NEW ENGLAND NATURAL GAS INFRASTRUCTURE

Docket No. PL04-01-000

Staff Report of the Federal Energy Regulatory Commission

December 2003

EXECUTIVE SUMMARY

An analysis of interstate natural gas pipeline capacity and storage in New England was conducted to determine if there is adequate natural gas pipeline and storage capacity to meet the increasing demand from gas-fired electric generation and other uses. This report concludes that adequate capacity exists to meet projected demand through 2005 and that proposed new construction of natural gas infrastructure would meet demand through 2010.

Winter is the peak natural gas use period in New England. From December through February, much of the region's pipeline system is fully loaded. While this situation is not unique to this region, it reduces the opportunity for New England to access natural gas from underground storage in New York and Pennsylvania. The absence of underground storage in New England, in combination with the inability to access storage in New York and Pennsylvania, makes New England dependent on its limited above ground storage, pipeline imports, and liquefied natural gas (LNG) to meet peak winter demands. Existing LNG and liquefied petroleum gas (LPG) above ground storage is evaluated and the potential for their expansion is discussed.

The potential impact of natural gas curtailment on electric generation was evaluated by quantifying firm and interruptible commodity and transportation contracts for natural gas for electric generation. An evaluation was also conducted to determine the impact of a curtailment of natural gas service equivalent to one that occurred in the winter of 1999/2000. The evaluation sought to determine whether the region could maintain electric service if the curtailment experienced during 2000 was fully absorbed by the power generation sector. The evaluation concludes that currently there is a sufficient regional electric generation capacity to maintain electric service if a curtailment similar to that of 2000 should recur.

The overall capacity of the natural gas infrastructure in New England is expected to remain tight for several years until Sable Island supplies are further developed. New pipelines to deliver Sable Island gas to the Boston and New York City area would augment the existing interstate pipeline system in New England. In the interim, expansion of existing and construction of new LNG facilities and integration of existing pipeline systems should help to provide the necessary natural gas supply and capacity.

In recognition of the high winter loading rates of the existing pipeline infrastructure and the just-in-time approach to meet additional capacity demands several recommendations are provided to help maintain the reliability of natural gas service.

- Further integration of the existing pipeline systems would help to minimize curtailments should incidents occur.
- Additional peakshaving and satellite storage facilities near areas of peak demand would help to ensure demands are met.
- Expansion of the LNG deliveries in the Boston to New York City area would free up capacity on Algonquin and Tennessee pipelines, thereby, providing additional access to gas in the storage fields in New York and Pennsylvania.

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BACKGROUND

Section 26 of the Pipeline Safety Improvement Act of 2002 requires the Federal Energy Regulatory Commission (FERC or Commission), in consultation with the Department of Energy (DOE) to prepare a report on the natural gas pipeline system and storage in New England. The report is to assess the ability of the transmission and storage facilities to meet current and projected demand by gas-fired electric generation and other uses.

The Commission, in consultation with the DOE, contacted the state public utility commissions, the New England Conference of Public Utility Commissions (NECPUC), the New England Independent System Operator (NE-ISO), and the Northeast Gas Association (NGA) and solicited their input for this study. Several meetings were conducted with these entities and written input was provided by many (See Appendix A). In addition, the FERC contracted with Energy and Environmental Analysis, Inc. (EEA) and Merrimack Energy Group (Merrimack Energy) for pipeline, gas use information and transportation contract information.

A number of valuable reports were reviewed during the preparation of this report notably:

- National Petroleum Council Report
- NE-ISO reports prepared by Levitan & Associates, Inc.
- EEA July 2003 Base Case
- DOE reports on the Impact of Interruptible Natural Gas Service and Expansion and Changes in the Natural Gas Pipeline Network

This report addresses the interstate natural gas pipeline system and storage in New England and storage in abutting states when that storage is connected to an interstate pipeline that serves New England. The primary study area includes the states of Maine, New Hampshire, Vermont, Rhode Island, Massachusetts, and Connecticut. Natural gas use and infrastructure capacity projections through the year 2010 are presented. Sources of supply are discussed in this report, yet supply is not assumed to be limiting during the study period. Projections of energy use and capacity are based on a synthesis of data from EEA, DOE's Energy Information Administration (EIA), and the FERC. EEA's assumptions for its long-term outlook and gas assumptions are presented in Appendix D.

Commission staff convened a technical conference in Boston, on November 14, 2003. Resulting comments and recommendations are incorporated in this final report.

INTRODUCTION

Natural gas provides approximately 18 percent of New England's energy needs and serves 2.3 million customers. One third of the homes are heated by natural gas with oil fueling approximately 50 percent. The market share of natural gas across all sectors has increased approximately 15 percent since 1990. Gas-fired electric generation is primarily responsible for the increased use of natural gas in New England's energy market. Lower facility costs and air quality considerations have made gas-fired electric generation the fuel of choice for replacement of older facilities and new electric generation since the mid-1990s.

During this same period, additional infrastructure has been constructed to support the increased natural gas demand. While New England has no native supply of natural gas, the pipeline infrastructure delivers gas from four separate sources: eastern and south-central United States, western Canada, Sable Island in eastern Canada, and from one of four liquefied natural gas import terminals in the contiguous United States located in Everett, Massachusetts which is near Boston (Figure 1).

Map is not internet public

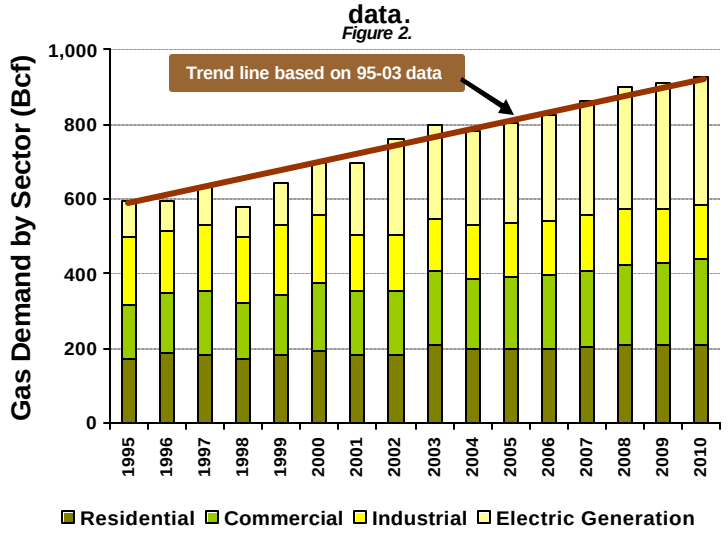
New England benefits from interstate pipelines that traverse the region to supply the major demand centers of New York City and Boston. However, much of the land area of New England, does not lie along one of these transportation corridors, and therefore, does not have natural gas service. Expansion of service to these areas is not expected in the near future. Residential use of natural gas (2.1 million customers) represents approximately one third of the New England market. Keyspan Energy Delivery (Keyspan), a local distribution company (LDC), is actively promoting residential customers to switch to natural gas. Keyspan projects an additional 57,000 new residential customers in 2003. Even if financial incentives result in residential switching in areas where natural gas is available, this increased residential use would

continue to be dwarfed by the use of natural gas for electric power generation (Figure 2).

Natural gas infrastructure expansion has kept up with demand, yet with little margin for error. Any delay in the construction of planned infrastructure or underestimates of demand during December through February could result in insufficient capacity to meet demands. During these peak demand months, interstate pipelines in New England are fully loaded (Figure 3). Several recommendations are presented herein to help ensure the highly reliable level of service is continued.

Gas for electric generation is the only sector projected to have an appreciable increase in demand through 2010. Projected gas use is generally consistent with a linear regression of 1995 through 2003 data.

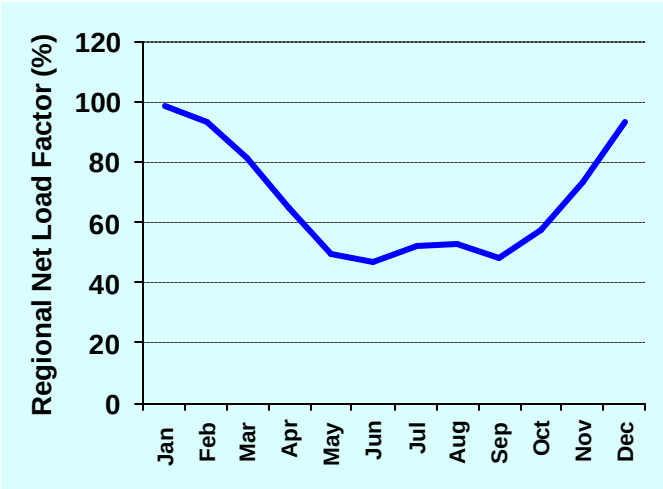
Figure 2.



Source: EIA , EEA , and FERC Staff

New England monthly pipeline load factor exceed 90% three months of the year. This indicates the pipelines are running full and have little excess capacity.

Figure 3.



Source: EEA

NEW ENGLAND NATURAL GAS INFRASTRUCTURE

New England has no native supply of natural gas. All natural gas is imported by pipeline from supply areas in the Gulf of Mexico, eastern and western Canada and from international sources via LNG tanker. This diversification of supply provides challenges and opportunities for New England. Diversification helps to ensure some supply of natural gas even if there is a disruption from any single source, however, none of these sources alone can fully meet New England's natural gas demand. Further, being remote from the source of supplies and at the end of long pipelines that telescope down in size, access to gas supply and storage is limited by pipeline capacity during periods of peak demand.

New England natural gas infrastructure comprises:

- interstate pipelines that transport natural gas from sources of supply in the Gulf of Mexico, western Canada, and Sable Island in eastern Canada to the point of use or storage;
- storage facilities to augment local natural gas supplies;
- local distribution networks that provide service to individual customers; and
- an LNG import and storage facility that serves as a source of supply for Boston and the surrounding region.

These facilities work together to provide reliable natural gas service. Natural gas companies that serve New England are described below.

Interstate Pipelines [1]

Algonquin Gas Transmission Company, a unit of Duke Energy Gas Transmission, incorporates approximately 1,000 miles of pipeline with 11 interconnections/receipt points. Its system commences in New Jersey, connecting with Texas Eastern Transmission, LP, and extends through New York, Connecticut, northern Rhode Island and eastern and southeastern Massachusetts. Existing import capacity is approximately 1,060 million cubic feet per day (MMcf per day).

Granite State Gas Transmission, Inc. is a subsidiary of Bay State Gas Company, a NISource company. It owns and operates a 105-mile interstate pipeline extending from the Massachusetts-New Hampshire border through the New Hampshire coastal area to Portland, Maine. The New Hampshire portion began operation in 1956; in 1966 the line was extended to Maine. Granite State has no direct import capacity.

[1] Source: NGA, CERA, and FERC Staff

Iroquois Gas Transmission System, LP is a 375-mile interstate pipeline owned by a partnership of nine U.S. and Canadian energy companies. It transports natural gas from TransCanada PipeLine at the Ontario/New York border and travels through New York and Connecticut to Long Island and into the New York City area. It interconnects with both the Tennessee and Algonquin systems. Iroquois has an import capacity of 467 MMcf per day into New England and an export capacity of 285 MMcf per day.

Maritimes & Northeast Pipeline, LLC (M&NE) is sponsored by an international consortium of energy companies. It transports gas from the Sable Island Offshore Energy Project of Nova Scotia to markets in Atlantic Canada and New England. The total pipeline is 650 miles. It became operational in 2000. Existing import capacity is 440 MMcf per day.

Portland Natural Gas Transmission System (PNGTS) is sponsored by an international consortium of energy companies. It transports western Canadian gas to New England from an interconnection with TransCanada PipeLines. In the U.S., 292 miles of pipeline extend through northern New Hampshire and southern Maine and interconnect with Maritimes & Northeast. It began operation in the region in 1999. Existing import and export capacity is 212 MMcf per day.

Tennessee Gas Pipeline Company is a business unit of El Paso Corporation. The Tennessee Gas Pipeline has more than 14,000 miles of pipeline. The source of gas is the Gulf of Mexico and the Permian and Appalachian basins. Tennessee's system enters New England at two points: western Massachusetts near West Pittsfield and southern Connecticut near Greenwich. Existing import capacity is 1,180 MMcf per day.

Natural Gas Company

Distrigas of Massachusetts Corporation (DOMAC), a subsidiary of Tractebel, owns and operates an LNG terminal in Everett, Massachusetts. It interconnects with both the Tennessee and Algonquin systems. It began operation in 1971. Its supply sources include Trinidad & Tobago and Algeria. Existing import capacity varies between 450 and 750 MMcf per day.

Importing Intrastate Pipeline Company

Vermont Gas has 300 miles of pipeline throughout Vermont. It receives its gas from TransCanada Pipeline at Highgate on the Vermont/Canadian border. Existing import capacity is approximately 52 MMcf per day.

Pipeline projects certificated by the Commission since 2001 and pending projects are shown in Tables 1 and 2.

Table 1

Certificated Projects Affecting New England (Since 2001)

Applicant	Project Name	Capacity (Mcf/d)	Facilities (Pipeline /Compression)	Filing Date	Order Date	Docket No
Maritimes	Maritimes Expansion	80,000	0 miles / 16,622 HP	04/13/01	07/13/01	CP01-154
Tennessee	Dracut Expansion	200,000	11.9 miles / 0 HP	05/07/01	11/20/01	CP01-360
Maritimes	Phase III Project	360,000	25 miles/ 0 HP	10/10//00 01/23/02	12/21/01 06/04/02	CP01-4
Algonquin	HubLine Project	300,500	29.4 miles / 0 HP	10/10/00 01/23/02	12/21/01 06/04/02	CP01-5
Islander East	Islander East Project **	285,000	50.4 miles/ 0 HP	06/15/01	09/19/02	CP01-384
Algonquin	Islander East Project **	285,000	0 miles / 10,310 HP	06/15/01	09/19/02	CP01-387
Iroquois	Brookfield *	85,000	0 miles/ 10,000 HP	11/20/01	10/31/01	CP02-31

* Granted extension of time until 11/01/05
** Awaiting Permits from the Corp.

Table 2

Major Projects Pending for New England

Applicant	Project Name	Capacity (Mcf/d)	Facilities (Pipeline /Compression)	Filing Date	Docket No.

None Pending

Major Projects on the Horizon Affecting New England

Applicant	Project Name	Capacity (Mcf/d)	Facilities (Pipeline /Compression)	Expected Filing
Tennessee	Freedom Trail Expansion	150,000	40 miles / 40,000 HP	None

NATURAL GAS STORAGE

New England has no underground natural gas storage and relies on bulk underground storage in New York and Pennsylvania to augment supplies. A discussion of the physical requirements for underground storage is presented in Appendix B, which also includes a listing of DOE's storage research that is pertinent to New England.

For New England customers to have access to the gas in underground storage in New York or Pennsylvania, capacity must be available on interstate pipelines to carry the natural gas from storage to New England (Figure 4). Interstate pipelines operating at or near full capacity between the storage fields and New England limit access to gas in underground storage. From December through February when interstate pipelines are fully loaded many New England customers must rely on above ground storage located within New England, pipeline imports, and imported LNG to meet demand.

Map is not internet public

LNG Import Facility

One of the four receiving points for LNG in the contiguous United States is located near Boston and is operated by Distrigas of Massachusetts LLC (Distrigas LLC). LNG is imported from various international sources including Trinidad & Tobago and Algeria. It is delivered by ship to the Distrigas terminal at Everett, Massachusetts. The LNG is sold to DOMAC, an affiliate of Distrigas LLC, a wholly owned subsidiary of Tractebel LNG North America LLC. At the Distrigas facility the LNG is either regassified for distribution as natural gas or trucked as LNG to storage sites where LDCs use it to meet peak demand. Regassified LNG serves many local entities including:

Boston Gas Company, an LDC;
Algonquin and Tennessee Gas pipelines; and
Mystic 8 and 9, electric generation units in Everett, Massachusetts,

The facility has on-site storage for LNG and a sustainable peak vaporization capacity of 700 MMcf per day. In addition, trucking provides for distribution of up to 100 million cubic feet per day (MMcf per day) for direct use by LDCs or for storage to meet periods of peak demand (peakshaving).

LNG Peakshaving and Satellite Storage facilities

There are 46 liquefaction and satellite storage tanks located in Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island owned and operated by LDCs. The total combined storage of peakshaving and satellite storage is 15 billion cubic feet (Bcf). Cumulative vaporization capacity of these storage tanks is approximately 1.3 Bcf/day which can supply as much as 30 percent of the region's peak day needs. [1] Thirty peakshaving storage LNG facilities and the Distrigas facility are shown on Figure 5 and twenty four are described in Table 3.

Map is not internet public

Liquefied Petroleum Gas

In addition to the satellite LNG storage, LDCs have 260 propane tanks in New England with a total storage capacity of 1 Bcf liquefied petroleum gas (LPG). Vaporization from LPG can meet 5 percent of New England's peak day needs. This LPG storage is used to augment supplies of natural gas. Propane, however, burns hotter than natural gas and in many cases is not directly interchangeable with natural gas. To compensate for this higher heat content, propane is mixed with air to achieve a thermal equivalent of natural gas. When the appropriate thermal equivalent is achieved, the propane/air mixture is incorporated in the natural gas distribution line to supplement natural gas supplies.

[1] NGA

Table 3. **New England LNG**

Parent Co. (Operating Co.)	Facility Location		Liquefaction Capacity (MMscfd)	Vaporization Capacity (MMscfd)	Storage Capacity (Bcf)	Type of Facility
Energy East (Connecticut Natural Gas)	Rocky Hill	Connecticut	6.00	56.80	1.210	Peakshaving
Energy East (Southern Connecticut Gas)	Milford	Connecticut	7.00	84.00	1.208	Peakshaving
Norwich Public Utilities	Norwich	Connecticut	N/A	3.41	0.005	Peakshaving
NiSource (Northern Utilities/Bay State Gas)	Lewiston	Maine	N/A	34.40	0.012	Peakshaving
City of Holyoke Gas and Electric Department	Holyoke	Mass	N/A	11.36	0.400	Peakshaving
Energy East (Berkshire Gas)	Whately	Mass	N/A	12.00	0.140	Peakshaving
Keyspan (KeySpan Energy Delivery)	Dorchester	Mass	6.00	252.00	1.160	Peakshaving
Keyspan (KeySpan Energy Delivery)	Haverhill	Mass	N/A	24.00	0.400	Peakshaving
Keyspan (KeySpan Energy Delivery)	Lynn	Mass	N/A	86.40	1.084	Peakshaving
Keyspan (KeySpan Energy Delivery)	Salem	Mass	N/A	30.00	1.098	Peakshaving
Keyspan (KeySpan Energy Delivery)	S. Yarmouth	Mass	N/A	27.00	0.164	Peakshaving
Keyspan (KeySpan Energy Delivery)	Tewksbury	Mass	N/A	64.80	1.122	Peakshaving
New England Gas (Fall River Gas)	Fall River	Mass	N/A	10.00	0.157	Peakshaving
NiSource (Bay State Gas)	Easton	Mass	N/A	35.00	0.800	Peakshaving
NiSource (Bay State Gas)	Lawrence	Mass	N/A	19.20	0.021	Peakshaving
NiSource (Bay State Gas)	Ludlow	Mass	10.00	56.70	1.000	Peakshaving
NStar Gas	Hopkington	Mass	19.20	456.00	1.830	Peakshaving
NStar Gas	New Bedford/Acus	Mass	N/A	30.00	0.500	Peakshaving
Unitil (Fitchburg Gas & Electric)	Westminster	Mass	N/A	7.20	0.004	Peakshaving
Westfield Gas & Electric Light (WG+E)	Westfield	Mass	N/A	18.00	0.004	Peakshaving
Keyspan (KeySpan Energy Delivery)	Concord	New Hampshire	N/A	6.00	0.004	Peakshaving
Keyspan (KeySpan Energy Delivery)	Manchester	New Hampshire	N/A	6.00	0.004	Peakshaving
Keyspan (KeySpan Energy Delivery)	Tilton	New Hampshire	N/A	12.00	0.004	Peakshaving
Keyspan (KeySpan Energy Delivery)	Providence	Rhode Island	N/A	35.00	2.260	Peakshaving

Source: Northstar Industries, Inc.

A description of storage facilities certificated since 2000 and proposed storage facilities are presented in Tables 4 and 5.

Table 4.

Storage Projects Certificated since 2000 in New York					
Company/Project	**Working Gas (Bcf)**	**Deliverability (MMcf/d)**	**In Service?**	**Reasons**	**Interstate Pipelines**
Stagecoach Storage	13.6	500	Y		Tennessee; CNG
Seneca Lake Storage, Inc.	0.8	50	N	Lack offers of long-term contracts; Millenium Pipeline not built.	Dominion Resources; Columbia Gas
Total	14.4	550			
Storage Projects Certificated in the 1990s in NY					
Thomas Corners Storage	5.3	70	N	Lack of customers	CNG Transmission
New Avoca Storage	1	100	N	Problem with brine disposal, but now solved. Forming new partnership. Plans to renew FERC 7-C permit in 2004 or 2005.	Tennessee; CNG; Nat. Fuel
Total	6.3	170			
Currently Pending					
Greyhawk Storage	6	400			Nat. Fuel; Columbia; Tenn.; Dominion
National Fuel Gas Supply Corp.	0	40			

Table 5

Storage and LNG Projects in Pre-Filing Affecting New England

Applicant	Project Name	Deliverability (Mcf/d)	Capacity (Bcf)	Compression
Weaver's Cove	Weaver's Cove Project (LNG)	400,000	4.4	None

Storage and LNG Projects on the Horizon Affecting New England

Applicant	Project Name	Deliverability (Mcf/d)	Capacity (Bcf)	Compression
U.S.				
Fairwinds	Fairwinds Project (LNG)	500,000	6.8	None
Somerset	Somerset Project (LNG)	430,000	3.5	None
Keyspan/ BG LNG Services	Providence Expansion	525,000	2.2	None
Unknown	Sears Island	Unknown	Unknown	Unknown

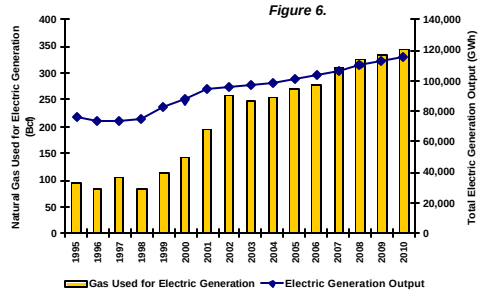
ADEQUACY EVALUATION

The adequacy of the natural gas infrastructure is based on its ability to fulfill its contractual commitments. Natural gas may be contracted on a firm or interruptible basis. Interruptible contracts are typically less expensive because capacity is only paid for if used, and the supplier or transporter may interrupt service. The natural gas infrastructure is considered adequate if firm commitments are met and terms of the interruptible contracts are satisfied.

Unmet demand may occur even when contractual commitments are met. This happens when a potential customer is unable obtain natural gas because interstate pipelines are fully loaded and the customer cannot acquire firm capacity on an interstate pipeline. This subjects the customer to the vagaries of an interruptible contract, use of an alternative source of fuel, or to forego the energy use altogether (demand destruction).

Two evaluations were conducted to determine the adequacy of the natural gas infrastructure to meet contractual requirements and overall demand. To determine if curtailment of service of interruptible contracts poses a threat to maintenance of electric service, interruptible contracts were quantified. In addition, a curtailment scenario is evaluated that is modeled after the January 2000 natural gas curtailment. The second adequacy evaluation looks at the ability of the natural gas infrastructure to meet all system requirements through 2010.

Between 1998 and 2003 gas-fired generation replaced some existing electric generation and met new demand. Projected gas use to meet increased electric demand is tempered by increased efficiencies in new gas-fired generation, yet gas-fired generation will continue to replace other types of electric generation.



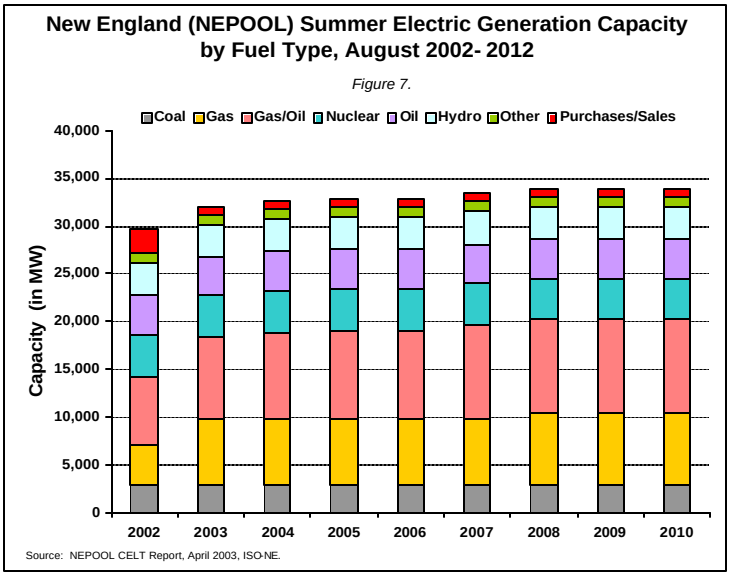
Source: EEA

Electric Power Generation

The fastest growing sector for natural gas use through 2010 is power generation (Figures 6 and 7). Since 1998, nearly 10,700 megawatts (MW) of new electric generation capacity have been added to New England with nearly all of this capacity fueled by natural gas.[1] In 2004, natural gas is expected to provide 35 percent of the fuel supply for electric generation followed by 26 percent nuclear, 12 percent each coal and

[1] ISO-NE

oil, hydroelectric and wood each contributing approximately 5 percent. Electricity imported from New York and Canada contributes from 8 to 12 percent of the total electric supply.



Newer gas-fired electric generation facilities are much more efficient - able to generate more electricity with less natural gas. Operation of the newer more efficient electric generation units will help to meet New England's growing electric demand while adding little to the increase in gas demand. Not until construction of additional new electric capacity (projected to start in 2007) will gas demand for electric generation markedly increase (See Figure 6).

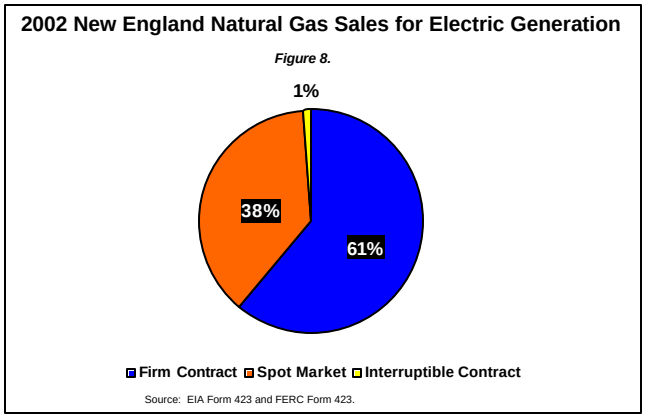
New England has substantial electric capacity reserves. The North America Energy Reliability Council (NERC) reports an electric reserve capacity margin for ISO-NE of 22 percent. Little new construction of electric generation is anticipated until capacity reserve margins decline. NERC reports that transmission constraints in Vermont and Connecticut periodically cause congestion and restrict the amount of electricity both entering and flowing within the region. Remote areas or areas with congested transmission facilities may require construction of new transmission or electric generation to meet demand or to maintain reliability.

ISO-NE is a not-for-profit corporation responsible for the day-to-day operation of New England's bulk electric generation and transmission system. In a series of reports prepared by the ISO-NE, the ISO-NE raises concerns regarding the reliability of gas-fired generation where the fuel is supplied on the spot market with interruptible contracts. The ISO-NE is concerned that should insufficient pipeline capacity be available to meet both firm and interruptible contracts, gas supply would be curtailed to interruptible customers. ISO-NE is concerned that during peak-use periods (December through February) curtailment of service to electric generation facilities with interruptible gas supply contracts could jeopardize the ability to serve the region's electric demand.

ISO-NE identifies three principal challenges:

- New England's relatively high dependence on natural gas for electric power generation;

- Limited natural gas supplies may increase the price and market volatility of natural gas; and
- Existing pipeline capacity is insufficient to satisfy the cumulative demands during the coldest part of the winter.



This report addresses the first and third challenges identified by the ISO-NE. The second is comprehensively addressed in the September 25, 2003 National Petroleum Council Report, Balancing Natural Gas Policy-Fueling the Demands of a Growing Economy.

Should gas demand exceed the pipeline system's capacity, customers with interruptible contracts would be the first to be curtailed. Two approaches were taken to evaluate the potential threat interruptible contracts posed to electric reliability. Two separate types of contracts are necessary to procure natural gas, a sales contract to procure the commodity and a transportation contract to get the commodity to the point of use. Both contracts may be either firm or interruptible. To determine the potential threat posed by curtailment of interruptible contracts, the amount of both types of contracts must be known. This report quantifies the amount of interruptible sales and transportation contracts and evaluates their potential impact.

EIA's Form 423 [2] provides specific information on the type of contracts used to purchase natural gas for utility and non-utility electric generation. For 2002, the first full year this data was collected, 61 percent of the natural gas sold for electric generation in New England was under firm contract, 1 percent was purchased with interruptible contracts, while 38 percent was purchased from the spot market (Figure 8). Spot market sales would be treated similar to that of interruptible contracts at the time of curtailment.

Transportation contracts necessary to deliver each power plant's gas supply were also identified. The difference between the amount of gas that would be required for the plant to operate on a peak-day basis and the amount of capacity contracted by the plant under firm transportation contracts was determined. The difference between the peak-day capacity and the amount of capacity purchased with firm transportation contracts is assumed to be the amount that the plant requires to be supplied by a fuel manager, [3] from

[2] EIA's reporting of data from FERC's Form 423.

[3] A third party that contracts to deliver natural gas that it has purchased from a producer or other seller. Transportation is typically arranged by the fuel manager.

Figure 9. Transportation Contract Type by State and Region

Source: Merrimack Energy

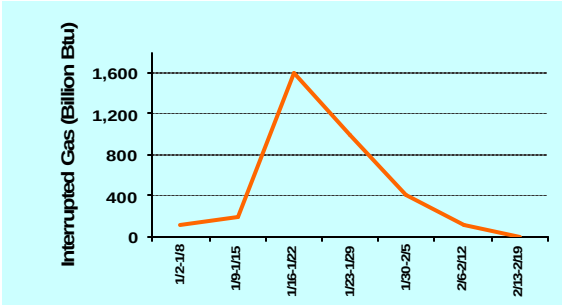
the capacity release market, or the interruptible market. The results of these analyses are presented in Figure 9 which provides both a state-by-state break down and an aggregation for New England. The results vary markedly by state, but in the aggregate 40 percent of the transportation contracts are for firm capacity. The remainder is supplied either by a fuel manager, interruptible contract, or by capacity release. (See Appendix C)

It is assumed that a customer would only pay for firm transportation if the natural gas is purchased with a firm commodity sales contract. Therefore, 40 percent of the natural gas supplied to electric generation is presumed to be under firm sales and purchase contracts. Should all non-firm capacity be curtailed, 60 percent of the gas supply to electric generation facilities would cease. Power facilities with dual fuel capabilities could switch for a short period of time to an alternative fuel source, yet gas-only facilities would be forced to suspend operation. [4]

Table 6 presents the results of an evaluation of the loss of 0, 60, and 100 percent of the gas-only electric generation on New England's ability to meet its peak electric demand. When all electric generation capacity is available, there is ample excess capacity with an operable capacity margin of 5,725 MW. A positive operable capacity margin is necessary to meet peak demand. With the loss of 60 percent of the gas-only facilities (all gas-only facilities with interruptible contracts) there is still a positive operable capacity margin of 1,225 MW. Should all gas-only generation be lost from the system, however, the operable capacity margin drops to a negative 1,775 MW, indicating that the system can no longer meet peak demand. This shows that New England currently has adequate electric generation capacity to meet electric demand with a short-term curtailment of gas service to electric generation facilities with interruptible contracts.

Reported Natural Gas Volume Interrupted in New England, by week January and February 2000

Figure 10.



Source: DOE

The impact of a historical natural gas curtailment was also reviewed. During January through February 2000 curtailments of up to 1,600 Billion Btu per week occurred (Figure 10). During the peak curtailment period there was virtually no gas delivered under interruptible service contracts in New England. [5] Under the scenario evaluated

[4] EIA estimates there is an average of 31,000 barrels per day of distillate fuel oil available for dual fuel use in the Northeast during December through February. EIA/DOE, 2001, Impact of Interruptible Natural Gas Service on Northeast Heating Oil Demand, Executive Summary. SR/OOG/2001-01.

[5] Ibid.

Table 6.

	Base	*Loss of all gas-only electric generation with interruptible contracts*	*Loss of all gas-only electric generation*	*"Historical" 2000 curtailment*
Percent of Gas Only Generation Available	100%	40%	0%	65%
January Year	2004	2004	2004	2000
	MW	MW	MW	MW
Projected Peak	21,600	21,600	21,600	20,275
Operating Reserves Required	1,700	1,700	1,700	1,600
Total Capacity Required	23,300	23,300	23,300	21,875
Projected Capacity	33,000	33,000	33,000	27,780
HQ FEC*	525	525	525	525
Assumed Outages	4,500	4,500	4,500	4,351
Gas-Only Units Curtailed	0	4,500	7,500	1,575
Total Capacity	29,025	24,525	21,525	22,379
Operable Capacity Margin	5,725	1,225	-1,775	504

* Hydro Quebec firm electric capacity

herein, the entire brunt of the curtailment is absorbed by the power generation sector. Since interruptible contracts are not restricted to the power generation sector, this

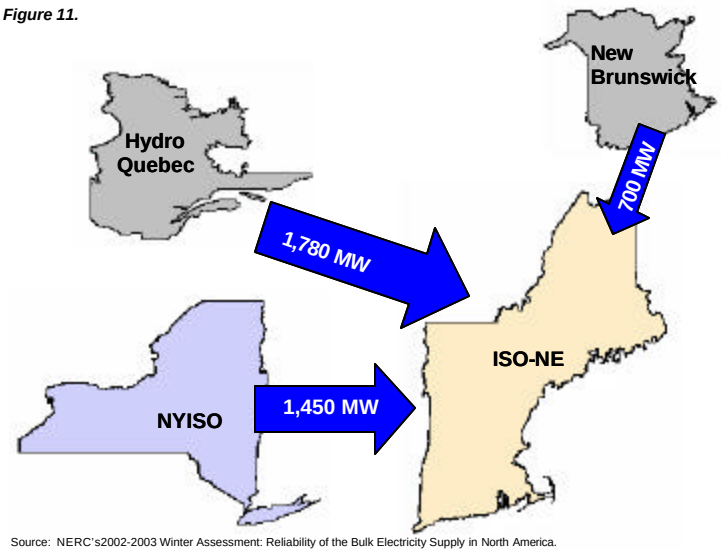
analysis is far more severe than the events of 2000.

Under this scenario, an equivalent of 1,600 Billion Btu per week of natural gas is reduced from the amount available for electric generation. Loss of this amount of natural gas equates to a 30 percent reduction in gas-fired electric generation. Since gas-fired electric generation represents approximately 35 percent of the total electric generation in New England, the total loss of electric generation would be approximately 10 percent.

To determine how the system would respond to a 10 percent loss in generation, several factors were taken into consideration. First of all, the ability of the system to restore that generation using alternative fuels was evaluated. To maintain service, additional generation facilities would be brought online to replace the 10 percent of lost generation. This would deplete the capacity reserve to approximately 10 percent. A capacity reserve margin of 10 percent should be adequate to maintain service for a short period of time until interruptible gas service can be restored. This shows that there is sufficient reserve capacity to replace the loss of interruptible gas fired generation and maintain service should an interruption of service similar to that experienced in 2000 recur.

NERC Estimated 2002-2003 Winter Electric Transfer Capabilities (MW)

Figure 11.



Source: NERC's2002-2003 Winter Assessment: Reliability of the Bulk Electricity Supply in North America.
NYISO Operating Study Winter 2002-2003

In addition to the surplus reserve margin described above, New England has both import and fuel switching capabilities. New England can import up to 12 percent of its electric needs from surrounding regions under normal conditions and up to 14 percent under emergency conditions (Figure 11). Since peak electric demand does not correspond to peak natural gas demand, Canada and New York would be expected to have excess electrical capacity during peak natural gas use periods. Also, 48 percent of New England's gas-fired electric generation has dual fuel capabilities.[6] This capability allows

[6] NEPOOL 2003-2012 Forecast Report of Capacity Energy Loads and Transmission. April 2003. The duration these duel-fuel facilities may operate using an alternate fuel source varies depending on the amount of alternative fuel on-site and the

these units to switch fuels from natural gas to fuel oil. Should natural gas be unavailable, these units could switch to fuel oil and continue operation. Overall, the New England region with its domestic generation, import capacity, and fuel switching capabilities would have adequate electric supplies should gas supplies to interruptible customers be curtailed. Based on available data, it appears that curtailment of interruptible service to gas-fired electric generation does not pose a significant regional threat to electric reliability in New England.

While New England currently has adequate electric capacity, isolated areas may have service disruptions should local generation be disrupted. Isolated areas with limited transmission interconnection that are dependent on sole-source gas-only generation could experience interruption of electric service should any event disrupt natural gas delivery.

2000 Curtailment Case Study

In January and February 2000, a cold snap in combination with supply constraints caused a suspension of interruptible natural gas contracts in New England. During the week of January 22, 2000, temperatures in the New England and Middle Atlantic areas shifted from being 15 to 17 percent warmer than normal respectively, to 24 to 22 percent colder than normal. The change increased weekly heating requirements by about 40 percent. Over a six week period, up to 1,600 Billion Btu (approximately 1.6 Bcf/week) of interruptible service was suspended (Figure 10). Customers with interruptible contracts either switched to an alternative fuel supply or curtailed or cut back operation until full service was again available in mid February. [7]

The cold snap dropped the temperature 24 percent below normal levels and increased weekly heating requirements by 40 percent. These conditions increased the average daily demand for the month of January by 1.14 Bcf. Curtailment of 0.48 Bcf/day was necessary to satisfy customers with firm contracts. In addition, 0.2 Bcf/day was withdrawn from storage. The pipeline system responded adequately to meet all firm capacity contracts.

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chain of supply necessary to replenish the fuel.

[7] See the following reports for additional information on the 2000 suspension of interruptible load:

- The Role of Interruptible Natural Gas Customers in New England Heating Oil Markets: A Preliminary Examination of Events in January-February 2000. Office of Policy, DOE. November 2000.
- Impact of Interruptible Natural Gas Service on Northeast Heating Oil Demand, Energy Information Administration. January 2001.

Should a similar situation recur in 2004, existing and projected firm capacity should be able to respond to meet firm capacity contracts. The demand on the system is projected to be 13 percent greater in 2004, with a proportional increase in demand of 1.28 Bcf/day. [8] Curtailment of interruptible service in combination with a withdrawal of 0.3 Bcf/day from storage could help to ensure that firm capacity contracts are met.

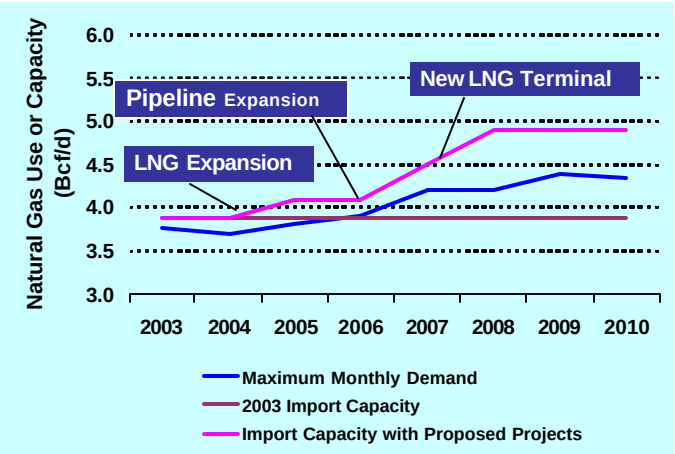
It should be noted however, that there are limits to increasing the contribution from storage. The capacity of above-ground storage near load centers in New England is limited (1.3 Bcf/day with a total storage capacity of 15 Bcf [9]) and gas in storage outside of New England may not be available when the interstate pipelines between the storage fields and the load centers are already fully loaded. Should a similar situation as described above recur after 2004, it becomes increasingly difficult to acquire new firm capacity or interruptible capacity transportation contracts during peak load periods.

Projected demand and capacity

The ability of the natural gas infrastructure to meet the needs of residential, commercial, industrial, and electric generation was evaluated based on projected peak month demand and projected available import capacity. Figure 12 shows projected demand, existing capacity, and capacity should proposed projects be constructed. This figure shows that existing capacity can meet demand through 2005. With the proposed projects that either have certificates or are in some stage of the certification process, projected demand can be met through 2010.

Projected maximum monthly natural gas use can be met with the existing import capacity through 2005.
Proposed additions* would provide adequate capacity through 2010.

Figure 12



* Certificated unconstructed projects or projects with pending applications.
Use = Demand + Exports + Storage
Source: EEA, NGA, FERC

Prior to 2010,

[8] EEA

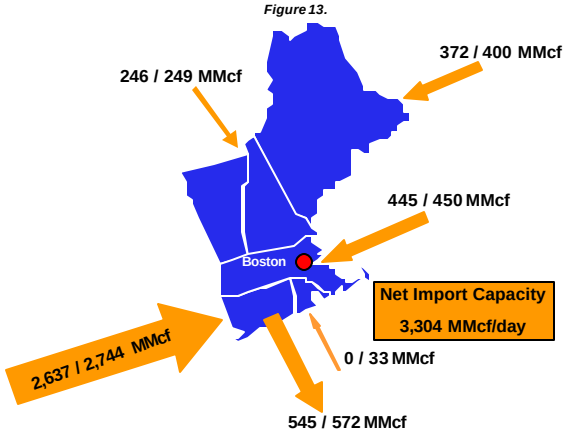
[9] These daily vaporization and gross storage capacities are for storage facilities used for peakshaving. They do not include storage at the Distrigas LNG terminal which is used primarily for supply. (Source: NGA)

additional natural gas capacity is expected to result from the expansion of existing and construction of new LNG terminals and from further development of supplies on the Scotian Shelf in eastern Canada. Figures 13 through 15 indicate how this additional capacity could change the bulk flow of natural gas in New England through 2010. Dashed arrows on these figures indicate changes.

Alternatively, additional pipeline capacity could be achieved with the construction of new or the expansion of existing pipeline systems connecting bulk storage facilities in New York and Pennsylvania to customers in New England.

Regional natural gas flow and pipeline capacity for January 2004

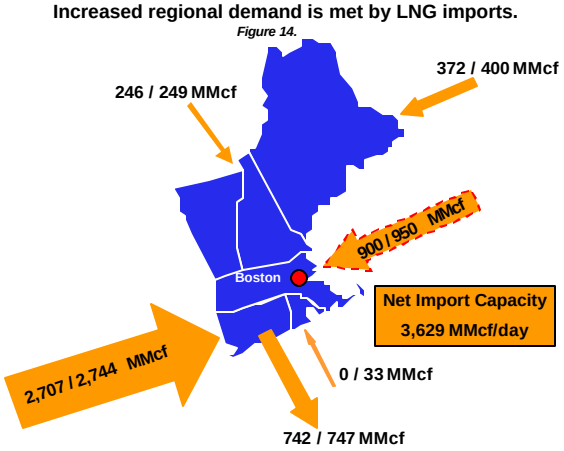
Figure 13.



Source: EEA

Regional natural gas flow and pipeline capacity for January 2007. Increased regional demand is met by LNG imports.

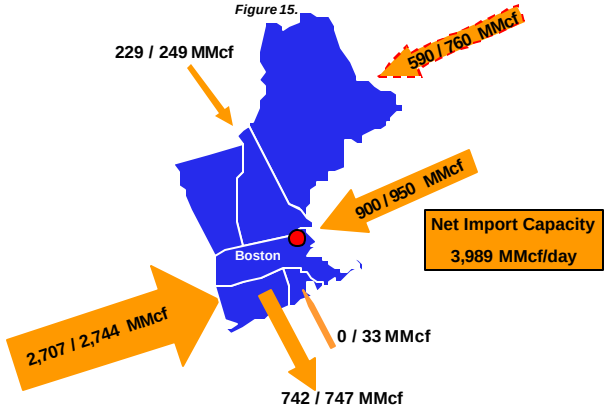
Figure 14.



Source: EEA

Regional natural gas flow and pipeline capacity for January 2010. Increased production from Sable Island promotes increased pipeline capacity.

Figure 15.



Source: EEA

STRENGTHENING THE NATURAL GAS INFRASTRUCTURE

The New England natural gas pipeline system is fully loaded December through February, and projected increases in capacity are expected to be completed just-in-time to meet new capacity demands. There is little opportunity for this system to rely on excess capacity as a buffer against curtailment. Should the unexpected occur, a localized curtailment of service is the likely outcome.

Development of additional natural gas supply or construction of new LNG terminals in the New England region will require additional pipeline capacity. This is not anticipated until 2007-2010. In the interim, additional system pipeline capacity, and further system integration would improve system reliability. With excess capacity and increasing system integration, a loss of capacity in one part of the system could be compensated for by re-routing flows to the area of the shortage, thereby, maintaining service. In addition, an LNG import terminal between Boston and New York City would provide a valuable new source of supply for natural gas.

Several projects have been proposed by the industry that would increase storage, pipeline capacity and integration among pipelines:

<u>New LNG import terminals</u>

Several entities have announced proposals to construct a new Somerset LNG import facility near Somerset, Massachusetts (Figure 16). Northeast Utilities (NU) plans to compete with a proposal by Weaver's Cove Energy LLC (Weaver's Cove) and Mill River Pipeline LLC to construct an LNG import terminal, storage, and vaporization facilities in Fall River, Massachusetts. The proponents are in the preliminary design stage and Weaver's Cove has elected to participate in the Commission's pre-filing application process. The proposed Weaver's Cove LNG Project would begin operation in 2007 and would provide a new source of supply with an average vaporization of approximately 400 MMcf/day.

Map is not internet public

Keyspan Corporation is also proposing a joint venture with BG LNG Services to upgrade Keyspan's existing LNG storage and receiving terminal in

Providence, Rhode Island. The existing facility provides LNG storage to LDCs. Currently, LNG is transported to the existing storage tank by truck from Everett, Massachusetts. The upgrade would allow direct imports via LNG tanker ships, expand vaporization capacity to 525 MMcf/day, and connect the facility to the Algonquin pipeline system. The proposed upgrades are scheduled for completion by the end of 2005.

A new source of supply of LNG in the proximity to both Boston and Providence would be a valuable addition to New England's natural gas infrastructure, reducing, but not eliminating the need for new pipeline capacity.

System Integration

Further integration of the existing pipeline systems would help minimize the impact of a pipeline disruption by providing alternative routing and alternative sources of supply. System integration can be challenging as demonstrated by the withdrawal of the certificate application for Algonquin's proposed Everett Extension Project. The proposed Everett Extension Project was proposed to connect Algonquin's HubLine and Distrigas' facilities. While this type of integration would have significant system benefits, the project failed to overcome routing challenges.

An example of novel integration is proposed by New England Gas and Yankee Gas Service who have petitioned the FERC to allow interconnection of their systems in Connecticut. The purpose of the interconnection would be to transfer interstate gas from the Algonquin system through the currently intrastate New England Gas and Yankee Gas facilities to deliver gas to Rhode Island. Algonquin would deliver gas to Yankee Gas at Montville, Connecticut where it would be transported by Yankee Gas's proposed 9-mile pipeline from Montville to Stonington, Connecticut. New England Gas would build a 75-foot long pipeline from Stonington, across the state border, to its facilities at Westerly, Rhode Island. The proponents state the above alternative is more feasible than the expansion of the existing 3-inch diameter Algonquin Gas Transmission pipeline that brings interstate gas to Rhode Island.

Linking of bulk storage facilities in New York and Pennsylvania with the interstate pipeline distribution system in New England could provide significant system benefits. Several proposed or certificated storage facilities in New York remain unconstructed for lack of potential customers. Construction of a pipeline between these bulk storage fields and New England's distribution system would provide valuable additional import capacity for New England. Tennessee Natural Gas Company's proposed Freedom Trail expansion project would add 150 MMcf/day of capacity. An application for this project has not yet been filed with the Commission.

Satellite/peakshaving LNG storage

Peakshaving facilities are used by local distribution companies as a short-term hedge against service curtailment or higher than anticipated demand. When the upstream pipeline system is fully loaded and additional natural gas is required to meet demand, only gas supply from storage in the proximity of the demand can be counted on to reach the demand. Forty six LNG satellite or peakshaving facilities are currently in operation in New England. Construction of additional peakshaving facilities in areas of high natural gas demand would help to ensure more reliable service until additional pipeline capacity is constructed.

What will be constructed and when?

The pipeline, storage, and LNG projects described above are in the early planning stages. When, and if any of the above are constructed is subject to their economic feasibility, available financing, permitting, and appropriate certification. While construction of these types of projects could improve the reliability of the natural gas infrastructure, there are many factors that will determine when and if they are constructed. The challenge is for appropriate market signals to be sent to the pipeline companies in sufficient time to ensure adequate pipeline capacity can be constructed to meet projected gas demand.

The NGA identified the following challenges and constraints in maintaining adequate natural gas infrastructure in New England:

- Timely and coordinated regulatory review of proposed projects
- The difficulty of siting energy projects
- Contracting arrangements that provide a clear indication of market demand and financial support
- Diversification of supply sources with strengthened ties to Canada and New York

Many of these challenges are beyond the scope of this study yet they provide valuable context to the constraints of constructing infrastructure. These challenges and constraints are described in greater detail in the NGA's letter included at Appendix A.

The existing interstate pipeline system is the result of independent projects constructed by a variety of pipeline companies. The NGA, an association of pipeline companies, states that it does not conduct demand forecasts and that its members rely on economic models to determine when to construct new system capacity. To date, this method has ensured that contractual obligations of its members' customers have been met. Yet unless system reliability becomes an integral component of New England's regional natural gas infrastructure planning, with the increasing demands on the natural

gas system, it will become increasingly difficult to maintain the historical level of service.

In its November 21 letter (Appendix A), the ISO-NE cites an excellent example of how regional planning can help solve a pending challenge. ISO-NE notes that the Pipeline Safety Act of 2002 will result in increased pipeline maintenance requirements for interstate, intra-state, and LDC pipeline systems. The required maintenance may have little or no effect on some pipelines while requiring others to reduce capacity or even to suspend service for several weeks. ISO-NE suggests coordinating pipeline maintenance outages with planned maintenance outages of the electric generation and transmission facilities which they serve. Such regional coordination could significantly reduce any disruption of service caused by the required pipeline maintenance.

CONCLUSION

- Infrastructure in New England has been adequate to meet demand of customers with firm capacity contracts.

- Little buffer exists in the system to meet extended cold periods in the peak winter months of December through February.

- Little redundancy or interconnectivity in the pipeline system make it particularly vulnerable should any component fail. In the event of a prolonged outage, isolated entities may not be able to depend on alternative sources to provide gas service.

- Recently constructed efficient gas-fired electric generation will help to moderate increased gas demand while meeting New England's electric demand.

- Proposed pipeline and LNG projects should maintain the status quo.

- Based on the design of the New England's pipeline infrastructure, peak shaving storage facilities located in the vicinity of areas of greatest demand would provide the greatest short and mid-term system benefits.

- As supply areas in eastern Canada are further developed or additional LNG terminals are constructed, additional natural gas pipelines will be built to supply the New York City area. Interconnection of these new onshore pipelines with New England's existing pipelines and LNG facilities would be a long-term solution, thereby increasing the gas pipeline infrastructure to meet New England's long-term natural gas supply needs.

APPENDIX A

Letters by ISO New England and Northeast Gas Association

August 14, 2003

J. Mark Robinson
Director
Office of Energy Projects
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Voluntary Response of ISO New England Inc. to Commission Request for Information to Support Study of New England Interstate Natural Gas Pipeline Infrastructure

Dear Mr. Robinson:

In a letter dated June 19, 2003, you asked ISO New England Inc. ("ISO") to assist the Federal Energy Regulatory Commission ("Commission"), Office of Energy Projects, in collecting relevant information to support the Commission's study on the adequacy of the New England interstate natural gas pipeline system and associated storage facilities. Specifically, you asked the ISO to provide the best available information it had to support the study and to identify what might be the most significant existing and future challenges and constraints facing New England concerning gas supply and deliverability needs. This letter and the enclosed document respond to your request for assistance.

The ISO has evaluated the supply and transportation of natural gas in New England on various occasions in the past. The information developed during these evaluations has provided natural gas suppliers, transporters and end-users, as well as other market participants, with important insights that can help them respond effectively to gas supply and transportation challenges facing New England. As indicated in a recent report prepared for the ISO by Levitan & Associates, Inc., "Steady-State and Transient Analysis of New England's Interstate Pipeline Delivery Capability, 2001-2005" (dated January 2002), there appear to be three principal challenges facing the region in the future:

1. <u>New England's Relative Dependence on Natural Gas</u>

   The New England region has a relatively high dependence on natural gas. In 2003, natural gas is expected to fuel approximately 41% of the electricity produced in New England. This level of dependence is expected to rise to approximately 50% by 2005 and remain at this level into 2010. New England's

dependence on natural gas is exacerbated for certain high population areas, such as metropolitan Boston, due to transmission constraints and the relative unavailability of diverse fuel generating resources within the metropolitan area. For example, reliance on natural gas for electricity production in the Boston area is forecast to reach approximately 80% by 2010.

2. Economic/Market Pressures Created by Limited Natural Gas Supplies

Producers of natural gas in the Gulf Coast and Western Canada regions, among others, are experiencing maturation of the traditional supply basins. Natural gas supply depletion is accelerating as old reservoirs are replaced by less prolific ones. The anticipated step-up in gas production from the Atlantic Canada region expected for 2004/2005 will be delayed. Although this delay is not cause for deep concern about future supply from this region, it appears that the next tranche of supply is unlikely to materialize before the end of 2008, and perhaps not until 2010. Clearly, electricity prices and, thus, market impacts are linked to the value of natural gas in New England. Limited supply portends higher commodity prices, increased price volatility, and higher trading bandwidths than New England has witnessed in the last decade. Increasing dependence on natural gas in New England can only exacerbate these circumstances. This is illustrated by the extremely cold winter in 2002/2003 across much of the nation during which market forces converged to drive commodity prices to the highest levels ever seen.

3. Deliverability of Competitively Priced Natural Gas to Power Plants

Over time, New England's comparative remoteness from gas producing basins has resulted in less flexible physical ties to the major producing and storage areas serving the region. In the last several years, improvements to the ties south of New England, in particular realization of bi-directional supplies in the upstream portions of these ties, has created valuable operating flexibility across all New England pipelines and, thus, has improved the security of gas deliveries. However, analysis of the coincident gas requirements of New England's gas utilities and merchant generators shows that these needs exceed the consolidated pipeline network's collective ability to satisfy demands during the coldest part of the winter.

It is the ISO's understanding that the Commission's staff has already obtained the Levitan report mentioned above as well as another recent report prepared by the same organization, entitled "Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Electric Load Pocket" (dated July 1, 2003). Consequently, the ISO is not providing these reports as part of this response. However, we believe that the enclosed report, entitled "NEPOOL 2003 – 2012 Forecast Report of Capacity, Energy Loads, and Transmission (2003 CELT Report)" should provide additional and useful information on future electric demand across the New England region, including the impacts of demand response efforts.

The ISO appreciates the opportunity to assist the Commission in preparing its study. If, after reviewing this response and the enclosed documents, the Commission has further questions regarding the nature of the natural gas pipeline infrastructure serving New England or the ability of these facilities to meet current and/or projected demand, please feel free to contact myself or James H. Douglass at (413) 540-4559.

Sincerely,

Stephen J. Whitley
Senior Vice President and Chief Operating Officer
ISO New England Inc.

Enclosure

November 21, 2003

Mr. John Schnagl
Office of Energy Projects
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: ISO New England Inc. Comments on New England Gas Pipeline and Storage Study, FERC Docket No. PL04-01-000

Dear Mr. Schnagl:

I am writing to provide the comments of ISO New England Inc. (the "ISO") on the presentation by the Federal Energy Regulatory Commission (the "Commission") of its *New England Gas Pipeline and Storage Study*. The Commission's presentation was made November 14, 2003 at the New England Natural Gas Infrastructure Study Conference at the Massachusetts Department of Telecommunications and Energy in Boston. The ISO participated in the conference and was asked to provide follow-up comments to the Commission. Since the ISO has not been provided a copy of the study, our comments are in response to the Commission's presentation.

As the Independent System Operator for New England, the ISO is responsible for the day-to-day reliable operation of the bulk electric power system, which includes dispatch of generating facilities, and for planning a reliable power system. As such, the ISO has an interest in the Commission's study of "the ability of natural gas pipeline and storage facilities in New England to meet current and projected demand by gas-fired power generation plants and other consumers." The ISO has compiled the following comments:

1. The ISO has published two reports on the subject currently being assessed by the Commission. The ISO reports are entitled, *Steady-State Analysis of New England's Interstate Pipeline Delivery Capability, 2001- 2005,* dated January 2001 and *Steady-State and Transient Analysis of New England's Interstate Pipeline Delivery Capability, 2001- 2005,* dated January 2002. The ISO suggests the Commission review the gas and electric assumptions contained within these reports, along with the methodology, results and findings. The ISO would be willing to work with the Commission during their evaluation of our previous analyses.

2. As stated at the November 14 conference, the ISO recommends that the Commission compile its electric input assumptions for New England from those found within the ISO's recently published year 2003 Regional Transmission Expansion Plan ("RTEP03"). This publication contains numerous forward-going electric-side assumptions for New England's bulk power system, *i.e.*, peak load and energy, generation, transmission, and demand-response.

3. Within the slide entitled, *NERC Estimated 2002-2003 Winter Electric Transfer Capabilities (MW)*, New England's winter import transfer capability from neighboring systems is identified. The figure shows 700 MW winter import capability from New Brunswick, 1,450 MW winter import capability from New York, and 1,780 MW winter import capability from Hydro-Quebec. The source of these assumptions is identified as the NERC 2002–2003 Winter Assessment and the NYISO Operating Study Winter 2002-2003. Although the transfer capabilities are correct as taken from Figure 2[1] within the NERC 2002-2003 Winter Assessment, the ISO emphasizes that those transfer capabilities are more representative of transfer limits rather than anticipated transfer levels.

   The values that should be used to reflect projected winter capacity purchases into New England during the winter of 2002-2003 are found on Page 21 of the NERC 2002-2003 Winter Assessment under the New England section. As stated, "*The forecast of average monthly winter external capacity purchases is 537 MW, which includes 310 MW from Hydro-Quebec, 100 MW from New Brunswick, and 127 MW from New York*." Any assumptions regarding New England's 2002-2003 winter capacity imports from neighboring systems, if used within the Commission's study, should be reflective of the latter assumption.

4. Within *Figure 9 – Transportation Contract Type by State and Region*, the seven pie-charts reflect gas-fired power plant pipeline transportation contracts defined within three categories: 1) firm capacity, 2) fuel manager, or 3) interruptible or capacity release. The Commission should clarify the meaning of firm transportation capacity in this context (primary firm versus secondary firm?) and should clarify the source and sink for the transportation capacity. For example, is the firm transportation capacity from the power plant back through the lateral to the interstate mainline? Is the firm transportation capacity from the power plant back to a centralized hub location such as Dracut? Is the firm transportation capacity from the power plant back to the gas storage fields to the west, *i.e.*, New York, Pennsylvania or Michigan? Is the firm transportation capacity from the power plant back to the gas supply basins such as Henry Hub or western Canada? The clarification of this question feeds directly into a critical input assumption as identified in *Table 6 - Untitled.*

5. Within *Table 6 – Untitled*, an Operable Capacity Analysis is presented for the New England system for the winter of 2004. The loss of all gas-only electric generation with interruptible contract (37%) equates to approximately 2,835 MW out of a total (assumed) installed gas-only capacity of approximately 7,700 MW. As noted in the comments in Item 4 (above), changing the assumption for the amount of gas-only electric generation with interruptible contracts from the assumed 37% to 74 % (a doubling), equates to approximately 5,700 MW of gas-only units being curtailed, thus eliminating any projected positive winter operable capacity margin within the region.

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[1] Figure 2 entitled, *Normal Base Electricity Transfers and First Contingency Incremental Transfer Capabilities (Non-Simultaneous) MW.*

In addition, the ISO notes that projecting operable capacity margins on a pool-wide basis does not reflect the intricate details and post-contingency requirements that exist within transmission-constrained sub-areas of a system. Fuel supply interruption may have greater consequences within reliability sub-areas.

6. The Commission's study does not assess electric sector impacts resulting from potential natural gas supply reductions materializing at New England's borders. The study suggests that all current gas-side commodity assumptions are maintained into the future. Other scenarios may be possible as suggested by the National Petroleum Council's ("NPC") September 25, 2003 report entitled, *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*. The ISO notes that a major finding of the NPC Report states *"North America is moving to a period in its history in which it will no longer be self-reliant in meeting its growing natural gas needs; production from traditional U.S. and Canadian basins has plateaued."*

7. As noted at the November 14 conference, the Commission stated that they did not assess their gas study results and findings against variations in key electric-side input assumptions such as load forecast deviation due to weather, price or demand-side activities, imports and exports to neighboring systems, and capacity attrition due to economics or environmental non-compliance. The ISO notes that such factors, working in unison or experienced coincidentally, may significantly change the overall results and findings of the Commission's analyses. In addition, it is suggested that some of the same variations in key input assumptions be assessed for the gas-side.

8. Although not specifically addressed with the results and findings of the Commission's gas study, the ISO notes that the Pipeline Safety Improvement Act of 2002 will result in increased pipeline maintenance requirements within interstate, intra-state and LDC systems. Within New England, the non-winter (off-peak) load factors on interstate gas pipelines are projected to increase due to growth in gas-fired generation serving summer electric peak loads. In essence, the opportunity to perform pipeline maintenance is shrinking. In an effort to increase electric system reliability, the ISO recommends the Commission assess the viability of coordinating the planned maintenance outages of gas pipelines with the planned maintenance outages of electric generation and transmission facilities.

If you have any questions regarding these comments, please contact me at (413) 535-4324. Thank you for your consideration.

Sincerely,

Mark R. Babula
Supervisor – Power Supply & Reliability
(413) 535-4324

August 29, 2003

Mr. J. Mark Robinson, Director
Office of Energy Projects
Federal Energy Regulatory Commission
Washington, D.C. 20426

Dear Mr. Robinson:

This letter is in response to your letter requesting information on New England's natural gas market, pursuant to the pending study "on the adequacy of the New England interstate natural gas pipeline system and associated storage facilities" being jointly prepared by the Federal Energy Regulatory Commission (FERC) and the U.S. Department of Energy (DOE). The FERC's letter also expressed interest in comments on "what you believe are the most significant existing and future challenges and constraints to New England's interstate natural gas pipeline infrastructure and associated storage facilities."

The Northeast Gas Association (NGA) appreciates the opportunity extended by FERC and DOE to provide comments on New England's natural gas market. This letter addresses the following areas:

- **Background on the Regional Gas Market**
- **Growth Projections through 2010**
- **Proposed Natural Gas Projects in the Region**
- **Challenges and Constraints**
- **Recommendations**.

To begin, a word about NGA.

The Northeast Gas Association (NGA) is a regional trade association that focuses on education and training, operations, planning, technology research and development, and increasing public awareness of natural gas in the Northeast U.S.

NGA represents the region's local natural gas distribution companies, interstate pipeline or transmission companies, liquefied natural gas importer, and manufacturers and suppliers to the industry. These companies provide natural gas to approximately 6.8 million customers in seven states (Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island and Vermont).

NGA was established on January 1, 2003, as a merger of The New England Gas Association (founded in 1926) and the New York Gas Group (founded in 1973).

Its headquarters are in Needham, Massachusetts; it has a New York office in Manhattan. Its web site is www.northeastgas.org/.

Background on the Regional Natural Gas Market

Natural gas represents approximately 18% of New England's primary energy consumption, compared to the national average of 24%. The region consumes far less coal than the national average, and far more oil. The region's fuel mix has been a function of its distance from fuel markets and the availability of infrastructure.

Natural gas came relatively late to the region, with the first interstate pipelines installed in the 1950s. New England was traditionally recognized as being "at the end of the pipeline." Gas service is available in approximately 500 communities in the six states, with the heaviest concentration in the three southern states (Connecticut, Massachusetts and Rhode Island).

The 1990s witnessed significant gas growth in New England, spurred by new infrastructure (three new pipelines from Canada). Since 1990, New England has added over 300,000 natural gas customers, an increase of 15%, and consumption has risen steadily, from approximately 400 Bcf in 1990 to over 700 Bcf today.

In 1979, gas represented 10% of New England's primary energy mix; in 1989, it was up to 14%; by 2000, the most recent data year, it was 18%.

The region has 2.3 million natural gas customers: 2.1 million residential, and 0.2 million commercial and industrial.

In the residential market gas represents about 33% of home heating, with oil about 50%. The New England region has the highest proportion of heating oil in the residential market. In the rest of the nation natural gas represents over 50% of residential space heating, with electricity the leading alternative and oil at less than 10%.

The fastest growing sector for natural gas is power generation. In 1980, gas represented less than 1% of the electric generation fuel mix in New England. By 2002, gas's share had risen to 29%, with another 10% of gas/oil units, according to ISO New England. According to the U.S. Energy Information Administration (EIA), this sector is currently, and in the future will remain, the largest end-use gas-consuming sector in the region.

New England has over 35,000 miles of pipeline and main, according to the American Gas Association. The region's pipelines deliver gas to New England from supply basins in the Gulf Coast, in western Canada, and in Eastern Canada (Sable Island Offshore). Peak day capacity on the regional interstate pipeline system is close to 4 billion cubic feet per day (Bcf/d), up from 1.9 Bcf/d in 1990.

The main supply trunklines to the region are two interstate systems – the Algonquin Gas Transmission System (part of Duke Energy), and Tennessee Gas Pipeline System (part of El Paso Corp). Together these two systems comprise nearly 80% of the region's pipeline deliverability.

As stated above, in the last decade New England added 3 new pipeline systems, delivering gas from different supply basins in Canada – Iroquois Gas Transmission System in 1992, Portland Natural Gas Transmission System in 1999, and Maritimes & Northeast Pipeline in 2000. Canadian supplies represent a significant component of New England's gas supply, more than most parts of the U.S. – over 40% of annual supply, according to the U.S. Department of Energy.

In addition, New England imports liquefied natural gas (LNG), by Tractebel LNG North America/ Distrigas of Massachusetts Corp. (DOMAC). The LNG is imported from such countries as Trinidad & Tobago and Algeria and is delivered by tanker to the Distrigas terminal at Everett, Mass. The Distrigas terminal has interconnections with pipelines, a major LDC, and a major power plant in the Boston area. It recently increased its vaporization capability from 435 million cubic feet per day to a new sustainable peak of approximately 700 million cubic feet per day (MMcf/d). Daily sendout by trucks represents another 100 MMcf/d.

LNG has traditionally been used for supplemental supplies, particularly for winter peak periods, when it can provide as much as 30% of the region's peak day needs. It is also important in a region such as New England to help maintain system pressures at different points of the regional natural gas system. And it is increasingly used for baseload purposes, and, as noted above, to feed into power generation.

There are 46 liquefaction and satellite storage tanks in localities in the region that are owned and operated by the local distribution companies (LDCs). In 2002, according to NGA, the LNG storage capacity in New England among the LDCs was 15 Bcf (which does not include the storage at the Distrigas terminal). Vaporization capacity for daily sendout was approximately 1.3 Bcf/day; and liquefaction capability by the LDCs was 45,000 MMBtu/day.

There is no underground storage located in New England.

NGA is enclosing a copy of its "2003 Statistical Guide" as Attachment A.

Growth Projections Through 2010

NGA does not conduct its own forecast of regional gas demand.

The 2003 EIA Annual Energy Outlook forecasts 1.0% annual energy growth for New England through the year 2025. EIA projects that natural gas consumption will grow the most of any fuel, 1.9% annually, with coal at 0.5%, renewables 1.8%, petroleum, 0.9%, and nuclear, 0.1%.

In the 2003 forecast, EIA projects gas consumption in New England to grow in total by 10.6% from 2002 to 2010, to slightly over one Tcf annually in 2010.

The major variable in growth is the power generation sector. EIA projects natural gas consumption in power generation to double over the period 2000 to 2010.

At the same time, New England remains an undersaturated gas market compared to other sections of the country. As such, it remains a growth market for LDCs. In general, residential market opportunities include: higher-efficiency space heating; water heating/cooking; hearth products; gas grills; pool heating; and gas lights. Commercial market opportunities include infra-red heating; cogeneration; desiccants; air compressors; incineration; distributed generation; and transportation (fleets, buses, trolleys).

Proposed Natural Gas Projects in the Region

New England's natural gas industry continues to make significant investments in its regional gas infrastructure to meet growing market demand. Over the last several years, recognizing the need for new infrastructure to meet market demand, the FERC issued approvals for several gas pipeline projects in New England and New York. Three of these are currently under construction and are scheduled to come into operation within the next several months.

Additional new infrastructure projects are planned for the region for the 2004 – 2010 timeframe. These projects will help further increase regional natural gas capacity, deliverability, flexibility and reliability, as well as provide economic benefits to the region.

In the last decade, New England's pipeline capacity has doubled, and the sources of its supply have diversified considerably. The region's natural gas system is committed to meeting market demand in a reliable, cost-effective, appropriate, and timely manner – in large measure to meet significant market growth in the power generation sector.

A summary of projects for the New England and New York area is provided below.

Granted FERC certificate, under construction:

- Iroquois Gas Transmission System, "Eastchester Extension";
- Duke/Algonquin Gas Transmission System, "HubLine";
- Maritimes & Northeast Pipeline, "Phase III Expansion."

Granted FERC certificate, delayed pending final permits:

- Columbia Gas Transmission Corp., TransCanada, Westcoast Energy, MCN Energy Group, "Millennium Pipeline";
- Duke/Algonquin Gas Transmission System, KeySpan, "Islander East."

Granted FERC certificate:

- El Paso/Tennessee Gas Pipeline, "Dracut Expansion."

Proposed and filed with FERC:

- Maritimes & Northeast Pipeline, "Phase IV Expansion."

Proposed:

- National Fuel Gas Supply, TransCanada PipeLine, "Northwinds Pipeline";
- El Paso/Tennessee Gas Pipeline, "Freedom Trail Expansion Project";
- El Paso/Tennessee Gas Pipeline, "Northeast ConneXion Project";
- El Paso, "Blue Atlantic."

A description of these projects is attached as Attachment B.

Challenges and Constraints

New England's natural gas system needs continued infrastructure additions and enhancements to meet growing market demands, notably in the power generation sector.

These additions and enhancements are needed to increase the availability of gas supply, as well as to support system flexibility and reliability. A diversity of gas supply sources is equally important.

The major electric power outage in the Northeast on August 14, 2003 underscored the importance of system reliability and flexibility. Increasing the reliability of both systems –

electric and gas – is essential. For both systems, timely review of infrastructure and supply projects remains key. The power outage also strengthened the case for distributed generation as a way to maintain power during an emergency.

In its comments on the several studies conducted by ISO-New England of the impact of increased natural gas use in the region's power generation sector, the New England Gas Association and now NGA have always indicated that continued infrastructure growth on the natural gas system is necessary. As stated above, the regional natural gas system has increased strongly in the last decade, on both the pipeline system and the LNG delivery system. The listing of pending and proposed projects, many already with FERC approval, indicates the natural gas industry's commitment to growth in the region.

The current "tightness" in the North American supply/demand balance reinforces the need for New England to strengthen wherever possible the robustness of its natural gas system and the diversity of its gas supply sources, from strengthened interconnections to storage and the interstate pipeline system, to LNG.

The FERC has asked several entities in the region, including NGA, to provide comments on "challenges and constraints." NGA would like to emphasize four major challenges:

- Need for timely review of projects.
- Challenge of siting.
- Contracting arrangements.
- Development of additional supply options.

Need for timely review of projects. Infrastructure projects require extensive planning, financial capital, engineering, siting, community outreach, and review by regulatory agencies at many governmental levels. Timely regulatory review of these projects is a necessary component to help ensure the viability of projects and to help meet market demand in a cost-effective and reliable manner. New England has several projects in development to increase pipeline and LNG availability. Timely review is key, as is streamlining and coordinating the review process as much as possible. These regional projects involve multiple jurisdictions (across multiple states and in some case across multiple provinces), and multiple government agencies at the federal, state/provincial and local levels. Improved coordination and streamlining of the regulatory process would be beneficial.

Challenge of siting. Siting is a challenge for all energy projects, from new generation facilities to fuel storage and electric and gas transmission. New England's regional gas market will be strengthened by the addition of projects that meet local, state and regional market needs. To the extent that siting issues hinder development, the energy market is less secure. As noted above, improved coordination and streamlining of the regulatory process at all levels would be beneficial.

Contracting arrangements. Infrastructure projects if they are to proceed and succeed require an indication of market demand and financial support. One challenge in the current regional gas/electric market is the level of gas transportation contracts entered into by merchant generators. For example, some power generators are opting to sign up for lower priority secondary capacity instead of contracting for more secure primary firm gas transportation. It is an economic decision by market participants. Those who contract for and pay for primary, firm rights will receive their gas first as planned, approved and regulated. The gas suppliers in the region have invested capital and executed firm contracts with all power developers who have requested and agreed to such firm supplies. Similarly, the suppliers have been clear in explaining "non-firm" risks to other developers. The mechanics of the electric dispatch system can help to encourage the level of reliability desired. The pipelines and other suppliers in turn will respond to the pricing signals of the end users and provide the infrastructure requested. The business environment today is different than in the past. Most if not all pipelines require a minimum ten year commitment from shippers to make the necessary investments for major infrastructure projects.

Need for development of additional supply options. As stated above, the development of additional supply delivery projects is currently being pursued by companies involved in New England's natural gas system. Diversity of supply sources helps support supply adequacy and system reliability. An enhanced interconnection system, with strengthened ties with New York and Canada, will only strengthen New England's natural gas network.

The current constraints in the North American natural gas market encourage New England and all other regions of the U.S. to expand their supply resource portfolio. The FERC has encouraged pipeline expansions and greater LNG access. Access to Canadian supplies as noted above has been vital to the growth of New England's natural gas system. The flowing of gas from the Sable Offshore Energy Project since early 2000 opened a new source of supply for the region and a new pipeline directional flow. Other projects have yet to be developed. In the first independent resource assessment of the deepwater Scotian Shelf, released in October 2002, the Canada-Nova Scotia Offshore Petroleum Board stated that the undiscovered gas potential for the deepwater is forecast to range from 15 to 41 Tcf. The timing of further development is to be determined. As Canada's National Energy Board noted in a June 2003 report on the Maritimes gas market: "Most market observers believe that there will be incremental supplies of natural gas discovered and developed in the offshore, but the timing of these developments is highly uncertain. No amount of analysis can reveal the answer to this uncertainty – the answer will come when the industry finds reserves that are economic to develop, having regard to the state of the market as they perceive it." Delays in the development of new supplies from the offshore could impact the timing of currently proposed pipeline projects from Eastern Canada to New England. (At the same time, as referenced below, there are proposals for new LNG facilities in Eastern Canada that could provide additional supply into existing pipeline infrastructure that serves the New England market). NGA is hopeful and expectant that additional gas from new offshore fields in Eastern Canada will flow to the region within the timeframe of this study by the FERC and DOE.

Another supply option is increased LNG. New England has one of four currently operating LNG facilities in the nation. The Distrigas facility has been one of the nation's most active LNG import terminals and is essential to New England's natural gas and energy supply and security. LNG through Distrigas has served as a veritable pipeline for New England. As noted above, Distrigas has recently increased its vaporization capability to serve both growing natural gas demand and power generation load. Additional LNG terminals have been proposed for Massachusetts and Eastern Canada. (For example, in February 2003 Weaver's Cove Energy submitted a formal request to the FERC to participate in a "pre-filing" process for its proposal to build an LNG import terminal in Fall River, MA.) New LNG development in Eastern Canada could provide additional supplies into existing pipeline infrastructure to New England. Additional LNG supplies would benefit New England's natural gas and energy markets. Like all projects, these proposals face siting challenges as well as potential supply competition from other proposed LNG facilities.

Finally, it should also be noted that there are many uncertainties in the marketplace that will likely have an impact on the region's natural gas system in coming years, such as the availability of capital, the need for electric transmission expansions, the reduction of regional oil storage facilities and its affect on fuel-switching capabilities, and the impact of price volatility.

Recommendations

The Northeast Gas Association (NGA) recommends the following to the FERC and DOE:

- Support for increased pipeline capacity and deliverability into New England to meet market demand and enhance system security and reliability;
- Support for additional LNG supplies to meet market demand and enhance system security and reliability;
- Support for increased natural gas resource development in the U.S.;
- Support for greater efficiency measures in all energy forms;
- Support for greater natural gas supply diversity into the region to enhance system security and reliability;
- Support for the timely review of projects, and a streamlining of the regulatory process where possible, to enable projects to proceed in a timely manner;
- Recognition that firm versus non-firm levels of transportation service can impact reliability of delivery to such end-users as power generators and that appropriate market signals need to be sent to ensure infrastructure is developed where and when it is needed on the system.

NGA appreciates the opportunity to provide these comments.

Sincerely,

Thomas M. Kiley
President

Attachments

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PROPOSED ENHANCEMENTS, NEW ENGLAND & NEW YORK NATURAL GAS SYSTEMS (as of 8-03)

PROJECT	COMPANY	DESCRIPTION	EST. IN-SERVICE	STATUS
Eastchester Extension	Iroquois Gas Transmission System	36 miles of new pipeline from Iroquois' mainline at Northport, LI into the Bronx; new compressor stations; supply increase of 230 MMcf/d	2003	Approved by FERC, 12-01; under construction
M&NE Phase III Expansion	Maritimes & Northeast Pipeline / Duke Energy	Approx. 25 miles of 30" pipe from Methuen to Beverly, MA, where it will interconnect with Algonquin's HubLine	2003	Approved by FERC, 12-01; under construction
HubLine	Duke Energy / Algonquin Gas Transmission	Approx. 30 miles of 24" pipeline primarily offshore between Beverly and Weymouth, MA, and approx. 5 miles of 24" offshore lateral pipe to MWRA facility on Deer Island	2003	Approved by FERC, 12-01; under construction
Islander East	Duke Energy / Algonquin Gas Transmission, KeySpan Energy Corp.	Will consist of approximately 50 miles of 24" pipe, extending from Algonquin's facilities in CT, across Long Island Sound, to Wading River, NY	Late 2004	Approved by FERC, 9-02; pending final permits
Millennium Pipeline	Columbia Gas Transmission Corp. (a NiSource company); TransCanada; Westcoast Energy; MCN Energy Group	Proposes to transport up to 700 million cubic feet of gas per day from a new interconnection with TransCanada PipeLines in Lake Erie to a termination point in Mt. Vernon, NY; more than 90 percent of the pipeline's 425-miles overland route uses existing utility corridors, with about 224 miles of the project replacing and upgrading a 50-year old system owned and operated by Columbia Gas Transmission System	2004/05	Filed with FERC, 1997; FERC completed its formal review, 9-02, by issuing final orders approving the last portion of the project's route and denying request for rehearing of earlier rulings conditionally authorizing construction and operation; pending final permits

Dracut Expansion	El Paso Corp./ Tennessee Gas Pipeline Company	Replace 12 miles of 16" pipe with 24", within existing right-of-way, Dracut to Burlington, MA; increase takeaway capacity by 200 Dth/d	2004	Approved by FERC, 11-01; awaiting supply and market commitment
Northwinds Pipeline	TransCanada PipeLines, National Fuel Gas Company	The project involves a 215-mile, 30-inch natural gas pipeline that will originate in Kirkwall, Ontario, cross into the U.S. near Buffalo, New York and follow a southerly route to its destination in the Ellisburg-Leidy area in Pennsylvania. Initial capacity of approx. 570 million cubic feet of natural gas per day, expandable to 1 Bcf.	2005-06	Project announced, 9-01.
Northeast ConneXion Project	El Paso Corp./ Tennessee Gas Pipeline	Will expand Tennessee's market area storage capability and pipeline capacity into New York / New Jersey and Pennsylvania. New facilities will add sections of pipeline loop and horsepower to the existing 300 Line to meet contractual commitments and a new line from the existing crossing down the Hudson River with initial capacity of 500,000 Dth/d into NY and NJ. Some service into CT can be provided depending on final scope.	2006	Project announced 5-01. Feasibility studies completed and discussions with permitting agencies positive. FERC Application will be prepared after market commitments obtained.
M&NE Phase IV Expansion	Maritimes & Northeast Pipeline	Involves the construction of four compressor stations in Maine and approx. 31 miles of additional pipeline loop facilities in Maine's Washington County. Will nearly double the M&NE pipeline capacity to transport natural gas for offshore Nova Scotia, from approx. 415,000	2006	Filed with FERC, 2-02

		Dth/day to 800,000 Dth/day.		

Freedom Trail Expansion Project	El Paso Corp./ Tennessee Gas Pipeline Company	Expand Tennessee's 200 Line through compression and looping to deliver up to 300,000 Dth/d of additional gas supplies from the Gulf, Niagara, and/or storage into New England and New York.	Nov. 2006	Open season announced, 7-03. Non-binding open season completed, 8-11-03.
Blue Atlantic	El Paso Corp.	Approximately 950 miles of subsea pipeline from offshore Nova Scotia to New York / Jersey; 36" pipe designed to carry up to 1 billion cubic feet per day.	2008	Project announced, 10-01. Currently delayed awaiting further developments of Sable Island gas supply.

(as of August 2003)

APPENDIX B

Analysis of Underground Natural Gas Storage Potential in New England

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Analysis of Underground Natural Gas Storage Potential in New England

New England has no underground natural gas storage. The closest available underground storage is located in New York and Pennsylvania. Access to gas in underground storage in New York or Pennsylvania requires available capacity on interstate pipelines. During New England's peak demand periods of December through February, these interstate pipelines are fully loaded precluding many New England customers from gaining access to gas in underground storage. If natural gas in underground storage is not available, New England must rely on pipeline imports, LNG and existing above-ground storage facilities to meet peak demand. If underground storage could be developed in New England, capacity constraints on interstate pipelines could be reduced. To determine if underground storage could be developed in New England an independent assessment was conducted

In the Northeastern region of the United States, sedimentary rocks in New York State contain bedded rock salt deposits that were formed by the accumulation of sodium chloride crystals left by the extensive ancient marine seas. Bedded salt deposits are vertically limited but laterally expansive as opposed to salt domes, which are vertically unrestricted but laterally limited. These bedded salts do not extend eastward beyond the Appalachian (Allegheny) stratigraphic structure of central and western New York. As dictated by geology, all active gas and oil fields and underground natural gas storage facilities of New York are located in the western half of the state within the Allegheny plateau. The New England markets, because of a lack of suitable reservoir rock formations, are devoid of underground storage facilities.

In recognition of the absence of suitable underground storage reservoirs in New England, non-traditional storage alternatives were examined. The Department of Energy (DOE) is examining a number of non-traditional natural gas storage options. Those which may be applicable to New England are described below.

<u>DOE Storage Research</u>

The National Energy Technology Laboratory (NETL), Strategic Center for Natural Gas of the Department of Energy has a number of storage research projects that would be applicable to the Northeastern region of the U.S. or in general:

1) Salt Cavern Storage
   Chilled Gas to -20 degree Fahrenheit before injection
2) Rock Cavern Storage
   Lined Rock Caverns; and Refrigerated Mined Caverns
3) Storing natural gas in the form of gas hydrates

4) Deliverability
   Identify mechanisms responsible for losses in well deliverability;
   Investigate innovative fracturing technologies to revitalize damaged wells
5) Reservoir Management
   Optimizing storage reservoir management through artificial neural networks;
   Horizontal wells to increase deliverability

The following DOE NETL research projects deal specifically with the Northeast's geology for storage facilities:

SCNG-Project Data

Systematic Technical Innovations Initiative for Brine Disposal in the NE
DE-FC26-01NT41298

In September 2001, the New York State Museum was awarded a contract to identify potential rock formations for brine disposal in the northern Appalachian Basin and to remove the barrier to gas storage development in evaporite formations. The project will look at options available to industry to dispose of brines generated during the development of caverns in subsurface salt deposits.

The northeastern states have had a growing demand for gas in the winter heating months. The electric generating companies have also been increasing their demand for gas and shortages are possible. Caverns are very efficient in gas storage, especially for peaking on a daily basis. To develop caverns, an economic means must be found to dispose of the brine created during solution mining of a salt deposit. This effort will address the problems and possible methods to handle these liquids. The successful results of this project will help provide gas for high demand periods of energy for industry and homes.

Project will end September 30, 2003.

SCNG-Project Data

Cavern Roof Stability for Natural Gas Storage in Bedded Salt
DE-FG26-02NT41651

In October of 2002, the National Energy Technology Laboratory awarded a grant to RESPEC Incorporated to develop an improved design criterion to assess long-term geotechnical integrity of natural gas storage caverns in bedded salt.

The most critical issue for natural gas storage caverns in bedded salt is the prevention of roof collapse. The key to preventing a roof collapse is to maintain a competent layer of salt above the cavern. The new design criterion will provide an improved method for evaluating the potential for salt failure over the range of possible stress states experienced by the salt surrounding and overlying a cavern.

Project will end 3/31/05.

SCNG-Project Data

Brine Disposal in the NE (Sandia)
FEW02-011307

In April of 2002, the National Energy Technology Laboratory entered into a field office work agreement with Sandia National Laboratories to develop salt cavern storage of natural gas in areas without ocean brine disposal.

In this project the geology of potential injection formations will be studied to understand the rock properties of target hydrogeologic units on a regional geologic scale. This will be accomplished from correlating rock properties to geophysical logs and then extending that information to the regional scale. In conjunction with the geologic studies, criteria to assess geologic formations for their ability to accept brine and salt cavern development will be developed and reviewed. These criteria will include geometric, material property, and requisite in-situ considerations for injection mechanics, and environmental and regulatory considerations. The criteria will be applied to known successful and problematic brine injection wells, and then to potential new brine injection sites. This system study will provide a blueprint approach to brine disposal by injection.

Projects will end 12/31/03.

SCNG-Project Data

Commercialization Potential of Natural Gas Storage in Lined Rock Caverns
DE-AC26-97FT34348

Sofregaz US, Inc. was awarded a contract in September 1997 to conduct conceptual designs and cost estimates for natural gas storage in lined rock caverns for regions of the United States where conventional underground storage does not exist. The lined rock caverns concept was demonstrated in three test caverns in Sweden in the early 1990s and is based on constructing a cavern, then lining it with a layer of concrete to dissipate the pressure, and then a gas-tight steel lining. The concept may have great application in the Northeast, South Atlantic, and Pacific Northwest where hard rock conditions exist and conventional underground gas storage is very limited or nonexistent.

A composite United States map was completed showing the various hard rock formations suitable to lined rock caverns, the major gas pipelines and market hubs. The general gas supply and demand situation had been studied for the three regions of Boston, New York and Atlanta. Boston and Atlanta were selected as the two geological cases for the study.

The project demonstrated that lined rock caverns can provide better service than liquefied natural gas because of its ability for multiple cycles and that it can lower cost for long haul transportation in the Northeast. Two facilities, a 4 billion cubic foot working gas facility near Atlanta, Georgia, and a 2 billion cubic foot working gas facility near Boston, Massachusetts, were investigated. Conclusions from the study for Atlanta, or the Southeast market in general, were that it would be difficult for lined rock caverns to compete with long haul transportation

by de-contracting, it would be competitive with liquefied natural gas through cycling, and would be useful in pipeline pressure balancing. Conclusions from the study for Boston, or the Northeast market in general, were that lined rock caverns could lower costs for long haul transportation through de-contracting, it would be competitive with liquefied natural gas through cycling, and would be useful in pipeline pressure balancing.

Project completed 3/31/00.

References

"Gas-Storage Assessment for New York State", The University of the State of New York.
"U.S. Underground Storage of Natural Gas in 1997: Existing and Proposed", EIA James Thompson.
DOE website www.netl.doe.gov/scng
OEP Staff Storage Projects database
EIA Staff Storage spreadsheets from Jim Tobin
Telephone consultations with gas storage companies

APPENDIX C

An Overview of Gas Transportation Capacity Contracting Practices of Gas-Fired Electric Power Generators in New England

FERC Technical Support Report:

An Overview of the Gas Transportation Capacity Contracting Practices of Gas-fired Electric Power Generators in New England

Merrimack Energy

October 31, 2003

Introduction

Merrimack Energy was retained by the Federal Energy Regulatory Commission (FERC) to conduct a detailed analysis of the contracting practices used by the gas-fired power generation sector in New England. Specifically, the task involves gathering publicly available information on how New England power plants contract for capacity on gas-pipelines to supply their respective plants, with the goal of quantifying the amount of firm capacity versus non-firm capacity currently in use.

Until recently, New England had one of the lowest levels of gas usage in the country, due to the fact it was at the end of the North American pipeline infrastructure grid. The increase in gas demand from the power generation sector could only be met with increased gas deliverability by the pipeline grid. In the last 4 years, capacity on existing pipelines and the vaporization capacity at the liquified natural gas (LNG) import terminal have expanded. Distrigas LNG added and interconnection with Tennessee and increased its ability to deliver gas into Algonquin. Also, several new pipelines have been built [Portland Natural Gas Transmission System (PNGTS), Maritimes and Northeast (M&NE) and Algonquin's HubLine project] in New England.

When considering the manner in which power plants contract for gas pipeline capacity, one must first consider effect of the restructuring of the electric industry in New England. Restructuring encouraged electric utilities to sell their generation assets to merchant power operators and a proliferation of new gas-fired power plants in the area. The race by the merchant power developers to be the first plant constructed and operating in the market resulted in an oversupply of power. This oversupply could put more pressure on the gas pipeline infrastructure and may lead to increased competition for available pipeline capacity if the new gas-fired generation is dispatched more consistently.

Also, increased tension between natural gas supply and demand forces has led to higher gas prices. It was assumed that the inefficient power plants using alternate fuels would be retired once the highly efficient combined cycle plants began operations. However, the relatively high gas prices means the less efficient oil and coal plants are running more than previously expected. The oversupply situation means that some of the new power plants are being dispatched down in the 70% level, rather than at the 85-95% level that was originally expected. Without long-term power contracts, project financing is based on spark spreads (the power price versus the fuel price). The shrinking spark spreads has left the short-term financial viability (and the need for firm gas transportation) of these plants in jeopardy.

The dispatch uncertainty leads to plant revenue uncertainty, which means merchant power plants in New England are reluctant to sign up for monthly fixed cost commitments such as those associated with gas pipeline demand charges. Power plants need operational flexibility to allow them to shut the plant down when it is not dispatched and to ramp the operation back up when it is dispatched. The flexibility required by the power plants is not synchronized with the gas pipelines' requirement for long-term contracts to underpin pipeline capacity expansions.

To build a data base of the individual power plant characteristics and to undertake an analysis of the contracting practices of power plants in New England, Merrimack has relied on information from public sources. The analysis started by cataloguing the individual gas-fired power plants in each of the New England states. The data collection for each plant includes: plant location, plant owner, plant type, fuel type (switchability), assumed dispatch pattern, the local distribution company (LDC) territory the plant is located in, the plant output capacity in Megawatts, the estimated plant heat rate, the interstate pipeline connection and the peak-day pipeline capacity requirement. Some of the information sources that Merrimack utilized are:

1. ISO-NE report entitled **"NEPOOL Forecast of Capacity, Energy, Loads and Transmission – 2003-2012"**
2. The web sites of Iroquois Gas Transmission, PNGTS, M&NE, Vermont Gas, Algonquin and the Tennessee pipeline.
3. The Tractebel web site for the LNG facilities at Everett, MA
4. When available, the web sites of the power plants
5. The filings by the power plants with the Departments of Environmental Protection and the Energy Facilities Siting Organizations in the six New England states.

The bottom-up approach involves starting with an individual plant and assessing the amount of gas that would be required for the plant to operate on a peak-day basis. One must keep in mind that not all of the plants will be operating coincidentally at their respective peak-day capacity. However, the peak-day amount is then compared to the capacity that the power plants have contracted on the interstate pipelines. The difference between the peak-day capacity and the amount of firm-transportation capacity contracts is the amount of gas that the plant requires to be supplied to the plant either by a 3rd party fuel manager or by capacity coming from the capacity release market or the interruptible market on a peak day. The goal of the analysis was to quantify the amount of capacity that New England power plants contracted for on interstate pipelines on a firm basis. Any gas requirements not satisfied with firm transportation contracts would have to be made up with non-firm contracts. Non-firm contracts include buying capacity on an interruptible basis, which means that one can use the capacity until one is interrupted. Non-firm contracts would also included is released capacity, which is capacity held by a firm shipper and assigned to another shipper on a temporary basis. Another transportation segment is when a 3rd party such as a fuel manager or an LDC contracts for firm capacity on a pipeline on behalf on a power plant. Firm capacity contracts are usually in the 5-10 year range. Interruptible or assigned capacity can be as short as a day in length. Some of the contracts that power plants have entered into with interstate pipelines in New England for capacity on a lateral are as long as 20 years.

The contracting practices of all of the gas-fired plants are aggregated on a state basis and then aggregated again on a regional basis to give a representative picture of gas contracting practices in New England. Please keep in mind that the oversupply of gas-fired generation further clouds the picture because gas generators could be "re-selling" firm transportation capacity in anticipation of even less operating time.

This report is presented in two parts:

A. An assessment of the contracting practices used by the gas-fired power generators on a plant by plant basis; and

B. Background Market Information
   1. An overview of the gas-fired power generation sector in New England;
   2. An overview of the gas transportation infrastructure in New England;

A. An Overview of Gas-fired Power Contracting Practices in New England

Traditionally, pipelines try to maximize revenue by keeping the pipeline full, i.e., transporting gas at a high load factor and thereby minimizing any excess or unused capacity. With little or no excess capacity available, a shipper can obtain new capacity by signing a contract for firm transportation capacity with the pipeline and the pipeline will then seek regulatory approval to construct incremental capacity to serve that shipper.

New England Power Market Environment

Traditionally, most power plants were owned by the utilities or were independent plants with power purchasing agreements (PPA) to rely on for a steady stream of income. The demand charges associated with gas pipeline capacity contracted to serve these plants could be paid via the PPA and passed on to the electricity user.

The restructuring of the power market in New England and the infusion of a large number of merchant generators has meant that generally power plant revenue comes from being dispatched on an economic basis into the "energy" market. The more efficient plants, i.e. lower heat ratings, would be dispatched more often than the higher heat rate plants. Also, there was an expectation that many of the older inefficient units would be retired leading to a higher price for energy. However, the lives of older generating units were extended (non-retirements) generally due to higher gas prices, which meant the new power plants are being dispatched at a lower level than was originally thought at the time of their construction.

The risk of an inconsistent revenue stream due to uncertainty of dispatch, led merchant power plants to adopt the following procurement principles:

- Limit the fixed cost exposure. Pay for fuel only when plant is operating.
- Contract for fuel at market-based indexes.
- Secure a delivery service at a trading hub from a supplier that guarantees delivery.
- Secure firm pipeline capacity only as needed, i.e., maybe for one unit or for a winter only service.
- Shift fuel-related risk to suppliers, pipelines or other entities best able to manage risk.

The new generation of power plants in New England needs much more operating flexibility such as:

- The flexibility to downsize the gas fuel purchases when dictated by plant economics
- The flexibility to shut plant down when the revenue from selling the plant fuel and pipeline capacity exceeds that of generating power
- The ability to ramp up plant to full power output during summer peaks
- May want to reduce some of the risks associated with fuel and power prices by tolling part of the plant. The tolling concept was driven by marketers and the demise of the marketer segment has led to a shelving of this approach.

Power Plant - Pipeline Relationship

The sale of generation assets by the utilities to merchant operators in New England and the proliferation of new merchant plants built without the security of PPAs altered the way in which power plants contracted for gas pipeline capacity. Without a PPA, the new fleet had to rely on gas-electric spark spreads to pay for the monthly pipeline demand charges. This led to a change in the relationship between power generators and interstate pipelines. There are two components to the relationship:

1. ***Connection***

   Power projects need to be connected to gas supplies from an interstate pipeline. Most have opted for a direct connection through a lateral owned by the pipeline or the power project, which bypasses the LDC. The reasons for bypassing the LDC are:

   - Usually an LDC system operates at a gas pressure (150 psig) that is much lower than required by the power plant (350-650 psig). If the power plant takes its gas feed off of the LDC system, then incremental compression would have to be installed to increase the gas pressure for the power plant.
   - The merchant power plant would also like a direct connection to the interstate pipeline in order to avoid pancaking of rates, i.e., paying a demand charge to the interstate pipeline and a demand charge to the LDC.
   - If a lateral is built directly from the power plant to the interstate, there a several options for ownership. First the power plant could own the lateral. Secondly the interstate could own the lateral and charge the power plant a transportation fee for the use of the capacity in the lateral. Thirdly, the LDC could build the lateral. When an LDC builds a direct lateral from and interstate pipeline to a merchant plant, it is often done for what is termed a "bypass" rate. A bypass rate means the LDC would build the lateral and essentially charge the merchant plant no more than it would cost for the merchant plant to build it itself.

2. ***Capacity Contracting***

   Once the connection between the plant and the pipeline is established, the power plant will minimize its fixed costs by contract for capacity only back to the nearest liquid pricing point. As a result, most merchant generation projects have not contracted for firm long-haul pipeline capacity, choosing instead to contract for short-haul pipeline capacity to a pipeline interconnection or hub.

   Another approach that merchant generators are using is to contract for firm pipeline capacity for a limited amount of total daily requirements. For example if the peak requirements of the plant is 90,000 Dth/d, the generator may contract for pipeline capacity of 45,000 Dth/d on a firm basis and obtain the rest from capacity release assignments or spot-market purchases. That way, one of the 250 MW units was assured of operating in a typical 2-unit 500 MW plant.

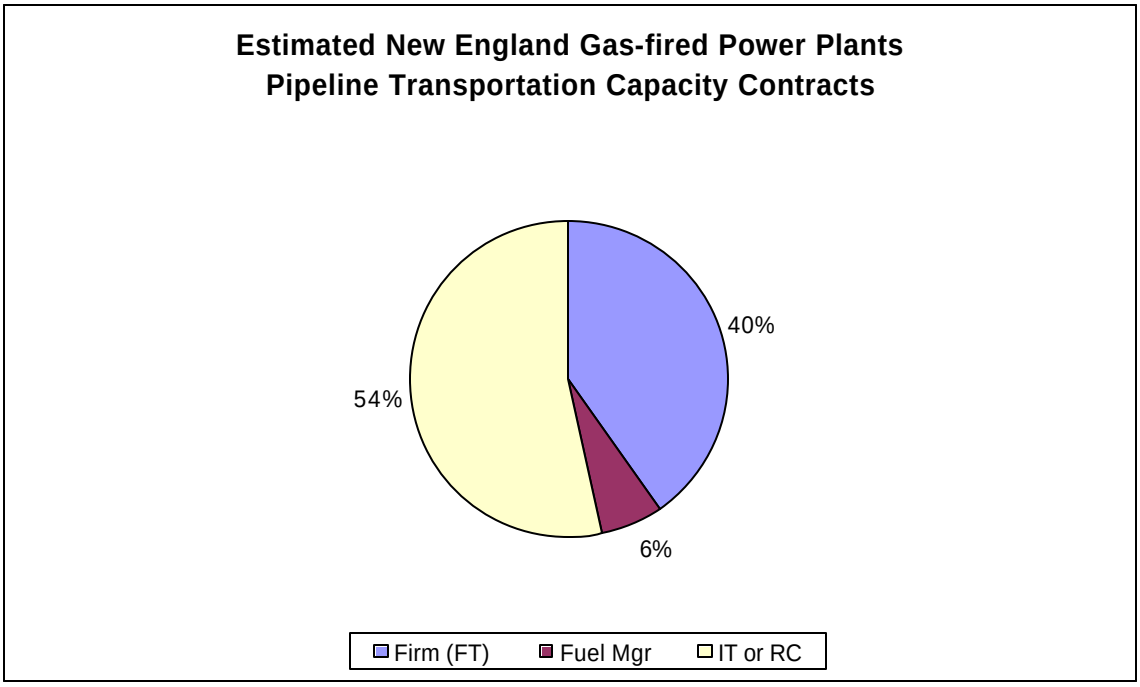
Pipeline Capacity Options

There are several options available to a power plant operator when procuring pipeline capacity to supply its plant:

1. The power plant can purchase firm transportation for all of its needs. This is by far the most expensive option, but may be required depending on the location of the plant relative to the pipeline.
2. Use a third party such as a marketer to procure the pipeline capacity on behalf of the plant. This option usually involves some form of revenue sharing on the days when the plant can not use the capacity and it is resold by the marketer.
3. Purchase a portion of the capacity needs on the open market, either on an interruptible basis from the pipeline or on an assigned basis from an existing shipper. Capacity assignments are more reliable but are often short term in nature and usually of insufficient size to meet the plants needs during peak periods.
4. Enter into a tolling arrangement where a third party supplies the gas and sells the power output and the power plant owner is paid a fee to operate the plant.
5. Some combination of the above. An operator of 2 units may have a tolling arrangement for one unit and supply fuel to the other unit by purchasing some firm pipeline capacity, some from a marketer and the balance in the interruptible or capacity release market.

Analysis of Pipeline Contracting Practices by Power Plants in New England

Figure IV shows the aggregate contracting practices that power plants in New England have with interstate pipelines.



The graph illustrates that more than half of the capacity required for the gas-fired power plants in New England to operate at full capacity would have to come from either the interruptible market or the released capacity market. However, contracting for pipeline capacity by power generators drastically differs from state to state and is often very location specific (see data in Appendices).

For instance, all but one of the power plants in Rhode Island (Appendix C) has sufficient firm capacity contracts to meet their peak-day requirements. One reason for this is that only option for gas supply to the older plants (pre-FERC Order 636) in Rhode Island was to contract for firm capacity. The released capacity market had not yet materialized and there were PPAs to pay for the pipeline demand charges. Although the newer plants did have access to the released capacity markets and did not have PPAs, they still needed to contract for firm pipeline capacity because there is no spare capacity available on the Algonquin system. Lately the certainty of firm capacity and the uncertainty of interruptible or released capacity at certain times in the year led the Rhode Island plants to buying firm capacity contracts on interstate pipelines.

Maine (Appendix D) is at the other end of the spectrum relative to Rhode Island. Maine has 5 new merchant plants and only one has firm transportation capacity contracts to cover the plants needs on a peak day. Fully 75% of the gas requirements for Maine power plants are supplied by non-firm transportation (IT or Released Capacity). The other 4 plants depend on spare capacity on either the PNGTS or M&NE system. A deeper look into the Maine situation shows that 3 of the 5 plants are owned by Calpine and Calpine optimizes its firm pipeline capacity between all three plants and makes up the balance on the IT market.

Vermont (Appendix F) only has one gas-fired power plant and gas is the secondary fuel, so there are no firm pipeline capacity contracts.

In New Hampshire (Appendix E), gas is the secondary fuel in the two vintage power plants and therefore there is no firm pipeline capacity associated with these plants. These 2 plants have access to a summer only capacity release agreement on PNGTS. There are also has 2 new power plants in New Hampshire: the ConEd Newington plant which is connected via the Newington lateral to the PNGTS/M&NE Joint Facilities and the AES Londonderry plant which is connected to the Tennessee system. The ConEd facility has a firm capacity contract on the lateral connecting the plant to the Joint Facilities, but has no mainline capacity, as there is plenty of excess capacity available on the Joint Facilities. The AES facility has contracted for its full requirements on Tennessee because there is no excess capacity available on that system.

Connecticut (Appendix B) has a contracting trend much like Maine or New Hampshire where approximately 35% of the peak-day needs could be met with firm pipeline capacity. New plant construction in Connecticut has run into problems which directly affect the ability of the sponsors to contract for capacity on interstates. There were 5 new power projects approved in Connecticut. The biggest is the Lake Road plant (800 MW) and its owner, PG&E filed for bankruptcy. The now defunct El Paso Energy built the Milford plant which is fueling the plant principally from the secondary market. Construction of the other El Paso plant, Meriden, was halted half way through the project. The PPL peaking plant at Wallingford permanently released all of its firm capacity after start-up. The Duke operated Bridgeport plant purchases 100% of its transportation capacity on the secondary market.

Massachusetts (Appendix A) also has approximately 37% of its peak-day needs covered with firm capacity contracts. The newer plants employ a mix of firm, fuel managed and secondary market capacity to supply their gas. Massachusetts has the highest level of third party commitment for pipeline capacity. The biggest plant is Mystic 8&9 (1600 MW) is fed directly off of the DOMAC LNG system. This plant along with the Edgar plant located at Fore River has been turned over to the banks by the owner Exelon. Financial problems directly constrain a plants ability to contract for firm capacity.

Conclusions

There are a number of conclusions which result from the analysis. These include the following:

- The first issue in pipeline contracting is the location of the plant relative to the closest interstate supply pipeline. All of the capacity on the 2 oldest pipelines in New England, Algonquin and Tennessee, is fully contracted. It would be difficult for a new 500 MW power plant to pick up 85,000 Dth/day of incremental capacity on one of these systems. There is however capacity available on the PNGTS and M&NE systems and expansions on IGTS are still economic.
- The second issue is the vintage of the plant. The older plants like the Ocean State plants in Rhode Island went into operation prior to FERC Order 636 and the flexibility of using released capacity and interruptible transportation were not available when these plants began operation, so contracting for firm capacity was the only option at that time, given the structure of the power market.
- Another consequence of FERC Order 636 was a tightening of operational flow orders (OFO) and the installation of flow control valves on pipeline laterals to the plants. Prior to FERC Order 636, power plants flexed their rates of take off of the pipelines during periods of peak power prices. The new environment has made this practice more difficult and thus increasing fuel to the plant must be done via a capacity contract not an OFO.
- The New England gas market is primarily driven by traditional gas heating load which means that the LDCs in the region contract for firm pipeline capacity to meet their winter loads (along with storage and peaking supplies). However, in the non-heating season (April-October), there is plenty of pipeline capacity available that the LDCs could release to power plants and often does at a discount.
- If a power plant could obtain a firm-winter service and depend on the released capacity of the LDCs in the summer time, then it would reduce its fixed cost obligations and retain the much needed operational flexibility required to be successful in the competitive power market in New England. The problem with this strategy is that most new plants have tried to adopt it and it has resulted in less summer capacity being available and what is available is no longer priced at a deep discount. The lack of excess capacity on the interstates in the winter means those without firm capacity contracts can not access gas.
- The demise of many marketing firms has meant that capacity contracts that marketers had with the interstate pipelines or managing the LDC portfolios to allow for greater sales to power generators were turned back to the pipelines or released on a permanent basis to other shippers. If a power plant is struggling financially, then it may not have a sufficient credit rating to qualify for entering into a firm capacity contract with an interstate pipeline. Some plants, especially the financially strapped ones are starting to use third party fuel management services; however it represents a small portion of the market (8%). Also, it is hard to say how long the financially distressed plants will employ a fuel manager, once the plant is sold.
- Merchant power developers thought their plants would be dispatched on a base load basis and various factors led to this not being the case. In order to compete, a merchant power generator must have a flexible operation where the fuel supply can be turned on and off daily or throughout the day. This hourly flexibility requirement is a mismatch with pipelines daily scheduling and the need for firm capacity contracts to underpin the pipeline construction efforts.
- The newer plants have air permits that allow them to operate on oil from 3 to 30 days per year (usually 720 hours), however it is difficult to operate on oil for much more than 4-5 days at a time. Also, plant operators are reluctant to use oil as the new vintage of high speed turbines do not operate well on oil, which results in more frequent maintenance and increased maintenance costs.

B. Background Market Information

1. An Overview of the Gas-fired Power Market in New England

The New England power market includes the six states of Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. The New England wholesale electric market was traditionally a centrally dispatched market organized around the New England Power Pool (NEPOOL). NEPOOL coordinated regional power planning and generation dispatch beginning in 1971, and was classified as a tightly coordinated power pool. At the state level, individual state public utility commissions, each with different policies and objectives, regulate the utilities within each of the six states.

The New England region has transformed its power market from a tightly regulated power market to a restructured competitive market. ISO New England (ISO-NE) has assumed responsibility for managing the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff. In addition, ISO-NE administers the restructured wholesale electric market for the region based on a bid-based power exchange. Operations and planning occur on a region-wide basis in New England.

Merchant Plant Activity

New England has undergone an explosive era of growth for gas-fired power generation. The strong demand for power, new gas supplies from offshore Nova Scotia in Canada and several pipeline infrastructure expansion proposals led to an upsurge in gas-fired merchant power plant proposals.

While the number of power projects proposed varies at any one time, over 50 gas-fired merchant generation projects were proposed in New England totaling nearly 30,000 MW of capacity. As of 2003, eleven projects, with a total capacity of over 3,500 MW, were constructed in New England. An additional eleven projects, with a total capacity of approximately 6,500 MW, entered service in 2002. It is expected that approximately 10,000 MW of merchant generation will have been brought into operations in New England between 1999-2003.

The proliferation of gas-fired merchant plants in New England has increased the reserve margin for power in the region to levels in excess of 30%. This oversupply of power generation capacity is expected to dampen average power prices and limit the amplitude of price spikes during peak hours.

The location of new power projects relative to the gas pipeline systems in New England is illustrated in Exhibit I. M&NE and Algonquin pipelines are closest to the vast majority these new plants.

Exhibit I
New England Plants Operating/Under Construction

Map is not internet public

The philosophy of most project developers was that electricity and gas prices would move in lockstep. Thus, if the gas market tightens and prices increase, then power prices will follow since gas will be the marginal fuel in the power exchange. However, surplus generation capacity, combined with a tight demand/supply balance for pipeline capacity, has pushed electric and gas prices in opposite directions or certainly reduced the correlation between the two products. This phenomenon has resulted in gas-fired merchant projects experiencing a reduction in their dispatch capacity factors and the financial viability of several new plants is being threatened. Some plants may have to be shut down in the interim (mothballed) or put up for sale at discounted prices. With lower and uncertain revenues, several of the new merchant power plants are financially unable to commit to monthly demand charges that are required by interstate pipelines for firm capacity (FT service).

2. Overview of the New England Natural Gas Supply Infrastructure

It is helpful to review of the gas supply infrastructure into New England to determine if the system capacity is sufficient to meet the growing demand for gas. Natural gas is transported to New England through six pipelines, as well by ship in the form of LNG from offshore sources to the Distrigas facilities in Everett, MA. Four of the six pipelines serving New England source their gas from Canada (Vermont Gas, Iroquois, PNGTS and M&NE). The other two pipelines, Tennessee and Algonquin also transport Canadian gas, however the majority of gas shipped on these two pipelines is sourced in the Gulf Coast.

The growth in gas demand, primarily fueled by the prolific construction of merchant gas-fired power plants, could put pressure on the gas supply infrastructure in the Northeast during peak periods. However, when gas prices are high, many gas-plants may not be dispatched and may release pipeline capacity into the market which would help the grid system. In any event, the increased demand for gas has led to significant expansions in the gas supply infrastructure feeding New England. The peak-day throughput capacities feeding the New England market are shown in Exhibit II below. The overall capacity will increase by approximately 23% in the next few years with the expansion of the Distrigas LNG facilities and the M&NE phase IV expansion.

Exhibit II
New England Gas Delivery Infrastructure Capacity (MMcf/d)

	Existing Capacity	Expected Capacity	Difference
Algonquin	1,433	1,433	0
Tennessee	1,090	1,090	0
M&NE	421	800	379
PNGTS	210	210	0
Iroquois	293	293	0
Vermont Gas	85	85	0
Distrigas	535	1,100	565
Total	4,067	5,011	944

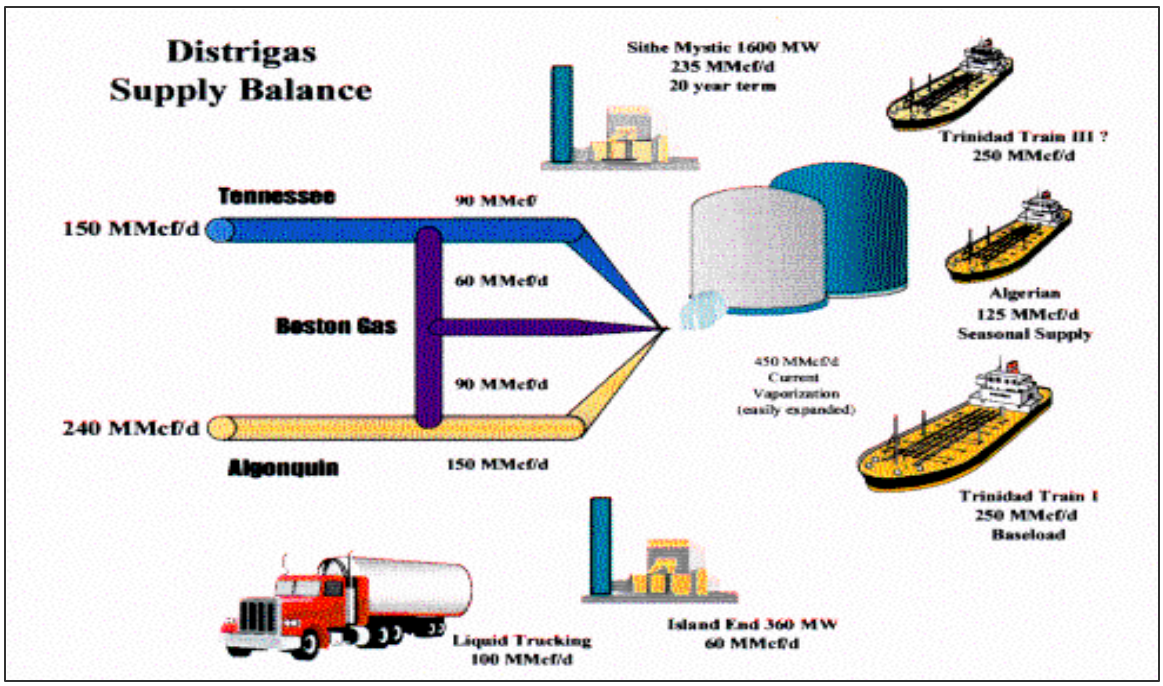
New England's infrastructure capacity has increased with the construction of the Portland Natural Gas Transmission System (PNGTS), the Maritimes & Northeast Pipeline (M&NE), and HubLine. The expansion of the Tennessee Gas Pipeline (Tennessee) and the expansion of the Distrigas LNG facilities have also been significant additions to the region's gas delivery systems.

LNG Supplies serving New England

LNG is an integral part of the gas supply portfolio in New England. Its use has changed since the Distrigas terminal in Everett, MA began to receive imported LNG cargoes in 1971. Initially used as a peaking service, LNG is now imported on a year-round basis and provides firm gas supply to several merchant power generators. During the summer season, LNG is used to refill satellite LDC tanks, replacing the volumes used during the winter season. Any summer surplus LNG is sold as vapor to interruptible gas users (including electric generating facilities) at prices that compete with domestic pipeline supplies. In winter, LNG liquid and vapor is delivered to LDCs to help them meet their winter peaking requirements. New England LDCs operate an extensive LNG storage system with about 15 Bcf of storage.

The Everett, Massachusetts terminal was shut down from 1985 through to 1988 due to the high cost of LNG relative to domestic gas supplies. The Tractebel Group, a Belgian conglomerate, bought the facility from Cabot Corp. for $680 million in 2000. The Company has stated that the terminal is capable of receiving 95 cargoes per year and has a regasification capacity of 535 MMcf/d and storage capacity of 3.4 Bcf. Tractebel increased the peak-sendout capacity of the terminal to 1.1 Bcf/d by the end of 2002, with a sustained sendout capability of 0.7 Bcf/d.

Distrigas is currently connected to Algonquin, Tennessee and the KeySpan (former Boston Gas) facilities (see Exhibit III). About 78 MMcf/d of gas is delivered to Algonquin and 90 MMcf/d to Tennessee on a firm basis, but actual deliveries can reach 300 MMcf/d on Algonquin and 150 MMcf/day on Tennessee. Off the Tennessee system, about 45 MMcf/d of LNG vapor is delivered to the Berkshire Power plant at Agawam, MA and 25 MMcf/d to the MassPower plant in Springfield, MA. Besides pipeline deliveries, Distrigas also has the capability to deliver 150 MMcf/d of vaporized LNG directly to the KeySpan (Boston Gas) distribution system and up to 100 MMcf/d to tanker trucks. **Exhibit III**



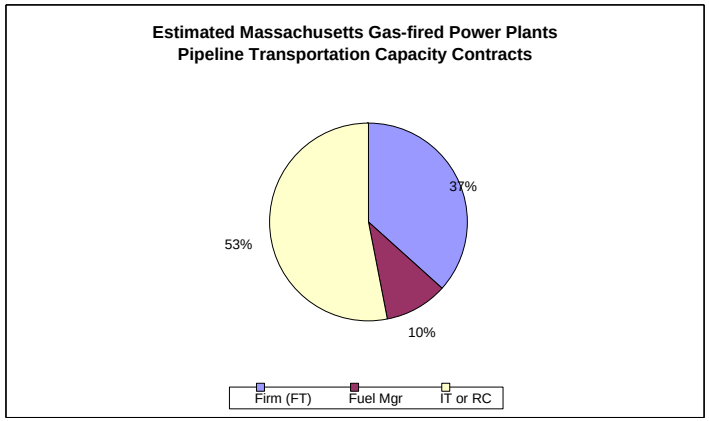
Appendix A - Massachusetts

Both Existing Gas Fired Generation and New Merchant Plants

Location	Company	Facility Name	Plant Type	Assumed Dispatch	Net Plant Heat Rate (Btu/kWh)	Fuel Type	Status	Summer Capacity (MW)	Winter Capacity (MW)	Annual Gas Capacity Factor	Annual Energy (MWh)	Peak-Day Pipeline MDQ (Dth/d)	Annual Gas Use (MMcf)	Pipeline Service	LDC Territory	Interstate Pipeline Capacity Contracts: Firm (FT) (Dth/d)	Fuel Mgr (Dth/d)	IT or RC (Dth/d)
Massachusetts																		
Boston, MA	Exelon	New Boston 1 & 2	ST	Base	10,200	FO6/gas	Op	350.0	354.9	75.0%	4,993,200	42,840	50,930.6	AGT	Boston Gas (KeySpan)	0	0	85,000
Boston, MA	Exelon	Medway 3	JE	Peaking	14,500	FO2/gas	Op	35.4	55.8	0.1%	1,473	19,432	21.4	AGT	BayState (NiSource)	0	0	19,432
Everett, MA	Exelon	Mystic Steam 7	ST	Base	10,000	FO6/gas	Op	554.9	559.8	4.0%	204,283	134,347	2,042.8	AGT	Boston Gas (KeySpan)	0	0	125,000
Sandwich, MA	Mirant	Canal 2	ST	Base	9,211	FO6/gas	Op	553.0	562.0	60.0%	2,995,920	124,238	27,595.4	AGT	Colonial Gas (KeySpan)	0	0	75,000
Middlesex, MA	Mirant	Kendall Steam 1-3	ST	Base	14,200	FO6/gas	Op	60.0	61.0	7.0%	42,311	20,789	600.8	AGT	Commonwealth Gas (Nstar)	0	0	20,789
Milford, MA	ANP	Milford Power L.P.	CC	Intermediate	8,500	Gas	Op	149.0	170.7	64.8%	959,723	34,823	8,157.6	AGT	Commonwealth Gas (Nstar)	30,200	0	0
Dartmouth, MA	El Paso	Dartmouth Power	Cogen	Intermediate	9,000		Op	61.8	68.2	93.1%	538,880	14,731	2,431.5	AGT	Commonwealth Gas (Nstar)	14,010	0	0
Somerset, MA	PG&E	Brayton Point 4	ST	Base	9,677	FO6/gas	Op	435.0	445.5	2.0%	76,796	103,466	743.2	AGT	Fall River (New England Gas)	62,000	0	58,000
Indian Orchard, MA	PG&E	Masspower	Cogen	Base	8,000		Op	231.5	270.0	73.1%		51,840		TGP	BayState (NiSource)	0	50,000	0
Pittsfield, MA	PG&E	Altresco	Cogen	Intermediate	8,000	FO2/gas	Op	141.0	173.0	31.4%	447,292	33,216		TGP	Berkshire (EE)	33500	0	0
Bellingham, MA	Tractabel/FPL	NEA Bellingham	Cogen	Intermediate	8,500	FO2/gas	Op	264.0	326.0			66,504		AGT	BayState (NiSource)	0	0	66,504
Braintree, MA	Braintree Electric	Potter CC	CC	Intermediate	11,000	Interr.	Op	78.0	96.0	6.5%	50,865	25,352	559.5	AGT	Boston Gas (KeySpan)	22,000	0	0
Agawam, MA	El Paso/PDC	Berkshire Power	CC	Base	7,000	Gas	Op	245.2	262.2			44,053		TGP	BayState (NiSource)	0	45,000	0
Charlton, MA	PG&E	Millennium	CC	Base	7,000	Gas	Op	337.8	386.8			64,982		TGP	None	0	0	60,000
Dighton, MA	Calpine	Dighton Power	CC	Base	7,800	Gas	Op	143.2	180.8			33,844		AGT	BayState (NiSource)	33,000	0	0
Bellingham, MA	ANP	ANP Bellingham	CC	Base	7,000	Gas	Op	444.2	504.5	75.0%		84,753		AGT	BayState (NiSource)	25,000	50,000	15,000
Blackstone, MA	ANP	ANP Blackstone	CC	Base	7,000	Gas	Op	444.2	504.5	75.0%		84,753		TGP	Blackstone Gas	50,000	20,000	20,000
Mystic, MA	Exelon	Mystic 8&9	CC	Base	7,000	Gas	Op	1,356.0	1,540.0	75.0%		258,720		Distrigas LNG	Boston Gas (KeySpan)	240,000	0	0
Middlesex, MA	Mirant	Kendall Repowering	CC	Base	7,000	Gas	Op	172.0	172.0			28,896		AGT	Commonwealth Gas (Nstar)	0	0	28,896
Fore River, MA	Exelon	Edgar Power Station	CC	Base	7,000	Gas	UC	700.0	843.0	75.0%		141,624		AGT	Boston Gas (KeySpan)	70,000	0	70,000
												1,413,203						
Co-gens																		
Taunton, MA	TMLP	Cleary 9 CC	CA	Intermediate	10,500	FO6/gas	Op	105.0	110.0	5.0%	47,449	27,720	498.2	AGT	BayState (NiSource)	0	0	27,720
Ludlow, MA	MMWEC	Stonybrook - CC	CC	Base	9,500	FO2/gas	Op	279.0	317.0			72,276		TGP	BayState (NiSource)	0	0	72,276
Hampden, MA	ConEd	West Springfield 3	ST	Intermediate	10,000	FO6/gas	Op	101.2	100.1	10.0%	93,732	24,022	937.3	TGP	BayState (NiSource)	0	0	24,022
Cambridge	Nstar	Blackstone 1 & 3	ST	Base	10,300	FO6/gas	Op	13.5	18.0	2.0%	2,891	4,450	29.8	AGT	Commonwealth Gas (Nstar)	0	0	4,450
Lowell, MA	UAE Power (Sempra)	UAE Lowell L'Energia	Cogen		9,000	FO2/gas	Op	75.5	87.5	89.3%	647,441	18,900		TGP via LDC	Lowell Gas (KeySpan)	0	0	18,900
Hampden, MA	Holyoke Muni	Cherry Street 7 -12	IC	Peaking	14,500	FO2/gas	Op	17.4	19.6	0.5%	727	6,821	10.5	TGP	Holyoke G&E	0	0	6,821
Hampden, MA	Holyoke Muni	Cabot 6 & 8	ST	Intermediate	10,500	FO6/gas	Op	9.0	9.0	3.0%	2,365	2,268	24.8	TGP	Holyoke G&E	0	0	2,268
Lowell, MA	Sempra	Lowell Cogen	Cogen		9,000	FO2/gas	Op	25.0	28.0	94.3%	213,086	6,048		TGP	Colonial Gas (KeySpan)	0	0	6,048
Peabody, MA	PMLP	Waters River 2	JE	Peaking	15,000	FO2/gas	Op	27.6	42.9	2.0%	7,148	15,444	107.2	TGP	Boston Gas (KeySpan)	0	0	15,444
Peabody, MA	PMLP	Waters River GT	GT	Peaking	12,000	FO2/gas	Op	14.0	20.0	2.0%	3,154	5,760	37.8	TGP	Boston Gas (KeySpan)	0	0	5,760
Essex, MA	Ipswich Muni	Ipswich Diesel 1,2,6,9-12	IC	Peaking	16,000	FO2/gas	Op	8.9	8.9	1.0%	776	3,418	12.4	TGP	Essex (KeySpan)	0	0	3,418
Pepperell, MA	Indeck PPA	Pepperell Power	CC	Intermediate	9,000	FO2/gas	Op	33.1	40.1			8,666		TGP via LDC	Colonial Gas (KeySpan)	0	0	8,666
								7,465.4	8,337.8			195,792				579,710	165,000	839,413

Information Sources:

- State of Massachusetts - Department of Environmental Services, Site Evaluation Committee
- ISO New England 2003 CELT report
- Tennessee Gas Pipeline Web Site
- Algonquin Gas Transmission Web site
- Individual Power plant web sites
- Conversations with representatives from interstate gas pipelines
- Conversations representatives from power plants
- Conversations representatives from LDCs



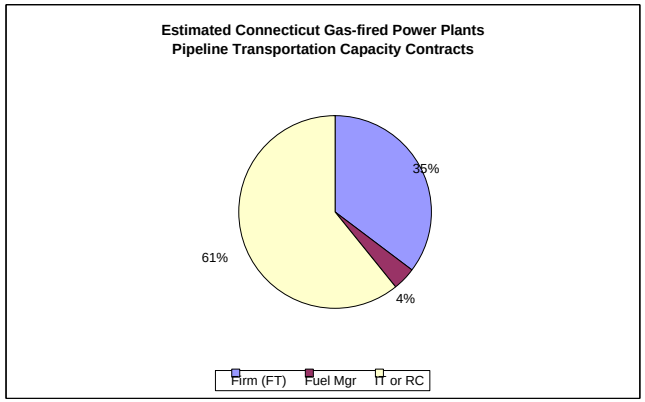
Appendix B - Connecticut

Both Existing Gas Fired Generation and New Merchant Plants

Location	Company	Facility Name	Plant Type	Assumed Dispatch	Net Plant Heat Rate (Btu/kWh)	Fuel Type	Status	Summer Capacity (MW)	Winter Capacity (MW)	Annual Gas Capacity Factor	Annual Energy (MWh)	Peak-Day Pipeline MDQ (Dth/d)	Annual Gas Use (MMcf)	Pipeline Service	LDC Territory	Interstate Pipeline Capacity Contracts: Firm (FT) (Dth/d)	Fuel Mgr (Dth/d)	IT or RC (Dth/d)
Connecticut																		
New Haven, CT	PSE&G	New Haven Harbor	ST	Intermediate	9,400	FO6/gas	Op	449.6	466.0	2.0%	78,314	101,430	736.2	AGT	Southern CT (EE)	0	0	46,000
Milford, CT	NRG Power	Devon 7 & 8	ST	Base	11,100	FO6/gas	Op	213.0	218.0	57.0%	1,039,984	58,075	11,543.8	IGTS	Southern CT (EE)	54,000	0	0
New Haven, CT	NRG Power	Devon 11-14	ST	Peak	13,000	FO2/gas	Op	123.4	160.8		0	50,173		AGT	Southern CT (EE)	0	0	50,173
Middletown, CT	NRG Power	Middletown 2 & 3	ST	Intermediate	10,000	FO6/gas	Op	352.0	365.0		0	87,600		AGT	Yankee Gas	82,500	0	0
New London, CT	NRG Power	Montville 5	ST	Intermediate	10,000	FO6/gas	Op	81.0	82.0	5.0%	35,771	19,680	357.7	AGT	Yankee Gas	0		19,680
Bridgeport, CT	Duke	Bridgeport II	CC	Base	7,000	Gas	Op	447.8	527.1	54.0%	2,273,499	88,556		IGTS	Southern CT (EE)	0	0	94,000
Milford, CT	PDC/El Paso	PDC Milford	CC	Base	7,000	Gas	Op	503.0	546.0	75.0%	3,421,584	91,728		IGTS	Southern CT (EE)	35,000	18,000	35,000
Merriden, CT	PDC/El Paso (PA w/ NRG)	Merriden	CC	Base	7,000	Gas	UC	503.0	546.0	75.0%		91,728		AGT	Yankee Gas			
Killingly, CT	PG&E	Lake Road	CC	Base	7,000	Gas	Op	690.9	797.8	75.0%		134,027		AGT	Yankee Gas	32,835	0	113,165
Wallingford, CT	PPL	Wallingford Power	CT	Peak	13,000	Gas	Op	214.7	251.3	15.0%		78,409		AGT	Yankee Gas	15,000	0	37,000
								3,578.4	3,960.0			801,406				219,335	18,000	395,018
Co-gens																		
Hartford, CT	Energy Network	Flagg/Harford Hospital	CC	Intermediate	9,000	Gas	Op	8.9	10.2	74.8%	63,771	2,203	573.9	AGT	CT Gas (EE)	2,203	0	0
Hartford, CT	Capital District	Aetna Capital District	CC	Intermediate	9,000	Gas	Op	48.0	54.0	58.3%	305,813	11,673	2,752.3	AGT	CT Gas (EE)	3220	7430	0
Windsor Locks, CT		Dexter Corp	CC	Intermediate	9,000	Gas	Op	38.0	39.0	86.3%	292,319	8,424	2,630.9	AGT	Yankee Gas	8,424	0	0
Sprague, CT	Carol Starr	Sprague Paper Board	CC	Intermediate	9,000	Gas	Op	12.0	12.0			2,592			Yankee Gas	0	0	2,592
E. Harford, CT	UTC	Pratt & Whitney (UTC)	CC	Intermediate	9,000	Gas	Op	24.8	24.8	90.0%	205,000	5,357	1,845.0	AGT	CT Gas (EE)	0	0	5357
								131.7	140.0			30,249				233,182	25,430	402,967

Information Sources:

- State of Connecticut - Connecticut Siting Council
- ISO New England 2003 CELT report
- Tennessee Gas Pipeline Web Site
- Algonquin Gas Transmission Web site
- Individual Power plant web sites
- Conversations with representatives from interstate gas pipelines
- Conversations representatives from LDCs



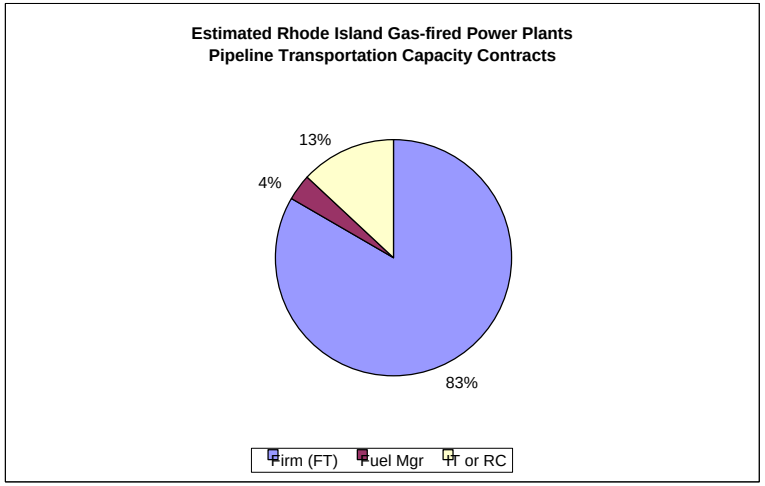
Appendix C - Rhode Island

Both Existing Gas Fired Generation and New Merchant Plants

Location	Company	Facility Name	Plant Type	Assumed Dispatch	Net Plant Heat Rate (Btu/kWh)	Fuel Type	Status	Summer Capacity (MW)	Winter Capacity (MW)	Annual Gas Capacity Factor	Annual Energy (MWh)	Peak-Day Pipeline MDQ (Dth/d)	Annual Gas Use (MMcf)	Pipeline Service	LDC Territory	Interstate Pipeline Capacity Contracts: Firm (FT) (Dth/d)	Fuel Mgr (Dth/d)	IT or RC (Dth/d)
Rhode Island																		
Providence, RI	US Gen	Manchester 9-11	CC	Base	8,500	FO2/gas	Op	421.4	490.4	75.0%	2,956,249	100,050	26,526.4	AGT via LDC	New England Gas	95,455	0	0
Burrillville, RI	TransCanada	Ocean State 1	CC	Intermediate	8,500	Gas	Op	272.0	318.0	76.3%	1,945,211	64,872	15,140.5	TGP	New England Gas	50,000	0	0
Burrillville, RI	TransCanada	Ocean State 2	CC	Intermediate	8,500	Gas	Op	275.0	323.0	76.3%	1,970,792	65,892	15,140.5	TGP	New England Gas	50,000	0	0
Pawtucket, RI	El Paso/NEP	Pawtucket Power	Cogen	Intermediate	8,500	Gas	Op	63.1	66.5	52.1%	294,418	13,556	2,431.5	TGP	New England Gas	0	12,695	0
Tiverton, RI	Calpine	Tiverton	CC	Base	7,800	Gas	Op	244.8	279.5	75.0%	1,702,438	52,313		AGT	New England Gas	46,000	0	0
Johnston, RI	FPL	Risep	CC	Base	7,000	Gas	Op	487.0	525.0	75.0%		88,200		TGP	New England Gas	45,000		45,000
								1763.3	2002.3		8,869,107	384,883				286,455	12,695	45,000

Information Sources:

- State of Rhode Island - Department of Environmental Services
- ISO New England 2003 CELT report
- Tennessee Gas Pipeline Web Site
- Algonquin Gas Transmission Web site
- Individual Power plant web sites
- Conversations with representatives from LDC
- Conversations with representatives from gas pipelines
- Conversations with representatives from power plants



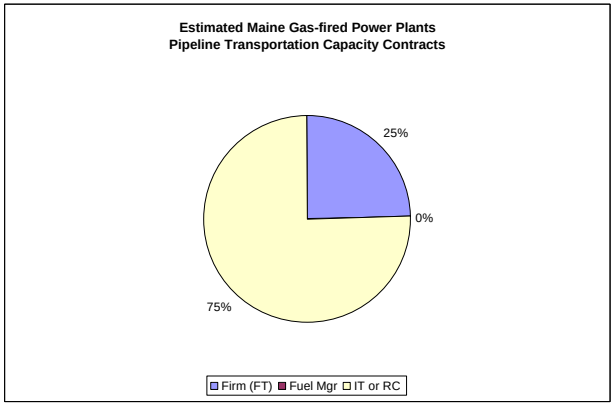
Appendix D - Maine

Both Existing Gas Fired Generation and New Merchant Plants

	Location	Company	Facility Name	Plant Type	Assumed Dispatch	Net Plant Heat Rate (Btu/kWh)	Fuel Type	Status	Maine Air Permit Information: Max Design Gas Consumption (Dth/d)	Maine Air Permit Information: Nominal Rating (MW)	ISO NE Information: Summer Capacity (MW)	ISO NE Information: Winter Capacity (MW)	Annual Gas Capacity Factor	Annual Energy (MWh)	Peak-Day Pipeline MDQ (Dth/d)	Interstate Pipeline Service	LDC Territory	Interstate Pipeline Capacity Contracts: Firm (FT) (Dth/d)	Interstate Pipeline Capacity Contracts: Fuel Mgr (Dth/d)	Interstate Pipeline Capacity Contracts: IT or RC (Dth/d)
Maine																				
	Veazie, ME	Duke	Maine Independence	CC	Base	7000	Gas	Op	92,976	520	493.7	543.7	75.0%	3,379,640	91,345	M&NE	None	0	0	91,345
	Bucksport, ME	HQ	Bucksport Energy	CC	Base	7000	Gas	Op	47,112	175	164.8	193.1	75.0%	1,159,583	32,446	M&NE	None	0	0	32,446
	Jay, ME	Calpine	Androscoggin Energy	CC	Base	7000	Gas	Op	23,496	150	127.9	155.6	75.0%	915,592	26,141	PNGTS	None	29,000	0	7,000
	Rumford, ME	Calpine	Rumford Power	CC	Base	7000	Gas	Op	46,805	265	244.9	269.8	75.0%	1,676,689	45,318	PNGTS	None	44,000	0	0
	Westbrook, ME	Calpine	Westbrook Power	CC	Base	7000	Gas	Op	85,176	528	511.6	551.2	75.0%	3,468,664	92,600	M&NE	Northern Utilities	0	0	92,600
											1542.88	1713.39		10,600,168	287,850			73,000	0	223,391

Information Sources:

- State of Maine - Department of Environmental Protection
- ISO New England 2003 CELT report
- Portland Natural Gas Transmission System
- Maritimes and Northeast Pipeline
- Individual web sites of the power plants
- Conversations with representatives from interstate gas pipelines
- Conversations representatives from power plants



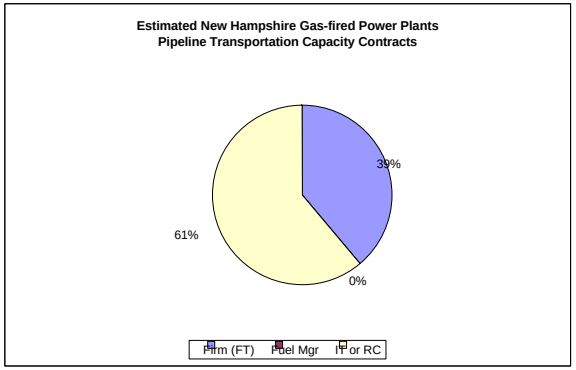
Appendix E - New Hampshire

Both Existing Gas Fired Generation and New Merchant Plants

Location	Company	Facility Name	Plant Type	Assumed Dispatch	Net Plant Heat Rate (Btu/kWh)	Fuel Type	Status	Air Permit Information: Max Design Gas Consumption (Dth/d)	Air Permit Information: Nominal Rating (MW)	ISO NE Information: Summer Capacity (MW)	ISO NE Information: Winter Capacity (MW)	Annual Gas Capacity Factor	Annual Energy (MWh)	Peak-Day Pipeline MDQ (Dth/d)	Annual Gas Use (MMcf)	Pipeline Service	LDC Territory	Interstate Pipeline Capacity Contracts: Firm (FT) (Dth/d)	Interstate Pipeline Capacity Contracts: Fuel Mgr (Dth/d)	Interstate Pipeline Capacity Contracts: IT or RC (Dth/d)
New Hampshire																				
Newington, NH	PSNH	Schiller Jet	JE	Peaking	16,200	FO6/gas	Op	-	-	17.0	18.0	1.0%	1,525	6,998	29	M&NE	Northern Utilities	0	0	6,998
Newington, NH	PSNH	Newington 1	ST	Intermediate	11,000	FO6/gas	Op	-	-	406.0	406.0	0.5%	17,783	107,184	196	M&NE	Northern Utilities	0	0	107,184
Newington, NH	ConEd/SCS Energy	SEI Newington	CC	Base	7000	Gas/oil	Op	87,876	525	528.5	542.6	75.0%	3,510,496	91,162	24,956	M&NE	Northern Utilities	0	0	90,000
Londonderry, NH	AES	AES Londonderry	CC	Base	7000	Gas/oil	Op	136,752	720	730.0	787.0	75.0%	4,951,026	132,216	36,194	TGP via LDC	Energy North (KeySpan)	130,000	0	0
										1,681.5	1,753.6		8,480,831	337,560				130,000	0	204,182

Information Sources:

- State of New Hampshire - Department of Environmental Services, Site Evaluation Committee
- ISO New England 2003 CELT report
- Tennessee Gas Pipeline
- Maritimes and Northeast Pipeline
- Individual Power plant web sites
- Conversations with representatives from interstate gas pipelines
- Conversations representatives from power plants



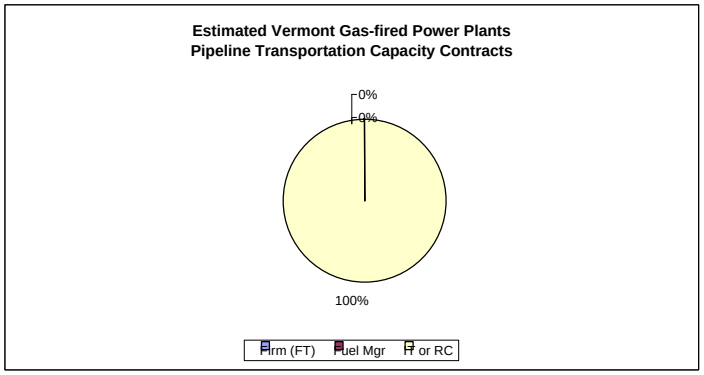
Appendix F - Vermont

Both Existing Gas Fired Generation and New Merchant Plants

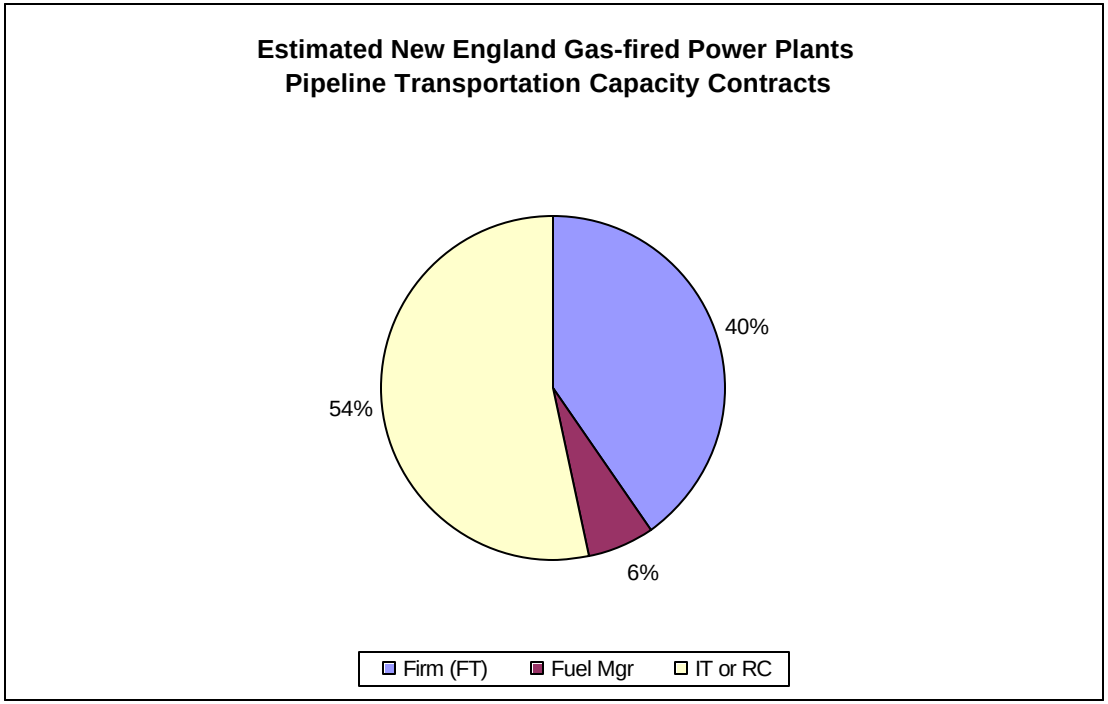
	Location	Company	Facility Name	Plant Type	Assumed Dispatch	Net Plant Heat Rate (Btu/kWh)	Fuel Type	Status	Summer Capacity (MW)	Winter Capacity (MW)	Annual Gas Capacity Factor	Annual Energy (MWh)	Peak-Day Pipeline MDQ (Dth/d)	Annual Gas Use (MMcf)	Pipeline Service	LDC Territory	Interstate Pipeline Capacity Contracts		
																	Firm (FT) (Dth/d)	Fuel Mgr (Dth/d)	IT or RC (Dth/d)
Vermont																			
	Chittendon, VT	VEPC	J.C. McNeil 1	ST	Intermediate	10,000	wood/gas/oil	Op	52.0	53.0	1.0%	4,591	12,720	38.6	Vermont Gas	Vermont Gas	0	0	12,720

Information Sources:

State of Vermont - Department of Environmental Services
ISO New England 2003 CELT report
Vermont Gas Pipelines
Individual Power plant web sites



	Interstate Pipeline Capacity Contracts		
	Firm (FT) (Dth/d)	Fuel Mgr (Dth/d)	IT or RC (Dth/d)
Maine	73,000	0	223,391
NH	130,000	0	204,182
Vermont	0	0	12,720
RI	286,455	12,695	45,000
Mass	579,710	165,000	839,413
CT	233,182	25,430	402,967
Total	1,302,347	203,125	1,727,672



APPENDIX D

EEA Assumptions for Long-term Outlook and Gas Consumption

EEA Assumptions for United States

Long-Term Outlook

- U.S. GDP bounces back to 2.8 percent growth per year in 2004
- Industry production at 2.0 percent growth per year in 2003 and 2.8 percent growth per year thereafter.
- Coal prices rise 1 percent per year nominally (decreases in real terms)
- RACC declines about $23/bbl by the end of 2004, growing at 2.0 percent per year (nominal) thereafter.
- LNG imports to the U.S. grow to about 2.4 Tcf by 2010
- Adding power-generation capacity according to near-term development plans and to satisfy 1.9 percent growth per year in electricity demand after 2005.
- Monthly oil-gas switchibility of new gas-fired power capacity limited to 8 percent in the near-term, 2 percent by 2010.
- Monthly combined cycle utilization capped at 90 percent.
- Coal-fired capacity utilization grows from 70 percent today to 74 percent in 2010.
- Marginal fossil unit heat rats improve by 9 percent through 2010 and slightly thereafter.
- Nuclear utilization continues at today's levels.
- No hydro generation capacity retirements.
- Pipeline and storage capacity added according to near-term development plans. In the long run, capacity added when economically justified.
- Regional supply assumptions reflect EEA's most likely view of resource base and development activity.

Gas Consumption

- U.S. gas consumption grows by about 1.5 percent per year throughout the projection.
- Future growth is sustained by "new" gas supplies from Alaska, the Mackenzie Delta, the deep Gulf of Mexico, Eastern Canada Offshore, and the Rocky Mountains, with growing reliance on LNG imports.
- Gas consumed in electric generation grows by 2.8 TCF (or by 5.4 percent per year) from 1999 to 2010.
- Gas consumption in the industrial sector cycles around 2001/02 levels throughout the projection. Reduced output in energy intensive industries and relatively high gas prices limit growth in this sector.
- In the long run, all regions exhibit significant growth in gas consumption, except the Gulf Shelf where lease and plant gas declines as production declines.
- Consumption grows most in regions dominated by power generation (e.g. Florida and Southwest).