor stations fuel use (Table F19), a minimum markup, and benchmark factors (Table F29), end-use gas prices for firm services by sector are determined by adding a markup to the regional hub price of natural gas price. These markups (Equations 38, 48) represent the cost of services provided by intrastate pipelines and distributors. For the nonutility sectors, they are assumed to be constant throughout the forecast (Table F21).

End-use prices for industrial interruptible service customers are a function of the interruptible supply price at the regional hub and a competitive fuel price. The competitive price is based on a discounted weighted average price of a market basket of substitute fuels (residual and distillate fuel oil, liquified petroleum gas, and steam coal). The regional weights applied to the prices of the substitute fuels that comprise the market basket are assumed to be constant throughout the forecast (Table F22). The competitive price of natural gas is assumed to be equal to a discount factor (percent) times the price of the market basket. This discount factor (Table F28), currently set at 60 percent, is assumed to be constant over the forecast period. In addition, the distributor markup for industrial interruptible service (Equation 46) is bounded below by $.10 (1987 dollars per thousand cubic feet) and bounded above by the industrial firm service markup.

In the electric generation sector, the derivation of the competitive natural gas price (Equation 50) employs a discount from price of competing fuels (residual or distillate fuel oil). The discount factors are assumed to be constant over the forecast period (Table F23).

Compressed natural gas used as a vehicle fuel is assumed to compete with motor gasoline in the transportation market, and thus, the distributor markup (Equations 43, 44) is a function of the gasoline price, the cost of natural gas at the city gate, federal and state motor fuel taxes, the cost of dispensing compressed natural gas at the refueling station, and a discount factor (Tables F19, F27). The end-use price for compressed natural gas after taxes (Equation 41) is priced under the motor gasoline price (in BTU equivalent units) after taxes, as long as necessary costs are covered. It is assumed that compressed natural gas is delivered to the refueling station under firm service transportation rates and the cost of dispensing the fuel is $0.41 (1993 dollars per gallon equivalent). The federal tax on compressed natural gas is equivalent to the $0.043 per gallon tax increase on gasoline as required in the Budget Reconciliation Act of 1993. For compressed natural gas, the markup from the firm service city gate price to the end-use price after taxes is set at 90 percent of the difference between the motor gasoline price (in BTU equivalent units) after taxes and the city gate price. This pricing methodology is phased in over a 5-year period to reflect the gradual phase-out of local incentive programs used to demonstrate compressed natural gas vehicles.

Pipeline Tariffs and Regulation

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: (1) factors (Table F13) to allocate each company's line item cost into the fixed and variable cost components of the reservation and usage fees (Equations 97 to 100); (2) capacity reservation shares (Table F14, assumed constant throughout the forecast) used to allocate costs to portions of the physical pipeline system; (3) share of a pipeline company's storage capacity located in a region (Table F18), used to allocate fixed and variable costs to network nodes (Equations 103, 104); (4) discounting factor and expected annual rate of growth for annual interruptible gas throughput (Table F35), and average interruptible service rate in year t-1 (Table F15). These assumed parameters are needed to compute fixed and variable costs and allocate them to reservation fees for firm service (Equation 110), to usage fees for firm service (Equation 111), and to interruptible service customers (Equation 112) by network arc; (5) load factor and maximum allowable annual escalation rate for tariffs (Table F35) and FERC Order 636 transition cost parameters (Table F24) needed for the derivation of pipeline tariffs for firm and interruptible transportation services (Equations 120 and 127) and storage tariffs (Equation 130); (6) capacity expansion cost parameters (Table F16) and pipe mileage (Table F17) used to derive total capital costs to expand pipeline capacity (Equation 133) and storage capacity (Equation 136), respectively.

The computation of tariffs for the arcs from the supply points to transshipment nodes includes gathering charges (currently set to zero) and an assumed seasonal differential in wellhead price, which equals the wellhead price from the Annual Flow Module times a factor (Table F43) reflecting the historical observed ratio of the average seasonal wellhead price to the average annual wellhead price.

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 (Table F24). It is assumed that the Gas Supply Realignment costs are recovered over a 5-year period beginning in 1994. Furthermore, it is assumed that 90 percent of these cost are assigned to firm transportation markets and 10 percent are assigned to interruptible markets as stipulated in Order 636. Purchase Gas Adjustment Account Balance (Account 191) costs are assumed to be collected over a 2-year period, also beginning in 1994. These costs will be paid only by firm transportation customers.

With full implementation of FERC Order 636 and the increasing array of unbundled services being offered by pipelines, it is assumed that segmentation of the natural gas market will continue and ultimately lead to prices reflecting the marginal costs of providing service to diverse groups of end users. The methodology employed in solving for the market equilibrium within the natural gas market assumes that marginal costs are the basis for determining market clearing prices throughout the forecast period. Future enhancements to the model will permit the use of average pricing techniques in the early years to more appropriately represent the transition period from average pricing policy (which currently dominates the industry) to marginal pricing.

Pipeline Capacity and Utilization

The model methodology assumes that pipeline and storage capacity are available 2 years from the decision to add new capacity.

It is assumed that pipelines and local distribution companies build and subscribe to a portfolio of pipeline and storage capacity to serve a 15 percent colder than normal winter demand level. Annual maximum pipeline capacity utilization is assumed to be limited to 95 percent of the design capacity (with the exceptions of capacity into Florida and California which is limited to 100 percent of design capacity). The level and composition of demand as well as the availability and price of supplies may cause realized pipeline utilization levels to be lower than the maximum.

The capacity expansion module is constrained by an assumed maximum level of incremental storage capacity that can be built in each NGTDM region (Table F26).

The model methodology assumes that storage utilization plans are developed annually and that all natural gas is injected into storage in the off-peak period and is withdrawn during the peak period. Annual net storage withdrawals equal zero in all years of the forecast.

Several data assumptions are embedded in the mathematical specification of the linear program in the Capacity Expansion Module. First, the supply utilization constraints at each supply point uses assumed shares (Table F30) to split the quantity flowing from the supply point into peak and off-peak supply, thus generating a peak supply constraint and an off-peak supply constraint. Second, the formulation of the capacity expansion and flow constraints for each interregional arc ensures that pipeline capacity is built to satisfy firm peak demand, and that the total flows along the network arcs cannot exceed the available design capacity (base and added capacity). Hence, seasonal maximum pipeline utilization rates for these constraints are used to capture the variation in load patterns. These seasonal utilization rates are determined as a function of an assumed maximum utilization rate (Table F34) times a weather factor (Table F40), which represents the percentage of the pipeline capacity reserved for the potential change in weather. Third, the storage expansion and flow are bounded above by the maximum storage levels determined from the assumed storage utilization rates (Table F31). Finally, to encourage consistency in flow patterns during the peak and off-peak periods in the Capacity Expansion Module and Annual Flow Module, minimum flows are set as lower bounds for the peak and off-peak flows in the firm market. These minimum flows are defined as an exogenously specified fraction (Table F32) of the resulting firm flows (passed by the Annual Flow Module) times assumed peak and off-peak shares (Table F38).

The Capacity Expansion Module provides the Annual Flow Module and Pipeline Tariff Module with a forecast of physical pipeline capacity and working gas storage capacity. In addition, this module also determines the maximum pipeline capacity utilization rates to be used in the maximum annual flow constraints in the Annual Flow Module. These calculations include a number of assumptions as follows: First, for pipeline capacity, the base capacity [which includes assumed annual planned expansions along a pipeline arc (Table F42)] is added to the level of expansion to obtain the total available physical pipeline capacity. Assumed maximum peak and annual utilization rates (Table F34) are used together with peak and off-peak flows by firm and interruptible markets to calculate the total annual pipeline capacity utilization rates used in the Annual Flow Module. Second, the existing regional working gas capacity [including planned storage expansions (Table F33)] is added to the level of storage expansion to obtain the regional working gas storage capacity level.

Supply

The Annual Flow Module linear program formulation has been developed to minimize an objective function (Equation 25) subject to the following constraints: capacity utilization constraints, mass balance constraints, and bounds on model variables (flows). The capacity utilization constraints for the firm market and total market along each interregional arc set the limits on the flows for the firm market and total market, respectively. These utilization levels represent the amount of physical capacity on the pipeline that is expected to be available under normal weather conditions. The capacities are de-rated based on assumed weather factors (Table F41). The minimum bounds on flows along bidirectional arcs or primary arcs for the firm and interruptible markets (Equations 33, 34, 35) are set as percentages (Table F32) of flows resulting from last year's solution. In the first forecast year, minimum flows are set as a percentage of historically derived flows for 1990 (Table F20). These minimum flows help to generate some continuity in flows patterns associated with firm contract demands.

The development of the supply curves for domestic dry gas production (Equation 20) incorporates the assumed values of short-term price elasticity of supply (Table F37) for three different types of supply curves. In addition, these supply curves are limited by minimum and maximum levels. The minimum production is calculated as a function of the production from the previous year. The maximum production is specified as a percentage (Table F11) of the reserves times the production-to-reserves ratio. These supply curves are used with the demand curves in solving for the market clearing prices (i.e., end-use, wellhead, and border prices) while taking into account the cost and availability of transmission and distribution services.

The supply representation in the Capacity Expansion Module employs a number of parameters (Table F30) to split the annual production designated as constant into peak and off-peak levels and to develop bounds on the seasonal levels of production designated as price responsive.

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 determined from Canadian pipeline capacities (provided by the Oil and Gas Supply Model) and exogenously defined seasonal utilizations (Table F34). Total gas flow into the United States from Canada (Equation 11) excludes the amount of gas that travels back into Canada through Michigan (Table F9). Liquefied natural gas imports from Algeria and the Alaskan Natural Gas Transportation System are provided by the Oil and Gas Supply Model.

Associated-dissolved gas production by forecast year provided by the Petroleum Market Model is held constant in both the Annual Flow Module and the Capacity Expansion Module. Using an assumed share of the related OGSM region's gas production within in an NGTDM/OGSM region (Table F5), this gas production can be dissagregated by NGTDM/OGSM region. Similarly, synthetic production of natural gas from coal provided by the Coal Market Model is assumed as a constant supply within the Annual Flow Module and the Capacity Expansion Module. However, synthetic gas production from liquid hydrocarbons in Illinois (Equation 9) is set to vary as a function of the regional gas price within exogenously specified minimum and maximum production levels (Table F1). Synthetic gas production from liquid hydrocarbons in Hawaii is held constant throughout the forecast period at an assumed average historical production level (Table F1). Finally, other supplemental supplies (Table F12) are held constant throughout the forecast in the Annual Flow Module and the Capacity Expansion Module.

Model Inputs

The NGTDM is a comprehensive framework which simulates the U.S. natural gas transmission and distribution industry 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 in the U.S. natural gas market. The NGTDM inputs are grouped into six categories: supply inputs, pipeline financial and regulatory inputs, pipeline capacity and utilization inputs, storage inputs, end-use pricing inputs, and demand inputs. Short input data descriptions and cross-references to Appendix tables that provide more detail on the sources and transformation of the input data are provided below.

Supply Inputs

Supply curve parameters (Tables E2, E9, E10, E11, E12, E13, F12, F37, and G2)[74]
Historical import levels and prices (Tables E3, E14, E15, and F9)
Alaskan Natural Gas Transportation System parameters (Table F7)
Regional supply shares for associated-dissolved gas and supplemental supplies (Tables F5, F12, and G4)
Maximum production-to-reserves ratios (Table F11)
Seasonal supply shares (Table F30)
Seasonal wellhead price differentials (Table F43)
Maximum and minimum synthetic natural gas production and historical data (Tables E16, F1, and G2)

[74]Table whose numbering begins with the letters E, F, and G can be found in the Appendices E, F, and G, respectively.

Pipeline Financial and Regulatory Inputs

Rate design specification (Table F13)
Pipeline rate base, cost, and volume parameters (Tables E4, E5, and F15)
Revenue requirement forecasting equation parameters (Table G3)
Order 636 transition cost parameters (Table F24)

Pipeline Capacity and Utilization Inputs

Seasonal transmission service utilization rates and minimum flows (Tables F32, F34, and F38)
Existing pipeline capacity and planned capacity additions (Tables E6 and F42)
Costs of new construction (Table F16)
Pipeline fuel usage parameters (Tables E7, F19, and F39)
Factors related to planning for abnormal weather (Tables F40 and F41)
Distance and capacity commitments by network arc (Table F17)
Emissions factors (Tables F25)
Company volume shares by arc (Table F14)

Storage Inputs

Existing storage capacity and planned additions (Table F33)
Seasonal utilization parameters (Table F31)
Share of company storage capacity by region (Table F18)
Costs of storage additions (Table F16)
Maximum storage capacity potential by region (Table F26)

End-Use Pricing Inputs

Discount factors for pricing interruptible service to electric utilities (Tables F23 and F29)
State and Federal taxes, costs to dispense, and other compressed natural gas pricing parameters (Table F27)
Distributor markups for firm service nonutility customers (Table F21)
Historical end-use prices (Tables E8 and E17)
Market basket definitions for alternative fuels used in the industrial sector (Table F22)
Pricing parameters for interruptible markets (Tables F28 and F35)

Demand Inputs

Subregion gas consumption shares for Census Divisions 5, 8 and 9 (Table F6)
Historical electric utility consumption levels by region and service category (Tables E1 and F4)
Seasonal consumption shares by type of service (Tables F3 and F4)
Historical export quantities and prices (Table E15)
Alaskan supply and demand parameters (Tables F7, F8, F10, and G1)
Lease and plant fuel consumption parameters (Tables E7 and F2)
Short-term demand elasticities (Table F36)

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)
- Natural gas wellhead prices by Oil and Gas Supply Model region (to NEMS REPORTS)
- Firm and interruptible natural gas prices by sector and Census Division (to NEMS PROPER)
- Dry natural gas production and supplemental gas supplies by Oil and Gas Supply Model region (NEMS REPORTS)
- Electric utility firm, interruptible, and competitive natural gas prices by NGTDM/Electricity Market Module region (to Electric Market Module)
- Dry natural gas production by Petroleum Administration for Defense Districts region (to Petroleum Market Module)
- Nonassociated dry natural gas production by NGTDM/Oil and Gas Supply Model region (to Oil and Gas Supply Module)
- Lagged natural gas wellhead prices used in the supply curve function (to Oil and Gas Supply Module)
- Canadian natural gas wellhead price and production (to Oil and Gas Supply Module)
- Natural gas imports, exports, and prices by border crossing (to Oil and Gas Supply Module)
- Synthetic natural gas supply price by NGTDM/Oil and Gas Supply Model region (to Coal Production Module)
- Capital expenditures for pipeline and storage expansion (Macro-Economic Module).

Internal Reports

The NGTDM produces reports designed to assist in the detailed analysis of gas market results. These reports include the following information:

- Average natural gas wellhead (marketed production) price by NGTDM region
- Natural gas hub price at each transshipment node, by type of service
- Natural gas distributor markups by end-use sector, type of service, and NGTDM region
- Matrices of data describing interregional transmission between NGTDM regions
  - Flows of natural gas by type of service

- Maximum physical pipeline capacity
- Maximum annual pipeline capacity utilization
- Realized annual pipeline capacity utilization.

• Peak period and off-peak period expected natural gas consumption levels by region and sector used in the Capacity Expansion Module

• Expected natural gas supply volumes as implied in the Capacity Expansion Module results, by Oil and Gas Supply Model region.

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 (firm and interruptible), and Census Division (and for the United States)

• Natural gas wellhead prices and production levels by NGTDM region (and the average for the United States)

• Pipeline fuel consumption by NGTDM region (and for the United States)

• Emissions of carbon dioxide, carbon monoxide, carbon, and methane emitted from the combustion of natural gas at pipeline compressor stations by NGTDM region (and for the United States)

• Unaccounted for natural gas[75]

• Pipeline capacity expansion by arc

• Storage capacity expansion by region.

[75]Unaccounted for natural gas is a balancing item between the amount of natural gas consumed and the amount supplied.

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: Jim Diemer
- Telephone: (202) 586-6126

Documentation: Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-xxx (Washington, DC, December 1993).

Previous Documentation: None

Reviews Conducted:

- 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, August 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, April 30, 1993

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

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

Archive Tape: 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 independently

- Time Unit/Frequency: Annually through 2010

- Product(s): Natural gas

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

Data Input Sources: (Non-DOE)

- National Oceanographic and Atmospheric Administration (NOAA)
  — Heating degree data

- *The Potential for Natural Gas in the United States* (National Petroleum Council, December, 1992)
  — Pipeline capacity expansion cost estimates

- *Gas Facts* (American Gas Association, 1991 and 1992)
  — Historical industrial firm and interruptible gas prices (1990 and 1991)

- Federal Offshore Statistics 1990, OCS Report, MMS91/0068
  — Offshore gas production and market values

- Canadian Petroleum Association Statistical Summary
  — Canadian natural gas wellhead price and production for 1990 and 1991

- Alaska Department of Natural Resources
  — State of Alaska historical and projected oil and gas consumption.

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-860, "Annual Electric Generator Report"
  - — Electric utility plant type and code information, used in the classification of power plants as firm or interruptible service 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 utility plant type and boiler information, by month, used in the classification of power plants as firm or interruptible service 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 firm or interruptible service 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 1992*, DOE/EIA-0384(92)
  - — Gross domestic product and implicit price deflator

- FERC Form 2, "Annual Report of Major Natural Gas Companies"
  - — Financial statistics of major interstate natural gas pipelines
  - — Annual purchases/sales by pipeline (volume and price)

- FERC-567, "Annual Flow Diagram"
  - — Pipeline capacity and flow information

- EIA-191, "Underground Gas Storage Report"
  - — Base gas and working gas storage capacity and monthly storage injection and withdrawal levels by region and pipeline company

- *Capacity and Service on the Interstate Natural Gas Pipeline System 1990*, DOE/EIA-0556
  - — Pipeline capacity and capacity reservations by customer.

Models and other:

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

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

General Output

Descriptions:

- Average natural gas end-use prices and consumptions levels by sector and region
- Average natural gas supply prices and production levels by region
- Compressor station emissions of C, CO, CO_2, CH_4, and VOC reported as carbon by region
- Pipeline fuel consumption by region
- Pipeline capacity additions and utilization levels by region
- Capital investment in pipeline construction.

Related Models: NEMS (part of)

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

Model Features:

- Model Structure: Modular; consisting of four major components: the Annual Flow Module (AFM), the Capacity Expansion Module (CEM), the Pipeline Tariff Module (PTM), and the Distributor Tariff Module (DTM)
  - — AFM 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
  - — CEM Develops pipeline and storage facilities capacity and capacity expansion plans, and establishes effective maximum utilization rates for each pipeline route based on a seasonal analysis of supply and demand capability
  - — PTM Develops firm/interruptible tariffs 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:
  - — AFM Linear program
  - — CEM Linear program
  - — PTM Accounting algorithm
  - — DTM Empirical process based on historical data and competing fuel prices.
- Special Features:
  - — Represents interregional flows of gas and pipeline capacity constraints
  - — Represents regional supplies

— Represents different types of transmission service (firm and interruptible)

— Calculates emissions associated with pipeline fuel use

— 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

— Provides a peak/off-peak, or seasonal analysis capability in the area of capacity expansion

— Quantifies capital investment in capacity expansion

— Distinguishes end-use customers by type of service (firm and interruptible).

Model Interfaces: NEMS

Computing Environment:

- Hardware Used: IBM 3090
- Operating System: MVS
- Language/Software Used: FORTRAN, Ver. 2.05
- Memory Requirement 8328K
- Storage Requirement: 19 Tracks for input data storage; 37 tracks for code storage; and 51 tracks for compiled code storage
- Estimated Run Time: 4.4 CPU minutes
- Special Features: NGTDM uses a proprietary software package, Optimization and Modeling Library (OML) distributed by the Ketron Management Science Division of the Bionetics Corporation. This is a specially designed linear programming interface that is callable from FORTRAN.

Status of Evaluation Efforts: None.

Date of Last Update: December 1993.

Appendix B

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Appendix C

Industry Operations

Industry Operations

The transmission and distribution system for natural gas in the United States is the product of both institutional arrangements (State and Federal regulatory bodies) and market forces. Its basic function in the market is to move gas physically from the wellhead where it is produced to the burner-tip where it is consumed. The principal requirement of the system is that it be capable of meeting the peak-day demand of its customers who have contracts for firm service. To meet this requirement, the Nation has a vast network of pipelines for transporting gas from supply areas (including Canada and Mexico) to every State in the continental United States. Pipeline companies deliver gas to local distribution companies which, in turn, are the principal providers of supply and local transportation service to end-users. As an additional part of the transmission and distribution system, underground storage facilities exist close to the production and market areas. Gas is transported into storage facilities during periods of slack demand and then withdrawn from storage and delivered to customers during periods of high demand. Storage provides increased flexibility in meeting seasonal demand and allows for a more efficient operation of pipelines upstream from the storage areas.

For many years the providers of natural gas transmission and distribution services have been considered to be natural monopolies. Accordingly State and Federal regulatory bodies have exercised considerable control over them in order to protect captive customers. The Federal Energy Regulatory Commission (FERC) regulates tariffs for gathering, transmission, storage, and distribution performed by interstate pipelines, while State public utility commissions regulate services rendered by intrastate pipelines and local distribution companies. The appropriate regulatory agency specifies the level of (or bounds on), and method for, cost recovery across the different services offered by a firm. The breakdown of revenue requirements by service is somewhat arbitrary because it is for the most part determined by the policy objectives of the individual regulatory agency. In addition, since average cost pricing is generally used and there are differences among pipelines in the vintage of their plants, prices for services vary across pipelines. Thus, the price of getting gas to consumers can and does differ among companies providing the same or equivalent service. In addition to setting rates for all services offered, FERC's authority over interstate pipelines also includes the right to approve most new services (transportation and storage) for each customer and approve most new pipeline construction. The reason for regulatory authority over offers of new service is that without regulatory scrutiny, such offers could interfere with the ability to meet existing commitments, and one of FERC's obligations is to ensure that long-term contract commitments for firm service will be satisfied. The theory behind the right to approve new pipeline construction is that, given cost-based ratemaking, pipeline companies would have a considerable incentive to build new projects regardless of their economic merits. FERC's authority to regulate new services and approve construction, coupled with its influence on the pricing of all company services, results in a regulatory system that to a large extent establishes the industry structure. It additionally establishes the incentives and requirements for changing that structure, and economic incentives for activities within the industry structure.

The natural gas industry has been undergoing major changes in recent years. The transformation of the industry has grown out of reduced Federal regulation, open-access transportation and the competitive environment for new, developing gas markets. Today's environment has less centralized control and more (potential for) price volatility, risk, and fragmentation than in the past. As a result of both regulatory initiatives and market forces, transporters of natural gas have fundamentally changed the way in which they provide transportation services to their customers. Traditionally, most gas sold at the wellhead was sold under long-term, price regulated contracts and purchased by pipelines who in turn resold it to local distribution companies and to end-users. The pipelines transported gas as part of a larger package of services (acquisition of the gas, physical transportation of the gas, load balancing storage near end-use markets, etc.). The price to consumers of this pipeline-owned gas (referred to as system supply) reflected the cost of acquisition plus the cost of the transportation and other services along with a regulator specified fair rate of return on investment. In industry terminology, transportation services, and their associated costs, were included in the "bundled" services pipelines provided in the sale of natural gas.

Prior to 1978, interstate sales of natural gas at the wellhead were heavily regulated. As gas prices increased, serious market distortions arose from these wellhead price controls. Producers held back supplies from the regulated interstate market and sold instead in the unregulated intrastate market, causing severe shortages and curtailments in markets dependent on interstate pipelines. To remedy the situation, Congress passed the Natural Gas Policy Act (NGPA) of 1978, which initiated a phased decontrol of natural gas purchase prices at the wellhead. This, in turn, led to new problems. By law, pipeline companies had an "obligation to serve," and, thus, were required to have supplies available to meet the volumes specified in their contracts with customers purchasing firm service. In order to insure supply availability to meet these volumes, pipelines entered into restrictive, long-term purchase contracts for their system supplies. These contracts often required them to take an agreed upon amount of gas whether or not they could resell it. When oil prices, and subsequently gas prices, began a downward trend in 1982, pipelines were left with contracts for relatively high cost gas that they could not sell, thus incurring high "take-or-pay" liabilities. While still incurring the costs associated with the obligation to serve, they were selling smaller quantities of gas through which to recover their costs. Producers, in turn, were left with a large deliverability surplus, often referred to as the gas "bubble."

While system supply prices remained high, spot prices were able to respond quickly to the falling oil prices. Many of the traditional customers of interstate pipelines, in particular large, price-sensitive consumers (such as industrial users and electric utilities) and local gas distributors chose not to take the system supply gas that was available to them under their sales agreements with the pipeline companies. Instead, they took advantage of opportunities to access lower cost supplies by purchasing natural gas directly from producers and entering into separate agreements with pipeline and distribution companies to deliver their gas from the wellhead for a fee. Spot market transactions became commonplace, and marketers arranging transportation services assumed a greater role as intermediaries between producers on the one hand and distributors and large end-users on the other. This resulted in a restructuring of the traditional system for marketing gas from the wellhead to the consumer, with pipelines increasingly transporting gas as a separate (or unbundled) service.

By 1987, although pipeline companies continued to provide their traditional bundled service to customers, many pipeline companies were transporting more natural gas for other parties than for their own sales customers, and large end-users (industrial and electric utility customers), as a group, were obtaining nearly half their deliveries via transportation programs.[76] Unbundled transportation of natural gas continued to grow in importance in both the interstate and end-user marketplace over the next few years, and in 1992 FERC Order 636 made unbundled ransportation mandatory.

Pricing of Services

Pipeline and distributor tariffs for transmission and distribution services represent a significant portion (about 50 percent) of the price of gas to end-users. The remaining portion of the end-use cost is the price that all customers must pay, either directly or indirectly, for the gas purchased at the wellhead. In actual industry operation, pipeline companies attempt to obtain a mix of customers and contract types in order to maximize system throughput. Consumers of natural gas are generally grouped into two categories: (1) those who need firm or guaranteed service because gas is their only fuel option or they are willing to pay for the 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 is referred to as core customers and the latter group is referred to as noncore customers. Core customers purchase firm transportation services, while noncore customers purchase interruptible services. Pipeline companies guarantee to their core customers that they will provide peak-day service up to the maximum volumes specified under their contracts even though these customers may not actually purchase or request transport of the 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 transmission service based on the quantity of gas actually transported (commodity charges). Residential and commercial gas customers generally have no other alternative for fuel and purchase gas from LDC's. Thus, they are considered core customers. Transmission and distribution rates to core customers are based on the average cost of the service provided by the pipeline or distribution company to all of its core customers.

Users with flexible production schedules or with the capability to switch to other fuels, such as many industrial and electric utility customers and some larger commercial customers, contract for service on an interruptible basis. As requirements of these noncore customers are generally not taken into account in determining the peak-day

[76]For further information see: Energy Information Administration, *Growth in Unbundled Natural Gas Transportation Services: 1982-1987*, DOE/EIA-0525 (Washington, DC, May 1989).

deliverability requirements of pipeline systems, during peak consumption periods the availability of capacity to serve these customers can be very limited, and curtailments can occur. The lower level of service provided under interruptible service contracts is reflected in substantially lower rates, customers purchasing interruptible service paying only a commodity charge. Due to the cost differential and the infrequency of interruptions in many markets, some traditional core customers assume the risk associated with service interruptions by subscribing to the less expensive interruptible service. Providing interruptible service is extremely important to the pipeline companies in their efforts to maintain a high pipeline throughput, and pipelines are willing to offer additional discounts if necessary to keep noncore customers from leaving the system. Rates for interruptible transmission and distribution services are priced within a regulator-approved range of rates, with actual price based on market conditions. Thus, there is a fundamental difference in the pricing mechanisms in effect for the different classes of customers.

As previously indicated, the actual demand or commodity charges (or tariffs) that interstate pipelines are allowed to charge are regulated by the FERC. FERC's ratemaking traditionally allows a pipeline company to recover its costs, which include what the regulators consider to be a fair rate of return on its capital. (States usually set rates for local distribution companies in the same way for the same reasons.) A fundamental question in cost-based rate design is to decide how to apportion costs among customer classes. How costs are apportioned determines the extent of differences in the rates charged to different classes of customers for different types of service and raises questions relating to the fairness of the methods applied. Broadly speaking, the more fixed costs that are included in commodity charges, the more noncore customers share in paying pipeline costs. Including a larger share of fixed costs in demand charges, however, leads to core customers bearing a larger share of system costs. FERC Order 636 generally requires that pipelines use a Straight Fixed Variable (SFV) rate design, which includes all fixed costs in the demand, or reservation, fee. This is a departure from the Modified Fixed Variable (MFV) rate design that had been widely used throughout the industry prior to Order 636, which included a portion of the fixed costs in the commodity, or usage, fee.

While FERC sets maximum and minimum rates a pipeline is allowed to charge for interruptible service, pipeline companies are allowed to offer discounts from the maximum demand or commodity charges at their discretion (the minimum rate allowed is the short-term marginal cost of moving gas) provided they do not unduly discriminate among customers. This provides an effective means by which they can meet competition from other pipelines or other fuels. Since rates may be discounted to the variable cost of moving the gas, and the major portion of pipeline costs are the fixed costs, the pipelines have considerable discretion in setting rates. Selective discounting occurs predominately in noncore markets that have several suppliers or available alternative fuels, as pipelines have few incentives to offer selective discounts to any customer unless the customer threatens to switch to another pipeline or another fuel. Some discounting may occur for firm service, but the pipeline must show that the customer would leave the system if it did not discount and that other viable full rate customers do not exist.

System Capacity

At present the Nation's pipeline capacity is generally perceived to be adequate to serve the peak-day requirements of its core customers in most regions of the country and additionally to satisfy noncore customers without major concern for unexpected interruptions.[77] Certain areas of the country, however (most notably the West, Northeast, and South Atlantic), experience very high capacity utilization. With natural gas usage projected to increase significantly in the future,[78] capacity constraints could become binding unless the existing pipeline system is expanded. The increased number of recent filings with FERC requesting authorization for new pipeline construction and improvements to existing systems reflects a need for increased capacity in certain areas. Several of the proposed projects reflect either a need to meet a shift in supply sources (within the Southwest region, which is the major producing region of the country, production has declined significantly in some areas and increased in others) or in end-use markets (large population gains in the Southeast, Southwest, and Western regions contrast with limited growth in the Central and Midwest regions). These shifts, while bringing about a need to develop increased

[77]For further information see: Energy Information Administration, *Capacity and Service on the Interstate Natural Gas Pipeline System, 1990: Regional Profiles and Analyses*, DOE/EIA-0556 (Washington, DC, June 1992).

[78]Energy Information Administration, *Annual Energy Outlook, 1993*, DOE/EIA-0383(93) (Washington,DC, January 1992), p. 34.

capability to move gas to growing markets on the west and east coasts, may leave underutilized capacity on some lines.

The planned and proposed capacity additions will play an important role in meeting the projected increased consumption. Some of the proposed projects may not be needed, and actual and potential markets need to be evaluated fully. The economic basis for some of these planned expansions may be changing, since additional regulatory proposals are under consideration that would both: (1) require pipeline companies to assume substantially more risk for new projects, and (2) allocate the costs associated with new projects more directly to the customers benefiting from the expansions.

As previously noted, FERC maintains the authority to approve most new pipeline construction. In general, its regulatory policy seeks to minimize excess capacity under normal market conditions. FERC will approve only the amount of peak capacity that customers are willing to subscribe to in order to protect ratepayers from subsidizing the overbuilding of capacity. Under the current regulatory structure, as mandated by Section 7(c) of the Natural Gas Act of 1938, a pipeline company must obtain a certificate that the public convenience and necessity require the proposed facility before construction can begin. This process is very time-consuming, complex, and sometimes controversial. To expedite the construction of new facilities, FERC has an optional approval program under which the pipelines assume more of the risk for expansion in turn for an Optional Expedited Certificate. Those electing expedited approval have no guarantee that they will be able to recapture all of their expansion costs through inclusion in the rate-base. With greater frequency, pipeline companies are using expedited approval certificates to get the pipelines built and subsequently refiling to operate under Section 7(c) authority where cost recapture is more assured.

Future Industry Directions

On April 8, 1992, FERC issued Order 636, known as the Restructuring Rule, and subsequently issued Order 636-A (August 3, 1992) and Order 636-B (December 8, 1992), further clarifying and refining the rule. FERC Order 636 requires unbundling pipeline sales and transportation services, separates transportation service into its constituent parts, requires the implementation of the Straight Fixed Variable (SFV) rate design, provides for secondary markets for capacity, requires electronic bulletin boards, and restructures pipeline service obligations. Summarized in the final section of this appendix are several key provisions of Order 636 that help to further the restructuring of the natural gas industry and promote greater competition.

FERC provided the framework for the restructuring of the natural gas industry through Order 636, and full compliance was achieved in time for the 1993-1994 winter heating season. In spite of widespread industry acceptance and compliance, however, uncertainties still exist regarding implementation of some of the provisions. Key areas of uncertainty are the level of transition costs, open-access reliability, SFV rate design, capacity rights, and interruptible service.

Order 636 provides that the transition costs are recovered through a reservation fee on firm transportation, nearly all of which will be borne by firm service customers. Some segments of the industry perceive that Order 636 gives pipelines a "blank check" recovery mechanism, which would result in billions of dollars of costs, including pipeline take-or-pay buy-out/buy-downs. With guaranteed cost recovery and no risk to the financial health of the pipelines, some customers feel that there is no incentive for pipelines to control transition costs. There is concern that firm service customers will be faced with significant cost increases (albeit over a multi-year period). The Government Accounting Office (GAO) recently issued the report *Costs, Benefits and Concerns Related to FERC's Order 636* GAO/RCED-94-11 (November 1993) that addresses these issues in detail and provides transition cost estimates.

The SFV rate design moves the revenue responsibility for the pipelines' return on equity and related taxes to the reservation fee for transportation service. The result is that achieving the approved rate of return will no longer be subject to the risk of the pipeline achieving throughput targets. These costs will be recovered exclusively through the monthly reservation fees paid by firm customers. In some cases this rate design change may cause a significant cost increase to firm, low load factor customers. Order 636 requires that if the cost increase is greater than 10 percent, it must be phased-in over a 4-year period. Over the long-term, low load factor customers can offset the increase in rates through revenues obtained by releasing their capacity during the periods when it is not needed. It can not be determined if the revenue obtained via capacity releasing programs will fully offset the cost shift attributed to changes in rate design until the value of the released capacity is known. While electronic bulletin boards will be a great asset on providing information as to the availability and value of released capacity, the industry is still developing standards and conventions regarding their use. The SFV rate design and the implications of its use are further discussed in the previously referenced November, 1993, GAO report and in the EIA report *Natural Gas 1992 Issues and Trends*, DOE/EIA-0560(92) (March 1993).

Although under Order 636 interstate pipelines will continue to offer interruptible transportation service, it is expected that the nature and availability of the service will change significantly. Order 636 allows firm customers to release their capacity (any portion of it) when it is not needed. Pipeline sponsored electronic bulletin boards will match offers to release capacity with those looking to obtain interruptible service. Terms of the release (the amount of capacity, receipt and delivery points, and release period) will be worked out between the two parties subject to operational constraints and maximum interruptible rates approved by FERC. How much capacity will be available is very uncertain because many of the firms who can release capacity have an obligation to stand ready to serve their customers. If many of these firms release capacity, the increase in the number of sellers of capacity should help to push the price of interruptible service down. If some of the released capacity is packaged such that it very closely resembles firm service, the released capacity may be able to command a higher price than in the pre-Order 636 environment.

The new "equitable and open" system will sharply increase the uncertainty faced by industrial gas end users, because the majority will face potentially less reliable and less available interruptible transportation service and great uncertainty as to which (if any) holders of firm capacity will release it and for how long. Industrial end users had adjusted to the new world of Order 436/500 and could reliably count on off-peak (interruptible) transportation. Under the Final Rule (Order 636) they feel they cannot count on anything.[79]

Order 636's requirement that firm customers (including local distribution companies) bid, based on price and term of contract, in order to renew their contracts for firm interstate capacity is also likely to increase further the risks and costs to the local distribution company and its captive customers. These companies are typically the only entities that have a service obligation to meet the natural gas needs in their market area. Therefore, they have no alternative to retaining their interstate capacity. Forcing them to bid against others to retain capacity that they need is likely to increase the cost of the capacity and the risk to the local distribution company by bidding up the price and term of the contract.[80]

Two of the key provisions of Order 636 could have a considerable impact on pipeline expansion decisions. The shift of risk from the pipelines to the firm customers under SFV rate design could make these customers less likely to provide to pipelines the long-term commitments they need in order to have their proposed expansions approved by FERC. On the other hand, the electronic bulletin boards will provide timely information as to which pipeline segments are oversubscribed and where additional capacity is most needed. The value associated with added capacity will also be easier to assess once the electronic bulletin boards are operational.

In an effort to streamline the review process for new pipeline construction, FERC issued Order 555 in September 1991. Order 555 has met with strong opposition, and FERC has indefinitely postponed the effective date of the order pending numerous requests for rehearing. Several aspects of the order were seen by parties in the natural gas industry as constraining, rather than encouraging, new pipeline construction. Among these are the requirement for executed, long-term firm contracts, at risk conditions if such contracts are not in place, and the delaying of rate determination until the first general rate proceeding that includes the project cost.

Under Order 555, applicants must show that all proposed capacity is covered by executed, long-term (10 years or more) contracts for firm service. In lieu of this, at-risk provisions are imposed that require the calculation of both

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[79]Edward J. Grenier, Jr. "Restructuring and the End User: Bumps in the New Road," *Natural Gas*, Vol. 8, No. 11, June 1992, pp. 5-7.

[80]John A. Gartman of Public Service Electric & Gas Company, *Prepared Testimony Before the U.S. House of Representatives Subcommittee on Energy and Power*, Washington, DC, July 8, 1992.

reservation rates and volumetric rates at high load factors. It is feared that the high load factor requirements will result in the construction of undersized facilities, since only facilities that are fully covered by long-term contracts will be able to avoid the at-risk conditions. Of special concern regarding the rate treatment is the fact that FERC would not decide whether rates are to be incremental or rolled-in until the first general rate proceeding that includes the cost of the project. This regulatory uncertainty leaves the applicant at a disadvantage when seeking financing and when attempting to attract shippers to the new project because the specific means of cost recovery and therefore the financial risks are unknown.

It is hoped that many of these issues will be resolved in future Orders. Parties have made many suggestions for modification of the rule, with an emphasis on taking into consideration the overall benefits of expansion projects such as access to new supplies, increased utilization of facilities, improved load management and increased service reliability. The complexity and unresolved status of Order 555 highlights the difficulty the gas industry faces in attempting to anticipate the future regulatory environment and in reassuring potential customers that facilities will be available and economic to provide committed gas supplies.

Thus the natural gas transmission and distribution industry continues to adapt to a more competitive environment. The market is, in general, moving to a more competitive pricing of services, yet exactly how this will happen and the resulting regulatory mechanism is unclear. The next few years will be crucial, in that the decisions made as the industry goes through the restructuring process will to a large extent shape the natural gas industry of the future. Additional regulatory/tariff questions and issues for the industry include:

- How should current State public utility commissions policies be characterized, how will these policies change over time, and to what extent will unbundling at the distributor level occur?

- How will service requirements change over time?

- What will be the evolution of purchasing strategies (spot versus long-term contracts)?

- To what extent will market centers for natural gas develop?

No model can be developed to reflect all possible policy options. The key implication for modeling is to maintain a flexible approach that is capable of adapting as the industry evolves. The NGTDM has been designed to represent the most important aspects of the natural gas market first. Future changes in key issues or market structures will be incorporated as appropriate for the analysis. The NGTDM is structured to be flexible enough to allow for the ready implementation of a range of likely policy options and to reflect their impacts on a regional/annual basis over the mid-term.

FERC Order No. 636 Provisions

Some of the major provisions of Order 636 are:

- Interstate pipeline companies must provide transportation services unbundled from sales services.

- Pipeline companies can sell gas at market-based rates.

- Pipeline companies must offer a new "no-notice" firm transportation service (i.e., advance notice by the shipper is not required) if they provided bundled citygate firm sales service on May 18, 1992.

- Pipeline companies must provide open-access transportation that is equal in quality for all gas supplies whether purchased from the pipeline company or not.

- The straight-fixed-variable (SFV) rate design must be used for billing and allocation purposes; other rate designs, however, may be adopted for ratemaking purposes such as cost classification. Pipeline companies are required to use various ratemaking techniques to mitigate "significant" changes in revenue responsibility to any customer class. If such changes still exceed 10 percent after mitigation, pipeline companies must phase in the increase over a 4-year period.

- Two new generic capacity assignment mechanisms were established. One authorizes and requires pipeline companies to provide firm shippers on downstream pipelines with access to capacity on upstream pipelines that is held by the downstream pipeline. The second authorizes a reallocation mechanism so that firm shippers can release unwanted capacity to those wanting it. These reassignments must first be posted on an electronic bulletin board.

Appendix D

Alternative Modeling Approaches

Alternative Modeling Approaches

During the design phase of the NGTDM, a survey was conducted of models and modeling approaches being used throughout the industry to analyze and forecast natural gas transmission and distribution activities. These approaches, along with other general modeling approaches, were considered as possible candidates for the NGTDM design. This appendix provides an overview of the methods and modeling techniques considered. First, the modeling techniques employed in several different natural gas transmission and distribution models are reviewed. Second, modeling approaches used in models not specifically designed for natural gas transmission and distribution, but which could be applied to this area, are discussed. Finally, conclusions based on the research and comparisons between other models and the methodology selected for the NGTDM are presented.

Other Natural Gas Transmission and Distribution Models

The natural gas transmission and distribution industry is a segment of the complex natural gas production/delivery/demand system, and therefore is usually modeled as part of a larger, overall modeling system. Because the market structure of the transmission and distribution industry is rapidly evolving, most representations developed in the past are no longer adequate. Several of the models reviewed have detailed supply and demand representations, with fairly simple mechanisms for linking the two. Others have incorporated mechanisms for dealing with such issues as capacity expansion and the unbundling of transportation services, but none offers a comprehensive modeling treatment of the transmission and distribution industry as a whole. Additionally, none of the models reviewed addresses the issue of the environmental impacts associated with the transmission and distribution of natural gas. It was ultimately decided that there were no models in existence that could be used either intact or as a base to begin with and modify for the development of the NGTDM. Although it would have been very difficult to develop a model that addresses all of the regulatory issues and complexities of the industry, the design of the NGTDM considered desirable features of all the modeling approaches reviewed, and the resultant model provides a more comprehensive analysis tool than any other models available. This section provides an overview of the other natural gas models that were considered.

Gas Analysis Modeling System (GAMS)[81]

EIA's previous model of the natural gas market is the Gas Analysis Modeling System (GAMS), a computer-based partial equilibrium model used to analyze the U.S. natural gas production/delivery/demand system. GAMS produces annual forecasts through 2010 of natural gas production, consumption, and prices. GAMS interacts with a separate supply component which represents the various available sources of natural gas supplies and separate demand components that represent natural gas consumption by end-use sector and Federal region. GAMS consists of a mechanism for representing the costs and losses associated with the transmission and distribution of natural gas and an iterative equilibration process that solves the entire system to determine the wellhead and end-use prices at which an overall supply/demand balance can be achieved. Although the model can be run in a stand-alone mode, it is primarily used as the natural gas module within the Intermediate Future Forecasting System (IFFS),[82] a modeling system representing the supply and demand response within all the primary U.S. energy markets. The GAMS demand representation is provided through IFFS by the Demand Modeling System (DEMS), for the nonutility demand sectors, and by the Electricity Market Model (EMM) for the electric utility sector. The representation of onshore Lower-48 natural gas production is provided through direct linkage with the Production of Onshore Lower-48

[81]For complete documentation of GAMS, see Energy Information Administration, *Documentation of the Gas Analysis Modeling System*, DOE/EIA-M044(92) (Washington, DC, December 1991).

[82]For more information on IFFS, see Energy Information Administration, *Documentation of the Integrating Module of the Intermediate Future Forecasting System*, DOE/EIA-M023(91) (Washington, DC, May 1991).

Oil and Gas Model (PROLOG).[83] Supply estimates for other sources of gas are either set exogenously or determined endogenously via additional supply submodules.

GAMS was developed in 1982 and 1983 when the complex system of price ceilings in effect under the Natural Gas Policy Act (NGPA) of 1978 covered both interstate and intrastate wellhead purchases of natural gas. The categorization of gas under the NGPA and the contractual nature of the natural gas market that existed at the time were primary factors in the early structure of the model. The laws and regulations concerning the natural gas market have changed rapidly in support of deregulation and increased competitiveness (for a detailed discussion on industry background, see Appendix C). The GAMS model has subsequently undergone a number of methodological changes, to represent the active spot market, the deregulation of wellhead gas prices, and the increase in competitive pressures throughout the industry.

In the original version of GAMS, a detailed pipeline network consisting of 17 pipeline systems was used to reconcile supply and demand in the market equilibration process. This network represented sales of gas from the wellhead, through pipelines, to distributors, and to end-users. Physical movement of gas through the system was not tracked, and pipeline capacities were not accounted for. Reserves were dedicated to the individual pipeline systems and drawn down, as produced, through an elaborate accounting mechanism that tracked gas by NGPA category and contract terms and conditions. The sales structure allowed for analysis of alternative wellhead contract pricing schemes and their effect on the natural gas market. In order to represent both the increased spot market activity and the growing competition within the marketplace, GAMS was subsequently modified to include a pool of spot or decontrolled gas available to all pipelines. Reserves were no longer treated as dedicated to individual pipelines. GAMS was also revised to reflect changes in producer contracts, with contracts treated as respondent to market conditions and new contracts excluding take-or-pay[84] restrictions.

As a result of increased competition and the unbundling of pipeline sales and transportation services, the cost-of-service representation of bundled rates originally used to represent tariffs within GAMS was no longer representative of the market. The tariff component in GAMS was replaced with a simple mechanism that calculates end-use prices by adding exogenously determined regional transmission and end-use distribution costs (which are fixed throughout the forecast) to the national average wellhead price. Competition was represented by allowing these costs to be discounted in the industrial and electric utility sectors. As pricing distinctions responsive to market conditions between different levels of transmission and distribution service developed, the different levels of service were represented by expanding the level of electric utility sector detail. The electric utility module (EMM) provides demand curves to GAMS in the form of step functions defined by a set of price/quantity pairs. The steps on the curves simulate the effect of large-scale fuel switching and changes in the plant dispatching order by electric utilities. To model the price variation associated with different levels of service, these demand curves were redefined to represent three categories of utility plant types as follows: (1) core customers assumed to purchase firm service and pay the highest rates, (2) noncore customers assumed to purchase interruptible service and pay lower rates, and (3) customers with fuel switching capabilities sometimes offered discounted rates based on competing fuel prices. In contrast to the detailed utility demand representation, each regional demand curve provided to GAMS by DEMS for the nonutility sectors is defined simply by a unique reference price/quantity pair and an associated elasticity.

Transmission/distribution losses and pipeline fuel use are taken into account within GAMS during the supply/demand equilibration process by applying factors based on historical data to total throughput. The equilibrating process includes the following steps: (1) estimating a national wellhead price (the initial estimate is the previous year's solution price, and subsequent estimates are based on the previous iteration's price), (2) adding appropriate markups (representing transmission and distribution tariffs) to arrive at regional/sectoral end-use prices, (3) evaluating end-use consumption levels at these prices using the appropriate demand curves, (4) summing these consumption levels and adding losses to arrive at the amount which would be demanded at the wellhead given the estimated wellhead price, and (5) comparing this aggregate consumption (plus losses) to the level (provided by PROLOG) that would be supplied given the estimated wellhead price. If the calculated consumption is not within a specified tolerance of the

[83]For more information on PROLOG, see Energy Information Administration, "Model Methodology and Data Description of the Production of Onshore Lower-48 Oil and Gas Model," DOE/EIA-M034(91) (Washington, DC, April 1991).

[84]Take-or-pay contract restrictions required a pipeline to pay for the specified quantity of gas whether or not it could be resold.

corresponding supply level, a new wellhead price is estimated and the process is repeated until convergence is achieved.

Data Resources, Inc. (DRI)[85]

The DRI natural gas market analysis is done in conjunction with an overall analysis of the entire U.S. energy sector. The principal models used are short-term natural gas spot price and demand models, a longer term U.S. and regional energy model (which has detailed sectoral demand submodels), and a U.S. oil and gas drilling/production model. Annual forecasts through 2010 are provided for 11 regions based on Census regions and subdivisions of Census regions.

The DRI modeling system uses an iterative process (based on achieving a wellhead price/residual fuel oil price ratio that is deemed to reflect accurately free-market supply/demand influences) which determines average regional wellhead gas acquisition prices and then applies region- and sector-specific markups to arrive at end-use prices. Average natural gas prices are projected for U.S. domestic wellhead gas (based on spot, contract, and regulation-influenced gas prices) and for Canadian and LNG imports. These prices are then combined into regional "acquisition" prices, based on the varying volume weights of each gas source in the region. Region- and sector-specific markups are then applied to each region's average acquisition cost to arrive at each sector's end-use price for the region. The markups are intended to capture the transmission, distribution, and other delivery costs for each sector in each region. The markups are based on historical EIA data. Thus interstate pipeline transmission rates are not separately and specifically estimated, but rather, are rolled in with local distribution and other charges into the overall retail markups. Growth in price markups is assumed to increase at the rate of inflation, as determined by the GNP deflator. Pipeline capacity constraints and capacity expansion issues are not addressed in the model.

Wharton Econometric Forecasting Associates (WEFA)[86]

WEFA models the transmission/distribution of natural gas by means of a supply/transportation model within its Natural Gas Modeling System. The North American natural gas market is defined as a collection of many markets (16 hubs) which trade gas both intra-regionally (within hubs) and inter-regionally (between hubs). Markets may be defined geographically, by type of transaction (spot or contract), by quality of service (interruptible or firm), and by season (heating or nonheating). The model is implemented as a spreadsheet that determines the production and consumption in each market and the volume of gas transported between markets and between seasons (storage), using a heuristic algorithm to solve iteratively for a set of prices across regions, seasons, and time periods that achieves a market balance. Annual forecasts are provided through 2020 for natural gas production and wellhead prices in 13 domestic supply basins, and for flows, capacity utilization, transportation costs, and required capacity expansion along the arcs connecting the 16 hubs.

Three key assumptions are made as follows:

- Producers maximize profits and consumers minimize costs, subject to demand requirements and capacity constraints
- Pipeline transportation and storage rates are a function of regulation, and capacity expansion only takes place if it is economic (i.e., if the marginal cost of expansion is less than the marginal price that consumers are willing to pay for the additional gas)
- Prices are permitted to adjust freely to clear all markets simultaneously.

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[85]The most current documentation on DRI's model was written in 1984 and is out of date. A brief report entitled "Natural Gas Forecasting Methodology" provided by Margaret Rhodes of DRI was used for a more accurate description of their current methodology.

[86]The WEFA model is used for internal forecasts only, and thus full documentation does not exist. Information on their current methodology was obtained from a brief methodology description in the *WEFA Natural Gas Service Long-Term Forecast* (Bala Cynwyd, PA, Winter 1992) and from telephone conversations with Morris Greenberg of WEFA.

Initial estimates of regional, end-use gas requirements are determined from econometric models for the nonutility sectors and from regional load dispatch models for the utility sector. The demand is then assigned to the different supply regions based on initial market shares. Initial estimates of regional/sectoral prices are also used. Actual prices are then determined, and the relevant demands adjusted via price elasticities for subsequent iterations. Transportation tariffs are initialized assuming a load factor of 85 percent, but may be discounted if the actual utilization is less.

Consumption is disaggregated into heating and nonheating seasons, and further disaggregated by users with and without fuel switching capability. Consumers have the flexibility of selecting alternative supply sources. Gas can be transported from regions linked by the pipeline network or withdrawn from storage, both subject to available capacity. Any gas withdrawn from storage during a heating season is replaced during the following nonheating season. Consumers adjust supply sources to minimize costs, given the price of gas in the source region and the transportation (or storage) rate, including fuel and loss. Transportation rates are determined assuming competitive conditions, and rates on routes with excess capacity can be discounted down to variable costs. Alternatively, if pipeline capacity on a given route is constrained, rates may be adjusted upward in the solution process to the point where they exceed the regulated transportation ceiling rate in order to clear the market. In this case, if the marginal value of the expansion, as measured by current and future price differentials and utilization rates, exceeds its marginal cost, capacity is expanded. If such expansion does not occur, transportation-constrained sources will lose market share to unconstrained routes.

Throughout the solution process, prices are adjusted to reduce excesses of supply or demand in any or all regions/seasons/time periods. The process is repeated iteratively until market-clearing prices are determined. Convergence is achieved when the following conditions are met:

- Excess supply/demand is zero in each market
- The delivered cost of gas to each region is the same for every active route
- Pipeline capacity utilization is less than or equal to 100 percent on every route
- The marginal value of transportation on each route is less than or equal to the marginal cost of expansion.

American Gas Association (AGA)[87]

Natural gas modeling at the American Gas Association is done within the framework of the American Gas Association's Total Energy Resource Analysis model (A.G.A.-TERA). The TERA modeling system provides annual projections through 2010 of natural gas production, consumption, and prices, with projections for the residential, commercial, industrial, and utility end-use sectors provided for the nine Census Regions. The approach is a heuristic one that simulates the market and does not assume optimization of either policy or market behavior. The equilibration process involves the interaction of three components: (1) a set of drilling models, (2) a demand/marketplace model, and (3) a deliverability model. The drilling models and the demand/marketplace model provide inputs for the deliverability model, but there is not an automated feedback loop from the deliverability model to the drilling and demand/marketplace models. Analyst intervention is often necessary to equilibrate the market via adjustments in the trial wellhead prices.

The models treat the natural gas transmission and distribution segment of the industry very simply. Flows are not explicitly represented, and capacity constraint/expansion issues are not treated. The prices of natural gas to consumers are calculated as linear functions of the wellhead price via ordinary least squares regression in order to reflect the combination of supply-related costs and transmission and delivery-related costs.

[87]*Introduction to the A.G.A-TERA Energy Modeling System*, American Gas Association (Arlington, VA, 1991), provides a very general overview of the overall model; phone conversations with Leon Tucker of the A.G.A. provided specifics on the handling of transmission and distribution.

Gas Research Institute (GRI) Energy Overview Model (EOM)[88]

In producing its yearly Baseline Energy Forecast, the Gas Research Institute (GRI) uses a model known as the Energy Overview Model (EOM). The transmission and distribution segment of the natural gas industry is represented by a separate model, the National Pipeline/Flowing Gas Model developed by Energy and Environmental Analysis, Incorporated (EEA). The EEA model is a simulation model that represents the U.S. pipeline system by means of 12 composite pipeline groups, which are aggregates of actual pipeline systems chosen to represent the major differences in gas supply areas serving the 10 Federal regions. The network has recently been expanded to include the entire North American gas market (including both Canada and Mexico). Each pipeline group has its own inventory of gas reserves, access to one or more of 15 supply regions (as represented in the GRI Hydrocarbon Supply Model), and an individual cost of service estimate for pipeline operations. The EEA model is integrated with the EOM, and thus flows are considered in the market equilibration process. Nonlinear optimization is used to minimize costs subject to supply and demand constraints.

The pipeline model simulates pipelines in their role as both merchants and transporters of gas. Transportation services are provided to distributors and end-users under a mix of rates based on the quality of service. Rates are based on cost-of-service with the flexibility for rate discounting caused by market pressures. An accounting system tracks both committed gas supplies under long-term contracts with pipelines and uncommitted supplies being marketed by producers and sold on the spot market. Associated with committed supplies are detailed contract terms and conditions.

The model represents the distribution of supply from the city gate to end-users by means of an aggregate local distribution company (LDC) in each demand region. Revenue requirement accounts are maintained for each LDC to set distribution margins by end-use sector, with margins and burnertip gas prices differing by demand region. LDCs themselves offer end-users both sales service and transportation of gas purchased on the spot market.

Seasonal transmission charges for each pipeline group and distribution charges for the LDC in each Federal region are estimated by the model based on cost-of-service estimates. The charges are then allocated to the services provided by the distributor or pipeline. Market pressures and regulatory structures determine the extent to which those charges recover gas transmission and distribution costs. A cost-of-service algorithm estimates year-to-year changes in the overall nongas costs of pipeline operations so as to take into account the response of the costs to changes in system throughput, compression costs (which change with volume and cost of gas), rate base, and the cost of capital. After determining the cost of service for each pipeline group, the model allocates these costs between the sales and transportation services offered to customers based on the mix of each pipeline's merchant and transport services. After allocating costs, the model pipelines establish a structure of differential rates for the various classes of service. The transmission margin included in pipeline resale rates is assigned on a fully allocated basis, meaning that the costs allocated to this service will be fully recovered in providing the service. Pipelines also maintain separate firm and interruptible rates applicable to transportation. Competitive forces and market pressures may prevent pipelines from fully recovering costs for interruptible service. The model allows margins on transportation to distributors to be reduced below full cost recovery to represent the potential discounting pressures on pipeline supplies caused by interpipeline competition. Costs not recovered due to discounting are reported.

The EEA model has recently been updated to include a detailed representation of capacity expansion in support of an ongoing National Petroleum Council (NPC) study.[89] The model takes into account both planned expansion and other future expansion. An input data file describes planned projects for the next 5 years, including their construction costs. For projects beyond the 5-year time horizon, the same data file contains "generic" projects that can be undertaken if it is economic to do so. Data for these generic projects include cost estimates on a dollars per thousand cubic feet/mile (where mileage figure represents miles that the gas is actually moved). Cost data are determined by using a cost algorithm that reflects today's capacity addition costs. Three sets of cost algorithms are employed: one

[88]*Guide to the Hydrocarbon Supply Model, 1990 Update*, Energy and Environmental Analysis, Inc. (Arlington, VA, October 1990) and conversations with EEA and GRI staff.

[89]The enhanced treatment of capacity expansion in the EEA Pipeline/Flowing Gas Model has not as yet been documented. The above information was provided through conversations with Robert Crawford of EEA.

for the Lower 48 States, one for Canada, and one for frontier areas where expansion is costly. Regional differences in construction costs are not captured. Costs are determined for three types of possible expansion: compression only, looping and compression combined, and construction of new pipe. Potential future projects are set up throughout the system as though they were real ones. Thus the model sees what is analogous to a supply curve for capacity additions at each node. The steps on the "supply" curve are analogous to the amount of each of the three types of expansion possible at that point in the system. The data allow for expansion everywhere in the system, with those areas deemed most likely to have more expansion activity provided higher bounds on the amount of expansion possible.

In solving for capacity expansion, the model begins each forecast year with an estimate of new capacity that would be needed to meet the demands for that year. Each potential new pipeline link has a supply source with an associated volume and price elasticity, and a demand at its destination. The model takes into account how much the supply price would be raised at the source due to the added volume, and how much the demand would be depressed as a result of the associated higher prices. Capacity to be added is controlled by the criteria that any added capacity must be able to operate at a minimum of an 80-percent load factor. New links compete against alternate supply sources and each other—capacity will not be added if there is a cheaper alternative for meeting demand. New costs are compared against the cost of adding capacity. The cost of the added capacity must be less than the price differential on competing links, and the throughput high enough (at least 80 percent) in order for capacity to be added.

Storage is considered to be a supply source during the winter months and a demand source during the summer months. Storage expansion is not endogenously determined. Offline scenarios are run to determine how much storage capacity would increase, and storage is fixed within any given model run. The offline analysis to determine storage expansion is an iterative process in which estimates of expected increases in storage are made, the model is run and results analyzed, estimates are revised and the model rerun until analyst judgment indicates a satisfactory estimate of future storage expansion.

Decision Focus, Inc. (DFI) North American Regional Gas Model (NARG)[90,91]

Decision Focus, Inc. has developed a multiregion Samuelson spatial equilibrium model used by the Gas Research Institute (GRI) for sensitivity analyses. This model is referred to as the GRI North American Regional Natural Gas Supply-Demand Model.

The model represents approximately 150 distinct gas supply sources in the United States and Canada. Fifteen demand regions are represented, 3 in Canada and 12 in the United States (based on disaggregations of the census regions), with distinctions within each demand region between core and noncore markets.[92] In the United States, all of the residential and commercial and half of the industrial demand are assumed to be core, while the balance of the industrial and all of the electric utility demand are assumed to be noncore.

The model's representation of the North American pipeline system includes:

- A comprehensive pipeline network consisting of current and potential future pipeline links from supply regions to demand regions

- Tariffs and losses for each pipeline link.

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[90]Dale M. Nesbitt *et. al.*, "Analysis of GRI North American Regional Gas Supply-Demand Model", in *North American Natural Gas Markets: Selected Technical Studies, Energy Modeling Forum (EMF) Report 9*, Volume III, pp. 185-234 (Stanford University, April 1989)

[91]Dale M. Nesbitt *et. al.* (DFI), "Appendices for the GRI North American Regional Natural Gas Supply-Demand Model," prepared for Gerald Pine (GRI), February 1990.

[92]The core service customer is guaranteed service (i.e., is assumed to purchase firm service) and generally pays the highest rate for natural gas. The noncore customers consume gas under a less certain and/or less continuous basis (i.e., an interruptible basis) and typically are offered a lower rate than the core customers.

The degree of pipeline detail is consistent with the degree of supply and demand detail elsewhere in the model. In particular, while the model could have been designed to enumerate and distinguish every individual pipeline in the United States, its developers instead sought commonalities among supply regions, pipelines, and demand regions that would allow aggregation. Rather than representing individual pipelines, the model instead represents pipeline corridors from its supply regions to its demand regions. These corridors are explicitly defined by the characterization of the model's supply and demand regions, and by the configuration of the U.S. and Canadian pipeline systems that exist today. Each of the existing pipeline corridors represented in the model begins in a given supply region, extends perhaps through intermediate supply and demand regions, and terminates in a demand region. The network of existing pipeline corridors interconnects all currently producing regions with all currently consuming regions.

The model also enumerates all prospective future pipelines that might be built in the next 50 years. These pipelines connect new producing regions (or subregions) with various demand regions, and connect Canada and Mexico to the United States. They are truly prospective in the sense that they will be built only if they become economic (i.e., only if supplies at the upstream end, marked up to account for the cost of the new pipelines, constitute the most competitive source at the downstream end). In the model, looping is considered as an option for all existing capacity, as well as for the existing links of the new corridors.

The linkage between Canada and the United States is potentially very important. The model therefore distinguishes the pipelines in Canada that directly or indirectly lead to the Lower 48 United States. The model also includes two prospective Canadian export routes to the United States. One of these routes runs from North Alaska through Alberta and ultimately to the United States, and represents the upstream leg of the Alaska Natural Gas Transportation System. The other runs from Northern Canada (MacKenzie and Beaufort Sea), through Alberta, and ultimately to the United States, and represents the pipeline that will have to be built in order to exploit Canadian Arctic gas (the Polar project and prospective expansions).

The current version of the model contains corridor capacity estimates prepared by Benjamin Schlesinger and Associates (BSA, under contract to the California Energy Commission). BSA also provided appropriate corridor transmission costs, which represent the embedded cost of each pipeline and specifically account for discounting behavior on the part of pipeline owners. Pipeline capacities and cost structures for all Canadian pipelines are based on data from the National Energy Board of Canada.

Several generic types of pipeline capacity expansion are explicitly represented (for each pipeline link) within the model:

- Expansion of capacity of a given pipeline by such actions as looping or increasing pressure
- Expansion of capacity along a given corridor by adding a new pipeline
- Addition of an entirely new pipeline corridor.

For each pipeline link, the model assumes that the embedded cost of the capacity currently in place will affect the rates for quantities of gas transported that do not exceed the current known capacity. In order to transport more gas than the current capacity of the corridor, it is necessary to augment the capacity through looping or pressure increases. Such augmentation is possible (at a cost) and is usually bounded by an upper constraint (i.e., looping and pressure increases can each add only a limited quantity of additional capacity). In order to exceed the capacity of an existing, fully looped, maximum pressure pipeline link, it is necessary to add new pipeline capacity. At the incremental cost of securing appropriate rights of way and building such a pipeline, it is possible to expand the capacity of that corridor virtually without bound.

The model thus requires current transportation cost information, capacity expansion costs through augmentation, and new capacity addition costs. For the current version of the model, such data (for every existing and prospective future corridor) were provided by BSA under contract to the California Energy Commission.

Stanford University North American Gas Trade Model (GTM)[93]

The North American Gas Trade Model (GTM) developed at Stanford University in conjunction with the Stanford University International Energy Project is an interregional natural gas trade partial equilibrium model which computes, for 2 single time periods (1990 and 2000), market clearing prices and a possible pattern of trade flows between 11 supply and 14 demand regions in the United States, Mexico, and Canada. Demands within the United States are provided for each of four consuming sectors (residential, commercial, industrial, and electric utility). Key inputs to the model include:

- The regional distribution of gas supplies and demands at alternate price levels
- Transportation charges
- Pipeline capacity constraints
- Canadian and Mexican export quantity limits.

In some regions, prices are free to move so as to equilibrate supplies and demands, while in others there may be disequilibria associated with controls over prices and/or quantities traded. The objective of the solution process is to maximize the sums of producers' and consumers' surpluses, or, alternatively, maximize the sum of consumers' benefits minus the costs of production and transportation. With the exception of the nonlinearity of the objective function, the GTM is a straightforward transportation model. The model is solved using MINOS, a nonlinear programming computer package.

Economic policy and technical constraints are handled as upper or lower bounds on objective function variables. For example, pipeline capacity limits are represented as upper bounds on the transportation variables, and take-or-pay contract limits are represented as lower bounds. The user can specify limits on certain demands or export volumes, which allows the simulation of export and price controls. Taxes or subsidies on individual supplies or demands can be similarly represented by constraints on individual supply and demand variables. Each of these conditions is represented as an upper or lower bound on an individual variable.

The objective function contains linear cost coefficients related to the transportation variables. Supply and demand variables enter in a separable nonlinear form. A market equilibrium is computed by maximizing the objective function subject to supply and demand constraints and upper and lower bounds on individual variables. If supply and demand are unconstrained, the shadow prices will be the marginal costs of production or the price consumers are willing to pay. This information can aid the analyst in making decisions (e.g., whether to expand production or increase capacity).

Massachusetts Institute of Technology (MIT) Center for Energy Policy Research[94]

The Center for Energy Policy Research Energy Laboratory at MIT has developed a North American natural gas trade model as part of a project on international gas issues. The primary purpose of the model is to estimate the costs and benefits to Canada and Canadian firms of alternative gas production and export programs. While it is an interregional trade equilibrium model similar in concept to the Gas Trade Model (GTM) described above, it has been formulated as a linear, rather than a nonlinear, programming problem. The model solves for exports to the United States and investment and production in each Canadian supply area, reporting additional information including marginal costs of production, export prices, marginal export revenues, capital rental charges, resource depletion costs, etc. The model includes nine different pools of Canadian reserves and three gas markets within the United States: West Coast, Middle West, and North East.

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[93]Mark A. Beltramo, Alan S. Manne, and John P. Weyant, "A North American Gas Trade Model (GTM)," *Energy Journal*, July 1986, pp. 15-32.

[94]Charles Blitzer, "A North American Natural Gas Model: Part I," *Final Report on Canadian-U.S. Natural Gas Trade*, (Cambridge, MA: MIT Center for Energy Policy Research October 1985).

Constraints involve supply/demand balances, production-reserve relationships, production-investment relationships, export delivery patterns, pipeline capacity constraints, and export revenues. Demand functions are represented by piece-wise linear approximations. Pipeline capacity is input exogenously. Investment in capacity expansion, although incorporated in annual capital costs, is not, however, endogenously determined. Pipeline operating costs are handled as linear functions of export volumes based on operating cost coefficients.

The model can be solved using any one of three objective functions:

- Maximize net benefits to Canada as a whole

- Maximize the sum of net benefits to Canada and to U.S. importers of Canadian gas

- Simulate competitive profit maximizing behavior among Canadian producers, inclusive of royalties.

The second objective function seeks to determine the perfectly competitive solution, in effect maximizing net benefits to Canada (producers' surplus) and net benefits to the United States (consumers' surplus).

Energy Information Administration Gasnet Model[95]

The Gasnet model is an optimization model, developed by EIA in the late 1970's to forecast short-term seasonal patterns of natural gas distribution given predetermined projections of both supply and demand for natural gas. Although no longer in use within EIA, the Gasnet model was reviewed in doing background research for development of the NGTDM as it explicitly represents a pipeline network, using a series of constrained optimization techniques to simulate the transmission pattern within the natural gas industry. Gasnet provides summary tables listing quarterly estimates of natural gas supply by State and consumption and excess demand by State for the residential, commercial, industrial, and electric utility sectors.

On the demand side, 48 States, the District of Columbia, Mexico, and 5 Canadian provinces are represented. On the supply side, there are 45 producing areas located in the 26 producing U.S. States and 4 Canadian provinces. Four of the producing States are divided into substate regions. Five major interstate pipeline activities are represented in the model: (1) selling gas to end-users, (2) receiving produced gas, (3) injecting or withdrawing gas from storage, (4) exchanging gas with other pipeline companies, and (5) transmitting their own gas volume to other States. Within the model, various nodes are interconnected by arcs. Each node is associated with one or more of the five major activities described above.

The model connects the demand regions and supply areas to estimate the sectoral effects of natural gas shortages. The model represents each pipeline by a system of interconnected nodes allowing the calculation of interstate flows along a pipeline system. A separate module, the Historical Apportionment Model (HAM), computes the distribution of the forecasted gas production through the network on the basis of the historical relative flows (i.e., the pattern determined from the base year data). The HAM model solution provides a base case for the final phase of the modeling process: the linear program. The linear program minimizes the deviations of gas from the desired storage goals, the sum of excess demands and supplies by consuming sector in each State, and the costs of operation for the transmission of gas throughout the entire network, subject to the following constraints:

- Mass balance at each node

- Regional gas production equation for each region

- Balance of supply and demand over all States and demand sectors.

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[95]Energy Information Administration, *Gasnet: Methodology Description* (Washington, DC, August 1978)

Solution Methods for Solving Network Flows

In developing the methodology for the NGTDM, a number of modeling techniques were evaluated other than those employed in natural gas models. In particular, specific mathematical formulations and solution techniques, such as linear programming (LP), mixed integer programming (MIP), special ordered sets (SOS), and nonlinear programming were considered.[96] In addition to the specific natural gas models discussed above, the following models were reviewed because they employ techniques that were considered for use in the NGTDM.

Energy Information Administration Project Independence Evaluation System (PIES)[97]

The PIES model, developed in the mid-1970's, was EIA's first large scale energy forecasting model. The PIES framework consists of three major components: a demand model, a supply network, and an equilibrating mechanism.

The PIES supply network is composed of production, conversion, and transportation activities. They are linked by means of a distribution network that represents the movement of raw materials or products. The major economic assumption implicit in the PIES structure is that market equilibrium conditions govern the purchase prices and quantities of fuels so that the sum of consumers' and producers' surplus is maximized across all regions and all energy industry sectors, subject to the constrained market conditions introduced by government regulation.

The following assumptions are made: (1) subject to regulatory constraints, participants in the economy act in their own self-interest, (2) consumers are rational and maximize their benefits, and (3) producers maximize profits. A linear programming formulation is used, incorporating step-like approximations to the supply and demand curves.

Stanford Research Institute SRI-GULF Energy Model[98]

The Stanford Research Institute's SRI-Gulf Energy Model is a highly-detailed regional, dynamic model of the supply and demand for energy in the United States. It was developed in 1973 to analyze synthetic fuels strategy for the Gulf Oil Corporation and has subsequently been extended and widely used in other energy analyses. It employs a generalized equilibrium modeling methodology which represents a synthesis of several modeling techniques. The conceptual framework of generalized equilibrium modeling emphasizes: (1) the need to focus modeling efforts on decisions and (2) the coordinated decomposition of complex decision problems using iterative methods. A decision problem is first conceptualized, and then decomposed to define the basic decision and physical processes that must be included in the modeling process. The overall model is then implemented using the following three basic elements of generalized equilibrium modeling: (1) *processes* describing the fundamental submodels, (2) a *network* describing the interactions among the processes, and (3) an *algorithm* for determining the numerical values of the variables in the model.

In the SRI-GULF model, 17 end-use demands are modeled for each of the 9 U.S. Census Divisions through 2025. Approximately 2700 processes are represented, with processes that describe end-use demands for energy and primary resource supply linked by a network of other processes describing market behavior, conversion, and transportation. The algorithm used to solve the model finds the set of variables (primarily prices and quantities) that satisfy the physical and behavioral relations embodied in the processes and the linkages among the variables as defined by the network.

Although the model involves hundreds of distinct processes, each can be implemented as one of a few basic processes which consist of: (1) simple conversion processes, (2) allocation processes, (3) primary resource processes,

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[96]For further information on formulations, see "An Evaluation of Problem Formulations and Mathematical Programming Software for the Gas Market Model of NEMS," Science Applications International Corporation (McLean, VA, April 1992).

[97]*The Integrating Model of the Project Independence Evaluation System, Volume I - Executive Summary*, Logistics Management Institute (Washington, DC, April 1979).

[98]*Generalized Equilibrium Modeling: The Methodology of the SRI-Gulf Energy Model*, Decision Focus, Incorporated (Palo Alto, CA, May 1977).

(4) end-use demand processes, (5) transportation processes, (6) complex conversion processes, and (7) secondary industry processes. The main process of interest in the SRI-Gulf model is the allocation process, which allocates the demand for a fuel among the competing sources of supply. The allocation process used in the model is a dynamic process that responds continuously to changes in price. The sharing method is represented in terms of simple market share curves and simple market penetration (behavioral lag) curves that reflect lags or time delays in responding to price changes. This is preferable to an allocation process that responds sharply to small differences in prices (as would be the case if demand were allocated entirely to the lowest price source), as the latter tends to overstate the market response to prices.

Conclusions

This section consists of two subsections. The first compares the NGTDM with EIA's former modeling system, GAMS, as one of the main goals of the design of the NGTDM was to address the weaknesses of the GAMS in modeling the current natural gas industry and provide EIA with a more effective modeling tool. The second section compares the NGTDM with the other modeling approaches considered, detailing which aspects of each approach were included and why each particular model or approach was, or was not, adopted for the NGTDM.

Comparison of Capabilities of GAMS to the NGTDM

GAMS has a number of limitations that precluded its use within the NEMS. The NGTDM was designed to address these limitations. As indicated in the Model Quality Audit review of GAMS performed for the Office of Statistical Standards,[99] one of the major limitations of GAMS was that it does not take into account significant regional differences in both supply availability and pricing. When GAMS was first modified to explicitly treat deregulated gas, a simple structure was included to represent a single national pool of deregulated gas. This national representation of deregulated gas means that GAMS does not fully account for regional supply distinctions on the overall market. The NGTDM represents both supply availability and price levels for all supply sources by region.

Another drawback to GAMS is that it does not include a representation of the physical flow of gas, and thus can not be used to analyze pipeline capacity issues. The assumption was made during the initial development of the model that sufficient capacity would exist to satisfy demand, and therefore neither capacity constraints nor future capacity expansion issues were considered. In reality, there are significant differences across regions in capacity utilization, with very heavy utilization occurring in certain sections of the country (specifically the West and Northeast).[100] One of the key determinants of how pipelines will price services in the future will be how intensely their systems are utilized. To represent this, a treatment of both capacity constraints and capacity expansion (pipeline and storage) decisions is necessary. These issues are addressed by a separate Capacity Expansion Module within the NGTDM. Flows are accounted for in the Annual Flow Module (AFM) by incorporating an aggregate representation of the natural gas transmission and distribution network. This allows a more comprehensive analysis of the results of supply and demand shifts on capacities and flow patterns, as well as a more representative analysis of the pricing of natural gas transmission and distribution services.

Also key to the pricing of natural gas transmission and distribution services is the representation of tariffs. While the GAMS representation of tariffs via markups based on fixed historical levels reflects both transmission and local distribution costs, the representation is simplistic and can not be easily adapted to reflect future market conditions. While pipelines and distributors formerly could be assumed to price strictly on the basis of their average cost of service, they are now offering a full range of services under competitive and market-based pricing arrangements. Although not totally deregulated, they have considerable pricing flexibility. The GAMS structure does not reflect this, and thus does not permit regulatory analysis of pricing issues. Tariffs in the NGTDM are endogenously determined along different segments of the physical pipeline system, with separate modules to model tariffs for

[99] Carpenter, Paul R., "Review of the Gas Analysis Modeling System," Incentives Research Inc. (Boston, MA, August, 1991). (Also contained in Appendix B of the GAMS Model Quality Audit.)

[100] Carpenter, Paul R., "Review of the Gas Analysis Modeling System," Incentives Research Inc.

pipeline and distributor services. The NGTDM also represents differences in pricing various classes of service more adequately than GAMS. GAMS applies the class-of-service pricing distinction only to the electric utility sector. Many industrial sector and large commercial sector users are also taking advantage of the lower prices associated with interruptible service, which is available to all customers. The NGTDM has the capability of distinguishing customers by type of service in all end-use sectors. Cost-based, average pricing is applied to core customers (firm service) within each sector and market-based, marginal pricing is applied to noncore customers (interruptible service).

Table D-1. Natural Gas Models Reviewed

Model Feature	DRI	WEFA	AGA	GRI	DFI	GTM	MIT	Gasnet	GAMS	NGTDM
Flows represented	no	yes	no	yes	yes	yes	yes	yes	no	yes
Endogenous tariffs	no	yes	no	yes	no	no	no	no	no	yes
Capacity constraints	no	yes	no	yes	yes	yes	yes	no	no	yes
Capacity expansion	no	yes	no	yes	yes	no	yes	no	no	yes
Core/noncore markets	no	yes	no	yes	yes	no	no	no	no	yes
Seasonal	no	yes	no	yes	no	no	no	yes	no	no
Spot and contract gas	yes	yes	no	yes	no	no	no	no	yes	no
Environmental issues	no	no	no	no	no	no	no	no	no	yes

There are two final areas not addressed in GAMS. The first is that of environmental impacts, which has become an area of considerable importance as a result of the Clean Air Act Amendments (CAAA) of 1990. The NGTDM tracks emissions of criteria pollutants associated with the transmission and distribution of natural gas. The second is that of energy related investment. Energy related investments in areas such as the capacity expansion of natural gas pipelines are quantified in the NGTDM.Key features of the natural gas models reviewed are summarized below in Table D-1. While some of the models, such as WEFA and GRI, do address most of the issues that were of concern in the development of the NGTDM, others, such as the DRI and AGA models, employ a very simplistic representation of the transmission and distribution segment of the industry. In the DRI and AGA models, flows are not explicitly represented, end-use prices are determined via fixed markups, and capacity constraints and capacity expansion decisions are not represented. These models were thus not suitable to address the requirements of NEMS.

Comparison of Capabilities of Other Models to the NGTDM

The WEFA and GRI/EEA models address several of the issues which are represented in the NGTDM. Like the NGTDM, these models track flows, take into account capacity constraints and capacity expansion decisions, and have endogenous determination of tariffs. Both models also have structures not represented within the NGTDM, as well as some general drawbacks in comparison to the NGTDM. The WEFA model is implemented as a spreadsheet, and is therefore not directly compatible with the NEMS system. While tariffs are endogenously determined, the methodology is a simple one which does not allow the type of regulatory analysis required by NEMS. While the GRI/EEA model has a more sophisticated determination of tariffs, all pricing is based on cost-of-service, and marginal pricing, which the NGTDM allows for, is the direction in which the industry is going. Capacity and capacity expansion issues are considered to be of great importance, and thus are treated in more detail in the NGTDM than in the GRI/EEA model.

Two features of the WEFA and GRI/EEA models not directly incorporated into the NGTDM are seasonal pricing and the distinction between wellhead spot and contract gas. A detailed treatment of contract pricing provisions for system supply is no longer necessary, since total deregulation of the wellhead market occurred in 1993. In addition, given the resulting competitive nature of the market at the wellhead, it is expected that the majority of new supply contracts will contain clauses tieing the contract price to the going price on the spot market, resulting in these prices moving in tandem over time. If the relative difference between the spot and contract gas price is determined to be significant, this distinction can be readily incorporated within the NGTDM. Seasonal pricing is an important issue for future consideration within NEMS, but is beyond the scope of the current design.

The basic structure of the GTM and MIT models is similar to the design of the NGTDM. Both are interregional trade equilibrium models which, like the NGTDM, are formulated as optimization problems that maximize the sum of producers' and consumers' surpluses subject to supply, demand, regulatory, and technological constraints. There are, however, a number of significant enhancements that are provided in the NGTDM. The GTM focuses on long-term market equilibria rather than on mid-term institutional and regulatory issues, which are important for NEMS to address. Like many of the other models, the GTM does not incorporate an endogenous determination of tariffs or capacity expansion decisions. While the structure of the MIT model is similar to that of the NGTDM, it is basically a Canadian model without the U.S. market detail required of NEMS.

Because of the number of supply regions and pipeline corridors, the representation of the transmission and distribution network incorporated in the DFI model is the most detailed of any of the models reviewed. Given that the solution time required to solve a system of this level of detail does not fall within the NEMS guidelines and that tariffs are determined based on exogenously determined values, the structure was not considered to be suitable for NEMS.

Since the Gasnet model was developed during a time period when the gas market was very different from the current market, it has a structure that could not be easily modified to address the issues relevant to NEMS. It does, however, provide a good example of the general technique of applying network optimization to natural gas transmission and distribution, which is the method that is used in the NGTDM to model the noncore transportation segment of the market.

Of the nonnatural gas models reviewed, PIES was most relevant to the design of the NGTDM. The PIES solution methodology, in fact, forms the basis for the linear programming approach used as the solution methodology in the NGTDM. The allocation process used in the SRI-GULF model was seriously considered to be used as the basis for an heuristic approach to modeling cost-of-service pricing in the core market within the NGTDM. This approach was subsequently abandoned due to added operational and convergence complexity that would be introduced by the use of separate modeling approaches for core and noncore markets.

Appendix E

Historical Data Inputs

Table E1

Data: Electric utility consumption for 1990 and 1991 by market type (firm, competitive with distillate, competitive with residual fuel oil) and by NGTDM/EMM region.

Author: Chetha Phang, EI-823, September 1993.

Sources: *Natural Gas Monthly* 1990, 1991, DOE/EIA-0130.
Natural Gas Annual 1990, 1991, DOE/EIA-0131.
Form EIA-860, Form EIA-767, Form-EIA 759.
Data created using PIPEJCL.GASEU.NGTDM90.D0512931.

Derivation: For each year, the monthly electric utility gas consumption by State and plant type were aggregated into the annual consumption by NGTDM/EMM region and market type (firm, interruptible, competitive), using the following definitions for classifying the market types from different plant types:

- Firm market is for gas steam and gas combined cycle turbines
- Competitive with residual fuel oil market is for dual fired steam turbines
- Competitive with distillate fuel oil market is for gas turbines and dual fired turbines

For each NGTDM/EMM region, market type and year, the above annual electric utility gas consumption was then scaled so that the NGTDM/EMM regional consumption for the combined markets match the annual electric utility consumption published in the *Natural Gas Annual*.

Notes: None.

Units: MMcf.

File: INITDAT

Variables:

QGFBCF	Electric utility firm service consumption by NGTDM/EMM region.
QGIBCF	Electric utility competitive with distillate consumption by NGTDM/EMM region.
QGCBCF	Electric utility competitive with residual fuel oil consumption by NGTDM/EMM region.

Electric Utility Gas Consumption (MMcf) for 1990 by NGTDM/EMM Region

NGTDM/ EMM Region	NGTDM - EMM Region	Firm Service	Competitive with Distillate	Competitive with Residual Fuel Oil	All Gas
1	01 - 07	3664.	7026.	55548.	66238.
2	02 - 03	2590.	14782.	32582.	49954.
3	02 - 06	4413.	35452.	183388.	223253.
4	03 - 01	7325.	10810.	12749.	30885.
5	03 - 04	733.	8584.	2258.	11576.
6	04 - 05	332.	9432.	2948.	12712.
7	04 - 10	1353.	10522.	18635.	30510.
8	05 - 01	0.	139.	0.	139.
9	05 - 03	0.	6804.	21508.	28312.
10	05 - 09	6079.	9498.	2091.	17667.
11	06 - 01	0.	283.	0.	283.
12	06 - 09	296.	16211.	53320.	69827.
13	07 - 02	181873.	64467.	761039.	1007380.
14	07 - 10	33117.	8821.	427909.	469847.
15	08 - 11	7198.	4158.	14316.	25672.
16	08 - 12	0.	2170.	3383.	5553.
17	09 - 11	7387.	190.	0.	7577.
18	10 - 08	23388.	19453.	145452.	188293.
19	11 - 12	26749.	7732.	15217.	49698.
20	12 - 13	29727.	9343.	417336.	456406.
21	22 - 00	15335.	19032.	0.	34367.

Note: Values are adjusted to match the *Natural Gas Annual 1990* values.

Mapping Between NGTDM, EMM, and NGTDM/EMM Regions

NGTDM Region	EMM Region	NGTDM/EMM Region
1	7	1
2	3	2
2	6	3
3	1	4
3	4	5
4	5	6
4	10	7
5	1	8
5	3	9
5	9	10
6	1	11
6	9	12
7	2	13
7	10	14
8	11	15
8	12	16
9	11	17
10	8	18
11	12	19
12	13	20

Table E2

Data: Average wellhead gas price for 1989 by NGTDM/OGSM region.

Author: Chetha Phang, EI-823, September 1993.

Sources: *Natural Gas Annual* 1990, DOE/EIA-0131.
Federal Offshore Statistics 1990, OCS report, MMS91/0068.
U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216, (Form EIA-23).
Annual Energy Review 1992, Appendix C.
Data created using PIPEJCL.WELLPRC.TDMOGSM.D0917931 and
JBE Data Disk \MISC\WELPRC.WK1.

Derivation: The dry gas production by substate (Form EIA-23) and the natural gas price by State (*Natural Gas Annual* 1990) were merged together at the State level for the onshore region. For the offshore region, we added the average wellhead gas price information from the *Federal Offshore Statistics* report to the previous dataset. Then, we computed the production cost (production times price) by State. We aggregated these costs and production at the NGTDM/OGSM regional level. Finally, we derived the average wellhead gas prices for the NGTDM/OGSM regions by dividing cost by production for each OGSM subregion. We converted these prices into 1987 dollar gas prices by dividing the current gas prices by the 1987 GDP implicit price deflator for 1989 from *Annual Energy Review* 1992.

Notes: The final wellhead price for the NGTDM/OGSM onshore region 1 is set to the onshore region 2's price, and the offshore region 1's price is set to the NGTDM/OGSM region 6's price. For onshore Texas and California gas prices, we computed the final average wellhead prices by excluding their offshore gas prices and production.

Units: 1987 $/Mcf.

File: INITDAT

Variables: WPRLAGON Average wellhead gas price for onshore by NGTDM/OGSM region.
WPRLAGOF Average wellhead gas price for offshore by NGTDM/OGSM region (1- Atlantic, 2- Gulf, 3-Pacific).

NGTDM/OGSM	1	2	3	4	5	6	7	8	9
WPRLAGON	2.19	2.19	2.61	1.33	1.59	2.78	1.95	2.19	1.52
NGTDM/OGSM	10	11	12	13	14	15	16	17	
WPRLAGON	1.41	1.31	1.24	1.29	1.89	1.44	1.44	2.08	

Offshore Region	1	2	3
WPRLAGOF	2.78	1.71	2.49

Mapping Between NGTDM, OGSM, and NGTDM/OGSM Regions

NGTDM Region	OGSM Region	NGTDM/OGSM Region
1	1	1
2	1	2
3	1	3
4	3	4
4	5	5
5	1	6
6	1	7
6	2	8
7	2	9
7	3	10
7	4	11
8	5	12
9	6	13
10	2	14
11	4	15
11	5	16
12	6	17

Table E3

Data: Canadian border prices in 1990, Canadian wellhead price in 1989, Canadian capacity expansion data for 1990.

Author: Chetha Phang, EI-823, October 1993.

Source: *Natural Gas Annual* 1991, DOE/EIA-0131.
Canadian Petroleum Association Statistical Summary.
The Potential for Natural Gas in the United States, National Petroleum Council, December 1992.

Derivation: Using the GDP implicit price deflator for 1990 of 1.132, the real Canadian border prices in 1990 for the NGTDM nodes 13 to 18 were computed from the current import prices read from the *Natural Gas Annual* 1991, Tables 89, 76, 66, 67, 56, 70, and 91.

The Canadian wellhead price in 1989 was obtained from the *Canadian Petroleum Association Statistical Summary*.

The Canadian capacity expansion data in 1990 for the NGTDM nodes 13 to 18 were derived from the *National Petroleum Council* report.

Notes: These initial values were used in the model, but they will not affect the solution results.

Units: For gas prices: 1987$/Mcf.
For capacity expansion: Bcf.

File: INITDAT

Variables: CN_BRDPRC90 Canadian border prices in 1990.
CN_WELPRC89 Canadian wellhead price in 1989.
CN_NEWCAP90 Canadian capacity expansion for 1990.

Table E4

Data: Pipeline company financial data at company level and by arc.

Author: Pum Kim, Science Applications International Corporation.

Source: Form FERC-2, *Statistics of Interstate Natural Gas Pipeline Companies*, DOE/EIA-0145 (90).

Derivation: The company level financial data is compiled by using 1980-1990 FERC-2 data for interstate pipelines. The arc level financial data is compiled by using 1990 FERC-2 data.

The calculations are based on the following key rate base and capital structure parameters; details can be obtained from the numerous comments, notes and explanations included in the program itself:

- Gross Plant
- Net Plant
- Gross Plant Allocation Factors
- Net Plant Allocation Factors
- Salary Allocation Factors
- Functionalized Rate Base and Return Components
- Functionalized Customer Clearing Expenses
- Functionalized O&M Expenses
- Functionalized Depreciation and DDA
- Functionalized Working Capital

Three flat output files are created for selected pipelines, the last containing base year (1990) data for subsequent use in the PTM.

Notes: None.

Unit: 1990$.

File: FORM2.

Variables:

DDA	Depreciation, depletion, and amortization costs.
OTTAX	All other taxes assessed by Federal, State, or local governments except income taxes.
TAG	Total administrative and general expense.
TCE	Total customer expense.
SEOM	Supervision and engineering expense.
CSOML	Compressor station operating and maintenance labor expense.
CSOMN	Compressor station operating and maintenance non-labor expense.
OTOM	Other operations and maintenance expense.
CWC	Cash working capital.
OWC	Other working capital.
ADIT	Accumulated deferred income taxes.
GPIS	Original capital cost of plant in service (gross plant in service).
ADDA	Accumulated depreciation, depletion, and amortization.

Table E5

Data: Revenue credits and rates of return by pipeline company.

Author: Pum Kim, Science Applications International Corporation.

Source: Pipeline rate cases filed by FERC (revenue credits) (exhibit I). Pipeline rate case settlements, as reported by FERC OPPR (rates of return).

Derivation: Revenue credit is derived from the most recent rate case as submitted by each pipeline company. Transition cost is based on the recommendation from FERC using amortization schedule. Rates of return from pipeline rate case settlements, as reported by FERC OPPr.

Notes: None.

Units: 1987$ or percentage

File: PTARIFF

Variables:

REVC	Revenue credits to cost-of-service (1-transportation, 2-storage).
PCMER	Rate of return, common stock equity in fraction.
PPFER	Rate of return, preferred stock in fraction.
PLTDR	Rate of return, long term debt in fraction.
DCMER	= PCMER - PLTDR.
DLTDR	= PLTDR - AA bond rating (from MC_RMPUAANS in MACOUT common block).

Table E6

Data: Pipeline capacity.

Author: Pum Kim, Science Applications International Corporation.

Source: Key Point Data, FORM FERC-567 DATA, *Annual Flow Diagram*, (90).

Derivation: Use pipeline capacity going from State to State. If two States are in different regions, then accumulate total capacity along arc. If two States are in same region, then accumulate intra-regional capacity.

Notes: None.

Unit: Bcf per year.

File: CAPACITY

Variables: PCAP_MAX Maximum physical capacity along arc.

Table E7

Data: Pipeline fuel consumption and lease and plant fuel consumption by Census Division. These historical data are used to overwrite model results for the reporting of these consumption categories.

Author: Chetha Phang, EI-823, November 1993.

Source: *Natural Gas Annual* 1991, DOE/EIA-0131, Tables 32-41.

Derivation: The numbers for 1990 and 1991 were read directly from the Natural Gas Annual 1991 Tables 32 to 41, except for Census Division 9 where the Pacific Contiguous and Pacific Noncontiguous Census Divisions were combined (Tables 40 and 41) to compute the aggregate consumptions for both fuels.

Notes: None.

Units: Bcf.

File: HISDATA

Variables:

QGPTR	Pipeline fuel consumption by Census Division.
QLPIN	Lease and plant fuel consumption by Census Division.
MNUMCR	Census Division (1 to 9).

	QGPTR		QLPIN	
MNUMCR	1990	1991	1990	1991
1	1.872	1.761	0.0	0.0
2	41.752	42.057	6.871	4.575
3	52.841	48.725	14.367	11.218
4	72.487	60.225	48.037	55.235
5	37.572	37.646	11.837	9.519
6	96.590	86.865	20.361	15.688
7	196.455	169.007	771.540	605.314
8	124.339	119.585	146.699	119.307
9	35.908	35.019	216.680	327.505

Table E8

Data: Natural gas prices to nonutility end-use demand sectors for 1990 and 1991, by sector, by firm and interruptible service class, and by Census Division. These historical data are used to overwrite the model results in these years that are reported and are passed to the demand model of NEMS.

Author: Chetha Phang, EI-823, November 1993.

Source: *Natural Gas Annual* 1991, DOE/EIA-0131, Tables 31, 44-94.
Gas Facts 1990, 1991, Tables 6-8, 7-6.
Annual Energy Review 1992, DOE/EIA-0384(92), Appendix C for GDP implicit price deflators.

Derivation: The firm gas prices for the residential and commercial sectors for 1990 and 1991 were read directly from the *Natural Gas Annual* 1991 Table 31. For Census Division 9 where the Pacific Contiguous and Pacific Noncontiguous Census Divisions were combined, we computed the firm price in these sectors by using the corresponding end-use gas consumptions (Tables 40, 41) as weights.

For the transportation sector, the firm gas prices for 1990 and 1991 by Census Division were computed using vehicle fuel prices and consumptions from Tables 44 to 94 in the *Natural Gas Annual 1991*.

The interruptible gas prices for the residential, commercial, and transportation sectors in 1990 and 1991 are assumed to be the same as the firm gas prices computed by the method above.

For the industrial sector, the firm gas prices for 1990 and 1991 were computed based on volume and revenues from *Gas Facts* 1990 and 1991, tables 6-8 and 7-6. The historical industrial interruptible prices for 1990 and 1991 were derived using the historical firm industrial prices minus the predicted discount for interruptible service at the city gate. Specifically, using model output, this discount was computed as the average of the differences between firm and interruptible city gate prices by region for 1992 and 1993. This approach assumes that (1) the firm/interruptible city gate price differential for 1990 and 1991 are equal to the average city gate differential for 1992 and 1993 and (2) the average distributor markup for interruptible service is equal to that of firm service.

All the firm and interruptible gas prices computed above were then converted into real prices (1987$/Mcf) by dividing the current prices by the GDP 1987 implicit price deflators from the *Annual Energy Review* 1992.

Notes: The firm and interruptible natural gas prices for electric utilities by Census Division were computed in the NGTDM model from the corresponding electric utilities gas prices and consumptions by NGTDM/EMM region.

Units: 1987$/Mcf.

File: HISDATA

Variables:	MNUMCR	Census Division (1 to 9).
	PGFRS	Residential, firm natural gas prices by Census Division.
	PGFCM	Commercial, firm natural gas prices by Census Division.
	PGFTR	Transportation, firm natural gas prices by Census Division.
	PGFIN	Industrial, firm natural gas prices by Census Division
	PGIRS	Residential, interruptible natural gas prices by Census Division.
	PGICM	Commercial, interruptible natural gas prices by Census Division
	PGITR	Transportation, interruptible natural gas prices by Census Division
	PGIIN	Industrial, interruptible natural gas prices by Census Division
	HPGFRSGR	Residential, firm natural gas prices by NGTDM region.
	HPGFCMGR	Commercial, firm natural gas prices by NGTDM region
	HPGFINGR	Industrial, firm natural gas prices by NGTDM region

Table E9

Data: Natural gas wellhead prices for 1990 and 1991 by OGSM region. These historical data are used to overwrite model results in these years before they are passed to the OGSM and are reported.

Author: Chetha Phang, EI-823, November 1993.

Source: *Natural Gas Annual* 1991, DOE/EIA-0131.
Federal Offshore Statistics 1991, OCS report, MMS91/0068.
U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216, (Form EIA-23).
Annual Energy Review 1992, DOE/EIA-0384(92), Appendix C for GDP implicit price deflators.

Derivation: The dry gas production by substate (Form EIA-23) and the natural gas price by State (*Natural Gas Annual* 1991) were merged together at the State level for the onshore regions. For the offshore regions, we added the average wellhead gas prices from the Federal Offshore Statistics report to the previous dataset. Then, we computed the average wellhead gas prices for 1990 and 1991 by OGSM region by using the production numbers as weights. Finally, we converted these current wellhead prices into real prices (1987$/Mcf) by dividing the current prices by the 1987 GDP price deflators (1.132 for 1990 and 1.178 for 1991) from *Annual Energy Review* 1992.

The wellhead gas prices for the Alaska regions (10- offshore North, 11- onshore North, 12- South) in 1990 and 1991 were set to the State average wellhead prices from the *Natural Gas Annual* 1991. These prices were then converted into real prices by dividing by the 1987 GDP price deflators.

Notes: None.

Units: 1987$/Mcf.

File: HISDATA

Variables:

MNUMOR	OGSM region (1 to 6 is for onshore regions, 7 to 9 is for offshore regions, 10 to 12 is for Alaska regions, 13 is for total Lower 48 States).
OGWPRNG	Natural gas wellhead price by OGSM region.

Table E10

Data: Domestic dry natural gas production for 1990 and 1991 by OGSM region. These historical data are used to overwrite the model results in these years before they are passed to the OGSM and are reported.

Author: Chetha Phang, EI-823, November 1993.

Source: *Natural Gas Annual* 1991, DOE/EIA-0131.
U.S. Crude Oil, *Natural Gas*, *and Natural Gas Liquids Reserves*, DOE/EIA-0216, (Form EIA-23).
Historical and Projected Oil and Gas Consumption, Alaska Department of Natural Resources, Division of Oil and Gas, February 1993, Table 4.
Data created using PIPEJCL.OUTPOGSM.OGPRDNG.D0823931.

Derivation: The dry gas production by substate (Form EIA-23) were aggregated into the OGSM regional level (for 6 onshore regions and 3 offshore regions) from the SAS code mentioned above. The production in region 1 was again adjusted to reflect the revision in the *Natural Gas Annual* 1991.

The production numbers for the Alaska regions (10- offshore North, 11- onshore North, 12- South) in 1990 and 1991 were computed using the total dry production from the *Natural Gas Annual* 1991 (Table 45) and the Alaska North/South split based on production numbers from the Alaska Department of Natural Resources.

Notes: None.

Units: Bcf.

File: HISDATA

Variables:

MNUMOR	OGSM region (1 to 6 is for onshore regions, 7 to 9 is for offshore regions, 10 to 12 is for Alaska regions).
OGPRDNG	Domestic dry natural gas production by OGSM region.

	OGPRDNG	
MNUMOR	1990	1991
1	780.9	793.1
2	4381.0	4452.2
3	3382.9	3224.1
4	1639.7	1653.4
5	1660.2	1808.6
6	301.7	313.6
7	0.0	0.0
8	5230.5	4978.0
9	51.4	55.8
10	0.0	0.0
11	193.0	225.2
12	188.4	184.2

Table E11

Data: Total dry gas production for 1990 and 1991 by PADD. These historical data are used to overwrite the model results in these years before they are passed to the Petroleum Market Model (PMM).

Author: Chetha Phang, EI-823, November 1993.

Source: *Natural Gas Annual* 1991, DOE/EIA-0131.

Derivation: The dry gas production by State for 1990 and 1991 from the *Natural Gas Annual* 1991 (Tables 44-94) were aggregated by Petroleum Administration for Defense Districts (PADD) region by year. The total U.S. dry gas production for 1990 and 1991 match the total dry production in the *Natural Gas Annual* Table 1.

The PADD regions are defined as follows:

PADD I: Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, District of Columbia, Delaware, Maryland, New Jersey, New York, Pennsylvania, Florida, Georgia, North Carolina, South Carolina, Virginia, and West Virginia.

PADD II: Indiana, Illinois, Kentucky, Tennessee, Michigan, Ohio, Minnesota, Wisconsin, North Dakota, South Dakota, Oklahoma, Kansas, Missouri, Nebraska, and Iowa.

PADD III: New Mexico, Texas, Louisiana, Arkansas, Mississippi, and Alabama.

PADD IV: Montana, Idaho, Wyoming, Utah, and Colorado.

PADD V: Washington, Oregon, California, Nevada, Arizona, Alaska, and Hawaii

Notes: None.

Units: Bcf.

File: HISDATA

Variables: MNUMPR PADD region (1 to 5).
PRNG_PADD Total dry gas production by PADD.

	PRNG_PADD	
MNUMPR	1990	1991
1	389.672	381.668
2	3148.031	3038.798
3	12420.686	12291.086
4	1114.590	1196.566
5	736.695	779.998

Table E12

Data: Nonassociated dry natural gas production for 1990 and 1991 by NGTDM/OGSM region. These historical data are used to overwrite the model results in these years before they are passed to the OGSM.

Author: Chetha Phang, EI-823, November 1993.

Source: *Natural Gas Annual* 1991, DOE/EIA-0131.
U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216, (Form EIA-23).
Data created using PIPEJCL.OUTPOGSM.OGPRDNG.D0823931.

Derivation: The nonassociated dry gas production by substate (Form EIA-23) were aggregated into the NGTDM/OGSM regional level (17 onshore regions and 3 offshore regions) from the SAS code mentioned above. The production for 1990 in subregion 3 was again adjusted to reflect the production revision in the *Natural Gas Annual* 1991.

Notes: The Alaskan nonassociated dry gas production of 177.8 Bcf in 1990 and 212.2 Bcf in 1991 are not part of the input data in this table.

Units: Bcf.

File: HISDATA

Variables:

NSUPSUB	NGTDM/OGSM onshore region (1 to 17).
NOCSREG	NGTDM/OGSM offshore region (1 to 3).
OGPRDNGON	Nonassociated dry natural gas production by NGTDM/OGSM onshore region.
OGPRDNGOF	Nonassociated dry natural gas production by NGTDM/OGSM offshore region.

	OGPRDNGON	
NSUPSUB	1990	1991
1	0.0	0.0
2	199.2	171.6
3	183.0	217.9
4	535.6	507.6
5	10.0	11.0
6	175.9	186.5
7	72.3	75.8
8	210.7	258.5
9	3702.9	3689.1
10	2480.9	2405.5
11	773.3	762.3
12	858.0	935.8
13	2.8	2.7
14	0.0	0.0
15	270.7	240.1
16	482.9	551.1
17	117.5	139.4

	OGPRDNGOF	
NOCSREG	1990	1991
1	0.0	0.0
2	4632.5	4393.0
3	17.8	17.6

Table E13

Data: Natural gas wellhead prices for 1990 and 1991 by NGTDM/OGSM region. These historical data are used to assign values to the variable for lagged wellhead price that is used in defining the 1991 and 1992 supply curve functions in the NGTDM.

Author: Chetha Phang, EI-823, November 1993.

Source: *Natural Gas Annual* 1991, DOE/EIA-0131.
Federal Offshore Statistics 1991, OCS report, MMS91/0068.
U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216, (Form EIA-23).
Annual Energy Review 1992, DOE/EIA-0384(92), Appendix C for GDP implicit price deflators.
Data created using Joe Benneche's LOTUS 1-2-3 Data DISC /MISC/WELPRC.WK1.

Derivation: The dry gas production and the natural gas price by State from *Natural Gas Annual* 1991 were merged together with the State production splits from the Form EIA-23. For the offshore regions, we added the average wellhead gas prices from the *Federal Offshore Statistics* report to the previous dataset. Then, we computed the average wellhead gas prices for 1990 and 1991 by NGTDM/OGSM region by using the production numbers as weights. Finally, we converted these current wellhead prices into real prices (1987$/Mcf) by dividing the current prices by the 1987 GDP price deflators (1.132 for 1990 and 1.178 for 1991) from *Annual Energy Review* 1992.

Units: 1987$/Mcf.

File: HISDATA

Variables:

NSUPSUB	NGTDM/OGSM onshore region (1 to 17).
NOCSREG	NGTDM/OGSM offshore region (1 to 3).
HWPRLAGON	Natural gas wellhead price by NGTDM/OGSM onshore region.
HWPRLAGOF	Natural gas wellhead price by NGTDM/OGSM offshore region.

Appendix H

Variable Cross Reference Table

Variable Cross Reference Table

The linear program (LP) formulation of the Annual Flow Module (AFM) is presented in matrix form in Figure H-1. The rows represent the objective function, variable bounds, and problem constraints, and the columns are the variables to be solved. Each row (constraint) and column (variable) has been given a unique name which also are defined in Figure H-1. The row and column names are used in the code to identify where changes are to be made in the working matrix during each model iteration or model year. Since the variables defined in the AFM LP equations are being referenced differently within 1) the mathematical equations presented in Chapter 5, 2) the LP matrix (referenced above), and 3) the code, a cross reference table (Table H-1) has been generated for these variables.

Similarly, Figure H-2 presents the LP matrix representation of the Capacity Expansion Module (CEM) formulation, as well as definitions of the abbreviations and names used. Again, the columns represent the variables, and the rows represent the objective function, variable bounds, and problem constraints corresponding to the model equations defined in Chapter 7. Table H-2 presents a cross reference of the names used within 1) the mathematical equations presented in Chapter 7, 2) the LP matrix (referenced above), and 3) the code to reference the variables in the model equations.

Note that in both figures, two coefficients are defined for a single variable in the mass balance constraints. This is a shortcut means of representing the coefficient associated with the same flow variable that is needed within two mass balance constraints. For example, when the arc represents flow into a node, the coefficient is the arc efficiency variable; however, when the arc represents flow going out of a node, the flow should not be reduced by efficiency, thus the coefficient is one.

The Distributor Tariff Module (DTM) and Pipeline Tariff Module (PTM) are represented by economic and regression equations (see Chapters 6 and 8 for details). Table H-3 presents cross references of model equation variables defined in this document and in the code for the PTM. The DTM equation variables in the document match those in the code.

Figure H-1. LP Matrix Definition for the Annual Flow Module (AFM)

```
            X     X          X    X         X    X    X    X       S     F     F     F     I     I     I                      R
            F     I          F    I         F    I    F    I       S     *     *     *     *     *     *                      H
            N     N          S    S         N    N    Q    Q       +     *     *     *     *     *     *                      S
            *     *          +    +         *    *    *    *       +     B     P     N     B     P     N
            *     *          +    +         *    *    *    *       N     ?     ?     ?     ?     ?     ?
            N     N          N    N         ?    ?    ?    ?       *     @     @     @     @     @     @
            *     *          *    *         @    @    @    @       *     @     @     @     @     @     @
            *     *          *    *         @    @    @    @       #           #     #           #     #
-----------------------------------------------------------------------------------------------------------------------------------------

AFMOBJ     TARF  TARI      TARF TARI      TARF TARI PZZF PZZI     PSUP -PDEMF-PDEMF+PDEMF-PDEMI-PDEMI+PDEMI
AFMBND   U                                                        USUP  UDEMF UDEMF UDEMF UDEMI UDEMI UDEMI
         L MINFF MINFI                                             0    UDEMF  0     0    UDEMI  0     0
-----------------------------------------------------------------------------------------------------------------------------------------

CPN**N**    1     1                                                                                        <= QCAP0(i,j)*UTILZT(i,j)*(1-PCTW)
          -------------------------------------------------------------------------------------------------------------------------------
CPF**N**    1                                                                                              <= QCAP0(i,j)*UTILZF(i,j)*(1-PCTW)
          -------------------------------------------------------------------------------------------------------------------------------
MFN**     EFF,-1            EFF             -1                                                               =           -1*NETSTR_F
          -------------------------------------------------------------------------------------------------------------------------------
MIN**           EFF,-1           EFF             -1                                                          =           -1*NETSTR_I
          -------------------------------------------------------------------------------------------------------------------------------
MF**?@@                                    EFF        1                   -1    -1    1                      =                0
          -------------------------------------------------------------------------------------------------------------------------------
MI**?@@                                         EFF        1                                -1    -1    1    =                0
          -------------------------------------------------------------------------------------------------------------------------------
MS++N**                     -1   -1                                1                                         =                0
-----------------------------------------------------------------------------------------------------------------------------------------

          Legend:  ** = nodes (01-21),  ++ = OGSM region (01-06),  ? = sector code (R,C,I,T,U),
                   @@ = census (01-09) or nerc region (01-13),  # = step number on curve (1-9)
```

Figure H-1. LP Matrix Definition for the Annual Flow Module (AFM) (Continued)

Columns

X F N * * N * *	=	Firm flow from node to node
X I N * * N * *	=	Interruptible flow from node to node
X F S + + N * *	=	Firm flow from supply to node
X I S + + N * *	=	Interruptible flow from supply to node
X F N * * ? @ @	=	Firm flow to end-use sector
X I N * * ? @ @	=	Interruptible flow to end-use sector
X F Q * * ? @ @	=	Firm flow from backstop supply to end-use sector
X I Q * * ? @ @	=	Interruptible flow from backstop to end-use sector
S S + + N * * #	=	Steps on regional supply curve
F * * B ? @ @	=	Base step on firm demand curve
F * * P ? @ @ #	=	Positive steps on firm demand curve
F * * N ? @ @ #	=	Negative steps on firm demand curve
I * * B ? @ @	=	Base step on interruptible demand curve
I * * P ? @ @ #	=	Positive steps on interruptible demand curve
I * * N ? @ @ #	=	Negative steps on interruptible demand curve
R H S	=	Right hand side of constraint equations

Rows

A F M O B J	=	AFM Objective Function
A F M B N D	=	AFM Variable Bounds
C P N * * N * *	=	Pipeline capacity limit--Total flow
C P F * * N * *	=	Pipeline capacity limit--Firm flow
M F N * *	=	Regional mass balance--Firm network
M I N * *	=	Regional mass balance--Interruptible network
M F * * ? @ @	=	End-use mass balance--Firm network
M I * * ? @ @	=	End-use mass balance--Interruptible network
M S + + N * *	=	Supply subregion mass balance

Legend: ** = nodes (01-21), ++ = OGSM region (01-06), ? = sector code (R,C,I,T,U),
@@ = census (01-09) or nerc region (01-13), # = step number on curve (1-9)

Appendix I

Model Equations

Model Equations

This appendix presents the mapping of the equation (by equation number) in the documentation with the subroutine in the NGTDM code where the equation is used or referenced.

Chapter 3 Equations	
EQ. #	**SUBROUTINE**
1 (Firm) (Interr.)	NGTDM CRVNONUFX* NGTDM CRVNONUIX*
2-8	NGTDM DMDALK
9	NGSYN LIQH*
10-13	NGCAN IMP*
14-15	NGTDM PRE
16-21 (Onshore) (Offshore)	NGPRD L48* NGPRD OCS*
* Function	

Chapter 5 Equations	
EQ. #	**SUBROUTINE**
22-24	Not applicable
25	NGTDM LPSI,NGTDM LPEI,NGTDM EFFLP, NGTDM TARPI,NGTDM TARDI,NGTDM SUPCI, NGTDM UTILCI,NGTDM NONUCI,NGTDM EXCI
26-29	NGTDM CAPI
30-31	NGTDM UTILCI,NGTDM NONUCI,NGTDM EFFLP,NGTDM LPEI
32	NGTDM SUPCI
33-35	NGTDM CAPI
36	PROPEROUT

Chapter 6 Equations	
EQ. #	**SUBROUTINE**
37	NGTDM NONUSI
38	NGTDM DTM
39-40	NGTDM HISOVR
41-42	NGTDM NONUSI
43	NGTDM DTM
44-45	NGTDM NONUSI
46-48	NGTDM DTM
49	NGTDM HISOVR
50	NGTDM UTILSI

Chapter 7 Equations

EQ. #	SUBROUTINE
51	CEMLSNY,CEMLPNE,CEMLPST,CEMCANIMP, CEMFLOWNN,CEMSUPCI,CEMSCAP,CEMBACK,CEMPCAP
52-55	CEMLPST,CEMLPNN,CEMLPSNB
56	CEMLPST
57-60	CEMLPNE,CEMDMD
61	CEMLPSUP,CEMCANSUP,CEMSUPCI
62	CEMLPSUP,CEMSUPCI
63	CEMLPSUP,CEMCANSUP,CEMSUPCI
64	UPDTRHS
65	CEMLPCAP,CEMCANIMP,CEMDMD,CEMPCAP
66	RESET RHS,CEMLPCAP,CEMCANIMP,CEMDMD,CEMPCAP
67	CEMLPCAP,CEMCANIMP,CEMDMD,CEMPCAP
68-69	CEMLPST UTIL,CEMSCAP,RESET RHS
70-71	CEMCANIMP,CEMFLOWNN
72-73	RESETMATRIX
74-75	GETSOLUTION1
76-77	NGCEM AFMUTILZ

Chapter 8 Equations	
EQ #	**SUBROUTINE**
78-94	CALCULATE COST
95-100	TRANS COST OF SERVICE
101-102	BASE YEAR PIPELINE
103-104	BASE YEAR PIPELINE, FORECAST PIPELINE
105-130	ALLOCATE ARC LEVEL COST
131-132	EXPAND GENERIC
133-137	BASE YEAR INITIALIZATION
138	CALCULATE COST
139-144	FORECAST COST
145	CALCULATE COST
146	FORECAST COST
147-155	CALCULATE COST
156	FORECAST COST
157	CALCULATE COST
158	FORECAST COST
159-160	CALCULATE COST
161-164	FORECAST COST

Appendix J

Model Variable Definition List

Fortran PARAMETERS Defined for the NGTDM

Parameters Defined for the NGTDM

Variable	Include	Value	Definition
CEMH	NGTDMLOC	3	Year of dmd data after cap. Expan yr
CEMN	NGTDMLOC	2	Number of years ahead for cap expan.
CEMNS	NGTDMLOC	6	Number of steps on cap expansion curves
FHISYR	NGTDMLOC	1990	First historical year
IBASYR	NGTDMOUT	1990	First year in simulation
IENDYR	NGTDMOUT	MNUMYR+IBASYR-1	Last year in simulation
JARC	NGTDMLOC	5	Max # of arcs into node
JSUP	NGTDMLOC	4	Max # of supply sources into node
JTOTSUP	NGTDMLOC	NSUPTYP*NGTDM*JSUP	Max # of total supply connections
JTREE	NGTDMLOC	6	Max # of branches on level of tree
JUTIL	NGTDMLOC	4	Max # of dmd reg. Per node
LHISYR	NGTDMLOC	1991	Last historical year
MAX_CT	NGTDMPTM	2	Mas num of cost types 1 = transportation cost 2 = storage cost
MAX_DESIGN	NGTDMPTM	3	Maximum number of rated design types
MAX_EXPANSION	NGTDMPTM	CEMNS	Maximum number of expansions
MAX_ITEM	NGTDMPTM	18	Maximum number of cost line items
MAX_PIPE	NGTDMPTM	80	Maximum number of pipeline companies
MAX_PT	NGTDMPTM	4	Max num of cost types 1 = individual pipeline 2 = scaled cost data 3 = 1990 hist by arc 4 = generic company data by arc
MAX_STEPS	NGTDMPTM	CEMNS	Maximum number of steps
NALKREG	NGTDMOUT	3	# of Alaska supply regions
NCAN	NGTDMOUT	6	# of boarder crossings into Canada
NDSTEP	NGTDMLOC	4	Number of steps on half of dmd curve
NEMMREG	NGTDMOUT	13	# of EMM utility dmd regions
NEMMSUB	NGTDMOUT	20	# of NGTDM/EMM subregions
NGTDM	NGTDMLOC	21	Number of NGTDM nodes
NLNG	NGTDMOUT	4	# of potential sup LNG sources
NMEX	NGTDMOUT	3	# of boarder crossings into Mexico

Parameters Defined for the NGTDM			
Variable	**Include**	**Value**	**Definition**
NNCEN	NGTDMOUT	9	# of Census divisions
NNGREG	NGTDMOUT	12	# of NGTDM regions (excluding boarder crossings)
NOCSREG	NGTDMOUT	3	# of off-shore supply regions
NONUSEC	NGTDMLOC	4	Number of non-utility sectors
NPREG	NGTDMOUT	NSUPREG+NOCSREG	# of OGSM regs (6-on,3-off)
NSSTEP	NGTDMLOC	9	Number of steps on supply curve
NSUPREG	NGTDMOUT	6	# of OGSM supply regions
NSUPSUB	NGTDMOUT	17	# of NGTDM/OGSM subregions
NSUPTYP	NGTDMLOC	8	Number of supply types
NTREE	NGTDMLOC	8	Number of levels on tree
NUMSTR	NGTDMCEM	10	Number of nodes with storage

Variable Definition List for NGTDM Global Variables
Grouped by Fortran INCLUDE Statement

INCLUDE (NGAFMDAT)

Variable	Common Name	Characteristics	Definitions
AK_C	NGAFMDAT1	Dimen: 3 Units: ---	Estimated coeff used to determine AK consump/ prod levels
AK_CM	NGAFMDAT1	Dimen: --- Units: 87$/mcf	Wellhead to end-use markups--commercial sec
AK_CN	NGAFMDAT1	Dimen: IBASYR:IENDYR Units: 1000 people	Number of commercial customers
AK_D	NGAFMDAT1	Dimen: 3 Units: ---	Estimated coeff used to determine AK consump/ prod levels
AK_E	NGAFMDAT1	Dimen: 3 Units: ---	Estimated coeff used to determine AK consump/ prod levels
AK_EM	NGAFMDAT1	Dimen: --- Units: 87$/mcf	Wellhead to end-use markups--utility sec
AK_F	NGAFMDAT1	Dimen: 3 Units: ---	Estimated coeff used to determine AK consump/ prod levels
AK_G	NGAFMDAT1	Dimen: 3 Units: ---	Estimated coeff used to determine AK consump/ prod levels
AK_PCTLSE	NGAFMDAT1	Dimen: 3 Units: fraction	Lease fuel/dry prod (S&N&A)
AK_PCTPIP	NGAFMDAT1	Dimen: 3 Units: fraction	Pipe fuel /dry prod (S&N&A)
AK_PCTPLT	NGAFMDAT1	Dimen: 3 Units: fraction	Plant fuel/dry prod (S&N&A)
AK_PCTSOUTH	NGAFMDAT1	Dimen: 5 Units: fraction	Percent of AK demand in South AK
AK_RM	NGAFMDAT1	Dimen: --- Units: 87$/mcf	Wellhead to end-use markups--residential sec
AK_RN	NGAFMDAT1	Dimen: IBASYR:IENDYR Units: 1000 people	Number of residential customers
ANGTS_TAR	NGAFMDAT1	Dimen: --- Units: 87$/mcf	Price markup for gas moved on ANGTS
CANFRMITR_SHR	NGAFMDAT1	Dimen: NCAN Units: fraction	Firm share--Canadian exports
CN_BRDPRC90	NGAFMDAT1	Dimen: NCAN Units: 87$/mcf	Starting border crossing price 1990
CN_NEWCAP90	NGAFMDAT1	Dimen: NCAN Units: Bcf	New pipe capacity in 1990

INCLUDE (NGAFMDAT)			
Variable	**Common Name**	**Characteristics**	**Definitions**
CN_WELPRC89	NGAFMDAT1	Dimen: --- Units: 87$/mcf	Canadian wellhead price in 1989
DEFPRICE	NGAFMDAT1	Dimen: --- Units: 87$/mcf	Default price if qty=0, any sector
EMISRAT	NGAFMDAT1	Dimen: MNPOLLUT Units: 1000 lb/Bcf	Emissions as percent of pipe fuel
MAXPROF	NGAFMDAT1	Dimen: NOCSREG Units: fraction	Maximum P/R ratio for offshore
MAXPRON	NGAFMDAT1	Dimen: NSUPREG Units: fraction	Maximum P/R ratio for onshore
MEXFRMITR_SHR	NGAFMDAT1	Dimen: NMEX Units: fraction	Share of Mexican exports to firm
NG_CENSHR	NGAFMDAT1	Dimen: NONUSEC,NNGREG Units: fraction	Shares to split census to NGTDM
OSUP_HVAL	NGAFMDAT1	Dimen: IBASYR:1991 Units: Bcf	Historical value for other supplemental supplies
OSUP_RSHR	NGAFMDAT1	Dimen: 7 Units: fraction	Shares for setting reg values for other supplemental supplies
OSUP_TOT	NGAFMDAT1	Dimen: IBASYR:IENDYR Units: Bcf	Tot other supplemental supplies--forecast
SHR_AD17	NGAFMDAT1	Dimen: NSUPSUB Units: fraction	AD gas shares (1-17)
SNG89	NGAFMDAT1	Dimen: --- Units: Bcf	SNG prod fr liq in ILL in 1989
SNGA1	NGAFMDAT1	Dimen: --- Units: ---	Estimated parameter--used to determine SNG from liq.
SNGA2	NGAFMDAT1	Dimen: --- Units: ---	Estimated parameter--used to determine SNG from liq.
SNGHI	NGAFMDAT1	Dimen: --- Units: Bcf	SNG prod fr liq in Hawaii
SNGMIN	NGAFMDAT1	Dimen: --- Units: Bcf	Minimum SNG prod fr liq allowed ILL
WOP89	NGAFMDAT1	Dimen: --- Units: 87$/BBL	1989 world oil price
WPR89	NGAFMDAT1	Dimen: --- Units: 87$/mcf	1989 AK wellhead price

INCLUDE (NGCEMRPT)			
Variable	**Common Name**	**Characteristics**	**Definition**
BKSTOP	CEMRPT	Dimen: NNGREG Units: Bcf	Total backstop supply from LP soln
OPSUP	CEMRPT	Dimen: NSUPTYP,NGTDM,4 Units: Bcf	Off-peak supply from LP soln
PFSTN	CEMRPT	Dimen: NUMSTR Units: Bcf	Peak firm storage usage from LP soln
PKSTN	CEMRPT	Dimen: NUMSTR Units: Bcf	Total peak storage usage from LP soln
PKSUP	CEMRPT	Dimen: NSUPTYP,NGTDM,4 Units: Bcf	Peak supply from LP soln

INCLUDE (NGTDMAFM)			
Variable	**Common Name**	**Characteristics**	**Definition**
ACAP_MIN_F	NGXFXI	Dimen: NGTDM,NGTDM Units: Bcf	Minimum flow along firm arc
ACAP_MIN_I	NGXFXI	Dimen: NGTDM,NGTDM Units: Bcf	Minimum flow along interrup arc
AD_FR_OIL	NGPERCENT	Dimen: 9,4 Units: ---	PARM1, PARM2, PARM3 defining AD from oil in equation: ADG= PARM1*(OILPRD**PARM2)*(ADGLAG**PARM3)
ADGPRDOF	NGADGPRD	Dimen: NOCSREG Units: Bcf	AD gas production--offshore
AFM_TOL--not used	FMISC	Dimen: --- Units: ---	Supply tolerance for AFM conv check
APCT_MINF	NGXFXI	Dimen: NGTDM,NGTDM Units: fraction	Min flow as % of last yr along firm arc
APCT_MINI	NGXFXI	Dimen: NGTDM,NGTDM Units: fraction	Min flow as % of last yr along interrup arc
ASTORE	LPCAP	Dimen: NNGREG Units: Bcf-annual	Annual storage vol used
AXMAX --not used	NGMAXIT	Dimen: --- Units: ---	Max. # Of iterations for afm conv.
B1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
CANTAR_F	AFMNEW	Dimen: NCAN Units: 87$/mcf	Tar along firm arcs to Can nodes
CANTAR_I	AFMNEW	Dimen: NCAN Units: 87$/mcf	Tar along interrup arcs to Can nodes
CONST_DMD	LPDMD	Dimen: --- Units: ---	Indicator defining const dmd scenario
CONST_EXP	AFMNEW	Dimen: --- Units: ---	Indicator for constant exports
DDD	LPNAME	Dimen: --- Format: char*3	Three blanks, used to define LP matrix var
DDDD	LPNAME	Dimen: --- Format: char*4	Four blanks, used to define LP matrix var
DIST_TAR	AFMNEW	Dimen: --- Units: ---	Indicator for changing dist tar coeff
DMD_TOL--not used	FMISC	Dimen: --- Units: ---	Dmd tolerance for conv check on tree

INCLUDE (NGTDMAFM)

Variable	Common Name	Characteristics	Definition
DXMAX--not used	NGMAXIT	Dimen: --- Units: ---	Max. # Of iterations for adjusting shares
E1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
F_BKSTOP	FNODE	Dimen: --- Units: Bcf	Tot backstop results for firm
F1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
FXMAX--not used	NGMAXIT	Dimen: --- Units: ---	Max. # Of iterations for firm conv.
HWPRLAGOF	NHLAGPRC	Dimen: NOCSREG,HISYR Units: 87$/Mcf	Wellhead price last year, offshore
HWPRLAGON	NHLAGPRC	Dimen: NSUPSUB,HISYR Units: 87$/Mcf	Wellhead price last year, onshore
I_BKSTOP	FNODE	Dimen: --- Units: Bcf	Tot backstop results for interrup.
I1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
ILAG	WELLPR	Dimen: --- Units: ---	# of lag years to estimate LNG
MEXEFF	AFMNEW	Dimen: NMEX Units: fraction	Eff along arcs to Mex nodes
MEXTAR_F	AFMNEW	Dimen: NMEX Units: 87$/mcf	Tar along firm arcs to Mex nodes
MEXTAR_I	AFMNEW	Dimen: NMEX Units: 87$/mcf	Tar along interrup arcs to Mex nodes
MF	LPNAME	Dimen: --- Format: char*2	Double letters, used to define LP matrix var
MI	LPNAME	Dimen: --- Format: char*2	Double letters, used to define LP matrix var
MINXF	NGXCES	Dimen: NGTDM,NGTDM Units: Bcf	Minimum excess for firm capacity
MINXI	NGXCES	Dimen: NGTDM,NGTDM Units: Bcf	Minimum excess for interrup. Cap.
MU--not used	FMISC	Dimen: --- Units: ---	Parameters used to reallocate shares

INCLUDE (NGTDMAFM)			
Variable	**Common Name**	**Characteristics**	**Definition**
N1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
NBRNCH--not used	FTREE	Dimen: NTREE Units: --	# of branches at each tree level
NG_ARCSIZE	LPCAP	Dimen: NGTDM,NGTDM Units: fraction	Arc split between NGTDM regions--used to determine pipeline fuel
NG_AVGPR_F	FNODE	Dimen: NGTDM Units: 87$/mcf	Avg price at firm node
NG_AVGPR_I	FNODE	Dimen: NGTDM Units: 87$/mcf	Avg price at interrup. node
NODE_DMD	FNODE	Dimen: NGTDM Units: Bcf	Total firm demand at node
NONU_PR_F	FSEC	Dimen: NONUSEC,NGTDM Units: 87$/mcf	Resulting nonutil firm price
NONU_PR_I	NGXFXI	Dimen: NONUSEC,NGTDM Units: 87$/mcf	Resulting interrup nonutil price
NONU_QTY_F	FSEC	Dimen: NONUSEC,NGTDM Units: Bcf	Resulting nonutil firm dmd
NONU_QTY_I	NGXFXI	Dimen: NONUSEC,NGTDM Units: Bcf	Resulting interrup nonutil qty
OBJAFM	LPMTRX	Dimen: --- Format: char*8	LP OBJ function name used by OML
P1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
PALK_NONU_F	QPALK	Dimen: NONUSEC Units: 87$/mcf	Alaska firm nonutil price
PALK_NONU_I	QPALK	Dimen: NONUSEC Units: 87$/mcf	Alaska interrup nonutil price
PALK_UTIL_C	QPALK	Dimen: --- Units: 87$/mcf	Alaska competitive util price
PALK_UTIL_F	QPALK	Dimen: --- Units: 87$/mcf	Alaska firm util price
PALK_UTIL_I	QPALK	Dimen: --- Units: 87$/mcf	Alaska interrup util price

INCLUDE (NGTDMAFM)			
Variable	**Common Name**	**Characteristics**	**Definition**
PBAS_NONU_F	PQBASE	Dimen: NONUSEC,NNGREG Units: 87$/mcf	Base nonutil firm price
PBAS_NONU_I	PQBASE	Dimen: NONUSEC,NNGREG Units: 87$/mcf	Base nonutil inter price
PBAS_UTIL_F	PQBASE	Dimen: NEMMSUB Units: 87$/mcf	Base util firm price
PBAS_UTIL_I	PQBASE	Dimen: NEMMSUB Units: 87$/mcf	Base util inter price
PCT_MINF--not used	NGXFXI	Dimen: --- Units: ---	OLD-- Minimum firm flow as % of last yr
PCT_MINI--not used	NGXFXI	Dimen: --- Units: ---	OLD-- Minimum interrup. Flow as % of last yr
PCTLSE_SUPL	NGPERCENT	Dimen: NSUPSUB Units: ratio	Lease consumption/dry gas prod
PDSTEP	LPSTEP	Dimen: NDSTEP Units: ---	# steps on half of LP demand curve
PIPE_TAR	AFMNEW	Dimen: --- Units: ---	Indicator for changing pipe tar coeff
PNEW_STRX	LPCAP	Dimen: NNGREG,MNUMYR Units: Bcf/yr	New storage capacity additions
PQ_PNG	NGTOTRPT	Dimen: 9 Units: 87$	P*Q by census, used to calc PNG**
PR_TOL--not used	FMISC	Dimen: --- Units: ---	Pr tolerance for conv check on tree
Q_PNG	NGTOTRPT	Dimen: 9 Units: Bcf	Q by census, used to calc PNG**
QALK_LAP	QPALK	Dimen: --- Units: Bcf	Alaska lease & plant
QALK_PIP	QPALK	Dimen: --- Units: Bcf	Alaska pipeline fuel
QALK_UTIL_C	QPALK	Dimen: --- Units: Bcf	Alaska competitive util dmd
QALK_UTIL_F	QPALK	dimen: --- Units: Bcf	Alaska firm util dmd

INCLUDE (NGTDMAFM)			
Variable	**Common Name**	**Characteristics**	**Definition**
QALK_UTIL_I	QPALK	Dimen: --- Units: Bcf	Alaska interrup util dmd
QBAS_NONU_F	PQBASE	Dimen: NONUSEC,NNGREG Units: Bcf	Base nonutil firm consump
QBAS_NONU_I	PQBASE	Dimen: NONUSEC,NNGREG Units: Bcf	Base nonutil interrup consump
QBAS_UTIL_F	PQBASE	Dimen: NEMMSUB Units: Bcf	Base util firm consump
QBAS_UTIL_I	PQBASE	Dimen: NEMMSUB Units: Bcf	Base util interrup consump
QGCBCF	NGHISTEL	Dimen: NEMMSUB+1,MNUMYR Units: Bcf	Hist comp util dmds
QGFBCF	NGHISTEL	Dimen: NEMMSUB+1,MNUMYR Units: Bcf	Hist firm util dmds
QGIBCF	NGHISTEL	Dimen: NEMMSUB+1,MNUMYR Units: Bcf	Hist intrp util dmds
REGTREE--not used	FTREE	Dimen: NTREE,JTREE Units: ---	Node ID's mapped into each branch
S1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
SIGMA--not used	FMISC	Dimen: --- Units: ---	Parameters used to reallocate shares
STAR_F	AFMNEW	Dimen: NGTDM,JSUP Units: 87$/mcf	Tar along firm arc from supply
STAR_I	AFMNEW	Dimen: NGTDM,JSUP Units: 87$/mcf	Tar along interrup arc from supply
SUP_QTY	NGXFXI	Dimen: NSUPTYP,NGTDM,JSUP Units: Bcf	Resulting total sup qty
SUP_QTY_F	NGXFXI	Dimen: NSUPTYP,NGTDM,JSUP Units: Bcf	Resulting sup qty for firm

INCLUDE (NGTDMAFM)			
Variable	**Common Name**	**Characteristics**	**Definition**
SUP_QTY_I	NGXFXI	Dimen: NSUPTYP,NGTDM,JSUP Units: Bcf	Resulting sup qty for interrup
SYNCOALNG	NGCOAL	Dimen: NSUPSUB Units: Bcf	SNG from coal
UTIL_DTAR_F	LPDTAR	Dimen: NGTDM,JUTIL Units: 87$/mcf	Distributor tar to firm util sector
UTIL_DTAR_I	LPDTAR	Dimen: NGTDM,JUTIL Units: 87$/mcf	Distributor tar to interrup util sector
UTIL_PR_F	FSEC	Dimen: NGTDM,JUTIL Units: 87$/mcf	Resulting util firm price
UTIL_PR_I	NGXFXI	Dimen: NGTDM,JUTIL Units: 87$/mcf	Resulting interrup util price
UTIL_QTY_F	FSEC	Dimen: NGTDM,JUTIL Units: Bcf	Resulting util firm dmd
UTIL_QTY_I	NGXFXI	Dimen: NGTDM,JUTIL Units: Bcf	Resulting interrup util qty
WPRCLAGOF (Not used)	WELLPR	Dimen: NSUPSUB Units: $/mcf	Lagged offshore wellhead price
WPRCLAGON (Not used)	WELLPR	Dimen: NSUPSUB Units: $/mcf	Lagged onshore wellhead price--NGTDM/OGSM subreg
WPRLAGOF	NGLAGPRC	Dimen: NOCSREG Units: 87$/mcf	Offshore wellhead price --last year
WPRLAGON	NGLAGPRC	Dimen: NSUPSUB Units: 87$/mcf	Onshore wellhead price --last year
X1	LPNAME	Dimen: --- Format: char*1	Single letters, used to define LP matrix var
XSPRNTA	LPMTRX	Dimen: --- Format: char*8	AFM soln print indicator used by OML

INCLUDE (NGTDMCEM)			
Variable	**Common Name**	**Characteristics**	**Definition**
ARC_OUTILZ	CEMDAT	Dimen: 21,21 Units: fraction	Max off-PK utilization of total cap available during off-PK period
ARC_PFUTILZ	CEMDAT	Dimen: NGTDM,NGTDM Units: fraction	Max PK firm utilization of total cap available during PK period
ARC_PUTILZ	CEMDAT	Dimen: 21,21 Units: fraction	Max PK utilization of total cap available during PK period
B	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
C	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
C1--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Estimated parameters for productive capacity equations
C2--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Estimated parameters for productive capacity equations
C3--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Estimated parameters for productive capacity equations
C4--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Estimated parameters for productive capacity equations
C5--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Estimated parameters for productive capacity equations
CANFLO_PFSHR	CEMDMDS	Dimen: --- Units: fraction	PK share of firm imports from Can.
E	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
EC	LPNAME3	Dimen: --- Format: char*2	Double letters, used to define LP variables
EM	LPNAME3	Dimen: --- Format: char*2	Double letters, used to define LP variables
EXP_PSHR	CEMEXP	Dimen: 9 Units: fraction	Peak share of annual exports
EXPMAP	CEMMAP	Dimen: 2,9 Units: ---	ID's 9 export border crossing arcs by NGTDM source and dest nodes (1=source, 2=dest)
F	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
HALPHA	ALPHADATA	Dimen: --- Units: fraction	A tracking of the high alpha value last used (real*8)

INCLUDE (NGTDMCEM)

Variable	Common Name	Characteristics	Definition
LALPHA	ALPHADATA	Dimen: --- Units: fraction	A tracking of the low alpha value last used (real*8)
LASTALPHA	ALPHADATA	Dimen: --- Units: fraction	A tracking of the alpha value last used (real*8)
M	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
N	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
NONU_POSHR_F	CEMDAT	Dimen: 2,4,NNGREG Units: fraction	PK, off-PK split of firm nonutil dmd
NONU_POSHR_I	CEMDAT	Dimen: 2,4,NNGREG Units: fraction	PK, off-PK split of interrup. nonutil dmd
O	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
OBJCEM	LPCEM	Dimen: --- Format: char*8	Objective function name for use by OML
OF_FLOW	CEMFLOW	Dimen: 21,21 Units: Bcf	Resulting off-PK firm flow along network arcs
OFSTRBND	STRBND	Dimen: NNGREG,2 Units: Bcf	Bound on OF flow into storage (1=lower, 2=upper)
OI	LPNAME3	Dimen: --- Format: char*2	Double letters, used to define LP variables
OI_FLOW	CEMFLOW	Dimen: 21,21 Units: Bcf	Resulting off-PK interrup. flow along network arcs
OISTRBND	STRBND	Dimen: NNGREG,2 Units: Bcf	Bound on OI flow into storage (1=lower, 2=upper)
OPPCNT	CEMDAT	Dimen: --- Units: fraction	Off-PK period as percent of year
P	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
PCTMIN_OF--not used	CEMDMDS	Dimen: --- Units: ---	== not used ==
PCTMIN_PF--not used	CEMDMDS	Dimen: --- Units: ---	== not used ==
PEAKPCNT	CEMDAT	Dimen: --- Units: fraction	PK period as percent of year

INCLUDE (NGTDMCEM)			
Variable	**Common Name**	**Characteristics**	**Definition**
PF_FLOW	CEMFLOW	Dimen: 21,21 Units: Bcf	Resulting PK firm flow along network arcs
PFSTRBND	STRBND	Dimen: NNGREG,2 Units: Bcf	Bound on PF flow out of storage (1=lower, 2=upper)
PI	LPNAME3	Dimen: --- Format: char*2	Double letters, used to define LP variables
PI_FLOW	CEMFLOW	Dimen: 21,21 Units: Bcf	Resulting PK interrup. flow along network arcs
PISTRBND	STRBND	Dimen: NNGREG,2 Units: Bcf	Bound on PI flow out of storage (1=lower, 2=upper)
PRDCAP89--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Hist 1989 prod cap by OGSM
PRDCAP90--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Hist 1990 prod cap by OGSM
PRDCAP91--not used	PRDCAPDAT	Dimen: NPREG Units: ---	Hist 1991 prod cap by OGSM
Q	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
QCAP0	RESET	Dimen: NGTDM,NGTDM Units: Bcf	Base capacity on cap expansion curve
QDEMOOF	CEMDMDS	Dimen: 4,21 Units: Bcf	Off-PK firm nonutil dmd in forecast yr CEMN or (CEMN + CEMH)
QDEMOOFU	CEMDMDS	Dimen: NEMMSUB Units: Bcf	Off-PK firm util dmd in forecast yr CEMN
QDEMOOI	CEMDMDS	Dimen: 4,21 Units: Bcf	Off-PK interup. nonutil dmd in forecast yr CEMN or (CEMN + CEMH)
QDEMOOIU	CEMDMDS	Dimen: NEMMSUB Units: Bcf	Off-PK interup. util dmd in forecast yr CEMN
QDEMOPF	CEMDMDS	Dimen: 4,21 Units: Bcf	PK firm nonutil dmd in forecast yr CEMN or (CEMN + CEMH)
QDEMOPFU	CEMDMDS	Dimen: NEMMSUB Units: Bcf	PK firm util dmd in forecast yr CEMN
QDEMOPI	CEMDMDS	Dimen: 4,21 Units: Bcf	PK interrup. nonutil dmd in forecast yr CEMN or (CEMN + CEMH)
QDEMOPIU	CEMDMDS	Dimen: NEMMSUB Units: Bcf	PK interrup. util dmd in forecast yr CEMN

INCLUDE (NGTDMCEM)			
Variable	**Common Name**	**Characteristics**	**Definition**
QSTR0	CEMDAT	Dimen: NUMSTR Units: Bcf	Base capacity on storage expansion curve
R	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
S	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
STOR_NODES	STORAG	Dimen: 11 Units: ---	mapping of storage locations into NGTDM nodes 1-12
STR_FUTILZ	STORAG2	Dimen: NUMSTR Units: fraction	1 - storage losses for PK firm network
STR_UTILZ	STORAG2	Dimen: NUMSTR Units: fraction	1 - storage losses for PK interrup. network
SUP_OUTILZ	CEMDAT	dimen: NSUPTYP,NGTDM,4 Units: fraction	Portion of total supply allocated to off-PK network
SUP_PKSHR	CEMSUP	Dimen: 8,NGTDM,4 Units: fraction	Peak share of annual supply
SUP_PUTILZ	CEMDAT	Dimen: NSUPTYP,NGTDM,4 Units: fraction	Portion of total supply allocated to PK network
T	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
TARO	CEMDAT	Dimen: NSUPTYP,NGTDM,4 Units: 87$/mcf	Tariff along supply arc for off-PK firm and off-PK interrupt. networks
TARP	CEMDAT	Dimen: NSUPTYP,NGTDM,4 Units: 87$/mcf	Tariff along supply arc for PK firm and PK interrupt. networks
TOTDMD	CEMDMDS	Dimen: --- Units: Bcf	Total interrup. dmd used in alpha loop (real*8)
U	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
UTIL_POSHR_C	CEMDAT	Dimen: 2,NEMMSUB Units: fraction	PK, off-PK split of competitive util dmd
UTIL_POSHR_F	CEMDAT	Dimen: 2,NEMMSUB Units: fraction	PK, off-PK split of firm util dmd
UTIL_POSHR_I	CEMDAT	Dimen: 2,NEMMSUB Units: fraction	PK, off-PK split of interrup. util dmd
WTHRFAC	CEMDAT	Dimen: NGTDM,NGTDM Units: fraction	Weather factor--percent of capacity normally not used for normal weather scenarios

INCLUDE (NGTDMCEM)

Variable	Common Name	Characteristics	Definition
X	LPNAME3	Dimen: --- Format: char*1	Single letter, used to define LP variables
YCAP	RESET	Dimen: NGTDM,NGTDM,CEMNS Units: Bcf	Step results on cap expansion curve in 1st alpha loop
YSTR	CEMDAT	Dimen: NUMSTR,CEMNS Units: Bcf	Step results on storage expansion curve in 1st alpha loop

INCLUDE (NGTDMLOC)			
Variable	**Common Name**	**Characteristics**	**Definition**
ADGPRD89	NGADGPRD1	Dimen: nsdomreg	1989 Ad gas prod onshore & offshore
ADGPRDON	NGADGPRD1	Dimen: NSUPSUB Units: Bcf	AD gas production onshore
AEFF_PIPE	LPCAP1	Dimen: NGTDM,NGTDM Units: fraction	Eff along pipeline arc
AFLOW_F	PTARAFM	Dimen: NGTDM,NGTDM Units: Bcf	Resulting firm NG flow
AFLOW_I	PTARAFM	Dimen: NGTDM,NGTDM Units: Bcf	Resulting interrup. NG flow
AFM_PTAR_I	AFMVARX	Dimen: NGTDM,NGTDM Units: 87$/mcf	Realized pipe tariff for interrup. market
ANEW_CAP	FFCAP	Dimen: NGTDM,NGTDM Units: Bcf	New annual capacity
ARC_CYCLE	FARCS	Dimen: 25,2 Units: ---	Node pairs identifying Bi-flow arcs
ARG0	LPARG	Dimen: --- Units: ---	Real*8 variable used to pass info to LP via OML
ARG1	LPARG	Dimen: --- Units: ---	Real*8 variable used to pass info to LP via OML
ARG2	LPARG	Dimen: --- Units: ---	Real*8 variable used to pass info to LP via OML
AUTILZ_F	LPCAP1	Dimen: NGTDM,NGTDM,CEMN Units: fraction	Capacity utilization limit for firm
AUTILZ_T	LPCAP1	Dimen: NGTDM,NGTDM,CEMN Units: fraction	Capacity utilization limit for firm + interrup.
BENCHF	LPDTAR1	Dimen: NONUSEC,NNGREG Units: 87$/mcf	Benchmarking adj for nonutilities
BGSCNT	PFRCEM	Dimen: NNGREG Units: Bcf	Non-jurisdictional BGSCT
BGSCT	PFRCEM	Dimen: NNGREG Units: Bcf	Base gas storage capacity at node
BIARC_PFSHR	MINFLOW	Dimen: --- Units: fraction	PK/Off-PK share of firm Bi-flow
BIARC_PISHR	MINFLOW	Dimen: --- Units: fraction	PK/Off-PK share of interrup. Bi-flow

INCLUDE (NGTDMLOC)			
Variable	**Common Name**	**Characteristics**	**Definition**
CAN_NODEIN	CANFLOW	Dimen: --- Units: --	Canadian node where 'Can flow-thru' gas flows in
CAN_NODEOUT	CANFLOW	Dimen: 2 Units: ---	Canadian nodes where 'Can flow-thru' gas flows out
CANEFF	EXPNEW	Dimen: NCAN Units: fraction	Eff along arcs to Canadian nodes
CANFLO_IN	CANFLOW	Dimen: --- Units: Bcf	'Can flow-thru' gas flowing into US
CANFLO_OUT	CANFLOW	Dimen: 2 Units: Bcf	'Can flow-thru' gas flowing out of US thru nodes 15 & 17
CANFLO_SHR	CANFLOW	Dimen: --- Units: ---	'Can flow-thru' share going out node 15
CEM_PCAP	PTARCEM	Dimen: NGTDM,NGTDM,CEMNS Units: 87$/mcf	Price on each step of pipeline capacity expansion curves
CEM_PCAPEST	PTARCEM1	Dimen: NGTDM,NGTDM,CEMN Units: $/mcf	Est price on pipeline cap expansion curve for use by PTM
CEM_PSTR	PTARCEM	Dimen: NNGREG,CEMNS Units: Bcf	Quantity on each step of storage expansion curves
CEM_PSTREST	PTARCEM1	Dimen: NNGREG,CEMN Units: $/mcf	Est price on storage expansion curve for use by PTM
CEM_QCAP	PTARCEM	Dimen: NGTDM,NGTDM,CEMNS Units: Bcf	Quantity on each step of pipeline capacity expansion curves
CEM_QSTR	PTARCEM	Dimen: NNGREG,CEMNS Units: 87$/mcf	Price on each step of storage expansion curves
CEMYR	NGMAPS	Dimen: --- Units: ---	Used to determine array position (1,CEMN) of current year CEM expansion results
CHAR0	CHARS	Dimen: --- Format: char*1	Single character for 0
CN_TOL	NGPRDCRV	Dimen: ---- Format: real*4	Allowed tolerance for CN_SHRDIF
CONST_SUP	LPMAPS	Dimen: NSUPTYP Units: ---	Indicator for constant supply by supply type
CP	LPNAME2	Dimen: --- Format: char*2	Double letter, used to create LP var & row names

INCLUDE (NGTDMLOC)			
Variable	**Common Name**	**Characteristics**	**Definition**
D	LPNAME2	Dimen: --- Format: char*1	Single blank, used to create LP var & row names
DD	LPNAME2	Dimen: --- Format: char*2	Double blank, used to create LP var & row names
DMDFLAG_I	LPDTAR1	Dimen: nngreg Format: logical	Flag to check constant demand- interruptible industrial
DMDPR_I	LPDTAR1	Dimen: nngreg	Dtar lower bound-inter ind
DTAR_CHK	LPDTAR1	Dimen: nngreg	1991 Dtar for firm transp
EFF_STR	LPCAP1	Dimen: --- Units: fraction	Storage eff (1-loss)
EMMSUB	NGMAPS	Dimen: NNGREG,NEMMREG Units: ---	NGTDM/EMM subreg, given NGTDM & EMM reg
EMMSUB_EL	NGMAPS	Dimen: NEMMSUB Units: ---	EMM reg mapped into NGTDM/EMM subreg
EMMSUB_NG	NGMAPS	Dimen: NEMMSUB Units: ---	NGTDM reg mapped into NGTDM/EMM subreg
EPHASE	LPDTAR1	Format: integer*4	End phase year
FTAX	LPDTAR1	Dimen: ----	Federal tax
IYRSWT	NGMAPS	Dimen: 40 Units: ---	Used to determine (1,CEMN) array position corresponding to current year CEM expansion results
LAST_TIME	TIMING	Dimen: ----	Timing variable for NGTDM code
LPRC_MAX		Units: ---- Format: integer*4	Maximum number of lagged price adjusted levels
LPRC_SBADJ	NGPRDCRV	Dimen: lprc_max	Phased portion of base mult.
LPRC_SBASE	NGPRDCRV	Dimen: lprc_max	Base multiplier of lag price
LPRC_SYEAR	NGPRDCRV	Dimen: lprc_max	Year of lag price adjst level
MD	LPNAME2	Dimen: --- Format: char*2	Double letter, used to create LP var & row names
MINBIOF	MINFLOW	Dimen: 25 Units: Bcf	Min Bi-flow for CEM Off-PK firm
MINBIOI	MINFLOW	Dimen: 25 Units: Bcf	Min Bi-flow for CEM Off-PK interrup.
MINBIPF	MINFLOW	Dimen: 25 Units: Bcf	Min Bi-flow for CEM PK firm

INCLUDE (NGTDMLOC)

Variable	Common Name	Characteristics	Definition
MINBIPI	MINFLOW	Dimen: 25 Units: Bcf	Min Bi-flow for PK interrup.
MN	LPNAME2	Dimen: --- Format: char*2	Double letter, used to create LP var & row names
MODYR	NGMAPS	Dimen: --- Units: ---	Current model year (i.e., 1990)
MS	LPNAME2	Dimen: --- Format: char*2	Double letter, used to create LP var & row names
NARC_CYCLE	FARCS	Dimen: --- Units: ---	Number of arcs defined as bidirectional flows
NEFF_PIPE	FSEC1	Dimen: NONUSEC,NGTDM Units: fraction	Eff along arc to nonutil sector
NETSTR_F	LPCAP1	Dimen: NNGREG,CEMN Units: Bcf	Net withdrawals from storage--firm
NETSTR_I	LPCAP1	Dimen: NNGREG,CEMN Units: Bcf	Net withdrawals from storage--interrup.
NEWFLOOR_I	LPDTAR1	Dimen: nngreg	Lower bound on price-inter ind
NG_ARCMAP	LPMAPS	Dimen: NGTDM,JARC Units: ---	Node ID mapped into each NGTDM reg
NG_ARCNUM	LPMAPS	Dimen: NGTDM Units: ---	# of arcs into each NGTDM reg
NG_BKSTOP_PR	EXPNEW	Dimen: --- Units: 87$/mcf	NG sup backstop price
NG_CENMAP	LPMAPS	Dimen: NGTDM Units: ---	CENSUS reg ID mapped into each NGTDM reg
NG_EMMMAP	LPMAPS	Dimen: NGTDM,JUTIL Units: ---	EMM reg ID mapped into each NGTDM reg
NG_EMMSUB	LPMAPS	Dimen: NGTDM Units: ---	# of NGTDM/EMM subreg per NGTDM reg
NG_SUPMAP	LPMAPS	Dimen: NSUPTYP,NGTDM,JSUP Units: ---	OGSM reg ID mapped into each NGTDM reg
NG_SUPSUB	LPMAPS	Dimen: NSUPTYP,NGTDM Units: ---	# of NGTDM/OGSM subreg per NGTDM reg
NGHIST_FLG	NGMAPS	Dimen: --- Units: ---	Flag indicating hist overwrite: 0=NO, 1=YES

INCLUDE (NGTDMLOC)			
Variable	**Common Name**	**Characteristics**	**Definition**
NGRATMAX	DTARAFM	Dimen: NEMMSUB Units: ---	Max NG discount rate off of alternate fuel
NGUNIT	NGTRAC	Dimen: --- Units: ---	Output unit # for NGTDM writes
NGWRITE	NGTRAC	Dimen: --- Units: ---	NGTDM trace write level indicator
NONU_DTAR_F	LPDTAR1	Dimen: NONUSEC,NGTDM Units: 87$/mcf	Distributor tar to firm nonutil sec
NONU_DTAR_I	LPDTAR1	Dimen: NONUSEC,NGTDM Units: 87$/mcf	Distributor tar to interrup. nonutil sec
NONU_ELAS_F	NGDMDCRV	Dimen: --- Format: real*4	Firm nonutil demand curve elasticities
NSDOMREG		Units: ---- Format: integer*4	# of domestic supply regions
NUM	LPNAME2	Dimen: 9 Format: char*1	Numbers 1-9, used to create LP var & row names
OCSMAP	NGMAPS	Dimen: NOCSREG Units: ---	Mapping of NGTDM/OGSM subreg into off-shore production regions
OILPRD89	NGADGPRD1	Dimen: nsdomreg	1989 oil prod onshore & offshore
PARM_MAXPR	NGPRDCRV	Format: real*4	Params to set max prod. level
PARM_MINSUP	NGPRDCRV	Dimen: 2	Params to set min prod. level
PARM_SUPCRV2	NGPRDCRV	Dimen: 2	Params defining supcrv 2
PARM_SUPCRV3	NGPRDCRV	Dimen: 2	Params defining supcrv 3
PCAP_AFM	PTARAFM	Dimen: NGTDM,NGTDM Units: Bcf	Physical cap along arc in AFM, t-1
PCAP_MAX	PTARAFM	Dimen: NGTDM,NGTDM,CEMN Units: Bcf	Maximum physical cap along arc
PCT_XCAP	PTARAFM	Dimen: --- Units: fraction	Percent excess capacity on pipe
PDELMX	LPSTEP2	Dimen: --- Units: 87$/mcf	Max price delta off base price--LP supply and demand curve
PMMMAP_NG	NGMAPS	Dimen: NSUPSUB Units: ---	PADD reg mapped into NGTDM/OGSM subreg
PNEW_CAP	FFCAP	Dimen: NGTDM,NGTDM Units: Bcf	New physical capacity

INCLUDE (NGTDMLOC)			
Variable	**Common Name**	**Characteristics**	**Definition**
PNEW_STR	LPCAP1	Dimen: NNGREG Units: Bcf	New storage added/built
PSSTEP	LPSTEP2	Dimen: NSSTEP Units: ---	Number of steps on LP supply curve
PSTR_MAX	PTARAFM	Dimen: NNGREG,CEMN Units: Bcf	Maximum annual storage available
PTAR_COM_F	PTARAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Firm pipeline commodity charge
PTAR_F	PTARAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Interregional pipeline tariffs for firm
PTAR_I	PTARAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Interregional pipeline tariffs for interrup.
PTAR_IMAX	PTMVARX	Dimen: NGTDM,NGTDM Units: 87$/mcf	Max pipe tariff allowed for interrup. market
PTAR_REV_F	PTARAFM	Dimen: NGTDM,NGTDM Units: 87$	Firm pipeline revenue requirements
Q1	LPNAME2	Dimen: --- Format: char*1	Single letter, used to create LP var & row names
QALK_NONU_F	QPALK1	Dimen: NONUSEC Units: Bcf	Alaska firm nonutil dmd
QALK_NONU_I	QPALK1	Dimen: NONUSEC Units: Bcf	Alaska interrup. nonutil dmd
REGNUM	LPNAME2	Dimen: NGTDM Format: char*2	NGTDM region num (01-21)
ROWNAM	LPMTRX2	Dimen: --- Format: char*8	LP row name sent to OML
SEC	LPNAME2	Dimen: NONUSEC Format: char*1	Nonutil sec ID (R,C,I,T), used to create LP var & row names
SEFF_PIPE	FOTHER	Dimen: NGTDM,JSUP Units: fraction	Eff along arc from sup
SOLN	LPARG	Dimen: 5 Units: ---	Real*8 Variable to hold info retrieved from LP via OML
STAT	LPMTRX2	Dimen: --- Format: char*2	LP variable status indicator from OML
STAX	LPDTAR1	Dimen: ngtdm	State tax
STPHASE	LPDTAR1	Format: integer*4	Start phasing-firm transp.

INCLUDE (NGTDMLOC)

Variable	Common Name	Characteristics	Definition
SUP_ID	LPNAME2	Dimen: NSUPTYP,9 Format: char*2	NG supply type code
SUP_MAX	FOTHER	Dimen: NSUPTYP,NGTDM,JSUP Units: Bcf	Max supply prod level
SUP_PR	NGXFXI2	Dimen: NSUPTYP,NGTDM,JSUP Units: 87$/mcf	Resulting supply price from LP soln
SUPSUB	NGMAPS	Dimen: NNGREG,NSUPREG Units: ---	NGTDM/OGSM subreg, given NGTDM & OGSM reg
SUPSUB_NG	NGMAPS	Dimen: NSUPSUB Units: ---	NGTDM reg mapped into NGTDM/OGSM subreg
SUPSUB_OG	NGMAPS	Dimen: NSUPSUB Units: ---	OGSM reg mapped into NGTDM/OGSM subreg
SUPWITR	NGMAPS	Format: char*4	Iterations to write out supply curve parameters
SUPWRYR	NGMAPS	Format: integer*4	Year to start writing supply curve parameters
TFLOOR	LPDTAR1	Dimen: ngtdm Format: integer*4	Dtariff lower bound for firm transportation
TPD1	LPDTAR1	Dimen: ngtdm	User specified % discount
TPD2	LPDTAR1	Dimen: ngtdm	Alt user specified % discount
TPD2YR	LPDTAR1	Dimen: ngtdm	Year switch
TYP_SUPCRV	NGPRDCRV	Dimen: ---- Format: integer*4	Supply curve functional form 1-orig est.,2-"gams",3-3 tier
U1	LPNAME2	Dimen: --- Format: char*1	Single letter, used to create LP var & row names
UBENCH	DTARAFM	Dimen: NEMMSUB Units: 87$/mcf	Benchmarking adj for utilities
UDFLOOR	DTARAFM	Dimen: NEMMSUB Units: 87$/mcf	Lower bound on distributor markup
UDPD1	DTARAFM	Dimen: NEMMSUB Units: fraction	Percent discount off alt. fuel price
UDPD2	DTARAFM	Dimen: NEMMSUB Units: ---	Alt. User % discount off alt. fuel price
UDPD2YR	DTARAFM	Dimen: NEMMSUB Units: ---	Year switch for % discount off alt. fuel price
UEFF_PIPE	FSEC1	Dimen: NGTDM,JUTIL Units: fraction	Eff along arc to util sector

INCLUDE (NGTDMLOC)			
Variable	**Common Name**	**Characteristics**	**Definition**
UNERR	NGTRAC	Dimen: --- Units: ---	Output unit # for error writes
UTIL_DTAR_ID	DTARAFM	Dimen: NGTDM,JUTIL Units: 87$/mcf	Competitive distillate price
UTIL_DTAR_IR	DTARAFM	Dimen: NGTDM,JUTIL Units: 87$/mcf	Competitive resid PR
VARNAM	LPMTRX2	Dimen: --- Format: char*8	LP variable name sent to OML
WGCNT	PFRCEM	Dimen: NNGREG Units: Bcf	Non-jurisdictional WGCT
WGCT	PFRCEM	Dimen: NNGREG Units: Bcf	Working gas capacity at node
WTHR_XCAP	PTARAFM	Dimen: NGTDM,NGTDM Units: fraction	Percent excess capacity on pipe
XSPRNT	LPMTRX2	Dimen: --- Format: char*8	LP solution print indicator for OML

INCLUDE (NGTDMOUT)

Variable	Common Name	Characteristics	Definition
CLSYNGWP	NGTDMOUT	Dimen: 17,MNUMYR Units: 87$/MMBtu	Price of synthetic NG from coal
OGPRDNGOF	NGTDMOUT	Dimen: 3,MNUMYR Units: Bcf	NA dry gas prod offshore
OGPRDNGON	NGTDMOUT	Dimen: 17,MNUMYR Units: Bcf	NA dry gas prod onshore
PGCELGR	NGTDMOUT	Dimen: 21,MNUMYR Units: 87$/MMBtu	Util competitive NG price
PGFELGR	NGTDMOUT	Dimen: 21,MNUMYR Units: 87$/MMBtu	Util firm NG price
PGIELGR	NGTDMOUT	Dimen: 21,MNUMYR Units: 87$/MMBtu	Util interrupt NG price
PRNG_PADD	NGTDMOUT	Dimen: MNUMPR,MNUMYR Units: Bcf	Tot dry gas production (w/ lease & plant)

Equivalence for FILER used for data storage

```
REAL EQ_NTOUT(MNUMYR*(3*21+2*17+3+MNUMPR))
EQUIVALENCE (EQ_NTOUT,OGPRDNGON)
```

Equivalence for MAIN to test convergence on natural gas to util

```
REAL MUPRC(21,MNUMYR,3)
EQUIVALENCE(MUPRC,PGFELGR)
```

INCLUDE (NGTDMPTM)

Variable	Common Name	Characteristics	Definition
A191END	TRANSC	Format: INTEGER	Year to end collecting acct. 191 costs
A191START	TRANSC	Format: INTEGER	Year to start collecting acct. 191 costs
A191YRS	TRANSC	Format: INTEGER	Num. years acct 191 costs are collected
A2P -- not used	CURVE	Dimen: NGTDM,NGTDM Units: ---	Arc to pipeline conversion
ADDA	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Accumulated DDA costs
ADIT	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Accumulated deferred income taxes
ADIT_C	PCOST	Dimen: MAX_PIPE Units: Nominal $	Constant for forecasting equation
ADIT_TEMP	TRANSC	Dimen: 2,9	Temp. var for ADIT equation
AFR	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of fixed cost to res.
AFU	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of fixed cost to usage
AGSRCOSTS	TRANSC	Units: MAX_PIPE	GSR costs by arc
ANUM191	TRANSC	Units: MAX_PIPE	191 transition costs by arc
ARC2P	CURVE	Dimen: NGTDM,NGTDM Units: ---	Arc to pipeline conversion
ARCCC	CURVE	Dimen: NGTDM,NGTDM,MAX_STEPS Units: 87$/mcf-mile	Arc capital cost size
ARCEX	CURVE	Dimen: NGTDM,NGTDM,MAX_STEPS Units: Bcf	Arc expansion size
ARCFAC	CURVE	Dimen: NGTDM,NGTDM,MAX_STEPS Units: fraction	Arc capacity expansion factor
ARCUSED	CURVE	Dimen: NGTDM,NGTDM,MAX_STEPS Units: Bcf	New pipeline capacity already added
ARF	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of fixed cost
ARV	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of variable cost
ASF	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of fixed storage cost
ASV	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of var. storage cost

INCLUDE (NGTDMPTM)			
Variable	**Common Name**	**Characteristics**	**Definition**
AVR	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of var. cost to res.
AVU	WITHIN	Dimen: MAX_DESIGN,MAX_ITEM Units: fraction	Alloc. of var. cost to usage
BASERADJ	TRANSC	Format: real*4	Adj factor for discounting in base year
BG2WG	WITHIN	Dimen: NNGREG Units: fraction	Base gas to working gas ratio (juris)
BG2WGN	WITHIN	Dimen: NNGREG Units: fraction	Base gas to working gas ratio (non-juris)
BLAE	PCOST	Dimen: --- Units: Nominal $	Capital expenditures associated with base year capacity (refurbishment/replacement exp) dollars
CAPCST	PCOST	Dimen: MAX_PIPE, MAX_CT,MAX_STEPS Units: 87$/Bcf	Total capital cost at each arc (historical avg)
CMES	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Value of common stock equity in dollars
CONDEM	READCD	Dimen: NGTDM,NGTDM Units: Bcf	Peak-day res. Firm tran, base year
COST	WITHIN	Dimen: 2,MAX_ITEM Units: Nominal $	Indiv. cost of service
CRATE	PCOST	Dimen: 3 Units: fraction	Rate of return array
CSOML	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Compressor station op and maint labor expense
CSOMN	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Compressor station op and maint nonlabor exp.
CTOT	PCOST	Dimen: 2 Units: Bcf	Total u.S. Capacity
CWC	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Cash working capital
DBGRPT	MISCC	Dimen: --- Format: char*15	Debug report flag
DCMER	PCOST	Dimen: MAX_PIPE Units: fraction	Rate of return differential
DDA	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Depreciation, depletion, and amortization costs

INCLUDE (NGTDMPTM)			
Variable	**Common Name**	**Characteristics**	**Definition**
DDA_C	PCOST	Dimen: MAX_PIPE Units: Nominal $	Constant for forecasting equation
DDA_TEMP	TRANSC	Dimen: 2,9	Temp. var for DDA equation
DISCNT_I	TRANSC	Format: real*4	Discount inter off maximum
DLTDR	PCOST	Dimen: MAX_PIPE Units: fraction	Rate of return debt (fraction) differential
FCR	WITHIN	Dimen: MAX_STEPS,NGTDM,NGTDM Units: Nominal $	Fixed res. cost
FCS	WITHIN	Dimen: MAX_STEPS,NNGREG Units: Nominal $	Fixed storage cost
FCU	WITHIN	Dimen: MAX_STEPS,NGTDM,NGTDM Units: Nominal $	Fixed usage cost
FRATE	TRANSC	Format: real*4 Units: fraction	Federal income tax rate
FSERV	PFRAFM	Dimen: NGTDM,NGTDM Units: Bcf/yr	Annual throughput volume for firm transportation
FSITC	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Federal and state investment tax credits
GCMER	TRANSC	Format: real*4	CMER for gen. pipe company
GLTDR	TRANSC	Format: real*4	LTDR for gen. pipe company
GPFER	TRANSC	Format: real*4	PFER for gen. pipe company
GPIS	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Gross plant in service
GSREND	TRANSC	Format: INTEGER	Year to end collecting GSR costs
GSRSTART	TRANSC	Format: INTEGER	Year to start collecting GSR costs
GSRYRS	TRANSC	Format: INTEGER	# years GSR costs are collected
IEXPCT	TRANSC	Format: real*4	Expected rate of growth in int. transp. service
ISERV	PFRAFM	Dimen: NGTDM,NGTDM Units: Bcf/yr	Annual throughput volume for interrup. Trans.
KARCEX	TRANSC	Dimen: MAX_STEPS Format: real*4	Arc expansion steps at Kern river (8->12)
KCMER	TRANSC	Format: real*4	CMER for Kern river(8->12)
KLTDR	TRANSC	Format: real*4	LTDR for Kern river (8->12)
LFAC	TRANSC	Format: real*4	Load factor for deriving max int. rate

INCLUDE (NGTDMPTM)

Variable	Common Name	Characteristics	Definition
LIMITFIRM	TRANSC	Format: real*4	Max limit set for firm tariff
LIMITINT	TRANSC	Format: real*4	Max limit set for inter tariff
LTD	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Value of long-term debt in dollars
MATRIX	WITHIN	Dimen: MAX_PIPE,MNUMYR Units: ---	Rate design specification
MAX	PTOAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Maximum rate for interruptible service
MAXDISC_I	TRANSC	Format: real*4	Max allowable discount for inter transp. service
MAXESC	TRANSC	Format: real*4	Maximum allowable escalation rate for tariff
MAXPID	MISCN	Dimen: --- Units: ---	Maximum valid pipelines used
MILES	READCD	Dimen: NGTDM,NGTDM Units: miles	Length of an arc
MIN	PTOAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Minimum rate for interruptible service
NEWCOST_PER	TRANSC	Format: INTEGER	# years new fac. costs are collected
NEWCOSTEND	TRANSC	Format: INTEGER	Year to end collecting new fac. costs
NEWCOSTSTART	TRANSC	Format: INTEGER	Year to start collecting new fac. costs
NODECC	CURVE	Dimen: NNGREG,MAX_STEPS Units: 87$	Capital cost for node
NODEEX	CURVE	Dimen: NNGREG,MAX_STEPS Units: Bcf	Node expansion size
NODFAC	CURVE	Dimen: NNGREG,MAX_STEPS Units: fraction	Node capacity expansion factor
NODUSED	CURVE	Dimen: NNGREG,MAX_STEPS Units: Bcf	New storage already expanded
NS	FUTURE	Dimen: MAX_PIPE,NNGREG Units: fraction	Node shares
OTOM	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Other operations and maintenance expense
OTTAX	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	All other taxes except income taxes

INCLUDE (NGTDMPTM)			
Variable	**Common Name**	**Characteristics**	**Definition**
OWC	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Other working capital
OWC_C	PCOST	Dimen: MAX_PIPE Units: Nominal $	Constant for forecasting equation
OWC_TEMP	TRANSC	Dimen: 2,9	Temp. var for OWC equation
P2AF -- not used	CURVE	Dimen: MAX_PIPE Units: ---	Pipeline to arc conversion
P2ARCF	CURVE	Dimen: MAX_PIPE Units: ---	Pipeline to arc conversion
P2ARCT	CURVE	Dimen: MAX_PIPE Units: ---	Pipeline to arc to conversion
P2AT -- not used	CURVE	Dimen: MAX_PIPE Units: ---	Pipeline to arc to conversion
PCMER	PCOST	Dimen: MAX_PIPE Units: fraction	Rate of return common stock equity
PFES	PCOST	Dimen: MAX_PIPE, MAX_PT,MAX_CT Units: Nominal $	Value of preferred stock in dollars
PGSRCOSTS	TRANSC	Units: MAX_PIPE Format: REAL*4	GSR costs based on ind. pipe company
PID	MISCN	Dimen: MAX_PIPE Units: ---	Pipeline ID number, 4 digits
PIPEEXP	WITHIN	Dimen: NGTDM,NGTDM Units: Bcf	Pipeline capacity expansion passed from cem
PLTDR	PCOST	Dimen: MAX_PIPE Units: fraction	Rate of return debt
PNAME	MISCC	Dimen: MAX_PIPE Format: char*32	Pipeline name
PNEWFAC	TRANSC	Units: MAX_PIPE	New facilities cost based on ind. pipe company
PNUM191	TRANSC	Units: MAX_PIPE Format: REAL*4	191 transition costs, by pipe company
PFER	PCOST	Dimen: MAX_PIPE Units: fraction	Rate of return preferred stock
PRESV	READCD	Dimen: NGTDM,NGTDM Units: Bcf	Peak-day res. Firm tran, adjusted with CAPEXP

INCLUDE (NGTDMPTM)			
Variable	**Common Name**	**Characteristics**	**Definition**
PREV_COM_F	PREVIO	Dimen: NGTDM,NGTDM Units: 87$/mcf	Previous year's commodity charge
PREV_IMAX	PREVIO	Dimen: NGTDM,NGTDM Units: 87$/mcf	Previous year's maximum interrup. Tariff
PREV_REV_F	PREVIO	Dimen: NGTDM,NGTDM Units: 87$/mcf	Previous year's usage charge
PREV_STAR	PREVIO	Dimen: NNGREG Units: 87$/mcf	Previous year's storage tariff
PREVPIPE	WITHIN	Dimen: NGTDM,NGTDM Units: Bcf	Pipeline capacity expansion passed from cem
PREVPSTR	WITHIN	Dimen: NNGREG Units: Bcf	Storage node expansion (juris+non juris.)
PRTRPT--not used	MISCN	Dimen: --- Units: ---	Print debug routines
PS	FUTURE	Dimen: MAX_PIPE,NGTDM,NGTDM Units: fraction	Pipeline shares
PSTRANDED	TRANSC	Units: MAX_PIPE	Stranded cost based on ind. pipe company
PTAR_191_F	TRANSC	Units: MAX_PIPE	Firm tariff based on 191 cost
PTAR_GSR_F	TRANSC	Units: MAX_PIPE	Firm tariff based on GSR cost
PTAR_GSR_I	TRANSC	Units: MAX_PIPE	Int. tariff based on GSR cost
PTMYR	PFRAFM	Dimen: --- Units: ---	Like CEMYR--used to determine array position of current year CEM expansion info
REVC	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Revenue credits to cost-of-service
RFEE	PTOAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Reservation fee for firm service cust
RFR	WITHIN	Dimen: MAX_ITEM Units: Nominal $	Fixed reservation cost
RFU	WITHIN	Dimen: MAX_ITEM Units: Nominal $	Fixed usage cost
RVR	WITHIN	Dimen: MAX_ITEM Units: Nominal $	Variable reservation cost
RVU	WITHIN	Dimen: MAX_ITEM Units: Nominal $	Variable usage cost
SCALE_F	TRANSC	Format: real*4	Scale for firm

INCLUDE (NGTDMPTM)			
Variable	**Common Name**	**Characteristics**	**Definition**
SEOM	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Supervision and engineering expense
SF	WITHIN	Dimen: MAX_ITEM Units: Nominal $	Fixed storage cost
SGCOST--not used	FUTURE	Dimen: NNGREG,MAX_ITEM Units:	Generic pipeline company stor. Line item cost
SHARE_GSR_F	TRANSC	Format: real*4	Fraction of GSR transition cost to firm
SHARE_GSR_I	TRANSC	Format: real*4	Fraction of GSR transition cost to int.
SHISEXP	CURVE	Dimen: NNGREG Units: Bcf	Historical storage expansion
SRATE	TRANSC	Units: fraction Format: real*4	Average state income tax rate
STAR	PTOCEM	Dimen: NNGREG Units: 87$/mcf	Storage Tariffs
STOT	PCOST	Dimen: 20 Units: Nominal $	Total u.S. Storage cost by line item
SV	WITHIN	Dimen: MAX_ITEM Units: Nominal $	Variable storage cost
TAG	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Total administrative and general expense
TAG_C	PCOST	Dimen: MAX_PIPE Units: Nominal $	Constant for forecasting equation
TAG_TEMP	TRANSC	Dimen: 2,9	Temp. var for TAG equation
TCE	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Total customer expense
TGCOST--not used	FUTURE	Dimen: NGTDM,NGTDM,MAX_ITEM Units:	Generic pipeline company trans. Line item cost
THISEXP	CURVE	Dimen: NGTDM,NGTDM Units: Bcf	Historical pipeline expansion
TOM	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Total operations and maintenance expense
TOM_C	PCOST	Dimen: MAX_PIPE Units: Nominal $	Constant for forecasting equation
TOM_TEMP	TRANSC	Dimen: 2,9	Temp. var for TOM equation
TOTAEX	CURVE	Dimen: NGTDM,NGTDM Units: ---	Number of expansions in an arc

INCLUDE (NGTDMPTM)

Variable	Common Name	Characteristics	Definition
TOTARC	CURVE	Dimen: --- Units: ---	Total number of valid pipeline arc
TOTNEX	CURVE	Dimen: NNGREG Units: ---	Number of expansions in a node
TPEB	PCOST	Dimen: MAX_PIPE,MAX_PT,MAX_CT Units: Nominal $	Transition expense balance
TTOT	PCOST	Dimen: 20 Units: Nominal $	Total u.S. Transportation cost by line item
UFEE	PTOAFM	Dimen: NGTDM,NGTDM Units: 87$/mcf	Usage fee for firm service
VCR	WITHIN	Dimen: MAX_STEPS,NGTDM,NGTDM Units: Nominal $	Variable res. cost
VCS	WITHIN	Dimen: MAX_STEPS,NNGREG Units: Nominal $	Variable storage cost
VCU	WITHIN	Dimen: MAX_STEPS,NGTDM,NGTDM Units: Nominal $	Variable usage cost
WGCNTEXP	WITHIN	Dimen: NNGREG Units: Bcf	Storage node expansion (non-juris)
WGCTEXP	WITHIN	Dimen: NNGREG Units: Bcf	Storage node expansion (juris)
WGN2WG	WITHIN	Dimen: NNGREG Units: fraction	Working gas (nj) to working gas ration

INCLUDE (NGTDMREP)

Variable	Common Name	Characteristics	Definition
NGPIPCAP	NGTDMREP	Dimen: 2,MNUMYR Units: Bcf	NG pipeline capacity--national
NGSTRCAP	NGTDMREP	Dimen: 24,MNUMYR Units: Bcf	NG undergnd storage capacity
OGIMCAN	NGTDMREP	Dimen: MNUMYR Units: Bcf	Net imports of Can pipe NG
OGIMLNG	NGTDMREP	Dimen: MNUMYR Units: Bcf	Net imports of LNG
OGIMMEX	NGTDMREP	Dimen: MNUMYR Units: Bcf	Net imports of Mex pipe NG
OGIMNGP	NGTDMREP	Dimen: MNUMYR Units: Bcf	Net imports of pipeline NG
OGPRDNG	NGTDMREP	Dimen: MNUMOR,MNUMYR Units: Bcf	Domestic dry NG prod
OGPRSUP	NGTDMREP	Dimen: MNUMYR Units: Bcf	Total supplemental gas (synthetic + other)
OGPRSUP3	NGTDMREP	Dimen: 3,MNUMYR Units: Bcf	Supplemental NG subcategories
OGWPRNG	NGTDMREP	Dimen: MNUMOR,MNUMYR Units: 87$/mcf	NG wellhead price

Equivalence for/FILER used for data storage

REAL EQ_NTREP(2*MNUMOR*MNUMYR+34*MNUMYR)

EQUIVALENCE (EQ_NTREP,OGWPRNG)

INCLUDE (NGTDMTMP)			
Variable	**Common Name**	**Characteristics**	**Definitions**
MNPERCNT	TMPSUP	Dimen: --- Units: fraction	Min % delta off base price for supply curve
SUPMULT	TMPSUP	Dimen: NSSTEP Units: fraction	% off of base supply price
WTPERCNT	TMPSUP	Dimen: --- Units: fraction	Relaxation % on last supply price

INCLUDE (OGSMOUT)*			
Variable	**Common Name**	**Characteristics**	**Definition**
OGCNPARM1	OGSMOUT	Dimen: --- Format: real	(alpha) actual gas allocation factor
OGCNPARM2	OGSMOUT	Dimen: --- Format: real	Responsiveness of flow to diff. in border prices
OGCNEXLOSS	OGSMOUT	Dimen: --- Format: real	Gas lost from U.S. export to Canada demand
OGCNDMLOSS	OGSMOUT	Dimen: --- Format: real	Gas lost from wellhead to Canada demand
OGCNCON	OGSMOUT	Dimen: 2,mnumyr Format: real Units: Bcf	Canada gas consumption
OGCNMARKUP	OGSMOUT	Dimen: 6 Format: real	Transportation markup at border
OGRESCAN	OGSMOUT	Dimen: 2,MNUMYR Format: real	End-of-year reserves
OGPRRCAN	OGSMOUT	Dimen: 2,MNUMYR Format: real	Temp. var for ADIT equation
OGQNGEXP	OGSMOUT	Dimen: MNUMBX,MNUMYR Format: real	NG exports by border crossing

*This common block contains other variables that are not used in NGTDM.

INCLUDE (PMMOUT)*			
Variable	**Common Name**	**Characteristics**	**Definition**
RFQTDCRD	PMMOUT	Dimen: MNUMOR+2,MNUMYR Format: real	Total domestic crude (incl. EOR)

*This common block contains other variables that are not used in NGTDM.

INCLUDE (MPBLK)*			
Variable	**Common Name**	**Characteristics**	**Definition**
PRSIN	MPBLK	Dimen: MNUMCR,MNUMYR Format: real	43 residual fuel, industrial
PDSIN	PBBLK	Dimen: MNUMCR,MNUMYR Format: real	51 distillate, industrial
PCLIN	MPBLK	Dimen: NBYNCR,MNUMYR Format: real	38 coal, industrial
PLGIN	MPBLK	Dimen: MNUMCR,MNUMYR Format: real	61 liquid petroleum gases, industrial

*This common block contains other variables that are not used in NGTDM.

INCLUDE (EMMOUT/UGOILOUT)			
Variable	**Common Name**	**Characteristics**	**Definition**
QRLELGR	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	3 LS Resid. use in D_F plants
QRHELGR	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	4 HS Resid. use in D_F plants
GSHRMIN	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	5 Min. gas use in D_F plants
GRATMIN	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	6 G/O price ratio at minimum
GSHRMAX	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	7 Max. gas use in D_F plants
GRATMAX	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	8 G/O price ratio at maximum
GSHRPAR	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	9 Parity gas use in D_F plants
GRATPAR	UGOILOUT	Dimen: 21,MNUMYR Format: real*4	10 G/O price ratio at par

Variable Definition List for Local Variables Defined Within the AFM

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
Subroutine PIPE		
AX -- not used	INTEGER*4	Counter for maximum AFM itr
I,J,K	INTEGER*4	Counters for setting IYRSWT
Subroutine NGTDM_DATARED()		
CH	CHARACTER*1	Dummy var. READ to find beginning of READ (@)
DATA	REAL*4	Used as temp storage for data
FILE_MGR	INTEGER*4	Function which passes unit numbers
FNAME	CHARACTER*18	File name ID
JJ, KK, LL	INTEGER*4	Counters
UNITNUM	INTEGER*4	Unit number passed from the file manager
Subroutine NEXTDATA(UNITNUM)		
CH	CHARACTER*1	Dummy var. READ to find beginning of READ (@)
UNITNUM	INTEGER*4	Unit number passed from the file manager
Subroutine NGTDM_DATASET		
DEST,I,J	INTEGER*4	Counters
NGREG,NSREG	INTEGER*4	Reg/subreg
NSEC,NSUP	INTEGER*4	Sector/supply reg
Subroutine NGTDM_CEM		
ADDYR	INTEGER*4	Num of years for storage addition data
BASET	REAL*4	Total base gas storage (Bcf)
CAP1	LOGICAL /.TRUE./	Flag indicating 1st itr, 1st yr
CAPADD	REAL*4	New capacity additions (MMcf/day)
CH	CHARACTER*1	Dummy var. READ to find beginning of READ (@)
FILE_MGR	INTEGER*4	Function which passes unit number
FNAME	CHARACTER*18	Filename identifier
IEXP	INTEGER*4	Arc counter
I,J,K	INTEGER*4	Counters
IOSHAT	INTEGER*4	Unit number passed from the file manager

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
NGREG, NN	INTEGER*4	Reg/subreg
NUMSTRX	INTEGER*4	Number of storage nodes
SRC, DEST	INTEGER*4	Source and dest nodes
WORKT	REAL*4	Total working gas storage (mmcf)
YRB4	INTEGER*4	Array position for previous year
Subroutine NGSET_EXPCAP(MAPYR,YR)		
IEXP	INTEGER*4	Arc counter
MAPYR	INTEGER*4	Mapped reference year
SRC, DEST	INTEGER*4	Source and dest nodes
YR	INTEGER*4	Reference year
Subroutine NGTDM_PTM1		
CH	CHARACTER*1	Dummy var. READ to find beginning of READ (@)
FILE_MGR	INTEGER*4	Function which passes unit number
FNAME	CHARACTER*18	Filename identifier
I,J	INTEGER*4	Counters
IOPTM	INTEGER*4	Unit number passed from the file manager
PTAR1	LOGICAL /.TRUE./	Flag indicating 1st itr, 1st yr
Subroutine NGTDM_DTM2		
CH	CHARACTER*1	Dummy var. READ to find beginning of READ (@)
DTAR1	LOGICAL /.TRUE./	Flag indicating 1st itr, 1st yr
FILE_MGR	INTEGER*4	Function which passes unit number
FNAME	CHARACTER*18	Filename identifier
I,J	INTEGER*4	Counters
UNITNUM	INTEGER*4	Unit number passed from the file manager
Subroutine NGTDM_AFM		
ACTFILE	CHARACTER*8 /'ACTFAFM '/	OML database containing the LP problem
ACTPROB	CHARACTER*8 /'ACTPROB '/	OML LP problem name
AFMBYT	INTEGER*4	Size of AFM LP workspace in bytes

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
DECK	CHARACTER*8 /'AFMDECK '/	OML LP deck name
FILE_MGR	INTEGER*4	File manager func in NEMS main
FNAME	CHARACTER*18	Filename for NGDBUG1 AFM LP output
I	INTEGER*4	Sector counter
IRET	INTEGER*4	OML return code
ITYP	INTEGER*4	Supply type counter
UNITNUM	INTEGER*4	Unit # for NGDBUG1 AFM LP output
Subroutine NGAFM_INITLP		
(no local variables)		

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
Subroutine NGTDM_LPSI		
IRET	INTEGER*4	OML return code
NGREG, NSREG	INTEGER*4	Reg/subreg counters
NSUPID, ITYP	INTEGER*4	Supply type counter
Subroutine NGTDM_LPEI		
EXNODE	INTEGER*4	Import/export node counter
IRET	INTEGER*4	OML return code
ITYP	INTEGER*4	Supply type counter
NGREG	INTEGER*4	Region counter
Subroutine NGTDM_EFFLP		
EMMREG, CENREG	INTEGER*4	EMM or Census reg ID
IRET	INTEGER*4	OML return code
NGREG, NSREG	INTEGER*4	Reg/Subreg counter
NSEC	INTEGER*4	Sector ID
Subroutine NGTDM_CAPI		
ACAP_MAX	REAL*4	Maximum annual capacity (Bcf)
ACAP_MIN	REAL*4	Minimum annual flow (Bcf)
IRET	INTEGER*4	OML return code
NEWFLOW	REAL*4	Estimated flow from new capacity (Bcf)
NGREG, AN, I	INTEGER*4	Reg/Subreg counters
RHSVAL	REAL*4	RHS value for storage variable
SRC, DEST	INTEGER*4	Node ID's
SRC_AKCAN	LOGICAL	Flag to indicate if CAN border crossing intersects w/ AK border crossing
Subroutine NGTDM_TARPI		
EST_FLOW	REAL*4	Flow used w/ rev. to calc firm tariff
IRET	INTEGER*4	OML return code
NGREG, AN, I	INTEGER*4	Reg/Subreg counters
SRC, DEST	INTEGER*4	Source & dest nodes

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
Subroutine NGTDM_TARDI		
EMMREG, CENREG, NSEC	INTEGER*4	Emm or Census reg ID, sector ID
IRET	INTEGER*4	OML return code
NGREG, NSREG	INTEGER*4	Reg/Subreg counters
Subroutine NGTDM_SUPCI(ITYP)		
DELSUP_PR	REAL*4	SUP_PR delta for iterations 1 & 2
IREG	INTEGER*4	NGTDM/OGSM subregion ID
IRET	INTEGER*4	OML return code
ITYP	INTEGER*4	Supply type
MINSUP	REAL*4	Minimum supply
MXFLAG	INTEGER*4	Maximum supply flag
NGREG	INTEGER*4	Node ID
NGTDM_SUPCRV	REAL*4	Supply curve function
NS	INTEGER*4	Supply curve step number
NSREG	INTEGER*4	Supply array position
NSUPID	INTEGER*4	Supply source ID
OLDSUP_PR (NSUPTYP,NGTDM,JSUP)	REAL*4	Old SUP_PR used to calc WTSUP_PR
PER	REAL*4	1 - % L&P
SPRICE (NSSTEP)	REAL*4	Price on supply curve steps
SQDEL (NSSTEP)	REAL*4	Length of steps (QTY) on supply curve
SQUANT (NSSTEP)	REAL*4	QTY on supply curve
WTSUP_PR	REAL*4	Weighted avg SUP_PR
Subroutine NGTDM_UTILCI		
BASE_PR	REAL*4	Base Pr on Util dmd curve
BASE_QTY	REAL*4	Base Qty on Util dmd curve
DPRICE (NDSTEP)	REAL*4	Pr on Util dmd curve steps
DQDEL (NDSTEP)	REAL*4	Length of step (Qty) on Util dmd curve
DQUANT (NDSTEP)	REAL*4	Qty on Util dmd curve
EMMREG, NS	INTEGER*4	Emm reg/subreg counter
IRET	INTEGER*4	OML return code

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
NGREG, NSREG	INTEGER*4	Reg/subreg counters
NGTDM_CRVUTILF	REAL*4	Firm util curve func.
NGTDM_CRVUTILIX	REAL*4	dmd curve function being tested
PR_FLAG	INTEGER*4	Conv. curve MAX/PAR price flag
PRX	REAL*4	Conv. curve MAX or PARITY price
Subroutine NGTDM_NONUCI(NSEC)		
BASE_PR	REAL*4	Base Pr on Nonutil dmd curve
BASE_QTY	REAL*4	Base Qty on Nonutil dmd curve
DPRICE (NDSTEP)	REAL*4	Pr on Nonutil dmd curve steps
DQDEL (NDSTEP)	REAL*4	Length of step (Qty) on Nonutil dmd curve
DQUANT (NDSTEP)	REAL*4	Qty on Nonutil dmd curve
IRET	INTEGER*4	OML return code
NGREG, CENREG	INTEGER*4	NGTDM & Census reg ID's
NGTDM_CRVNONUF	REAL*4	firm nonutil curve function
NGTDM_CRVNONUI	REAL*4	Interrup. nonutil curve function
NGTDM_CRVNONUIX	REAL*4	Interrup. nonutil curve function w/ elasticity
NS, NSEC	INTEGER*4	Counters
Subroutine NGTDM_EXCI		
DELQ	REAL*4	Length of steps (Qty) on export dmd curve
DPRICE (NDSTEP)	REAL*4	PR on export dmd curve steps
EXNODE	INTEGER*4	Export node ID
EXPQTY, EXPPR	REAL*4	Export Qty & Pr
I	INTEGER*4	Counter
IRET	INTEGER*4	OML return code
ITYP, NGREG, NS, SRC	INTEGER*4	Reg/Subreg/Supply type counters
MINF	REAL*4	Min flow on export arcs
NGEXP_CAN, NGEXP_MEX	REAL*4	Can & Mex export functions
Subroutine NGTDM_MAXPT		
DEST, I	INTEGER*4	Reg/Subreg counters
IRET	INTEGER*4	OML return code

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
NEWTAR	REAL*4	Realized TARIFF_I
NGREG, NSREG, NS, SRC	INTEGER*4	Reg/Subreg counters
NTLEV, NBLEV -- not used	INTEGER*4	--not used
Subroutine NGTDM_SPLYSI(ITYP)		
IRET	INTEGER*4	OML return code
ITYP, NGREG, NSREG	INTEGER*4	Reg/Subreg/Supply type counters
NSUPID, NS	INTEGER*4	Supply counters
Subroutine NGTDM_UTILSI		
EFF	REAL*4	Intrareg. * Dist. eff
EMMREG, NS	INTEGER*4	EMM reg/subreg ID
IRET	INTEGER*4	OML return code
KK	INTEGER*4	NGTDM/EMM subregion counter
LAGPR	REAL*4	Lagged utility price
NGREG, NSREG	INTEGER*4	Reg/Subreg counters
PERCDISC,AFP	REAL*4	Dist tariff variables
POILOLD	REAL*4	Oil price used by EMM
PR_MIN	REAL*4	Min gas price from G/O ratio
UINTD,FLOOR	REAL*4	Dist tariff variables
UTIL_PR_ID	REAL*4	Price of distillate to util (holding)
UTIL_PR_IR	REAL*4	Price of competitive to util (holding)
Subroutine NGTDM_NONUSI(NSEC)		
CENREG, NS	INTEGER*4	Census reg ID & counters
EFF	REAL*4	Intrareg. * Dist. eff
IRET	INTEGER*4	OML return code
LAGPR	REAL*4	Lagged nonutil price
NSEC, NGREG	INTEGER*4	Sector & reg counters
Subroutine NGTDM_FLOWSI		
I, NGREG, NSREG, NS	INTEGER*4	Reg/Subreg counters
IRET	INTEGER*4	OML return code

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
SRC, DEST	INTEGER*4	Source & dest node ID
Subroutine NGTDM_IMPORTSI		
CFR,CTO	INTEGER*4	From/to nodes for Can. imports
CNFPRC	REAL*4	Price of firm Can. imports at border xing
CNFSHR	REAL*4	Quantity or shr of firm Can. imports at border xing
CNIPRC	REAL*4	Price of interrup. Can. imports at border xing
CNISHR	REAL*4	Quantity or shr of interrup. Can. imports at border xing
IIMP,NSUPID	INTEGER*4	Region/type ID's
IRET	INTEGER*4	OML return code
ITYP	INTEGER*4	Supply type ID
NGREG,NSREG	INTEGER*4	Region/type ID's
Subroutine BKSTOP_CHK		
EMMREG,CENREG	INTEGER*4	Region ID's
EXNODE	REAL*4	Export node ID
IRET	INTEGER*4	OML return code
ITYP	INTEGER*4	Supply source type
NGREG,NSREG	INTEGER*4	Region ID's
NSEC	INTEGER*4	Sector ID
REAL FUNCTION NGTDM_CRVNONUF(NGRG,CNRG,NSEC,PRICE) -- not used		
CNRG	INTEGER*4	Census region
NGRG	INTEGER*4	NGTDM region
NSEC	INTEGER*4	Nonutility sector identifier
PRICE	REAL*4	Input price
REAL FUNCTION NGTDM_CRVNONUFX(NGRG,CNRG,NSEC,PRICE)		
CNRG	INTEGER*4	Census region
NGRG	INTEGER*4	NGTDM region
NSEC	INTEGER*4	Nonutility sector identifier
PRICE	REAL*4	Input price
QO	REAL*4	Base qty in curve equation

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
PO	REAL*4	Base price in curve equation
REAL FUNCTION NGTDM_CRVNONUI(NGRG,CNRG,NSEC,PRICE) -- not used		
CNRG	INTEGER*4	Census region
NGRG	INTEGER*4	NGTDM region
NSEC	INTEGER*4	Nonutility sector identifier
PRICE	REAL*4	Input price
REAL FUNCTION NGTDM_CRVNONUIX(NGRG,CNRG,NSEC,PRICE)		
CNRG	INTEGER*4	Census region
ELAS (NONUSEC)	REAL*4	Elasticity in curve eq.
NGRG	INTEGER*4	NGTDM region
NSEC	INTEGER*4	Nonutility sector identifier
P0	REAL*4	Base pr in curve eq.
PRICE	REAL*4	Input price
Q0	REAL*4	Base qty (comp) in curve eq.
REAL FUNCTION NGTDM_CRVUTILF(NGRG,EMRG,PRICE)		
EMRG	INTEGER*4	EMM region
NGRG	INTEGER*4	NGTDM region
PRICE	REAL*4	Input price
REAL FUNCTION NGTDM_CRVUTILIX(NGRG,EMRG,PRICE,PR_FLAG,PRX)		
EMRG	INTEGER*4	EMM region
KK	INTEGER*4	NGTDM/EMM subregions (1-20,21)
M,B	REAL*4	Slope and intercept
NGRG	INTEGER*4	NGTDM region
POILOLD	REAL*4	Oil price used by EMM
PR_FLAG	INTEGER*4	Flag when price on vertical
PRICE	REAL*4	Input price
PRX	REAL*4	Price on vertical ($/mcf)
QI	REAL*4	Interruptible util dmd
RAT	REAL*4	Gas to oil price ratio

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
RATMAX	REAL*4	G/O ratio when gas at max
RATMIN	REAL*4	G/O ratio when gas at min
RATOLD	REAL*4	G/O ratio from prev iteration
RATPAR	REAL*4	G/O ratio at effective price
SHRMAX	REAL*4	Gas quantity at maximum
SHRMIN	REAL*4	Min quantity of gas
SHROLD	REAL*4	Gas quantity from prev iteration
SHRPAR	REAL*4	Gas quantity at parity
REAL FUNCTION NGTDM_CRVUTILIY(NGRG,EMRG,SBRG,PRICE) -- not used		
ELAS	REAL*4	Elasticity in curve eq.
EMRG	INTEGER*4	EMM region
NGRG	INTEGER*4	NGTDM region
P0	REAL*4	Base pr in curve eq.
PRICE	REAL*4	Input price
Q0	REAL*4	Base qty (comp) in curve eq.
QI	REAL*4	Interruptible util dmd
SBRG	INTEGER*4	NGTDM/EMM subregion
REAL FUNCTION NGTDM_CRVUTILI(NGRG,EMRG,PRICE) -- not used		
EMRG	INTEGER*4	EMM region
NGRG	INTEGER*4	NGTDM region
PRICE	REAL*4	Input price
REAL FUNCTION NGTDM_SUPCRV(STYP,NODE_ID,NSREG,INVAL,VALUE)		
I,J	INTEGER*4	Counters
INVAL	CHARACTER*1	Type of variable value is (Q or P)
NGCAN_IMP	REAL*4	Supply function: import from Can.
NGPRD_L48	REAL*4	Supply function: L48 regions
NGPRD_OCS	REAL*4	Supply function: OCS regions
NGSYN_LIQH	REAL*4	Supply function: gas from liq
NODE_ID	INTEGER*4	NGTDM node identifier
NSREG	INTEGER*4	Supply array position

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
STYP	INTEGER*4	Supply type identifier
SUPL_ID	INTEGER*4	OGSM region or supply number
VALUE	REAL*4	P or Q for setting Q or P
REAL FUNCTION NGPRD_L48(INVAL,VALUE,IREG)		
BASE	REAL*4	Intermediate value RES*(P/R)
INVAL	CHARACTER*1	Character indicating if the input value is a P or Q
IREG	INTEGER*4	NGTDM/OGSM region (1-17)
PER	REAL*4	percent prod not lease & plant
RA	REAL*4	Est. reserve additions (temporary)
VALUE	REAL*4	Input price or quantity
REAL FUNCTION NGPRD_OCS(INVAL,VALUE,IREG)		
BASE	REAL*4	Intermediate value RES*(P/R)
INVAL	CHARACTER*1	Character indicating if the input value is a P or Q
IREG	INTEGER*4	Offshore region (1-3)
PER	REAL*4	Percent prod not lease & plant
VALUE	REAL*4	Input price or quantity
REAL FUNCTION NGSYN_LIQH(INVAL,VALUE)		
INVAL	CHARACTER*1	Character indicating if the input value is a P or Q
LAGIYR	INTEGER*4	Year last time function was called
SNGILL	REAL*4	Temp array to hold ILL prod
SNGLAG	REAL*4	Last forecast year's ILL prod
SNGMAX	REAL*4	Maximum allowed ILL prod level
VAL	REAL*4	
VALUE	REAL*4	Input value (price or quantity)
REAL FUNCTION NGCAN_IMP(IBRDX,BPRC)		
AA,BB,CC (NCAN)	REAL*4	Hold intermediate calc's
BPRC	REAL*4	Input border crossing price
CN_BRDPRC (NCAN)	REAL*4	Local border crossing prices
CN_DEMAND	REAL*4	Canadian consumption

Local Variables Defined Within the AFM

Variable Name	Format	Definition
CN_EXPORT	REAL*4	Gas from U.S. to Canada
CN_FLOLAG (NCAN)	REAL*4	Adjusted imports in t-1
CN_FLOSHR (NCAN)	REAL*4	Per imports at each border xing
CN_PARMWELPR	REAL*4	R WELPR equivalent for node price
CN_PRODUC	REAL*4	Canadian dry gas production
CN_WELPRC	REAL*4	Canadian wellhead price
CN_WPRCLAG	REAL*4	Wellhead price t-1
DD1 (NCAN),EE	REAL*4	Hold intermediate calc's
I	INTEGER*4	Counter
IBRDX	INTEGER*4	Input border crossing
LAGBD	INTEGER*4	IBRDX last time func called
LAGIT	INTEGER*4	NEMS iter last time called
LAGYR	INTEGER*4	Yr last time function called
NGCAN_DEMAND	REAL*4	Canadian dmd function
SUBTOT	REAL*4	Sum of BPRC**PARM2
TOT_BRDQ	REAL*4	Tot production left for U.S. imports
TOT_FLOLAG	REAL*4	Total adjusted imports in t-1
REAL FUNCTION NGCAN_DEMAND(CN_WELPRC)		
CN_WELPRC	REAL*4	Canadian wellhead price

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
REAL FUNCTION NGEXP_CAN(ICAN,ID,TSTYR)		
FISHR	REAL*4	Share variable
ICAN	INTEGER*4	Canadian border crossing ID
ID	CHARACTER*1	Indicator for firm (F) or interrupt. (I)
TSTYR	INTEGER*4	Year
REAL FUNCTION NGEXP_MEX(IMEX,ID,TSTYR)		
FISHR	REAL*4	Local share variable
ID	CHARACTER*1	Indicator for Firm (F) or interrup. (I)
IMEX	INTEGER*4	Mexican border crossing ID
TSTYR	INTEGER*4	Year
Subroutine NGTDM_PRE		
ADGLAG (9)	REAL*4	AD gas production last yr
ADGPRD89 (9)	REAL*4	AD gas prd 89 (6-ONSH, 3-OFFSH)
EMMREG	INTEGER*4	EMM region ID
I,J,K	INTEGER*4	Counters
NGREG, NSREG	INTEGER*4	Reg, subregion counters
OILLAG (9)	REAL*4	Oil prod last yr (MMBbl)
OILPRD89 (9)	REAL*4	Oil prd 89 (6-ONSH, 3-OFFSH)
QGICTOT	REAL*4	Tot util inrt & comp dmd (Bcf or TBtu)
SREG	INTEGER*4	Supply region identifier
TEMP	REAL*4	Temporary holding variable
Subroutine NGTDM_DMDALK(YRCALC)		
AK_CONS_N	REAL*4	Tot end-use consumption in N AK
AK_CONS_S	REAL*4	Tot ene-use consumption in S AK
AK_PCTALL (3)	REAL*4	1-AK_PCTPLT-AK_PCTLSE-AK_PCTPIP
AK_PROD (3)	REAL*4	Prod S,N,ANGTS
AK_WPRC (3)	REAL*4	Well price S,N,ANGTS
ANGTS_ON	LOGICAL	Gas flowing on ANGTS
CNTYR	INTEGER*4	Converted YRCALC where eq 1 for 1990

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
ELDMD	REAL*4	Util demands in AK
EXPJAP	REAL*4	LNG exports from AK to Japan
I	INTEGER*4	Counter
SAK_CONS_DIFF	REAL*4	
SAK_IND	REAL*4	
SAK_OVRMAX	LOGICAL	True if S.AK consump exceeds S.AK production
SAK_PROD_DIFF	REAL*4	
WOPCUR	REAL*4	Current world oil price
WOPLAG	REAL*4	Lagged world oil price
WPRLAG	REAL*4	Lagged AK wellhead price "SOUTH"
YRCALC	INTEGER*4	Year to be calculated (e.g., 1995)
Subroutine SETSUPMX		
I,J	INTEGER*4	Indices
NGAFM_ANGTS	REAL*4	Function to set max ANGTS supply to L48
NGIMP_CANX	REAL*4	Function to set max Can NG imports
NGIMP_LNG	REAL*4	Function to set max LNG NG imports
NGIMP_MEX	REAL*4	Function to set max Mex NG imports
NGPRD_L48X	REAL*4	Function to set max Onshore NG production
NGPRD_OCSX	REAL*4	Function to set max Offshore NG production
NGSUP_OTHR	REAL*4	Function to set max NG prod form other supplemental
NGSYN_LIQX	REAL*4	Function to set max SNG liq prod
STYP	INTEGER*4	Supply type identifier
SUPID	INTEGER*4	Supply counter
REAL FUNCTION NGPRD_L48X(IREG)		
BASE	REAL*4	Intermediate value RES*(P/R)
IREG	INTEGER*4	NGTDM/OGSM region (1-17)
REAL FUNCTION NGPRD_OCSX(IREG)		
BASE	REAL*4	Intermediate value RES*(P/R)
IREG	INTEGER*4	OFFSHORE region (1-3)

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
REAL FUNCTION NGSUP_OTHR(ISUP)		
ISUP	INTEGER*4	Other supplemental location
VALUE	REAL*4	Temporary holding variable
REAL FUNCTION NGSYN_LIQX()		
NGSYN_LIQH	REAL*4	Functin to set SNG liq prod
REAL FUNCTION NGIMP_LNG(ILNG,TSTYR)		
ILNG	INTEGER*4	LNG terminal identifier
TSTYR	INTEGER*4	Test year for LNG imports
REAL FUNCTION NGIMP_CANX(ICAN,TSTYR)		
BORDER_SHR (NCAN)	REAL*4	Share of total to each border (90 #'S)
ICAN	INTEGER*4	Indicator of Canadian border crossing
PERMAX	REAL*4	Percent above base for max setting
TOTIMP (IBASYR:IENDYR)	REAL*4	Total base quantity imported from Canada
TSTYR	INTEGER*4	Year for Canadian imports

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
REAL FUNCTION NGIMP_MEX(IMEX,TSTYR)		
IMEX	INTEGER*4	mexican border crossing number
TSTYR	INTEGER*4	Year for Mexican imports
REAL FUNCTION NGAFM_ANGTS(TSTYR)		
TSTYR	INTEGER*4	Current year of model
REAL FUNCTION NGIMP_ANGTS1(PRCLAG)		
DOIT1	LOGICAL	Initiate build
DOIT2	LOGICAL	Initiate expansion
ILEV	INTEGER*4	Indicated current flow level
LEVEL (4)	REAL*4	Stages of ANGTS flow into U.S. (Bcf)
MYR1	INTEGER*4	First possible year of ANGTS flow
NGNOD	INTEGER*4	NGTDM transhipment node
OGNUM	INTEGER*4	OGSM number in this type
PRCLAG	REAL*4	Test border price (87$/mcf)
PRICE1	REAL*4	Price to initiate build next year
PRICE2	REAL*4	Price to initiate expand next year
SUPTYP	INTEGER*4	Supply type number
Subroutine NGTDM_POST		
I,J	INTEGER*4	Counters
LP (NSUPSUB)	REAL*4	Lease and Plant
NSEC	INTEGER*4	Sector ID counter
Subroutine EMMOUTPUT()		
EFF	REAL*4	Efficiency along arc to EU node
I,J,K	INTEGER*4	Counters
TOT	REAL*4	Temporary total I + C (UTILITY)
Subroutine OUTOGSM(OGSM_LP)		
CN_TOTFLO	REAL*4	For tot flow from Canada to U.S.
CN_TOTPRD	REAL*4	For tot Canadian production

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
CN_TOTREV	REAL*4	For tot Can. producer revenue
I,J,K	INTEGER*4	Counters
INBRD	INTEGER*4	Can. border xing for flow in (16,4)
LP2	REAL*4	Lease & plant for offshore
NGCAN_DEMAND	REAL*4	Canadian dmd function
OGSM_LP (NSUPSUB)	REAL*4	Lease & plant consumption
PERLP	REAL*4	Total percent lease & plant
SUP_PQT_OFF (NOCSREG)	REAL*4	P*Q total for offshore prod
SUP_PQT_ON (NSUPREG)	REAL*4	P*Q total for onshore prod
SUP_QT_OFF (NOCSREG)	REAL*4	Qty total for offshore prod
SUP_QT_ON (NSUPREG)	REAL*4	QTY total for onshore prod
SUP_QTY_TOFF (NOCSREG)	REAL*4	Total AD+NA+LP from offshore prod
SUP_QTY_TON (NSUPSUB)	REAL*4	Total AD+NA+LP from onshore prod
SUPREG	INTEGER*4	Supply reg counter
TOFF	REAL*4	Offshore L48: AD+NA+LP
TOTPQ	REAL*4	Total P*Q
XSUPPLY	REAL*4	NA + AD, lower 48
Subroutine REPORTOUT		
I,J	INTEGER*4	Counters
IIMP	INTEGER*4	Import ID
NODE	INTEGER*4	Import node number
SUP_TOTAL	REAL*4	Placeholder for totals
Subroutine NGFEL		
I,J	INTEGER*4	Region counters
TOTPQ	REAL*4	Stores P*Q values for a NGTDM reg
TOTPQ_CEN (9)	REAL*4	Stores P*Q values by Census reg
TOTQ	REAL*4	Stores Q totals for a NGTDM reg
TOTQ_CEN (9)	REAL*4	Stores Q totals by Census reg
Subroutine NGIEL		
I,J,K	INTEGER*4	Region counters

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
TOTPQ	REAL*4	Stores P*Q values for a NGTDM reg
TOTPQ_CEN (9)	REAL*4	Stores P*Q values by Census reg
TOTQ	REAL*4	Stores Q totals for a NGTDM reg
TOTQ_CEN (9)	REAL*4	Stores Q totals by Census reg
Subroutine NGQRSEL		
DEL	REAL*4	Stores change in comp gas demand
I,NGREG,EMMREG,CENREG	INTEGER*4	Region counters
KK	INTEGER*4	Region counters
NGTDM_CRVUTILIX	REAL*4	Comp gas function
PR_FLAG	INTEGER*4	Flag when price on vertical
PRX	REAL*4	Price on vertical
QRSELGR	REAL*4	Total resid use portion of GOIL
RHDEL	REAL*4	Change in high sulfur resid portion
RLDEL	REAL*4	Change in low sulfur resid portion
Subroutine NGFNONU(NSEC)		
I,J	INTEGER*4	Region counters
NSEC	INTEGER*4	Sector ID counter
TOTPQ_CEN (9)	REAL*4	Stores P*Q values by Census reg
TOTQ_CEN (9)	REAL*4	Stores Q totals by Census reg
Subroutine NGINONU(NSEC)		
I,J	INTEGER*4	Region counters
NSEC	INTEGER*4	Sector ID counter
TOTPQ_CEN (9)	REAL*4	Stores P*Q values by Census reg
TOTQ_CEN (9)	REAL*4	Stores Q totals by Census reg
Subroutine PROPEROUT(LP)		
CENREG	INTEGER*4	Census division 1-9
DEST	INTEGER*4	Destination node ID
I,J	INTEGER*4	Counters
LP (NSUPSUB)	REAL*4	

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
NGREG	INTEGER*4	NGTDM region 1-12
PFC (21)	REAL*4	Pipeline fuel consumption
PIPE	REAL*4	Pipeline fuel variable (temporary)
SRC	INTEGER*4	Source node ID
Subroutine NGOUTAFM		
NGREG, ITYP, I	INTEGER*4	Reg/other counters
Subroutine NGREPIN		
IO,I,J,IY	INTEGER*4	Unit #/Counters
Subroutine NGREPOUT		
IO,I,J,IY	INTEGER*4	Unit #/Counters
Subroutine NGTDM_SUPICR8 -- not used		
CAN6_SHRI (6)	REAL*4	Estimated shr of tot consumption from Can border crossings
I,J	INTEGER*4	Counters
OFF2_SHRI (12)	REAL*4	Estimated shr of tot consumption from offshore supply
ONS1_SHRI (12,4)	REAL*4	Estimated shr of tot consumption from onshore supply
PRCLAP,PRCPIP	REAL*4	(1+pct)*total consump for L&P and Pipeline fuel
SNG4_SHRI (12)	REAL*4	(1+pct)*total consump from SNG supply
TOTCONS	REAL*4	Total consumption
Subroutine NGTDM_CEM1 -- not used		
FOREYR	INTEGER*4	Forecast year
I,J	INTEGER*4	Loop counters
YRB4	INTEGER*4	Previous forecast year
Subroutine NGSUPCHK		
CANDEM	REAL*4	NG demand in Can
CANSUP	REAL*4	NG supply in Can
CONTOT	REAL*4	Total NG consumption in Can
CPRTST (6) -- not used	REAL*4	-- not used
CQNTST (6) -- not used	REAL*4	-- not used

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
ELSTOT	REAL*4	Est. elasticity for ????
I,J,K	INTEGER*4	Counters
L48DEM	REAL*4	Lower 48 dmd for NG
L48SUP	REAL*4	Lower 48 supply of NG to Can
NGCAN_DEMAND	REAL*4	Function to set NG consump in Can
NGCAN_IMP	REAL*4	Function to set NG imports from Can
OTHDEM	REAL*4	Other NG dmd
OTHSUP	REAL*4	Other NG supplies
PRCITR	REAL*4	?????
PRCLAG	REAL*4	Lagged total avg wellhead price for NG
PRICE	REAL*4	Est. total avg wellhead price for NG
REVTOL	REAL*4	???
SUPTOL	REAL*4	???
SUPTOT	REAL*4	???
Subroutine PIPE_REPORT		
FILE_MGR	INTEGER*4	Function which passes unit number
FNAME	CHARACTER*18	Filename ID
I,J,JJ,KK	INTEGER*4	Counters
NUMARCVAR -- not used	INTEGER*4	-- not used
NUMNODVAR -- not used	INTEGER*4	-- not used
UNITNUM	INTEGER*4	Unit num passed from the file manager
Subroutine NGLP_RPT(IUNIT) -- not used		
ACAP_MAX	REAL*4	Maximum capacity
ACAP_MIN	REAL*4	Minimum flow
COLSOL	CHARACTER*8 /'ACLUD '/	MF
FDEMFL	REAL*4	Firm demand in FL
FEFFCAPFL	REAL*4	Unadjusted eff firm cap into FL
FFLWFL	REAL*4	Required firm flow into FL for base demand
FRFL	INTEGER*4	Connect transhipment node to FL
I	INTEGER*4	Counter

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
IDEMFL	REAL*4	Interruptible demand in FL
I,J,K	INTEGER*4	Counters
IRET	INTEGER*4	OML return code
IUNIT	INTEGER*4	Unit num for output file
NAME	CHARACTER*8	OML row or col name
PERFL	REAL*4	Percent of supply used for L&P
ROWSOL	CHARACTER*8 /'ASLUP '/	MF
STAT2	CHARACTER*2	OML LP status code
SUPPFL	REAL*4	Base level of supply in Florida
TEFFCAPFL	REAL*4	Unadjusted eff total cap into FL
TFLWFL	REAL*4	Required total flow into FL for base demand
VALUE (5)	REAL*8	OML solution
Subroutine NGTDM_BKADJ		
DRGFL	INTEGER*4	Nonutility demand region for FL
IRET	INTEGER*4	OML return code
SRGFL	INTEGER*4	NGTDM/OGSM region in FL
SUPFL	INTEGER*4	NGTDM/OGSM region for FL
TOFL	INTEGER*4	Transhipment node in FL
URGFL	INTEGER*4	Utility subregion for FL
Subroutine NGTDM_HISOVR		
ALFA,BETA	REAL*4	Define assumed rel betw F,I,C EU price
CH	CHARACTER*1	End of data flag (#)
CN_NGEMMAP (9,4)	INTEGER*4	maps from Census region to NGTDM/EMM subregion
CN_NGEMSUB (9)	INTEGER*4	Number of NGTDM/EMM subreg in Census region
EMMREG	INTEGER*4	EMM region counter
FILE_MGR	INTEGER*4	Function which passes unit numbers
FNAME	CHARACTER*18	Input file name
HCLSYNGWP (FHISYR:LHISYR)	REAL*4	Hist SYN from coal gas price

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
HOGPNGEXP (MNUMBX,FHISYR:LHISYR)	REAL*4	Hist gas export prices
HOGPNGIMP (MNUMBX,FHISYR:LHISYR)	REAL*4	Hist gas import prices
HOGPRDNG (MNUMOR,FHISYR:LHISYR)	REAL*4	Hist NG dry gas prod (by OGSM)
HOGPRDNGOF (3,FHISYR:LHISYR)	REAL*4	Hist OFSHR NONASSOC gas prod
HOGPRDNGON (NSUPSUB, FHISYR:LHISYR)	REAL*4	Hist ONSHR NONASSOC gas prod
HOGPRSUP (FHISYR:LHISYR)	REAL*4	Hist SYN fr LIQ gas price
HOGQNGIMP (MNUMBX,FHISYR:LHISYR)	REAL*4	Hist gas import quantities
HOGWPRNG (MNUMOR,FHISYR:LHISYR)	REAL*4	Hist wellhead price
HPGFCM (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist comm firm pr--CEN
HPGFCMGR (NNGREG,FHISYR:LHISYR)	REAL*4	Hist comm firm pr--NGREG
HPGFELGR (NEMMSUBA, FHISYR:LHISYR)	REAL*4	Est. firm E.U. price (NA)
HPGFIN (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist inds firm pr--CEN
HPGFINGR (NNGREG,FHISYR:LHISYR)	REAL*4	Hist inds firm pr--NGREG
HPGFRS (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist resd firm pr--CEN
HPGFRSGR (NNGREG,FHISYR:LHISYR)	REAL*4	Hist resd firm pr--NGREG
HPGFTR (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist tran firm pr--CEN
HPGFTRGR (NNGREG,FHISYR:LHISYR)	REAL*4	Hist tran firm pr--NGREG
HPGICM (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist comm interpt pr--CEN

Local Variables Defined Within the AFM		
Variable Name	**Format**	**Definition**
HPGIIN (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist inds interpt pr--CEN
HPGIRS (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist resd interpt pr--CEN
HPGITR (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist tran interpt pr--CEN
HPNGELGR (NEMMSUBA,FHISYR:LHISYR)	REAL*4	Hist avg E.U. price
HPRNG_PADD (MNUMPR,FHISYR:LHISYR)	REAL*4	Hist NG dry gas prod (by PADD)
HQGPTR (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist pipeline fuel consumption
HQLPIN (MNUMCR,FHISYR:LHISYR)	REAL*4	Hist lease & plant consumption
I,J,K	INTEGER*4	Counters
NEMMSUBA	INTEGER*4	Num NGTDM/EMM regs (w/AK)
NEMMSUBA=NEMMSUB+1	PARAMETER	
NGREG	INTEGER*4	NGTDM region counter
NSREG	INTEGER*4	NGTDM subregion counter
QGFEL_LOC (MNUMCR)	REAL*4	Hist Q firm EU consumption by Census (Bcf)
QGIEL_LOC (MNUMCR)	REAL*4	Hist Q I/C EU consumption by Census (Bcf)
QT	REAL*4	Temp holding array (tot E.U. consumption)
TMAP (14)	INTEGER*4	Imp/Exp mapping border crossing positions to tot
UNITNUM	INTEGER*4	Unit number passed from file manager
YR	INTEGER*4	Historical year
Subroutine NGTDM_HISOVREL		
I,CEN	INTEGER*4	Counter, Census region

Variable Definition List for Local Variables Defined Within the CEM

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
SUBROUTINE NGTDM_CEM2		
ACTFILE/'ACTFCEM '/	CHARACTER*8	OML DB containing LP problem
ACTPROB/'ACTPROB'/	CHARACTER*8	OML LP problem name
DECK/'CEMDECK '/	CHARACTER*8	OML LP deck name
MODEL	INTEGER*4	Size of the CEM LP workspace in bytes
IRET	INTEGER*4	OML return code
I	INTEGER*4	Counter
CEMBYT	INTEGER*4	Size of CEM LP workspace
UNITNUM	INTEGER*4	Unit number for NGDBUG2 output
FILE_MGR	INTEGER*4	File manager function
FNAME	CHARACTER*18	Filename for NGDBUG2 LP output
STOP_FLAG	LOGICAL	Flag to stop the CEM
ERRMSG	CHARACTER*180	Error message
SUBROUTINE ALPHA_LOOP(STOP_FLAG)		
FIRSTTIME	LOGICAL	First time flag
FIRSTTIME2	LOGICAL	Second loop first time flag
STOP_FLAG	LOGICAL	Flag to stop looking for ALPHA
ALPHAFLAG	LOGICAL	Flag for switching up loop
BKSTOP_FLAG	LOGICAL	Flag for backstop
FLAG2	LOGICAL	Flag for XXITOT
IRET	INTEGER*4	OML return code
NALPHA	REAL*8	New ALPHA
ZEROFIVE	REAL*8	0.05
ERRMSG	CHARACTER*180	Error message
GOODALPHA	REAL*8	ALPHA that gives optimal solution
SUBROUTINE CHECKXXITOT(FLAG,ALPHA,HL,FLAG2)		
FLAG	LOGICAL	Flag for upper limit
FLAG2	LOGICAL	Flag for upper limit when ALPHA=1.0
IRET	INTEGER*4	OML return code
ALPHA	REAL*8	ALPHA

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
HL	CHARACTER*1	High/low switch
SUBROUTINE UPDTRHS(ALPHA)		
ALPHA	REAL*8	ALPHA
VALUE	REAL*8	Placeholder for OML
IRET	INTEGER*4	OML return code
SUBROUTINE READ_CEM_DATA		
I,J,K,NS	INTEGER*4	Counters
UNITNUM	INTEGER*4	Unit number of open file
FILE_MGR	INTEGER*4	Function to open/close file
FNAME	CHARACTER*18	Filename
SUBROUTINE SETNO_CHANGE		
SUBROUTINE RESET_RHS		
I,NS,NSEC,SRC,DEST, NGREG	INTEGER*4	Region/loop ID's
IRET	INTEGER*4	OML return code
SUBROUTINE CEMLPST_UTIL		
I,J,NS	INTEGER*4	Counters
IRET	INTEGER*4	OML return code

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
SUBROUTINE CEMLPST		
I,J	INTEGER*4	Counters
IRET	INTEGER*4	OML return code
SUBROUTINE CEMLPNN		
I,J,K	INTEGER*4	Counters
SRC,DEST	INTEGER*4	Source and destination nodes
IRET	INTEGER*4	OML return code
SUBROUTINE CEMLPSNB		
NGREG,NSREG,ITYP	INTEGER*4	Counters
NSUPID	INTEGER*4	Supply ID
IRET	INTEGER*4	OML return code
SUBROUTINE CEMLPSNY		
PKPRCFAC	REAL*4	Hist PK avg well prc/annual avg well prc
OPPRCFAC	REAL*4	Hist OP avg well prc/annual avg well prc
NGREG,NSREG,ITYP	INTEGER*4	Counters
NSUPID	INTEGER*4	Supply ID
IRET	INTEGER*4	OML return code
SUBROUTINE CEMLPNE		
NGREG,NSREG,CENREG,	INTEGER*4	Counters
ITYP,NSEC,EMMREG	INTEGER*4	Counters
NSUPID	INTEGER*4	Supply ID
IRET	INTEGER*4	OML return code
EFF	REAL*4	Intrareg. eff * Dist. eff
SUBROUTINE CEMLPCAP		
I,NS,NGREG,NSREG,NSUP	INTEGER*4	Counters
IRET	INTEGER*4	OML return code
SRC,DEST	INTEGER*4	Source and destination nodes
UPF	REAL*4	Coeff in CPF**N** cap constraint

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
UP	REAL*4	Coeff in CPI**N** cap constraint
UO	REAL*4	Coeff in CON**N** cap constraint
SUBROUTINE MATR_COEFF		
I	INTEGER*4	Counter
SUBROUTINE CEMCANSUP		
ITYP,NGREG,NSREG,NS,NSUPID,DEST	INTEGER*4	Counters
UPP	REAL*4	Peak supply utilization
UPO	REAL*4	Off-peak supply utilization
IRET	INTEGER*4	OML return code
YRB4	INTEGER*4	Array position of year before CEM year
SUBROUTINE CEMCANIMP		
IEXP	INTEGER*4	Export node counter
SRC	INTEGER*4	Source node ID
DEST	INTEGER*4	Destination node ID
NS	INTEGER*4	Step number on capacity curve
IRET	INTEGER*4	OML return code
FOREYR	INTEGER*4	CEM forecast year
YRB4	INTEGER*4	IYRSWT for yr before CEM year
NXTYR	INTEGER*4	Mapped YR= current YR +1
UPF	REAL*4	Coeff in CPFN**N**
UP	REAL*4	Coeff in CPIN**N**
UO	REAL*4	Coeff in CON**N**
AKFLOW	REAL*4	Alaska supply along arc 18 to 9
PFFLOW	REAL*4	PK firm flow--import arcs
PIFLOW	REAL*4	PK intrp flow--imports
OFFLOW	REAL*4	OffPK firm flow--imports
OIFLOW	REAL*4	OffPK intrp flow--imports
TOTCAN	REAL*4	Total Canadian imports
PFAK	REAL*4	PK firm Alaska imports
OFAK	REAL*4	OffPK firm Alaska imports

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
TOTAK	REAL*4	Total Alaska imports
SUBROUTINE CEMFLOWNN		
IEXP	INTEGER*4	Export node counter
SRC	INTEGER*4	Source node ID
DEST	INTEGER*4	Destination node ID
I,J,K,NS	INTEGER*4	Counters
IRET	INTEGER*4	OML return code
FOREYR	INTEGER*4	CEM forecast year
YRB4	INTEGER*4	IYRSWT for year before CEM year
AFMYR	INTEGER*4	IYRSWT for current AFM year
MINXPF	REAL*8	Min flow peak, firm
MINXOF	REAL*8	Min flow offpeak, firm
NEW	REAL*4	PCAP added between AFMYR & CEMYR
FCAP	REAL*4	Effective PCAP based on firm flow
PCAP	REAL*4	Min effective PCAP
PF	REAL*4	Effective peak firm flow
OF	REAL*4	Effective off-peak firm flow
UO	REAL*4	Coeff in CON**N**
MINFLOW	REAL*4	Minimum flow quantity
AKFLOW	REAL*4	Alaska supply arc 18 to 9
PFFLOW	REAL*4	PK firm flow -- imports
PIFLOW	REAL*4	PK intrp flow--imports
OFFLOW	REAL*4	OffPK firm flow--imports
OIFLOW	REAL*4	OffPK intrp flow -- imports
NGEXP_CAN,NGEXP_MEX	REAL*4	Export functions
REAL FUNCTION CEMPRD_L48X(IREG)		
IREG	INTEGER*4	NGTDM/OGSM subregions (1-17)
BASE	REAL*4	Intermediate value RES * (P/R)
SUBROUTINE CEMLPSUP		
ITYP,NGREG,NSREG	INTEGER*4	Counters

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
NS,NSUPID,DEST	INTEGER*4	Counters
NGTDM_SUPCRV	REAL*4	Supply curve function
UPP	REAL*4	Peak supply utilization
UPO	REAL*4	Off-peak supply utilization
IRET	INTEGER*4	OML return code
SUBROUTINE NGCEM_SUPMX		
I,J	INTEGER*4	Indices
STYP	INTEGER*4	Supply type ID
SUPID	INTEGER*4	Supply source ID
ILOC	INTEGER*4	Array location
FOREYR	INTEGER*4	CEM forecast year
CEMPRD_L48X	REAL*4	Function
NGIMP_MEX	REAL*4	Function
NGSUP_OTHR	REAL*4	Function
NGSYN_LIQH	REAL*4	Function
NGCEM_ANGTS	REAL*4	Function
CEMIMP_CAN	REAL*4	Function
CEMIMP_LNG	REAL*4	Function
BASE	REAL*4	Intermediate value RES*(P/R)
REAL FUNCTION CEMPRD_OCSX(IREG)		
IREG	INTEGER*4	Offshore region (1-3)
BASE	REAL*4	Intermediate value
REAL FUNCTION CEMIMP_LNG(ILNG,TSTYR)		
TSTYR	INTEGER*4	Test year for LNG imports
ILNG	INTEGER*4	LNG terminal identifier
NGIMP_LNG	REAL*4	Function
REAL FUNCTION CEMIMP_CAN(SUPID,FOREYR)		
SUPID	INTEGER*4	Can supply source (1-6)
FOREYR	INTEGER*4	Model year array position

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
REAL FUNCTION NGCEM_ANGTS(TSTYR)		
TSTYR	INTEGER*4	Test year for ANGTS
REAL FUNCTION NGCEM_SUPCRV(STYP,NODE_ID,NSREG,INVAL,VALUE,K)		
I,J,K	INTEGER*4	Counters
STYP	INTEGER*4	Supply type identifier
NODE_ID	INTEGER*4	NGTDM node identifier
NSREG	INTEGER*4	Supply array position
SUPL_ID	INTEGER*4	OGSM region or supply number
VALUE	REAL*8	P or Q for setting Q or P
VALU4	REAL*4	Hold R*8 value in R*4 variable
CEMPRD_L48	REAL*4	L48 supply func (1-17)
CEMPRD_OCS	REAL*4	OCS supply func (1-3)
NGSYN_LIQH	REAL*4	Supply function gas from liq
INVAL	CHARACTER*1	Variable type for value (Q/P)
REAL FUNCTION CEMPRD_L48(INVAL,VALUE,IREG)		
IREG	INTEGER*4	NGTDM/OGSM region (1-17)
BASE	REAL*4	Intermediate value RES*(P/R)
VALUE	REAL*4	Input price or quantity
PER	REAL*4	Percent prod not lease & plant
INVAL	CHARACTER*1	Char. indicating if input is 'P' or 'Q'
SUBROUTINE CEMPCAP()		
NSREG,NGREG	INTEGER*4	Counters
NSEC,NSUP	INTEGER*4	Counters
DEST,SRC	INTEGER*4	Destination,source nodes
I,J,NS,IRET	INTEGER*4	Counters
FOREYR	INTEGER*4	CEM model year
IEXP	INTEGER*4	Export node counter
YRB4	INTEGER*4	Year before forecast year
NXTYR	INTEGER*4	Mapped YR= CURIYR+1
QDEL	REAL*4	Length of step on curve

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
PCAPCURV	REAL*4	Price on CEM cap. curve
QCAPCURV	REAL*4	Quantity on CEM cap. curve
SUBROUTINE CEMSUPCI(ITYP)		
ITYP	INTEGER*4	Supply type
NGREG	INTEGER*4	Node ID
NSREG	INTEGER*4	Supply array position
NSUPID	INTEGER*4	Supply source ID
NS	INTEGER*4	Supply curve step number
MXFLAG	INTEGER*4	Maximum supply flag
IREG	INTEGER*4	NGTDM/OGSM region ID
SRC,DEST	INTEGER*4	Source and destination nodes
IRET	INTEGER*4	OML return code
K	INTEGER*4	Counter
PER	REAL*4	1 - % L&P
MINSUP	REAL*4	Minimum supply
SPRICE(NSSTEP)	REAL*8	Supply price on curve
SQUANT(NSSTEP)	REAL*8	Supply quantity on curve
SQDEL(NSSTEP)	REAL*8	Delta on curve
NGCEM_SUPCRV	REAL*4	Function - supply curve
SHR	REAL*4	Supply share along network
REAL FUNCTION CEMPRD_OCS(INVAL,VALUE,IREG)		
IREG	INTEGER*4	Offshore region (1-3)
BASE	REAL*4	Intermediate value RES*(P/R)
VALUE	REAL*4	Input price or quantity
PER	REAL*4	Percent prod not lease & plant
INVAL	CHARACTER*1	Character indicating if the input is 'P' or 'Q'
SUBROUTINE NGCEM_ADJCAP(SRC,DEST,PCAPCURV,QCAPCURV)		
I	INTEGER*4	Counter
SRC,DEST,NS	INTEGER*4	Counters
NXTYR	INTEGER*4	Mapped YR= CURRENT YR +1

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
STEPFLAG	INTEGER*4	Flag for PCAPMAX < QCAP
SUMPQ	REAL*4	Sum of PRICE * QUANTITY
SUMQ	REAL*4	Sum of quantity
QCAP	REAL*4	Quantity on capacity curve
PCAPCURV	REAL*4	Price on CEM cap. curve
QCAPCURV	REAL*4	Quantity on CEM cap. curve
SUBROUTINE NGCEM_ADJSTR(NODEID,PSTRCURV,QSTRCURV)		
I	INTEGER*4	Counter
NODEID,NS	INTEGER*4	Counters
NXTYR	INTEGER*4	Mappec YR= CURRENT YR +1
STEPFLAG	INTEGER*4	Flag for PSTRMAX < QSTR
SUMPQ	REAL*4	Sum of PRICE * QUANTITY
SUMQ	REAL*4	Sum of quantity
QSTR	REAL*4	Quantity on storage capacity curve
PSTRCURV(CEMNS)	REAL*4	Price on CEM cap. curve
QSTRCURV(CEMNS)	REAL*4	Quantity on CEM cap. curve
SUBROUTINE CEMSCAP()		
NS,NGREG,I	INTEGER*4	Counters
PSTRCURV	REAL*4	PR on CEM storage cap curve
QSTRCURV	REAL*4	QTY on CEM storage cap curve
IRET	INTEGER*4	OML return code
SUBROUTINE CEMDMD		
I,NS,DEST,SRC	INTEGER*4	Counters
IARG	INTEGER*4	
NGREG,NSREG	INTEGER*4	Counters
NSEC,NSUP	INTEGER*4	Counters
CENREG,EMMREG	INTEGER*4	Counters
FOREYR	INTEGER*4	Forecast year
IRET	INTEGER*4	OML return code
ARCSRC	INTEGER*4	Source node along border crossing arc

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
NGEXP_CAN,NGEXP_MEX	REAL*4	Canada and Mexican export function
EXPT	REAL*8	Total export into Can at border crossing
PFFLOW	REAL*8	PK-F flow along border crossing arc
OFFLOW	REAL*8	OFFPK-F flow along border crossing arc
PIFLOW	REAL*8	PK-I flow along border crossing arc
OIFLOW	REAL*8	OFFPK-I flow along border crossing arc
UPF	REAL*8	Coeff for PK-F capacity constraint
UP	REAL*8	Coeff for PK capacity constraint
UO	REAL*8	Coeff for OFF-PK capacity constraint
SUBROUTINE CEMBACK		
NGREG,NSREG	INTEGER*4	Counters
NSEC,NSUP	INTEGER*4	Counters
DEST,CENREG,EMMREG	INTEGER*4	Counters
IRET	INTEGER*4	OML return code
SUBROUTINE GETDEMANDS		
I,J,K,NSREG	INTEGER*4	Counters
FOREYRN	INTEGER*4	Forecast year (T + N)
FOREYRH	INTEGER*4	Forecast year (T + N + H)
DEMANDF (NONUSEC,NNGREG)	REAL*4	Converted forecasted demand
DEMANDI (NONUSEC,NNGREG)	REAL*4	Converted forecasted demand
DEMANDF_U(NEMMSUB)	REAL*4	Converted forecasted demand
PIDMDTOT(NNGREG)	REAL*4	PK interruptible total demands
OIDMDTOT(NNGREG)	REAL*4	OFF-PK interruptible total demands
EFF	REAL*4	Intrareg. EFF * DIST. EFF
SUBROUTINE CEMBKSTOP_CHK(STOP_FLAG)		
STOP_FLAG	LOGICAL	Backstop flag
NGREG,NSREG	INTEGER*4	Region ID's
EMMREG,CENREG	INTEGER*4	Region ID's
NSEC	INTEGER*4	Sector ID
ITYP	INTEGER*4	Supply source type

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
EXNODE	REAL*4	Export node ID
IRET	INTEGER*4	OML return code
SUBROUTINE GETSOLUTION1		
I,NS,NGREG,NSEC	INTEGER*4	Region/loop ID's
SRC,DEST	INTEGER*4	Region/loop ID's
IRET	INTEGER*4	OML return code
YRB4	INTEGER*4	Array position for year prior to CEM year
NEWCAP	REAL*8	New capacity
SUBROUTINE GETSOLUTION2		
PFSTR,PISTR	REAL*4	Storage flows
OFSTR,OISTR	REAL*4	Storage flows
I,IRET,NS,NGREG	INTEGER*4	Region/loop ID's
NSEC,SRC,DEST	INTEGER*4	Region/loop ID's
SUBROUTINE RESETMATRIX		
I,NS,NGREG,NSEC	INTEGER*4	Region/loop ID's
SRC,DEST	INTEGER*4	Region/loop ID's
IRET	INTEGER*4	OML return code
UP	REAL*8	Peak utilization
USP	REAL*8	Storage utilization
SUBROUTINE POST_PROCESS		
MAXUTILZ_T	REAL*4	Max UTILZ_T based on PUTIL,OUTIL
I,SRC,DEST	INTEGER*4	Region/loop ID's
SUBROUTINE NGCEM_AFMUTILZ(SRC,DEST)		
P_FLOW,O_FLOW	REAL*4	Temp flows
F_FLOW,T_FLOW,REC	REAL*4	Temp flows
PFAK	REAL*4	Peak firm ANGTS supply
OFAK	REAL*4	Off-peak firm ANGTS supply
I,SRC,DEST	INTEGER*4	Region/loop ID's

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
FOREYR	INTEGER*4	CEM forecast year
SUBROUTINE CEMINP		
IY	INTEGER*4	Year T + N + H
IYN	INTEGER*4	Year T + N
I,J	INTEGER*4	Counters
IO	INTEGER*4	IO unit number

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
SUBROUTINE CEMOUT		
I,J	INTEGER*4	Counters
IY	INTEGER*4	Year
IO	INTEGER*4	IO unit
SUBROUTINE NGTDM_DATASET2		
SUBROUTINE HORZ		
I	INTEGER*4	Counter
SUBROUTINE CEMREPORT		
I,J	INTEGER*4	Counters
REAL FUNCTION NGCEM_PROD(INTYP,INREG,INPRC)		
CEMG	INTEGER*4	Number of foresight yrs in avg PCAP calculation
INTYP	INTEGER*4	1-onshore, 2-offshore
INREG	INTEGER*4	Region number for on- or off-shore
SREG	INTEGER*4	OGSM reg (1-6 on,7-9 off-shore)
ONREG	INTEGER*4	NGTDM/OGSM subreg on-shore 1-17
LAGIYR	INTEGER*4	Year the last time func called
NPCAPYR	INTEGER*4	Num yrs prod cap calc after current
I,J	INTEGER*4	Counter
INPRC	REAL*4	Gas price in year T+N
PRDCAPTOT	REAL*4	Total productive capacity
PRDCAP (NPREG, 0:NPCAPYR)	REAL*4	Productive capacity by OGSM region
PRDCAPLG1(NPREG)	REAL*4	Prod cap in CURIYR-1 by OGSM region
OPR(NPREG,NPCAPYR)	REAL*4	Foresight oil wellhead price
DELGPR (NPREG, 0:NPCAPYR)	REAL*4	Annual change in fore gas price
GPR(NPREG,0:NPCAPYR)	REAL*4	Forecast gas price
TT(NPREG)	REAL*4	TT=3 when EGR tax credit is on
STOT	REAL*4	Cur yr onshore prod in OGSM reg
SUBSHR	REAL*4	Prod in INREG / STOT

Local Variables Used in the CEM		
Variable Name	**Format**	**Definition**
SUBROUTINE CEMREPORTOUT		
I	INTEGER*4	Counter
NGREG	INTEGER*4	Counter
SUBROUTINE CEMPIPE_REPORT		
I,J,JJ,KK	INTEGER*4	Counters
UNITNUM	INTEGER*4	File channel
FILE_MGR	INTEGER*4	Function to open/close file
IRET	INTEGER*4	OML return code
NGREG,NSREG	INTEGER*4	Region/loop ID's
ITYP,NSUPID	INTEGER*4	Region/loop ID's
FNAME	CHARACTER*18	Filename
SUBROUTINE NGPRTINF(MATRIX)		
I	INTEGER*4	Index
MATRIX	CHARACTER*3	Representing 'CEM' or 'AFM'
ROWSOL/'ASLUP '/	CHARACTER*8	Row solution
COLSOL/'ACLUD '/	CHARACTER*8	Column solution
IRET	INTEGER*4	OML return code

Variable Definition List for Local Variables Defined Within the PTM and DTM

Local Variables Defined Within the PTM		
Variable Name	**Format**	**Definition**
SUBROUTINE NGTDM_PTM		
AF, AT, E, N, P	INTEGER*4	Index variables
SUBROUTINE CHECK_TARIFFS		
AF, AT, E, N, P	INTEGER*4	Index variables
SUBROUTINE BASE_YEAR_INITIALIZATION		
ADIT_E	REAL*4	Est. coef for accum. deffered. inc. tax
AF, AT, N, YR	INTEGER*4	Index variable
CAPEXP	REAL*4	Capacity expansion size
CCOST	REAL*4	Capital cost to expand 1 unit of pipeline
CSTFAC	REAL*4	Factor to accommodate regional diff. in cost
CT	INTEGER*4	Cost type, 1=transportation, 2=storage
DDA_E	REAL*4	Est. coef for depre., depletion and amort.
E	INTEGER*4	Expansion step on cost curve
EOF	INTEGER*4	End of file indicator
EXPFAC	REAL*4	Mult. factor for increasing capacity from base
FACTOR	REAL*4	Factor to inc. or dec. cost due to region
FILE_MGR	INTEGER*4	Function declaration of FILE_MGR routine
FINDEX	INTEGER*4	Function to find index of READIN pipe ID
G	INTEGER*4	Generic pipeline index
IFORM	INTEGER*4	I/O file unit for FORM2 data file
IPTAR	INTEGER*4	I/O file unit for PTARIFF file
IRDES	INTEGER*4	I/O file unit for RATE DESIGN file
MINPID	INTEGER*4	Minimum index number to start search from
OWC_E	REAL*4	Est. coef for other working capital
P	INTEGER*4	Pipeline arc index
PIPEID	INTEGER*4	Pipeline ID number
PIPEYR	INTEGER*4	Year of model run
PREVAF	INTEGER*4	Previous arc from index
PREVAT	INTEGER*4	Previous are to index
PREVID	INTEGER*4	Previously read in ID

Local Variables Defined Within the PTM		
Variable Name	**Format**	**Definition**
PREVN	INTEGER*4	Previous node index
STEP	INTEGER*4	Step number on the capacity expansion curve
T	INTEGER*4	Pipeline type, 1=individual, 2=generic
TAG_E	REAL*4	Est. coef for tot. admin. and general
TNS	REAL*4	Fraction of total gas given to a CD point
TOM_E	REAL*4	Est. coef for tot. op. and maintenance
TPFES, TCMES, TLTD	REAL*4	Temporary read variables
SUBROUTINE REPORT_BASE_YEAR		
AF,AT,N,P,T,YR	INTEGER*4	Index variable
EOF	INTEGER*4	End of file indicator
FINDEX	INTEGER*4	Function to find index of READIN pipe ID
M	REAL*16	Million (in decimal)
MINPID	INTEGER*4	Minimum index number to start search from
PIPEID	INTEGER*4	Pipeline company ID
PREVID	INTEGER*4	Previously read in ID
TOTRAT	REAL*4	Total shares for a pipeline
SUBROUTINE BASE_YEAR_PIPELINE		
AF,AT,E,I,N,P,RD	INTEGER*4	Index variable
RATE_DESIGN	INTEGER*4	RATE_DESIGN function

Local Variables Defined Within the PTM		
Variable Name	**Format**	**Definition**
INTEGER FUNCTION FINDEX(MINPID, PIPEID)		
I	INTEGER*4	Index number
MINPID, PIPEID	INTEGER*4	Passed variables
SUBROUTINE CAPACITY_COST_CURVE		
AF,AT,E,I,N,P,RD	INTEGER*4	Index variable
CAP_STEP	REAL*4	Capacity difference between step 1 and 2
CAPUNIT	REAL*4	Capital cost based on historical cost
CUNIT	REAL*4	Capital cost based on first step on curve
RATE_DESIGN	INTEGER*4	RATE_DESIGN function
SUBROUTINE FORECAST_PIPELINE		
AK_FLOW,DEL_AKFLOW	REAL*4	Alaska flow variables in node 18
RATE_DESIGN	INTEGER*4	RATE_DESIGN function
RD,AF,AT,N,P,I	INTEGER*4	Index variable
SUBROUTINE FORECAST_COST(P, T, CT)		
ADIT_ADIT	REAL*4	Est. coef for the accum. deffered inc. tax
ADIT_CONST	REAL*4	Est. intercept term
ADIT_GPIS	REAL*4	Est. coef for the gross plant in service
CT, P, T	INTEGER*4	Index variable
DDA_AGE	REAL*4	Coef for LN(GPIS / (GPIS-ADDA))
DDA_CONST	REAL*4	Estimated intercept term
DDA_GPIS	REAL*4	Coef. for estimated gross plant in service
GDPINFL	REAL*4	GDP inflator
LN_AGE	REAL*4	LN(GPIS / (GPIS-ADDA))
NCAE	REAL*4	New cap. exp. expenditures allowed in the
NEWCOST	REAL*4	New facility cost in nominal dollars
OWC_BETA0	REAL*4	Coef for gross plant in service
OWC_BETA1	REAL*4	Coef for GDP deflator index
OWC_BETA2	REAL*4	Coef for current model year trend
OWC_CONST	REAL*4	Intercept term

Local Variables Defined Within the PTM		
Variable Name	**Format**	**Definition**
OWC_RHO	REAL*4	RHO value from autoregressive trans.
PGPIS	REAL*4	Previous year's GPIS
TAG_BETA0	REAL*4	Coef for gross plant in service
TAG_BETA1	REAL*4	Coef for GDP deflator index
TAG_CONST	REAL*4	Intercept term
TAG_RHO	REAL*4	RHO value
TOM_BETA0	REAL*4	Coef for gross plant in service
TOM_BETA1	REAL*4	Coef for GDP index
TOM_BETA2	REAL*4	Coef for trend year independent variable
TOM_CONST	REAL*4	Estimated intercept form
TOM_RHO	REAL*4	RHO value from autoregressive trans.
TYEAR	REAL*4	Model year
SUBROUTINE FORECAST_GENERIC		
AF,AT,CT,I,N,P,RD	INTEGER*4	Index variable
CUREXP	REAL*4	Total expansion prior to this forecast year
PREEXP	REAL*4	Total expansion prior to this forecast year
RATE_DESIGN	INTEGER*4	RATE_DESIGN function
SUBROUTINE EXPAND_GENERIC(EXPCAP, HISCAP, RD, P, CT)		
AF,AT,CT,P,RD	INTEGER*4	Index variable
AVAIL	REAL*4	Capacity available to be expanded
CAPEXP	REAL*4	Capacity expansion size
EXPAND	REAL*4	Capacity to be expanded after complete exp.
EXPCAP	REAL*4	Capacity to be expanded
HISCAP	REAL*4	Historically existing capacity
NCAE	REAL*4	New cap. exp. expenditures allowed in the
S	INTEGER*4	Step index for capacity cost curve
INTEGER FUNCTION RATE_DESIGN(PIPELN, YEAR)		
PIPELN	INTEGER*4	Pipeline ID index
PREVIOUS_RATE_DESIGN	INTEGER*4	Previous rate design used
PREVRD	INTEGER*4	Previous rate design used

Local Variables Defined Within the PTM		
Variable Name	**Format**	**Definition**
RD	INTEGER*4	Index of new rate design to be used
YEAR	INTEGER*4	Year of model run
INTEGER FUNCTION PREVIOUS_RATE_DESIGN(NEW_RD)		
I	INTEGER*4	Rate design index
NEW_RD	INTEGER*4	New rate design
READIN(MAX_DESIGN)	INTEGER*4	All rate designs read in
SUBROUTINE READ_ALLOCATION(RD)		
FILE_MGR	INTEGER*4	FILE_MGR function
FILENO	INTEGER*4	Line item index
I	INTEGER*4	Line item index
IALLO	INTEGER*4	Unit number of file to be read in
RD	INTEGER*4	Rate design index
SUBROUTINE CALCULATE_COST(P, T, CT)		
APRB	REAL*4	Adjusted pipeline rate-base
ATP	REAL*4	After-tax profits
CMER	REAL*4	Common equity rate of return (fraction)
CMEN	REAL*4	Return on common equity
CT	INTEGER*4	Cost type, 1=transportation, 2=storage
FIT	REAL*4	Federal income tax
FRATE	REAL*4	Federal income tax rate (fraction)
FSIT	REAL*4	Federal and state income tax
I	INTEGER*4	Line item index
LTDN	REAL*4	Return on long-term debt
LTDR	REAL*4	Long-term debt rate (fraction)
NIS	REAL*4	Net capital cost of plant in service
P	INTEGER*4	Pipeline index
PFEN	REAL*4	Return on preferred stock
PFER	REAL*4	Preferred stock rate (fraction)
SIT	REAL*4	State income tax
SRATE	REAL*4	Average state income tax rate (fraction)

Local Variables Defined Within the PTM		
Variable Name	**Format**	**Definition**
T	INTEGER*4	Pipeline type, 1=individual, 2=generic
TCOS	REAL*4	Total cost-of-service
TNOE	REAL*4	Total normal operating expenses
TOTAX	REAL*4	Total federal and state income tax liability
TOTCAP	REAL*4	Total capitalization
TRR	REAL*4	Total revenue credits to cost-of-service
TRRB	REAL*4	Total return on rate-base (before taxes)
WAROR	REAL*4	Weighted-average before-tax return on capital
SUBROUTINE REPORT_LINE_ITEMS(P, RD)		
AF, AT, I, J, N	INTEGER*4	Index variable
M	REAL*4	Million (decimal value)
P	INTEGER*4	Pipeline ID index
RD	INTEGER*4	Rate design index
TRFR, TRVR, TRFU, TRVU, TSF, TSV	REAL*4	Accumulate total.
SUBROUTINE REPORT_ARC_COST		
AF, AT, N	INTEGER*4	Index variable
TFCR, TVCR, TFCU, TVCU, TFCS, TVCS	REAL*4	Accumulate total.
SUBROUTINE ALLOCATE_ARC_LEVEL_COST(EX)		
AF, AT, N, P, T	INTEGER*4	Index variable
CIS	REAL*4	Costs assigned to interruptible service customer
EX	INTEGER*4	Expansion step index
F	REAL*4	Fixed storage cost / working gas capacity
FADFS	REAL*4	Allocation determinant for fixed costs in firm
FADIS	REAL*4	Allocation determinant for fixed costs in interrup.
FCSN	REAL*4	Fixed cost storage rate, non-jurisdictional
FCST	REAL*4	Total fixed cost storage rate
IEXPCT(NGTDM,NGTDM)	REAL*4	Expected rate of growth
INCR_LIMIT	REAL*4	Maximum tariff increase allowed for a year
LFAC	INTEGER*4	Load factor

Local Variables Defined Within the PTM		
Variable Name	**Format**	**Definition**
RADJ	REAL*4	Adjustment factor for discounting (ratio)
RCFS	REAL*4	Reservation costs assigned to firm ser. customer
UCFS	REAL*4	Usage costs assigned to firm service customers
V	REAL*4	Variable storage cost / working gas capacity
VADFS	REAL*4	Allocation determinant for var. costs in firm
VADIS	REAL*4	Allocation determinant for var. costs in interrup.
VCSN	REAL*4	Variable cost storage rate, non-jurisdictional
VCST	REAL*4	Total variable cost storage rate
VSUM	REAL*4	Total variable costs for firm and interruptible
WGCTT	REAL*4	Total working gas capacity
SUBROUTINE REPORT_BASE		
AF, AT, E, N, P	INTEGER*4	Index variable
SUBROUTINE REPORT_FORECAST		
AF, AT, N	INTEGER*4	Index variable
SUBROUTINE REPORT_BOTH		
AF, AT, N, P	INTEGER*4	Index variable
SUBROUTINE REPORT_CAPACITY_COST_CURVE		
SUBROUTINE REPORT_FORECAST_GENERIC		
SUBROUTINE SCALE_LINE(P, CT, E, EXPCAP, HISCAP)		
AF	INTEGER*4	Convert pipeline index to source node
AT	INTEGER*4	Convert pipeline index to dest. node
CT	INTEGER*4	Cost type (1=transportation, 2=storage)
E	INTEGER*4	Expansion index
EXPCAP	REAL*4	Expansion capacity size
FACTOR	REAL*4	Scaling factor for line item
HISCAP	REAL*4	Historical capacity size
P	INTEGER*4	Pipeline index

Local Variables Defined Within the PTM		
Variable Name	**Format**	**Definition**
SUBROUTINE TRANS_COST_OF_SERVICE(RD)		
I, RD	INTEGER*4	Index variable
RF	REAL*4	Fixed cost
RV	REAL*4	Variable cost
SUBROUTINE STORAGE_COST_OF_SERVICE(RD)		
I, RD	INTEGER*4	Index variable
SUBROUTINE NGPTM_ADJ		
AF, AT, E, N, P	INTEGER*4	Index variable
SUBROUTINE NGPTM_ADJSTR(NODEID,PTM_SCAP)		
MAPYR	INTEGER*4	Mapped yr= current yr
NODEID, NS	INTEGER*4	Counters
PR_ADJ	REAL*4	Price delta
PTM_SCAP	REAL*4	Tariff
QSTRMAX	REAL*4	Current year max cap
SUBROUTINE NGPTM_ADJCAP(SRC,DEST,PTM_PCAP)		
MAPYR	INTEGER*4	Mapped yr= current yr
PR_ADJ	REAL*4	Price delta
PTM_PCAP	REAL*4	Tariff
QCAPMAX	REAL*4	Current year max cap
SRC, DEST, NS	INTEGER*4	Counters
SUBROUTINE REPORT_GENERIC_LINE		
M	REAL*16	Million (in decimal)
AF, AT, CT, P, T	INTEGER*4	Index variable
SUBROUTINE REPORT_EXPANSION(P,CT,RD,PREEXP, CUREXP, ASKEXP)		
AF,AT,I,J,M,N,T	INTEGER*4	Index variable
ASKEXP	REAL*4	Expansion size asked for
CT	INTEGER*4	Type of cost 1=trans, 2=storage
CUREXP	REAL*4	Avail. exp. size for current forecast year

Local Variables Defined Within the PTM		
Variable Name	**Format**	**Definition**
P	INTEGER*4	Pipeline ID index
PREEXP	REAL*4	Expansion size before current expansion
RD	INTEGER*4	Rate design index
TRFR, TRVR, TRFU, TRVU, TSF, TSV	REAL*4	Accumulate total.

Local Variables Defined Within the DTM		
Variable Name	**Format**	**Definition**
SUBROUTINE NGTDM_DTM		
ADJ_DTAR_F(4,NNGREG	REAL*4	Adjusted markup
AFP	REAL*4	Alternate fuel price($87/MCF)
BETA	REAL*4	Phase variable 0-1
DIST(3,NNGREG)	REAL*4	($87/MCF)
DIST0(3,NNGREG)	REAL*4	Base dt from hist input ($87/MCF)
DTMWRITE	INTEGER*4	Report control variable set at 2
FILE_MGR	INTEGER*4	FILE_MGR function
HPGFRSGR	REAL*4	HISTORICAL Residential firm price
IFLOOR(NNGREG)	REAL*4	Lower bound on markup ($87/MCF)
I,J,K,M,MSEC	INTEGER*4	Index variable
IPD1(NNGREG)	REAL*4	User specified % discount
IPD2(NNGREG)	REAL*4	Alt user specified % discount
IPD2YR(NNGREG)	INTEGER*4	Year switch
LIT_DTAR_F(4,NNGREG)	REAL*4	Last iteration's markup
NEW_TFLR(NNGREG)	REAL*4	Adjusted TFLOOR with taxes
PERCDISC	REAL*4	% discount
TFD	REAL*4	Used to determine Fed gasoline tax($87/MMBTU)
TFD1	REAL*4	User Federal gasoline tax($87/MMBTU)
TFD2	REAL*4	Alt user adj to Fed gasoline tax($87/MMBTU)
TFD2YR	INTEGER*4	Year switch
TILT	REAL*4	TILT determ. fr user input ($87/MCF)
TILT1(3,NNGREG)	REAL*4	User adj to dt ($87/MCF)
TILT2(3,NNGREG)	REAL*4	Alt. user adj to dt($87/MCF)
TILT2YR(3,NNGREG)	INTEGER*4	Year switch
TST	REAL*4	Used to determine st gasoline tax($87/MMBTU)
TST1(NNGREG)	REAL*4	User state gasoline tax($87/MMBTU)
TST2(NNGREG)	REAL*4	Alternate state gasoline tax($87/MMBTU)
TST2YR(NNGREG)	INTEGER*4	Year switch
UBENORG(NEMMSUB)	REAL*4	Utility bench factors calculated in last historical year
UBENPER	REAL*4	Percent of UBENORG not phased out

Local Variables Defined Within the DTM		
Variable Name	**Format**	**Definition**
UBENYRD	INTEGER*4	Number of years UBENORG phaseout
UINTR	REAL*4	Compet w/resid mkup for util sec($87/MCF)
UNITNUM	INTEGER*4	Unit number of I/O file
URFLOOR(NEMMSUB)	REAL*4	Lower bound on markup($87/MCF)
URPD1(NEMMSUB)	REAL*4	User specified % discount
URPD2(NEMMSUB)	REAL*4	Alt % discount
URPD2YR(NEMMSUB)	INTEGER*4	Year switch
UTILT1(NEMMSUB)	REAL*4	User adjustment to dt ($87/MCF)
UTILT2(NEMMSUB)	REAL*4	Alt. user adj to dt($87/MCF)
UTILT2Y(NEMMSUB)	INTEGER*4	Year switch
W_COAL(NNGREG)	REAL*4	Ratio for coal
W_DIST(NNGREG)	REAL*4	Ratio (weight) for distillate
W_LPG(NNGREG)	REAL*4	Ratio for liquid petroleum gas
W_RESID(NNGREG)	REAL*4	Ratio for residual
SUBROUTINE REPORT_GENERATOR		
I,J,K	INTEGER*4	Index variable
TEMP_F(NEMMSUB)	REAL*4	Temporary variable firm utility
TEMP_I(NEMMSUB)	REAL*4	Temporary variable int. utility
SUBROUTINE REPORT_LOOP(NONU_DTAR)		
I,J,K	INTEGER*4	Index variable
NONU_DTAR (NONUSEC,NNGREG)	REAL*4	Non-utility distributor tar.

Appendix K

NEMS Model Documentation Reports

NEMS Model Documentation Reports

The National Energy Modeling System is documented in a series of 15 model documentation reports, available early in 1994 by contacting the National Energy Information Center, 202/586-8800.

Energy Information Administration, *National Energy Modeling System Integrating Module Documentation Report*, DOE/EIA-M057 (Washington, DC, December 1993).

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

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

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

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

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

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

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

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

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

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

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

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

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