Natural Gas Assessment

New York State Energy Plan 2009

December 2009

1 Overview

This Assessment describes the workings of the natural gas market in New York and the northeast region, discusses current use and projected need for natural gas and analyzes the findings of the modeling effort undertaken for the 2009 Plan. Since the regional natural gas market is dependent on the national gas market, the Assessment describes aspects of the national markets for natural gas that are considered most likely to have an impact on New York or the northeastern U.S. gas markets over the planning horizon.

Adequate supplies and pipeline capacity are needed to meet natural gas demand. Overall, natural gas supplies are expected to remain adequate to meet projected demand, both nationally and for New York. However, adequate pipeline delivery capacity is critical to ensure that available gas supplies can be provided to the markets that require them. In order to assess the adequacy of the natural gas pipeline delivery system serving New York, the combined gas requirements of the State's residential, commercial, industrial and electric generation customers were considered together and compared to currently available pipeline delivery capacity at peak periods. This effort was accomplished by modeling New York's natural gas and electric systems. The modeling results of a Reference Case and four scenarios were examined: retirement of the Indian Point nuclear power plant with replacement of the plant with gas-fired generation, re-powering existing downstate residual oil-fired units with gas-fired facilities, a much colder than normal winter, and a combination of the previous three scenarios. All scenarios resulted in a certain level of unmet natural gas demand in 2018. Additional electric system modeling conducted to assess the impacts from this unmet demand indicates that some electric generator demand for natural gas will not be served due to the lack of natural gas delivery capacity. Additional analyses are being conducted to determine the significance of this unserved load for reliably meeting electric customer requirements.

2 New York State Natural Gas Market

New York currently uses approximately 1,200 billion cubic feet of natural gas per year, making it the fourth largest gas consuming state in the nation. The breakdown of this gas consumption by sector is residential 393 billion cubic feet (33 percent), commercial and industrial 375 billion cubic feet (32 percent), and electric generation 404 billion cubic feet (34 percent).[1] Table 1 summarizes commonly used measurements for natural gas.

Table 1. Common Units for Natural Gas

Common Volume Measurements for Natural Gas
1 Cubic Foot (cf)
Thousand Cubic Feet (Mcf)
Common Heat Content Measurements for Natural Gas
1 Therm (Th) = 100,000 Btu
1 Dekatherm (Dt) = 1,000,000 Btu = 1 MMBtu
1 MMBtu = 1 Dt = approximately 1 Mcf

The State has approximately 4.7 million natural gas customers served by eleven local gas distribution companies (LDCs).[2] These LDCs are regulated by the Public Service Commission (PSC). Figure 1 illustrates the service areas of the New York LDCs.

The downstate market (geographically: Long Island, New York City, Westchester, Orange and Rockland Counties) is served by National Grid (formerly KeySpan Energy Delivery of New York City and KeySpan Energy Delivery of Long Island) and Consolidated Edison Company of New York/Orange & Rockland Utilities, Inc. (Con Edison/O&R). These companies depend on common interstate pipeline companies,[3] which connect either directly to production areas in the Gulf Coast region, to Canada, or to major storage areas in the northeast.

The upstate market is served by Central Hudson Gas & Electric, Corning Natural Gas, National Fuel Gas Distribution Corporation, National Grid Upstate, New York State Electric & Gas Corporation, Rochester

[1] Other uses, i.e., pipeline and distribution use and vehicle fuel, account for roughly 15 billion cubic feet of demand.

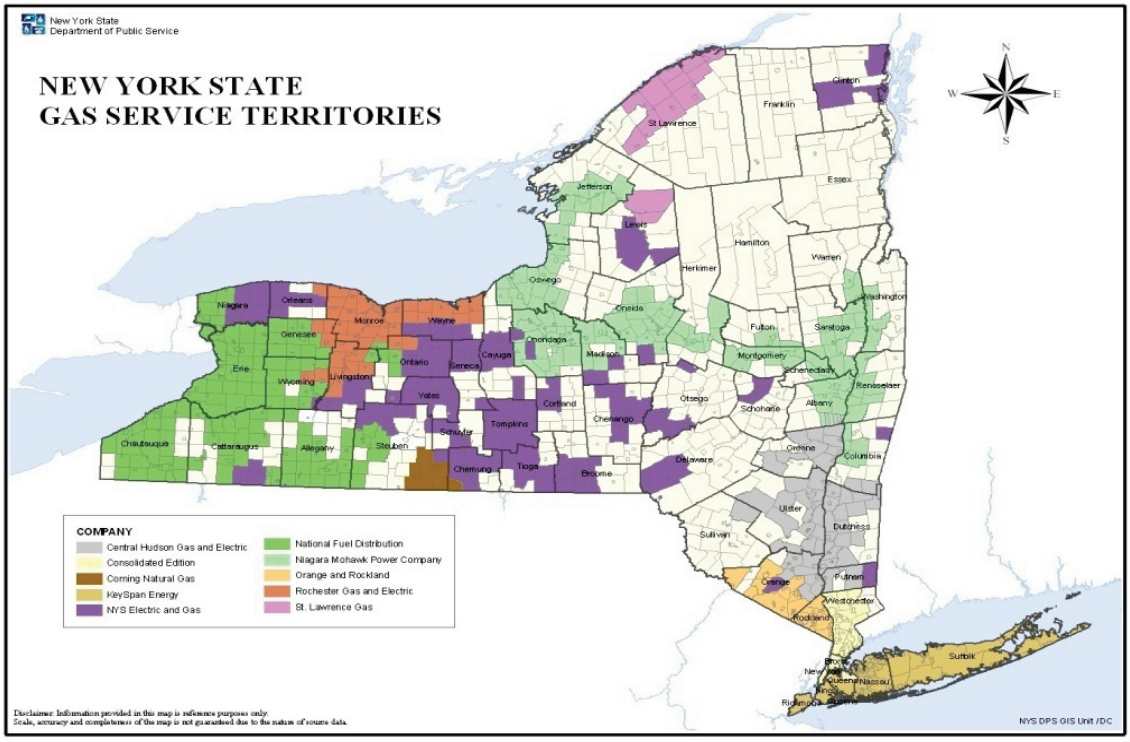
[2] The breakdown of customers by sector is 4.3 million residential customers and 0.4 million commercial, industrial, and electric generation customers.

[3] Algonquin Gas Transmission (Algonquin), Iroquois Gas Transmission System (IGTS), TransCanada Pipeline Limited (TCPL), Tennessee Gas Pipeline Co. (Tennessee), Texas Eastern Transmission LP (Texas Eastern), Millennium Pipeline Company LLC (Millennium) and Transcontinental Gas Pipeline Corp (TRANSCO).

Gas and Electric Corporation, and St. Lawrence Gas. Most of the LDCs serving the upstate market depend on a common set of interstate pipeline companies.[4]

The LDC natural gas franchise territories branch out from the more densely populated areas of New York. There are many rural areas in the State that do not have natural gas service because it is not economically practical to extend gas mains into areas with limited potential natural gas load. In order to expand service into new areas, an LDC needs to demonstrate that it can achieve a reasonable return on the cost of installing the expansion facilities.[5] In situations where expansion of natural gas facilities into new areas is not economically viable, it may be possible to receive contributions towards the costs of the expansion facilities from potential customers, interested municipalities in the region, and State economic development funds.[6]

Figure 1. New York State Gas Service Territories



Interstate pipelines provide a transportation service, moving gas from producing and/or storage areas, for their customers such as gas utilities and electric generators. The interstate pipelines serving the northeast are illustrated in Figure 2. Interstate pipeline companies do not sell the gas commodity; customers, such

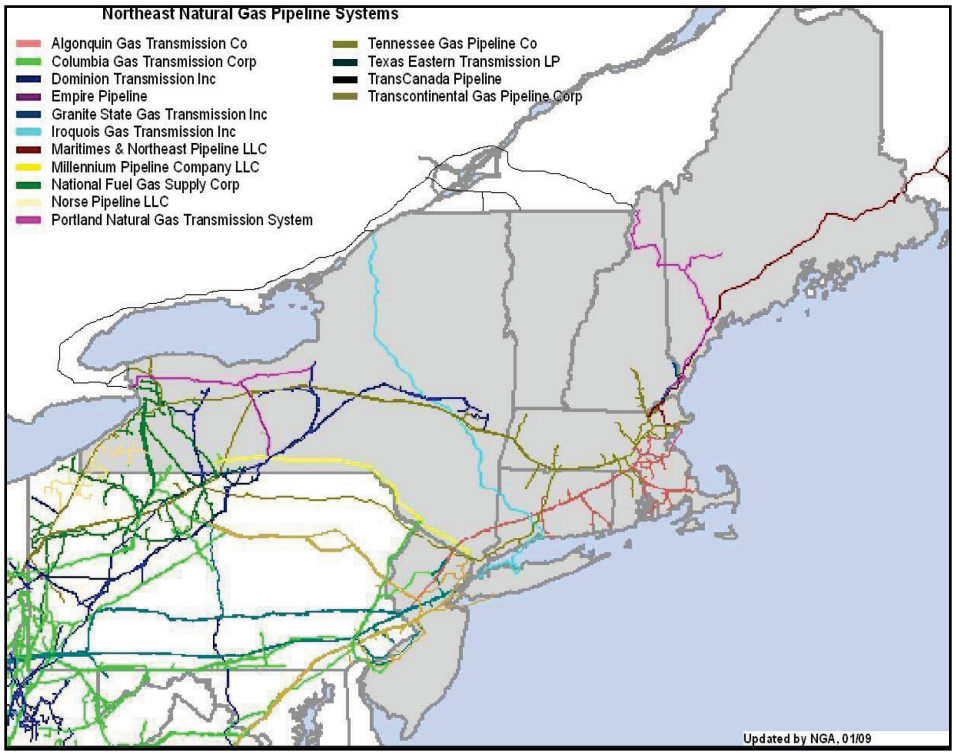
[4] Dominion Transmission Inc. (Dominion), Columbia Gas Transmission Corp. (Columbia), Empire State Pipeline Co. (Empire), Iroquois Gas Transmission System (IGTS), National Fuel Gas Supply Corporation (NFGS), Millennium Pipeline LLC (Millennium) and TransCanada Pipeline Limited (TCPL).

[5] PSC. Case 89-G-078. *Statement of Policy Regarding Rate Treatment to be Afforded the Expansion of Gas Service into New Franchise Areas*. Issued and Effective December 11, 1989.

[6] St. Lawrence Gas Company is considering a pipeline expansion from its existing facilities in St. Lawrence County to the Village of Chateaugay in Franklin County. Since the cost of the project cannot be supported by new customer revenues alone, potential additional dollars are being sought through the counties, municipalities, and State economic development funds.

as the LDCs, purchase the natural gas from gas producers and gas marketers. The interstate pipelines are regulated by the Federal Energy Regulatory Commission (FERC).

Figure 2. Northeast Natural Gas Pipeline Systems



Natural gas storage plays a significant role in meeting the State's weather sensitive gas needs. LDCs access interstate pipeline and independently owned storage facilities located at different points along the interstate pipeline systems in the natural gas production and market areas. Generally, the regulation of existing storage facilities and certification of new facilities fall under FERC jurisdiction.

LDCs deliver natural gas to their customers on either a firm or interruptible basis.[7] As explained below, customers may also choose to purchase the commodity from the LDC or from another provider. Firm deliveries are generally provided to residential and small commercial and industrial customers that do not have alternative fuel burning capability. Interruptible delivery service is not guaranteed and is used by larger customers, e.g., some apartment buildings, commercial and industrial customers that have alternate fuel burning capability. Electric generators generally depend on interruptible delivery services whether or not they have dual fuel capability.[8]

All customers have the right to purchase natural gas from either the LDC or an Energy Service Company (ESCO). When customers opt to purchase gas supplies from the LDC, they are referred to as "sales

[7] The same is true for interstate pipeline companies.

[8] For reference, a residential customer in New York uses between 100 and 140 Dt per year, and about 1 Dt on a peak day. In contrast, a 350 MW combined cycle electric generating plant uses about 54,000 Dt per day, assuming an 100 percent capacity factor, and about 12,000,000 Dt per year, assuming a 60 percent annual capacity factor.

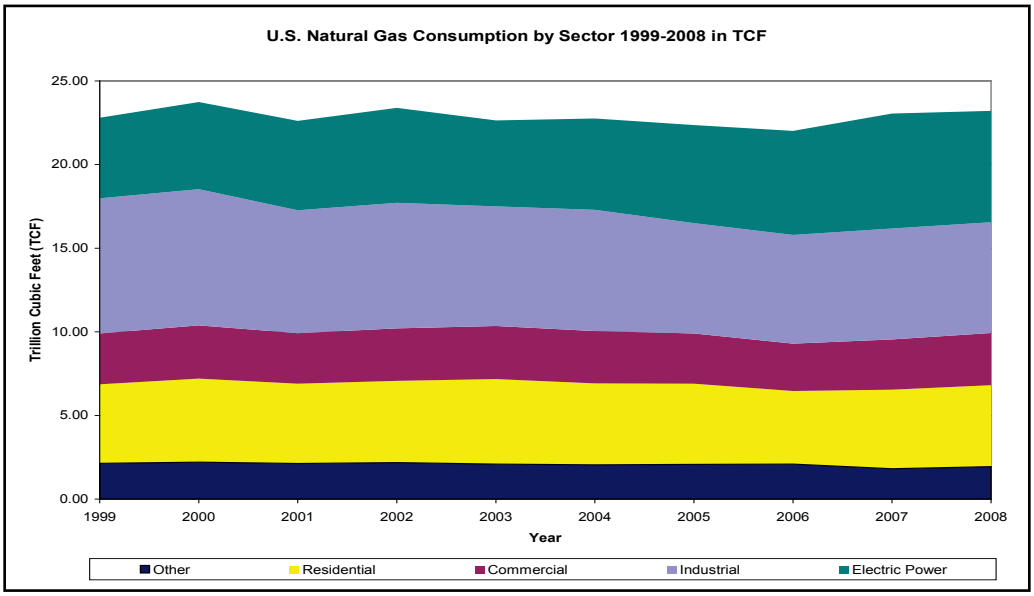
customers." Those who purchase the commodity from an ESCO are "transportation customers." In this case, the LDC is simply providing the delivery service. Therefore, there are four possible combinations of delivery service and commodity service options: firm or interruptible utility provided gas, and firm or interruptible delivery service with gas provided by third parties. Approximately 14 percent of residential customers purchase gas from ESCOs, as do 29 percent of small commercial and industrial customers, 41 percent of larger industrial customers, and virtually all electricity generators. LDC rates have been unbundled into separate delivery and commodity charges to facilitate customer choice and competition among commodity suppliers. Natural gas supply purchased by LDCs is passed on to their "sales" customers at cost, without any markup or profit.

3 Natural Gas Demand, Supply and Price

3.1 United States Demand

Natural gas consumption comprises about 23 percent of the total energy consumption in the United States. Natural gas is used for many purposes: home space and water heating, cooking, commercial and industrial space heating, commercial and industrial processes, as a raw material for the manufacture of fertilizer, plastics, and petrochemicals, as vehicle fuel, and for electric generation. Over 50 percent of the homes in the United States use natural gas as the primary heating fuel. In 2008, U.S. natural gas consumption totaled about 23.2 trillion cubic feet, nearly matching the peak consumption of 23.3 trillion cubic feet reached in 2000. Figure 3 presents U.S. historical natural gas demand by sector.

Figure 3. U.S. Natural Gas Consumption by Sector, 1999 to 2008 (TCF)



Source: EIA. *Natural Gas Consumption by End Use*. 2009. http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

Nationally, the electric generation sector consumed about 6.7 trillion cubic feet, accounting for about 29 percent of total U.S. natural gas demand for 2008. There has been significant growth in the use of natural gas for electric generation, and it has increased about 40 percent from 1999 levels.

The residential sector represents about 4.9 trillion cubic feet or 21 percent of total U.S. natural gas consumption for 2008. Residential natural gas demand is largely a function of heating demand and is highly weather sensitive. Over 70 percent of annual residential consumption occurs during the five winter months (November through March). The commercial sector represents about 3 trillion cubic feet or 13 percent of total U.S. natural gas consumption for 2008. Demand in the commercial sector has been relatively flat over the past ten years. The industrial sector accounted for approximately 6.7 trillion cubic

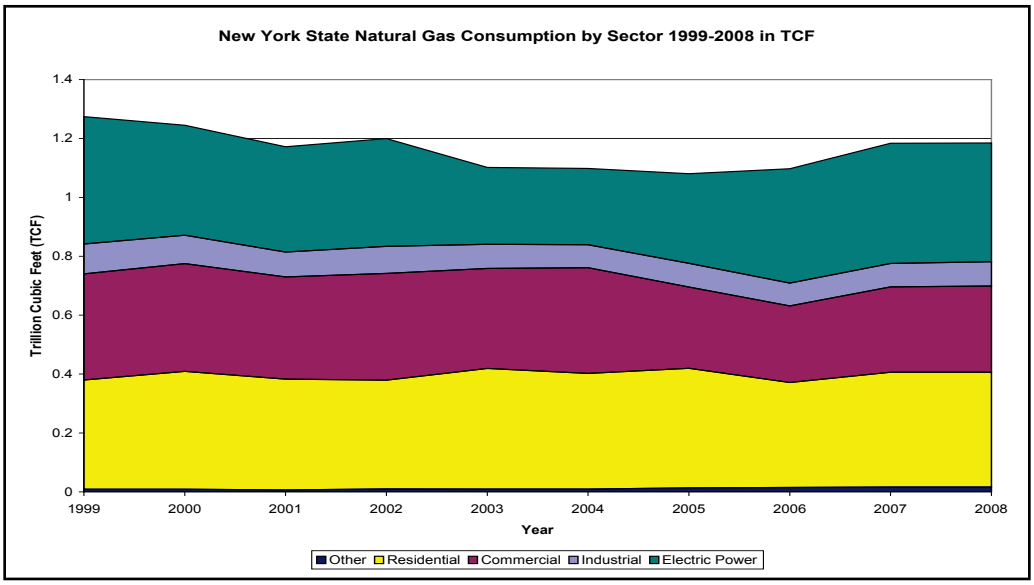
feet or 29 percent of total U.S. natural gas consumption in 2008. Demand in the industrial sector has decreased about 18 percent in the last decade. Other uses of natural gas, including natural gas drilling operations, pipeline delivery, and transportation, accounted for about 1.9 trillion cubic feet of total natural gas consumption in 2008.[9]

3.2 New York State Demand

New York is the fourth largest natural gas consuming state in the nation using about 1,200 billion cubic feet of natural gas per year, accounting for about five percent of U.S. demand.[10]

In 2008, New York's 4.3 million residential customers used about 393 billion cubic feet of natural gas or 33 percent of total statewide gas use. The State's 394,000 commercial customers used about 292 billion cubic feet or 25 percent of total natural gas use. Natural gas consumption in the residential and commercial sectors in New York represents a larger proportion of the total consumption than U.S. consumption for those sectors (21 and 13 percent, respectively). The primary use of natural gas in New York for residential and small commercial customers is for space heating and is highly weather sensitive. The State's natural gas market is winter peaking with over 70 percent of residential and 60 percent of commercial natural gas consumption occurring in the five winter months (November through March). Figure 4 presents New York historical natural gas demand by sector.

Figure 4. New York State Natural Gas Consumption by Sector



Source: EIA. *Natural Gas Consumption by End Use*. 2009. http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SNY_a.htm

[9] "Other" uses include: 1.3 trillion cubic feet of natural gas consumed in natural gas drilling and processing operations; 0.6 trillion cubic feet of consumption for pipeline and distribution use; and 0.03 trillion cubic feet for vehicle fuel.

[10] The 1,200 billion cubic feet includes: 393 billion cubic feet for the residential sector; 292 billion cubic feet for the commercial sector; 83 billion cubic feet for the industrial sector; 404 billion cubic feet for the electric generation sector; and roughly 15 billion cubic feet for other uses (pipeline and distribution use and vehicle fuel).

Although the total number of residential and commercial natural gas customers has increased, particularly in the downstate market area, overall statewide gas consumption has remained relatively flat for these sectors. This can be attributed to decreased customer usage due to conservation measures and increased efficiency for new natural gas appliances.[11]

Natural gas use in New York's industrial sector accounts for about 83 billion cubic feet or seven percent of total consumption in the state. Industrial consumption has decreased over the historic period due to both the industrial manufacturing capacity leaving the State and the continued movement away from energy intensive manufacturing processes towards less energy intensive processes. New York's industrial sector natural gas use is a much smaller percentage of overall State natural gas demand than that of the national industrial use to total national gas demand.

In 2008, the electric generation sector used about 404 billion cubic feet of natural gas or 34 percent of the State's total natural gas consumption. Consumption of natural gas for electric generation has fluctuated during the historic period 1999 through 2008. Much of this fluctuation can be attributed to economic fuel switching by older, dual-fuel oil/gas steam plants and peak demand weather related variances. Natural gas has become and will continue to be the fuel of choice for new and replacement generation in New York for the next several years due to its economic, operational and environmental advantages. In general, natural gas-fired generation plants have lower capital costs, are cleaner burning, are more energy-efficient, and have a greater degree of operational flexibility than other fossil fueled alternatives. Between 2001 and 2007, approximately 5,000 MW of new natural gas-fired combined cycle and combustion turbine capacity was built in New York. During the same period, about 3,000 MW of older dual-fuel (oil and natural gas) units were retired. About 31 percent of electricity generated in New York was fueled by natural gas in 2007.[12]

3.3 U.S. Natural Gas Supplies

Since natural gas is a national market, developments nationwide regarding gas supply are critical to the State. Below are highlights of noteworthy aspects of U.S. natural gas supply.

U.S. natural gas dry production totaled 20.5 trillion cubic feet in 2008, which was six percent higher than in 2007.[13] About 98 percent of the natural gas produced in the United States comes from production areas in the lower 48 States.[14]

As shown in Figure 5, the overall U.S. dry natural gas production has been relatively flat over much of the last ten years. However, in the past few years, there has been a significant shift in gas supplies from conventional or traditional supply areas and sources to unconventional or new supply areas and sources. U.S. natural gas production from traditional, more mature and accessible natural gas supply basins, has steadily declined. However, this decline has been offset by increased drilling activities and by increased

[11] Historic consumption has not been normalized for weather.

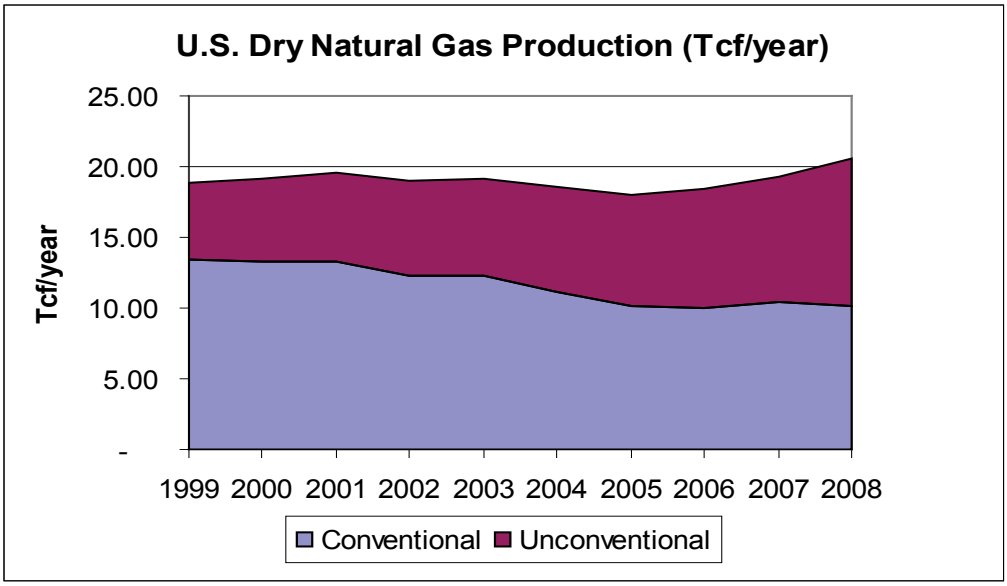
[12] 2007 was latest available EIA generation statistics by energy source. http://www.eia.doe.gov/cneaf/electricity/epa/generation_state.xls

[13] Natural gas produced from a well may contain liquid hydrocarbons which are removed at a natural gas processing plant and the gas is then considered "dry" and is sent to pipelines for delivery to customers.

[14] Natural gas production from Alaska currently accounts for about two percent of the total U.S. dry natural gas production.

production from new unconventional gas supply areas.[15] In 2008, natural gas production from new supply resources totaled about 10.4 trillion cubic feet (28.5 billion cubic feet per day) or about 51 percent of the total U.S. dry natural gas production.[16]

Figure 5. U.S. Dry Natural Gas Production



Source: EIA. *Natural Gas Production Data*. http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html

Higher natural gas prices resulted in increased drilling activity, particularly in areas that were formerly too expensive to develop. Higher prices have also contributed to the development of improved drilling and production technology that has allowed for the economic production of natural gas in deep water areas in the Gulf of Mexico and other large unconventional resources.

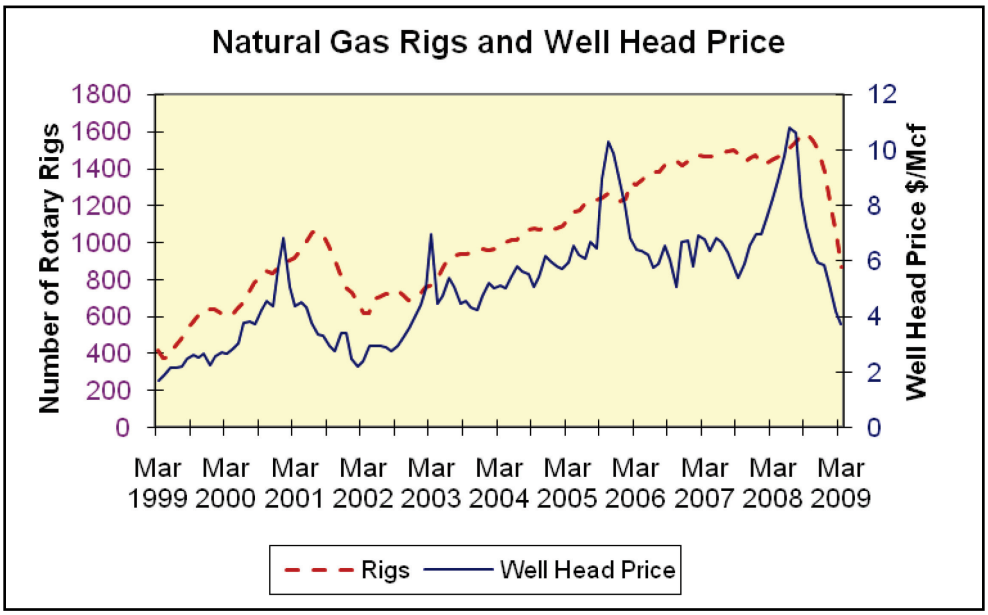
As shown in Figure 6, natural gas prices peaked in the summer of 2008 and are much lower now, which has resulted in a decline in drilling activity. Total natural gas drilling rigs in operation have declined by over 50 percent from the September 2008 peak. Although a corresponding decline in natural gas production has yet to appear in available data through March 2009, a decline in natural gas production is expected for the balance of 2009 and will continue into 2010. As the economy improves, the demand and supply balance tightens, and natural gas prices increase, production is expected to respond adequately. It is anticipated that natural gas prices and the number of operational drilling rigs need not return to 2008 levels for production to increase. Recent improvements in technology have reduced finding and

[15] Unconventional natural gas is a widely used industry term and generally refers to gas that is more difficult and more expensive to extract which usually involves new and developing production and well drilling technologies. Examples of what may currently be considered unconventional sources of natural gas are: deep natural gas – gas that is beyond conventional well drilling depths; tight sands natural gas; shale gas; coal bed methane gas; geopressurized zone gas; and methane hydrate gas. As production from current unconventional sources matures and the technology used is more fully developed the sources may evolve into being considered conventional.

[16] For 2008, unconventional natural gas production is based on forecast EIA data, since actual unconventional production data has not been finalized.

development costs, lowered well completion times, and enhanced well productivity, increasing the natural gas production potential from domestic sources.[17]

Figure 6. Natural Gas Rigs and Well Head Price



Source: EIA. *U.S. Natural Gas Rotary Rigs in Operation*. 2009. http://tonto.eia.doe.gov/dnav/pet/hist/e_ertrrg_xr0_nus_cm.htm

The increased production from unconventional resources is primarily from tight sands, coal-bed methane, and shale formations. The Rocky Mountain Region is the fastest growing region for tight sands natural gas production and the predominate region for coal-bed methane natural gas production in the United States. There are at least 21 shale gas basins located in over 20 states in the United States. Currently, the most prolific shale producing areas in the country are in the southeast region and include the Barnett Shale area in Texas, the Haynesville Shale in Texas and Louisiana, the Woodford Shale in Oklahoma and the Fayetteville Shale in Arkansas. In the Appalachian region, which extends into New York, the Marcellus Shale is expected to develop into a major natural gas production area.

Proven natural gas reserves for the United States totaled over 237 trillion cubic feet at the end of 2007, an increase of about 12 percent over 2006 levels.[18] The increase in reserves was the ninth year in a row that U.S. natural gas proven reserves have increased.

[17] EIA. *Short Term Energy Outlook*. 2009. http://eia.doe.gov/steo

[18] The latest EIA proven reserves data is for 2007. Proven natural gas reserves are those which analysis of geologic and engineering data demonstrates with reasonable certainty to be recoverable from known reservoirs, under existing economic and operating conditions. http://tonto.eia.doe.gov/dnav/ng/ng_enr_dry_dcu_NUS_a.htm

3.4 Natural Gas Storage

Natural gas storage is essential in meeting customer demands. The natural gas demand cycle is highly weather related, while supplies tend to be relatively stable. In order to ensure sufficient natural gas supplies to meet customer requirements, gas is injected into underground natural gas storage facilities during lower demand periods, typically April through October, and withdrawn from storage during the higher demand winter season. However, with the recent trend towards natural gas-fired electric generation, demand for natural gas during the summer months is now increasing. Natural gas storage also serves as insurance against unforeseen incidents, such as natural disasters (hurricanes), or other incidents that may affect the production or delivery of natural gas. There are approximately 400 natural gas storage facilities in the United States with a total working gas storage capacity of approximately 3.8 trillion cubic feet of natural gas.

Natural gas storage plays a significant role in meeting the State's weather sensitive gas needs. Approximately 35 to 40 percent of LDCs winter gas requirements are met through gas withdrawn from storage facilities, primarily depleted gas wells, located in Pennsylvania and western New York.[19] Generally, using storage facilities that are close to market is an economic way to meet seasonal demands. The alternative would be to build additional pipeline capacity all the way back to the gas production areas. In addition, some LDCs have peaking supplies such as liquefied natural gas or propane plants located within their service territories that are critical to meeting gas demand on peak winter days.

3.5 Imports of Natural Gas

In 2008, the United States imported approximately 4 trillion cubic feet of natural gas mainly from Canada along with some Liquefied Natural Gas (LNG) from a number of countries. Canada has been an important source of supply to meet U.S. natural gas requirements. Imports from Canada totaled about 3.6 trillion cubic feet [20] and account for about 90 percent of total imports and 15.5 percent of the total U.S. natural gas requirements.

Canada's production from its primary resource region, the Western Canadian Sedimentary Basin, has been relatively flat over the last ten years and is expected to decline over time. Moreover, Canada's natural gas consumption has been increasing for industrial and electric generation requirements. The combination of falling Canadian natural gas production and increasing demand is expected to result in decreased natural gas exports to the United States. Potential new Canadian unconventional production from shale formations may mitigate declines in production.

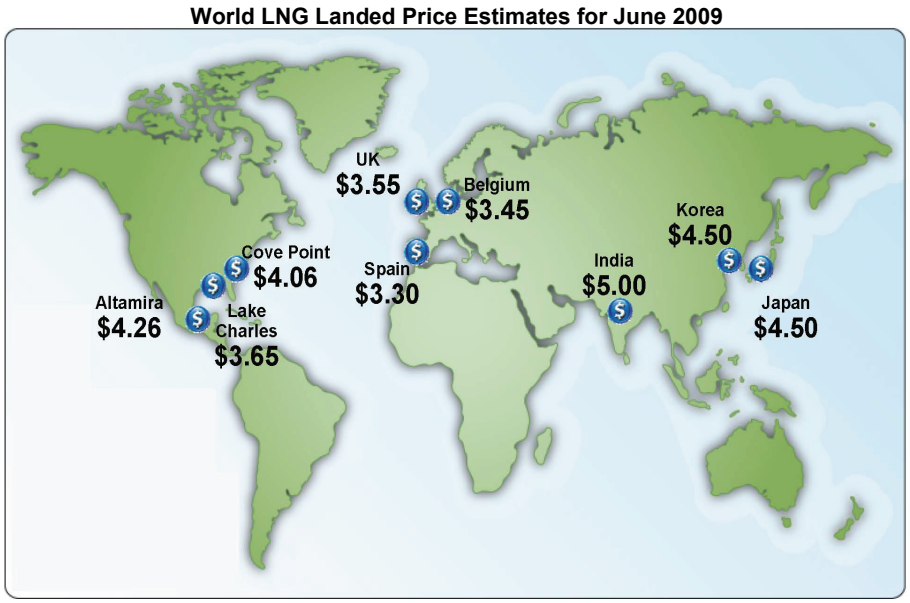
Another source of the U.S. natural gas supply is from imported LNG. In 2008, the U.S. received about 400 billion cubic feet (1.1 billion cubic feet per day) of LNG imports, a decrease from 2007 levels which were 771 billion cubic feet (2.11 billion cubic feet per day). The 2008 annual LNG imports represent about 1.7 percent of total U.S. natural gas requirements. The principal reasons for the decline in LNG deliveries were that 2008 LNG prices in the United States were lower than prices in other parts of the LNG-importing world and Asian and European demand for LNG was high. Figure 7 illustrates the LNG price variations around the world.

[19] The storage fields in Pennsylvania and New York have total working gas storage capacity of about 390 billion cubic feet and 100 billion cubic feet respectively.

[20] The United States exported 0.6 Tcf to Canada in 2008, therefore, U.S. net Canadian imports for 2007 were 3 Tcf.

Due to the world-wide economic recession, world LNG prices have fallen substantially, demand in Asia and Europe has fallen off. Meanwhile, additional world LNG supplies are scheduled to come on-line. It is expected that LNG deliveries to the United States in 2009 will increase over 2008 levels.

Figure 7. World LNG Landed Price Estimates for June 2009



Source: FERC Monthly LNG Market Report $/MMBtu

The U.S. domestic production in the lower 48 states has increased with the development of new supply basins, so the need for substantial increased volumes of imported LNG has diminished for the near term. However, if new domestic production is not able to more than offset declining older production and meet increasing demand, the United States will need incremental LNG imports.

Currently, there is more import and re-gasification capacity built in the world than there is liquefaction and export capability. Some experts predict that as liquefaction capacity is completed, world supply dynamics will change. The increased ability to liquefy and put the product out on the world market should put downward pressure on world prices, and U.S. prices should be able to better compete for LNG cargoes in the world market.

The United States has eight existing LNG receiving re-gasification terminals with a total capacity of about 11.54 billion cubic feet per day, which far exceeds the current LNG import levels.[21] In addition to the existing LNG terminals, there are 22 U.S. and four Canadian LNG import terminals that have received FERC, Maritimes Administration (MARAD/Coast Guard), and National Energy Board of Canada (NEB) certification approval. There are also an additional nine U.S. LNG terminal proposals that are in various stages of the FERC and MARAD certification processes.[22]

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[21] Existing LNG Terminals: DOMAC LNG, Everett, Mass.; Dominion Cove Point LNG, Cove Point, MD.; El Paso Southern LNG, Elba Island, GA; Southern Union Trunkline LNG, Lake Charles, LA; Gulf Gateway Energy Bridge, Gulf of Mexico; Northeast Gateway, Offshore Boston, MA; Cheniere Freeport LNG, Freeport, TX; and Sabine Pass Cheniere LNG, Sabine, LA.

[22] FERC. LNG data. http://www.ferc.gov/industries/lng.asp#skipnavsub

3.6 New York State Natural Gas Supply Resources

Over 95 percent of the natural gas supply required to meet the demands of New York natural gas customers is from natural gas supply production regions in other states, principally the Gulf Coast region, and Canada. The gas supply is brought to the New York market by interstate pipelines that move the gas from producing and storage areas for customers, such as LDCs and electric generators, who purchase the gas supplies from gas producers and marketers.

New York natural gas production supplies about five percent of the State's natural gas requirements. Production of natural gas from wells in New York dates back to 1821 when the first commercial natural gas well in the United States was drilled in Fredonia. Currently, there are about 6,700 active natural gas wells in the State. For the 2008 calendar year, total reported State natural gas production was 50.3 billion cubic feet, down nine percent from the 2006 record total of 55.2 billion cubic feet. These figures represent an increase of over 200 percent since 1998 (16.7 billion cubic feet).[23] The increase in New York natural gas production is driven by prolific wells in the deep (7,000 to 11,800 feet) Trenton-Black River formation in the Finger Lakes region. The largest area of production from this formation is in Chemung and Steuben counties. Annual production from the formation has grown from about 1.6 billion cubic feet in 1998 to over 40 billion cubic feet between 2005 and 2007, dropping to 34.8 billion cubic feet in 2008. Trenton-Black River production accounts for about 69 percent of the State's overall natural gas production from just 100 producing wells, with one well alone producing about 2 billion cubic feet.[24]

The Marcellus Shale formation is attracting attention as a significant new source of natural gas production in New York. The Marcellus Shale extends from Ohio through West Virginia and into Pennsylvania and New York. Estimated natural gas reserves for the Marcellus Shale formation are very significant and it is expected that the region will become a major natural gas production area in the United States. In New York, the Marcellus Shale is located in much of the Southern Tier stretching from Chautauqua and Erie counties in the west to the counties of Sullivan, Ulster, Greene and Albany in the east. While economically recoverable natural gas reserves for the entire extent of the Marcellus Shale are estimated to be up to 50 trillion cubic feet, it is not yet clear what fraction of that amount will be commercially recoverable in New York.[25]

Horizontal well completions combined with hydraulic fracturing will provide the best means for producing economic volumes of natural gas from the Marcellus Shale. While both horizontal drilling and hydraulic fracturing are not new to natural gas development in New York, there are environmental concerns with respect to the effects of fracturing on water supplies, and disposal and contamination issues related to the chemical composition of the fluids used in the fracturing process. New York has a well established regulatory program to oversee oil and gas drilling administered by the Department of Environmental Conservation (DEC). There are regulations governing the well permitting, drilling operations, and well site restoration when drilling is completed. To assess the potential environmental concerns related to the development of the Marcellus Shale formation in New York, the DEC is reviewing horizontal drilling and hydraulic fracturing in the context of a Supplemental Generic Environmental Impact Statement (GEIS), which is expected to be finalized in 2010.

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[23] DEC. *2007 Annual Oil and Gas Production Data*. 2008. http://www.dec.ny.gov/energy/36159.html

[24] DEC. *New York Oil, Gas and Mineral Resources*. 2007. http://www.dec.ny.gov/pubs/36033.html

[25] Geologists estimate that the entire Marcellus Shale formation contains between 168 and 516 Tcf of natural gas reserves and that roughly 10 percent of those reserves are economically recoverable: http://www.dec.ny.gov/energy/46288.html

The extraction of projected economically recoverable reserves from the Marcellus Shale presents a unique challenge with regard to the construction of the pipeline facilities necessary to tie this source into the network and bring the produced gas to market. In the course of developing a conventional source of natural gas, a company would drill a well and only if that well is successful, would it submit an Article VII application to the PSC to construct the associated pipeline. It has been suggested that this procedure may not be well suited for development of the Marcellus Shale. Some producers claim that the technique used to tap into the Marcellus requires that the gas be produced immediately once the well has been fractured and completed or the well may seal and cease to be productive. The Marcellus Shale formation has a high concentration of clay, which makes it susceptible to re-closing if the gas does not flow immediately. As a result, some producers contend that the pipeline must be certified, built, and ready to accept gas before knowing for certain that the well will be a success.

3.7 Natural Gas Prices

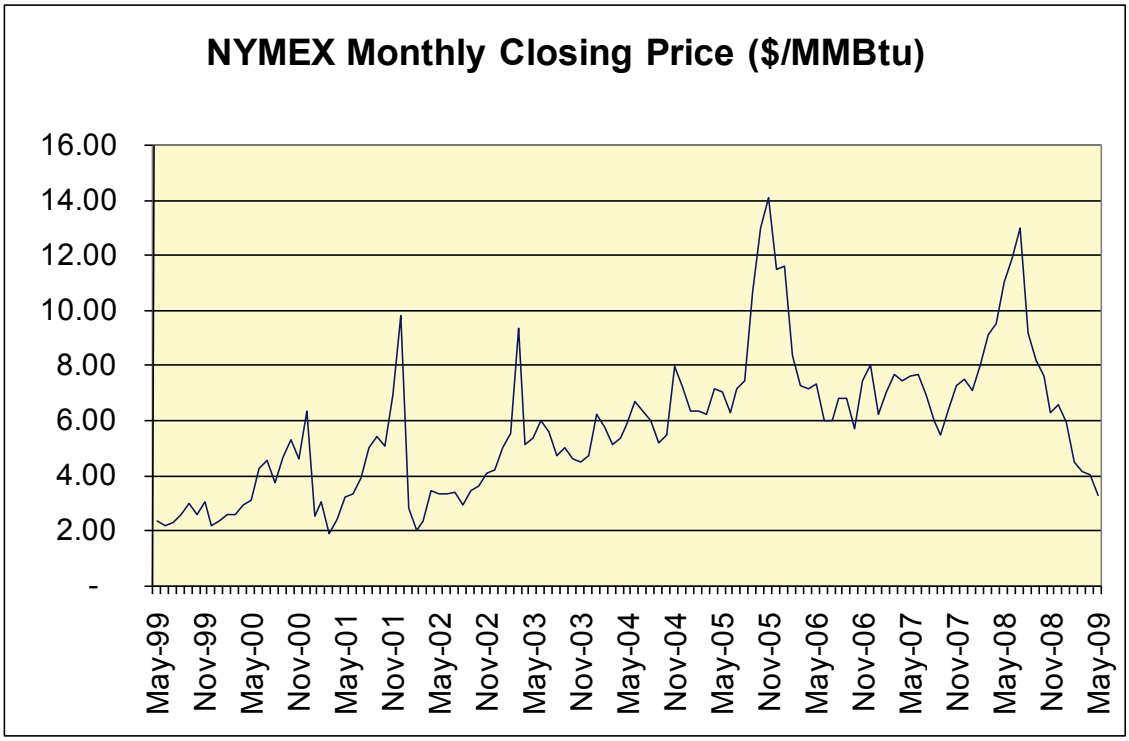
The natural gas market price paid by customers is composed of three major components: the wellhead price paid to the producer, interstate gas pipeline transportation costs, and the local distribution company's delivery charge.

As shown in Figure 8, natural gas commodity prices have shown an increasing trend with a high degree of volatility over the past 10 years. Natural gas commodity prices have ranged from approximately $2 per MMBtu in early 1999 to peaks as high as $12 to $14 per MMBtu in recent years.[26] The NYMEX gas commodity price in the third quarter of 2009 was in the $4 to $5 per MMBtu range. There are several interrelated reasons for these changes, including higher oil prices, increased nationwide gas demand and a general tightening in the national gas supply/ demand balance, hurricane seasonal damage to production facilities, and the increased participation by non-commercial entities in the natural gas financial market.[27]

[26] Based on New York Mercantile Exchange (NYMEX) data. Gas prices on the NYMEX are quoted for delivery at the Henry Hub. The Henry Hub is a major interconnection point, or transportation hub, on the U.S. natural gas pipeline system located in Louisiana, interconnecting with nine interstate and four intrastate pipelines. Price differentials, or basis, between the Henry Hub and city gate delivery points reflect pipeline transportation services.

[27] Natural gas is traded as the value of a commodity and natural gas prices are determined through the interaction of two types of markets for natural gas; the physical market, which involves the purchase and sale of physical quantities of natural gas; and the financial market, which involves the purchase and sale of derivatives and financial instruments in which the buyer and seller seldom take physical delivery of the natural gas.

Figure 8. NYMEX Monthly Closing Price



Source: NYMEX. *Monthly Closing Price*.

One of the most significant impacts to prices during the last 10 years was caused by hurricanes Katrina and Rita in 2005. As the storms made their way through the Gulf of Mexico, they damaged oil and gas production platforms, refineries, and processing plants which resulted in prices soaring to unprecedented levels ($14 per MMBtu during the month of November 2005).

Prior to Katrina and Rita, prices tended to follow a somewhat more predictable pattern with prices increasing in the winter when demand increased and dropping during the summer months when demand lessened. By the spring of 2006, prices were back down to the average levels of the period 2003 to 2005 (pre-Katrina) with the price for natural gas averaging approximately $7 per MMBtu.

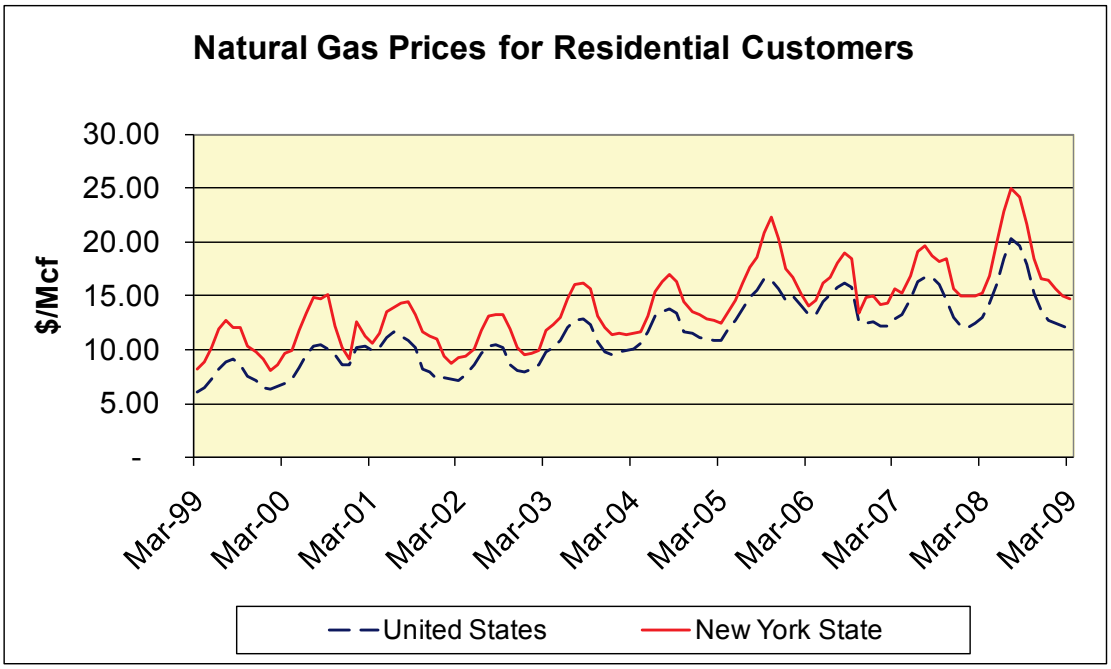
During the following winter of 2006/2007, gas prices did not display the typical heating season increases that had been experienced in 2003 and 2004. Instead, prices tended to remain fairly constant during the period, with a noticeable drop in prices during the summer of 2007. The fact that little to no hurricane activity in the Gulf of Mexico was experienced in 2006 and 2007 may have contributed to the relative stability in prices. The winter of 2007/2008, however, saw the start of a large increase in prices which reached a peak in July 2008 near $13 per MMBtu, which was a level never before experienced during any previous summer. Many factors could have contributed to this spike in a non-heating period which historically does not produce dramatic increases in prices, including record high world oil prices. Speculators in the natural gas financial market are also thought to have contributed to the spike in prices during this period.

Since the 2008 summer natural gas price peak, prices have steadily fallen to levels that have not been seen in close to six years. Several supply, demand and economic factors contributed to the decline in gas prices: high natural gas storage levels, increased onshore natural gas production, the general economic downturn and its negative impact on gas demand and prices, as well as the collapse of world oil prices.

The 2008 hurricane season was the most active since 2005 and hurricanes Gustav and Ike, while not as devastating as Rita and Katrina, caused significant damage to oil and gas production facilities in the Gulf region in September 2008. Despite the hurricane activity there was not a significant spike in natural gas prices during the fall of 2008 and the downward trend in prices continued into 2009 with prices appearing to stabilize in the $3 to $5 per MMBtu range.

Retail prices include the commodity cost of natural gas and the pipeline and LDC delivery charges. Since the commodity price makes up a significant portion of the customer's delivered price, retail prices have exhibited a similar pattern of growth and volatility. As shown in Figure 9, the average delivered price of natural gas to residential customers in New York was about $8.20 per MMBtu in January 1999, climbing to $24.50 per MMBtu in August 2008, and decreasing to about $15 per MMBtu in March 2009. New York average delivered price to customers is approximately $3.00 per MMBtu higher than the national average.

Figure 9. Natural Gas Prices for Residential Customers



Source: EIA. *Natural Gas Prices*. 2009. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

Because of the historically volatile nature of gas prices, the PSC expects LDCs to diversify the pricing of their gas purchases in order to ameliorate price volatility. The PSC issued a Gas Purchasing Policy Statement in 1998, which outlined the purchasing options that a diversified supply portfolio might include.[28] Among these options are a blend of short and long-term fixed price purchases, spot acquisitions, use of physical and financial hedges, and contracts that provide flexibility in the amount of gas taken. The policy is intended to mitigate the effect of price volatility on customers' bills. However, the policy also acknowledges that market price fluctuations cannot be predicted with great accuracy and therefore the weighted average price of a sufficiently diversified gas supply portfolio may turn out to be

[28] PSC. Case 97-G-0600. *Request for Gas Distribution Companies to Reduce Gas Cost Volatility and Provide for Alternate Gas Purchasing Mechanisms, Statement of Policy on Gas Purchasing Practices.* Issued April 28, 1998.

lower or higher than the prevailing market price. The PSC stated that excessive reliance on any one gas pricing mechanism or strategy does not appear to reflect the best management of the gas portfolio and any LDC without a diversified gas purchasing strategy will have to meet a heavy burden to demonstrate that its approach is reasonable.

4 Natural Gas System Modeling and Analysis

4.1 Analytic Approach

In order to assess the adequacy of the natural gas delivery system, the combined gas requirements of the electric generation and residential, commercial and industrial gas utility customers must be considered together and compared to available pipeline delivery capacity at peak periods. This is the analytical challenge that the Plan has addressed through modeling of New York's natural gas and electric systems.

The natural gas interstate transmission system is sized to supply fuel to customers with firm contracts whose natural gas needs peak in the winter. For the most part electric generators rely upon interruptible service, which entitles generators to utilize available capacity when it is not needed to serve customers with firm contracts. At present, the electric generation sector is increasingly reliant on natural gas for a number of reasons: it is cheaper than oil; it meets increasingly strict environmental requirements; and it requires no significant on-site fuel storage. The reliance of electric generation on natural gas, coupled with the reliance on interruptible services for the delivery of that gas, raises reliability concerns regarding the adequacy of the natural gas infrastructure to support electric generation requirements.

Generally, the peak need for natural gas for electric generation occurs in the summer, but some dual-fuel electric generators may require gas during peak winter months. However, during peak winter months customers with firm capacity contracts may require the entire available capacity leaving no pipeline capacity for electric generators and other interruptible customers. Many generators have dual-fuel capability allowing them to burn an alternate fuel, typically distillate fuel oil,[29] during times when natural gas supplies are limited.[30] As long as there are adequate units that are dual-fueled, and there is alternate fuel available and generators are permitted to use it, reliance on interruptible services represents an efficient utilization of assets. During times of peak gas system demands, electric reliability could be impaired if there is a lack of ability to burn alternate fuels, either because not enough units have alternate fuel ability, or if their alternate fuel is not available due to either supply or environment limitations.

This reliability concern could deepen as some of the older dual-fuel units are replaced with newer units fueled only with natural gas. Many of the older existing base load generation facilities, particularly in New York's downstate region, use natural gas with residual fuel oil as backup fuel. These plants typically have a large amount of residual oil storage capacity on-site, and are virtually not limited as to how much oil they can burn. Newer, gas-fired combined cycle generation facilities typically use distillate oil as an alternate fuel and have limited ability to burn such oil, typically limited to 720 hours or 30 days.[31] These plants have very limited oil storage capacity on-site, typically only enough for a few days. These newer gas units, however, benefit the gas system in that they use less gas per kilowatt-hour

[29] Distillate fuel oil includes No. 2 heating oil, kerosene, diesel fuel, and jet fuel.

[30] Generators without dual-fuel capability will not operate if they do not have firm contracts and gas supplies are not available.

[31] The air emission rules provide for new facilities to opt for different levels of oil burn. However, permits that would allow more oil burning require installation of more expensive equipment to reduce emission levels. The additional equipment that would be required to meet the emissions requirements adds cost to the facility, so new facilities generally opt for the permit that provides for the limited burning of oils as the lower cost alternative.

generated. This improved efficiency may assist in lowering the annual electric generation natural gas demand (TBtu), while the GWh generated by natural gas-fired units is projected to increase.

While a requirement that generators hold more gas pipeline on a firm basis would resolve the issue,[32] there would be a myriad of issues involved in accomplishing that, given the competitive structure of the generation market. Such issues as who would acquire the capacity, how much would be required, how would it be paid for, and how would it be made available to generators who needed it would need to be addressed. An important related issue is the availability of distillate oil in sufficient quantities to meet the demands of generators when natural gas deliveries are not available. This issue will be addressed further in both this Assessment and the Petroleum Assessment.

4.2 Model Scenarios

A combination of five different models was used to assess the adequacy of the natural gas delivery system to meet the needs of both the electric power and "core" natural gas markets.[33] The Integrated Planning Model (IPM) was used to determine the electric system growth and system dynamics at the national and regional levels, consistent with the Electricity Assessment. The output of IPM, which includes new generator data such as installation date, size, and fuel type, was used as input to the General Electric Multi-Area Production Simulation (MAPS) model. MAPS economically dispatches individual electric generators and the output contains generator specific information, including generator run time, fuel usage, and emissions. This results in detailed gas usage by generation unit, at all locations in the State. Three models were then used to assess the adequacy of the natural gas system: the Gas Market Model (GMM), the Gas Production Cost Model (GPCM), and the Regional Infrastructure Assessment Modeling System (RIAMS). GMM is a national network model that was used to determine the overall supply, demand, and prices of natural gas for each of the scenarios. GPCM was used to determine the utilization of New York- specific infrastructure and identify any potential bottlenecks on an annual basis. RIAMS was used to project daily and seasonal constraints on New York's natural gas delivery system.[34]

Using this suite of models, a Reference Case and four scenarios were examined: 1) retirement of the Indian Point nuclear units and replacing them with gas-fired generation; 2) re-powering existing downstate oil- fired units with gas-fired facilities; 3) much colder than normal weather conditions; and 4) combination of the other three scenarios.[35]

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[32] Historically, from a generator's perspective, committing to pay on a year round basis for firm pipeline capacity when the generator does not know when it will be dispatched, is generally not economically viable and may result in increasing retail electricity costs.

[33] These models were provided by ICF International (ICF), a consulting firm that has considerable experience modeling New York's power systems. ICF, under contract with NYSERDA and under the direction of NYSERDA and DPS, conducted studies using the models to evaluate the ability of the electric and gas systems to simultaneously meet their demands and to identify any potential problems that could adversely affect the reliability of the electric system over the planning period from 2009 to 2019. ICF developed the modeling databases by acquiring New York Independent System Operator (NYISO) data, historic gas usage provided by LDCs, and other proprietary information.

[34] RIAMS is an economic mathematical model, which is less granular than a traditional hydraulic model; it is a reasonable choice considering monetary and time constraints.

[35] The Reference Case and scenarios reflect the carbon policy developed under the Regional Greenhouse Gas Initiative (RGGI) and do not reflect a national carbon policy.

4.3 Key Assumptions

The modeling effort reflects the following key assumptions:

- U.S. GDP growth of 3.0 percent annually
- New York GDP growth of 2.8 percent annually
- Long-term Refiners Acquisition Cost of Crude Oil (RACC) of $65/bbl in 2008 dollars
- No U.S. carbon policy
- Normal weather based upon a 30-year average except for the much colder than normal weather scenario and the combination scenario
- The model's peak day analysis is based on average temperatures, which are about 95 percent of design day temperatures[36]
- Recently completed pipeline expansion projects, including the Millennium Pipeline and Empire Connector, and associated expansions on Algonquin and Iroquois, and the Transcontinental Leidy to Long Island project
- A recently completed storage project "Thomas Corners" in western New York
- Completion of the Maritimes and Northeast Phase 4 project in New England
- Completion of the Texas Eastern TIME II project in Pennsylvania and New Jersey
- Completion of the Spectra Steckman Ridge and Dominion Storage Factory projects in Pennsylvania

These key assumptions were used in all of the natural gas modeling scenarios presented below.

4.4 Reference Case: Gas Demand and Supply Projections

The results of the modeling are presented below. It is important to recognize that many assumptions go into such a modeling effort, and while the results provide a valuable tool for understanding the expected trends in the market, the accuracy of the results is limited to the strength of the assumptions. While every effort has been made to reflect the most accurate assumptions available, given the uncertainty surrounding market changes it is best when interpreting the results to err on the conservative side in order to ensure reliability. For example, while efforts to directly reduce gas demand through efficiency programs have been initiated in New York, electric efficiency efforts in this State may increase gas demand by encouraging conversion of certain electric appliances, e.g., water heaters, to natural gas. Therefore, a simple comparison of the models' numerical results, e.g., demand versus supply projections, needs to be tempered with an understanding of the underlying markets. Further, all of these analyses assume that all elements of the gas system, such as pipelines, compressors and production facilities are operating as designed. The vulnerability of the State from pipeline or compressor failures has not been assessed and would need to be examined as part of a separate contingency analysis.

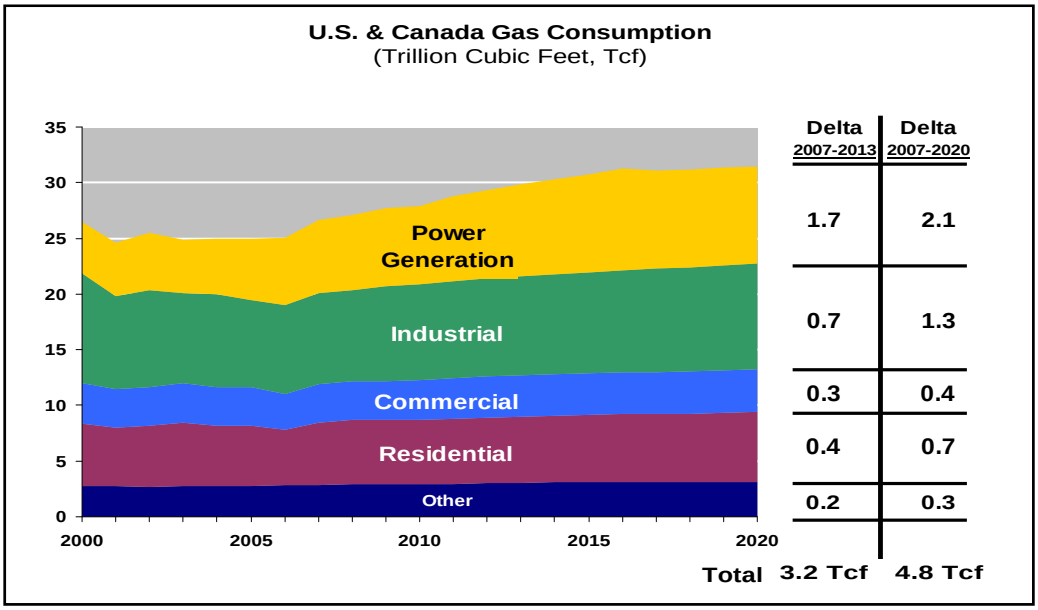
The projections of national and New York demand and supply for natural gas, as described below, result from the ICF International natural gas and electric system models.

[36] For this modeling effort, design day temperature is defined as temperatures 10 percent colder than normal. For this analysis, this equates to an average daily temperature in New York City of 5º F and in Buffalo an average daily temperature of -3º F.

4.5 U.S. Natural Gas Demand

The projections for the residential, commercial and industrial sectors show steady growth, but are moderated by demand side management (DSM), conservation and efficiency gains.[37] The U.S. natural gas demand for electric power generation is expected to increase by about 2.5 percent annually as both the electricity demand and the use of natural gas to fuel power plants increases. As shown in Figure 10, the U.S. power sector natural gas consumption is expected to increase by about 2.1 trillion cubic feet by 2020.

Figure 10. U.S. and Canada Gas Consumption



Source: ICF International. March 2009.

As the demand for electric generation capacity increases, natural gas is expected to continue to be an important fuel of choice for new electric generation facilities. Since 1998, natural gas-fired combined cycle and combustion turbine capacity grew by over 200,000 MW in the United States. Gas-fired plants have continued to be favored due to relatively low capital costs and low pollutant emissions.

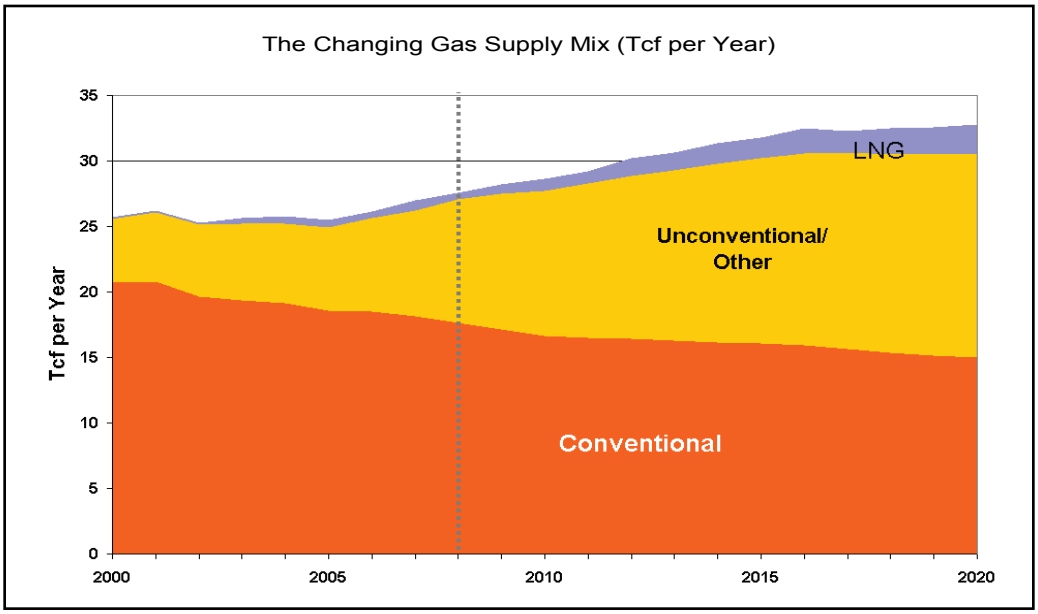
Currently, gas-fired electric generation makes up about 20 percent of the total U.S. electric generation capacity. In the next 10 years, it is projected that gas-fired electric generation will grow to about 26 percent of total U.S. generation. Natural gas will act as an important bridge fuel for the implementation of a carbon-limiting policy. The growth in gas-fired electric generation is expected to slow after 2015, as new advanced coal generation units, renewable capacity, and some new nuclear generation facilities enter the electric generation market.

[37] U.S. projected average annual demand growth rates are 0.9 percent for the residential sector; 0.9 percent for the commercial sector; and 1.0 percent for the industrial sector.

4.6 U.S. Gas Supply

North American gas supply is projected to increase over the forecast period in order to satisfy increased demand. As shown in Figure 11, dry natural gas production for the United States and Canada is expected to increase by about 30 percent from about 26.2 trillion cubic feet in 2007 to 30.6 trillion cubic feet in 2020. Declining production from conventional natural gas supply basins will be more than offset by increases in production from unconventional sources and increased LNG imports over the forecast period.

Figure 11. The Changing Gas Supply Mix



Source: ICF International. March 2009.

4.7 Lower 48 U.S. Production

Production from the Lower 48 States is projected to increase from about 19.2 trillion cubic feet in 2007 to 24.2 trillion cubic feet in 2020. The projected increase in Lower 48 production is attributed to increasing natural gas production in new supply sources[38] and deepwater Gulf of Mexico offshore regions. Projected growth in production from new supply sources and deepwater Gulf of Mexico are partially offset by projected declines in conventional existing production.

4.8 Alaskan Natural Gas Production

Alaskan gas production is gas produced in association with oil production on the Alaskan North Slope, and the majority of the gas currently produced is re-injected into the supply basin. Current annual Alaskan marketed gas production is about 420 billion cubic feet. The Alaskan Gas Pipeline is projected to be in-service starting in 2020, assuming that the project can obtain adequate financing, and will provide additional supplies to the Lower 48. The Alaskan Pipeline is projected to have an initial capacity of about

[38] New supply sources would include unconventional basins, such as tight sands, coalbed methane, and gas shale formations.

1.46 trillion cubic feet (4 billion cubic feet per day), and expanding in 2023 by another 0.7 trillion cubic feet (2 billion cubic feet per day).

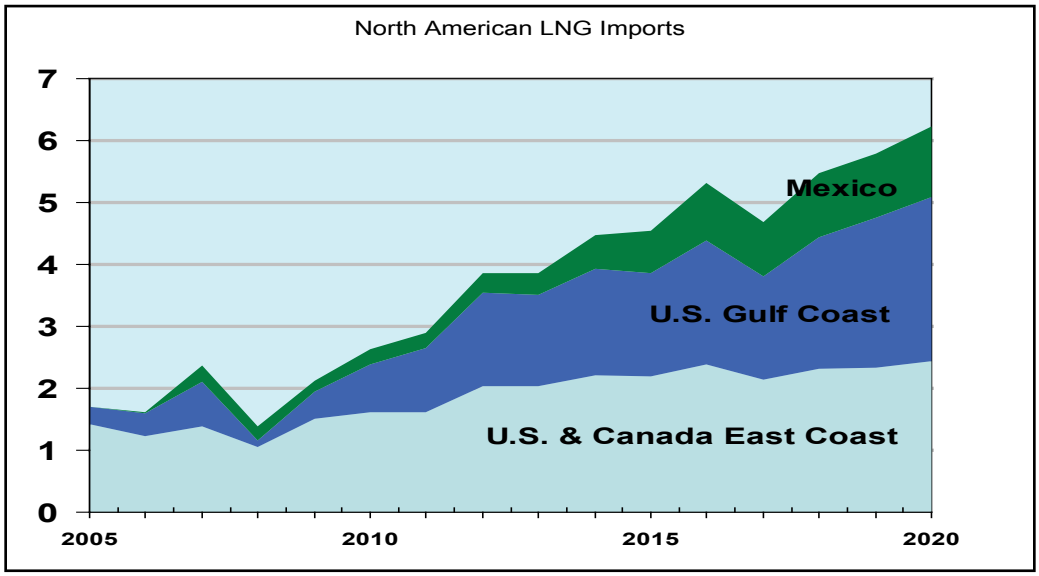
4.9 Canadian Supply

Canadian production is expected to decline by about 700 billion cubic feet (1.9 billion cubic feet per day) by 2020. The decline in production will be partially offset by increased LNG imports to Canada. Coupled with the projected decline in net Canadian supply is a projected increase in Canadian domestic demand particularly in the electric power generation and industrial sectors. As a result, it is expected that the amount of Canadian gas available to export to the United States will decline by about 1.5 trillion cubic feet (4.1 billion cubic feet per day) by 2020.

4.10 LNG

It is expected that LNG imports to North America will increase from current levels of 2.3 billion cubic feet per day in 2007 to 3.9 billion cubic feet per day by 2013, and 6.2 billion cubic feet per day by 2020, supplying about six percent of U.S. and Canadian gas needs by 2020 as shown in Figure 12. North American re-gasification capacity is expected to continue to exceed LNG deliveries. Utilization of North American re-gasification facilities averages about 20 percent of capacity throughout the projection period.

Figure 12. North American LNG Imports



Source: ICF International. March 2009.

For 2008, U.S. LNG imports were below recent prior levels due to lower U.S. market prices versus the global market. LNG prices in Europe were nearly double U.S. market prices, and Asian prices have been three times the U.S. market price in 2008. European and Asian markets are heavily dependent on LNG to meet their gas demand. The Asian markets are tied to oil prices, so given the disparity between natural

gas and oil prices, cargoes of LNG will seek those markets first, followed by European markets, before gas is delivered to American LNG re-gasification facilities.[39]

While it would be preferable not to depend upon imported energy supplies if domestic energy supplies can meet all of our needs, avoidance of additional gas imports may not be sustainable in the long run. Further, there are advantages in having a diversified portfolio of supplies available to meet growing market needs. Having the flexibility to be able to accept LNG imports could provide New York with added supply access and options that could serve to put downward pressure on prices in the future, particularly during periods of high demand.

[39] A possible exception would be if a long-term contract exists between the LNG receiving terminal and an LNG supplier. The existing LNG facility in Everett, Massachusetts, which has been in operation for over 30 years, has a long-term contract with its LNG supplier.

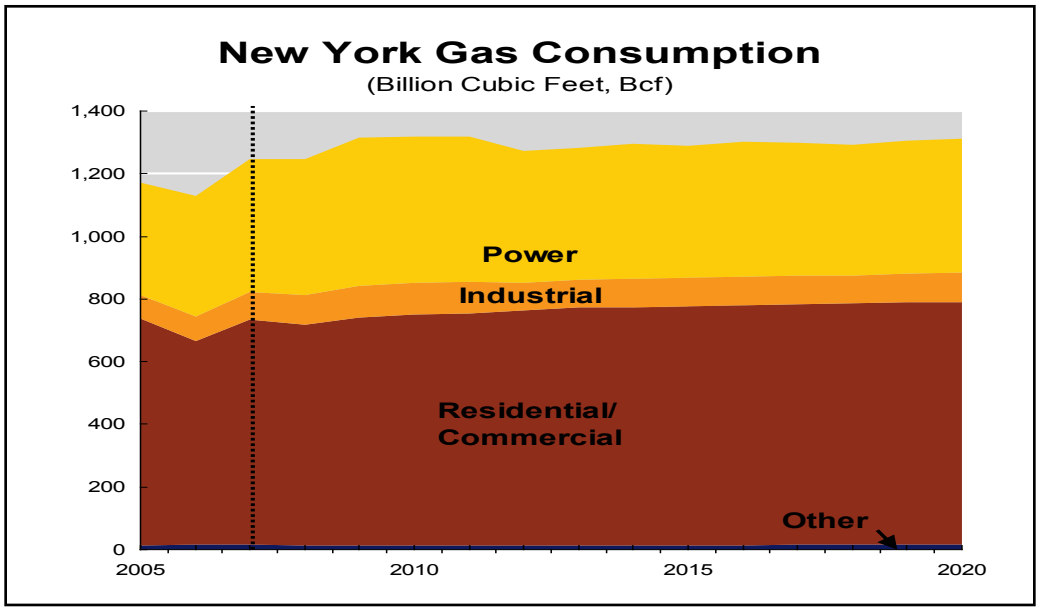
5 New York State Forecast Overview

The projections of New York State demand and supply for natural gas as described below are from the ICF natural gas and electric system Reference Case models. The Reference Case shows that natural gas demand in the residential and commercial sectors is expected to grow moderately while gas demand in the electric generation and industrial sectors is expected to remain essentially flat. Most of the growth in natural gas demand over the planning period is projected to be in the capacity constrained downstate region. Some additional pipeline capacity would be needed to transport incremental gas supplies to meet this projected demand.

5.1 New York State Demand

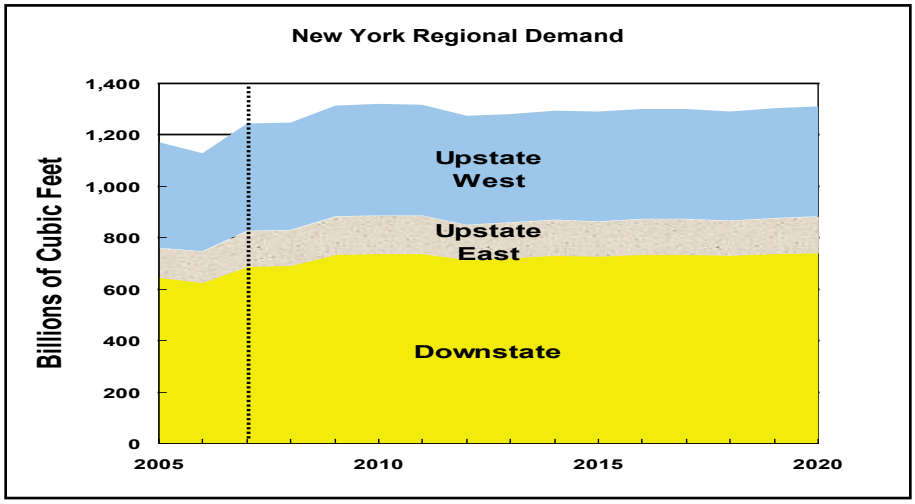
State annual gas demand is expected to grow by about 66 billion cubic feet (five percent) by 2020 to about 1.3 trillion cubic feet. The residential and commercial sectors are expected to increase an average 0.6 percent annually. Consumption in the industrial and electric generation sectors is predicted to remain relatively flat during the forecast period, as shown in Figure 13. About 80 percent of the growth in New York gas demand is concentrated in the capacity constrained New York City and Long Island regions, as shown in Figure 14.

Figure 13. New York Gas Consumption



Source: ICF International. March 2009.

Figure 14. New York Regional Demand



Source: ICF International. March 2009.

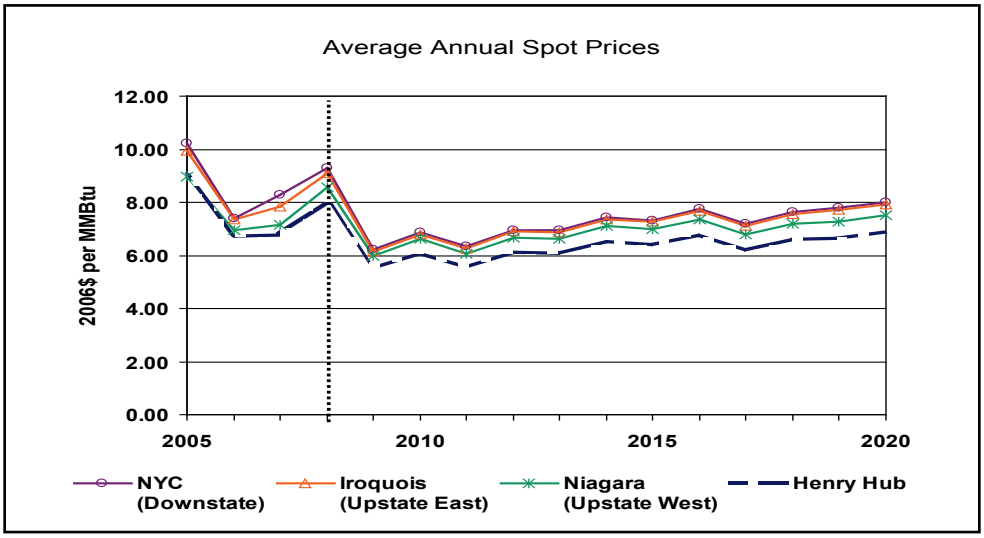
Gas consumption for electric generation is dependent on the electric modeling results. The IPM electric model Starting Point Reference Case served as the basis for the electric generation build schedule including the type and location of generator retirements, re-powering, and new units. The Starting Point Reference Case electric demand forecast is based on the NYISO 2009 Reliability Needs Assessment (RNA), which assumes approximately 30 percent of the projected electricity use reductions needed to achieve the goals of the 15 by 15 policy. Consequently, a slow growth in electricity demand combined with the increasing generation from renewable resources contributes to the relatively flat growth of natural gas demand in the electric generation sector through the study period. Full achievement of 15 by 15 would put further downward pressure on natural gas consumption in the electricity generation sector.

5.2 New York State Natural Gas Commodity Prices

The analysis used for the 2009 Plan projects that New York market natural gas prices will follow national trends, reflected by the benchmark Henry Hub price.[40] As shown in Figure 15, New York average annual spot prices are expected to be between $6 and $8 per MMBtu in constant 2006 dollars throughout the planning period. Prices are expected to continue to vary significantly throughout the year due primarily to weather conditions.

[40] Henry Hub is the pricing point for natural gas futures traded on the New York Mercantile Exchange (NYMEX). It is a major interconnection point on the U.S. natural gas pipeline system located in Louisiana, interconnecting with nine interstate and four intrastate pipelines.

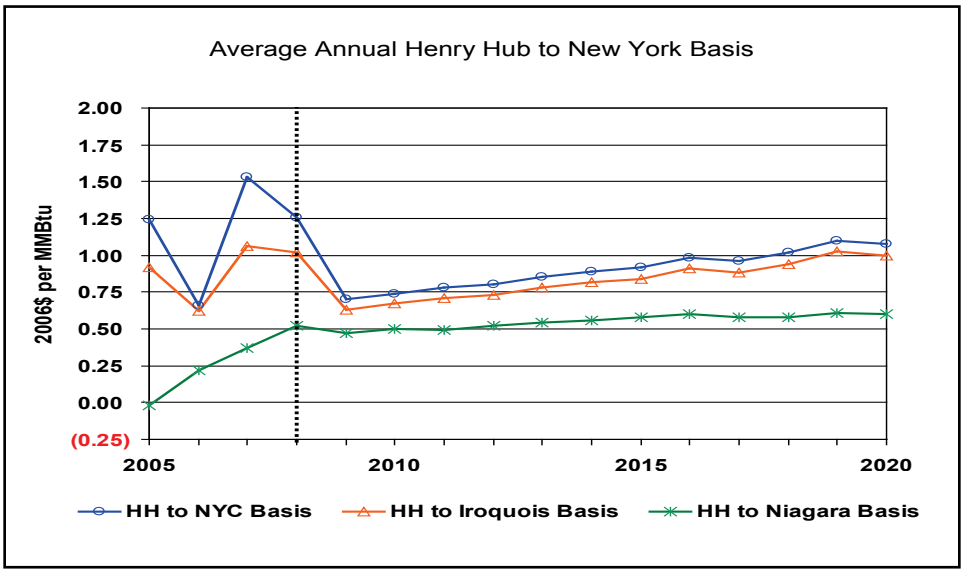
Figure 15. Average Annual Spot Prices



Source: ICF International. March 2009.

Delivered prices to New York are projected to remain at a premium to Henry Hub prices, with prices into the New York City market being at a significantly higher premium, as illustrated in Figure 16. That difference, referred to as the delivery basis into New York City, which averaged $1.14 per MMBtu between 2005 and 2007, is forecast to average $0.90 per MMBtu throughout the projection period. The basis reflects the pipeline transportation or delivery fee component of the gas cost, which can vary between locations depending on the distance from the Henry Hub, weather, demand, and pipeline constraints. The basis forecast is based on normal weather conditions. Colder-than-normal winter weather can create significant price volatility and much higher basis differentials.

Figure 16. Average Annual Henry Hub to New York Basis

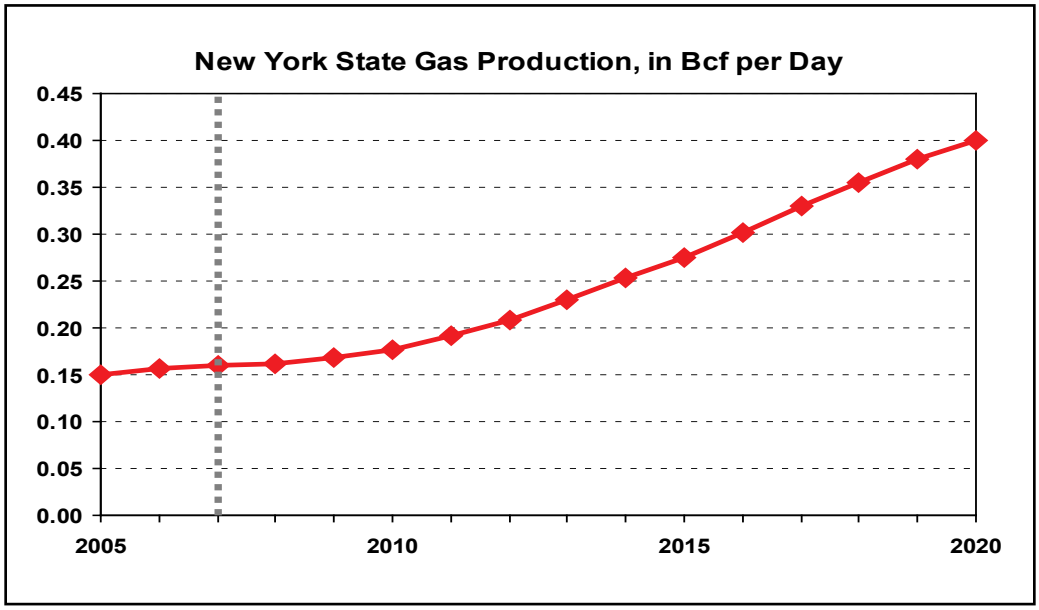


Source: ICF International. March 2009.

5.3 New York Natural Gas Production

The State's natural gas production is expected to increase significantly over the forecast period, due largely to the projected production from the Marcellus Shale formation. As shown in Figure 17, the State's natural gas production is expected to more than double from 55 billion cubic feet in 2007 to about 146 billion cubic feet, representing about 11 percent of the State's natural gas requirements by 2020. The natural gas model reflects a conservative Marcellus Shale natural gas production level to account for potential permitting and production difficulties related to horizontal drilling, and hydraulic fracturing. If these difficulties are minimized, Marcellus production levels could potentially be much higher.

Figure 17. New York State Gas Production

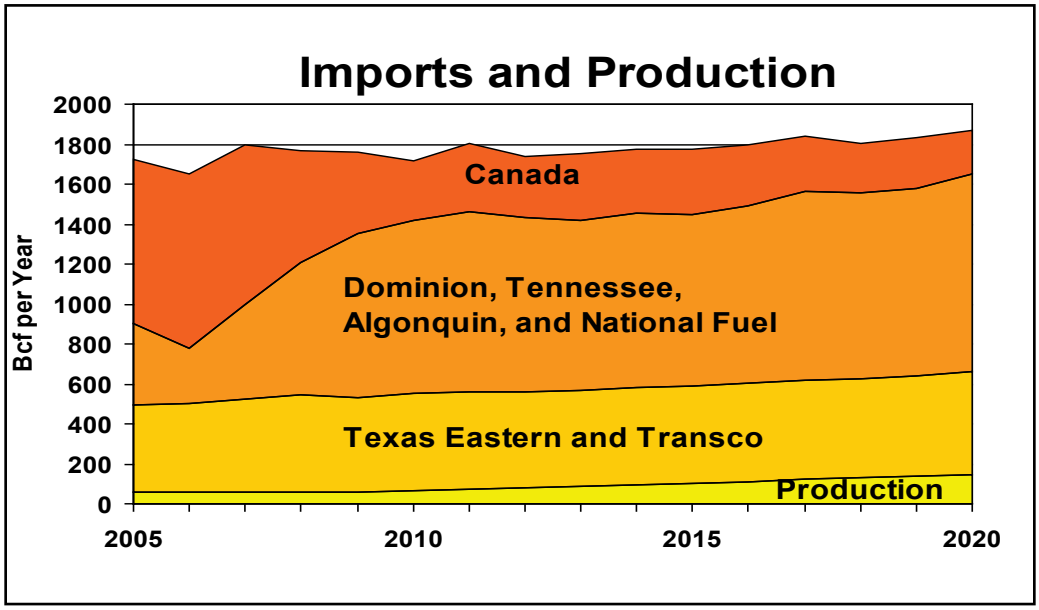


Source: ICF International. March 2009.

5.4 New York Pipeline Imports

Annual pipeline imports from Canada into New York are expected to continue to decline over the forecast period, as shown in Figure 18. Natural gas supplies are projected to increase from the south and the west, as production from shale formations as well as the Rocky Mountains replaces declining imports from Canada.

Figure 18. Imports and Production



Source: ICF International. March 2009.

5.5 Peak Day Demand Results

The results of the projected peak day gas demand modeling analysis using the RIAMS model are shown in Table 2.

In the Reference Case, statewide natural gas peak day demand increases approximately three percent over the planning period. While residential, commercial and industrial peak day gas demand in the downstate region increases, that growth is offset by a projected reduction in electric generation gas demand downstate. Conversely, residential, commercial and industrial peak day gas demand is essentially flat in the upstate regions, while gas demand for electric generation is expected to grow.

For the modeling scenario that examined retirement of the Indian Point Nuclear Plant and replacement of its capacity with a gas-fired power plant, natural gas peak day demand for electricity generation increases significantly in the downstate area and declines slightly in the upstate east areas. Overall, statewide peak day gas demand is approximately 4.5 percent higher than in the Reference Case.

Table 2. Projected Peak Day Gas Demand

Projected Peak Day Gas Demand (MMcfd)						
Region	**Reference Case**		**IP Retirement**	**Re-Powering**	**Colder than Normal**	**Combination**
	2009	**2018**	**2018**	**2018**	**2018**	**2018**
Upstate West						
R/C/I	2,554	2,564	2,555	2,564	2,855	2,828
Electric Gen.	108	184	184	84	44	29
Total	2,662	2,748	2,739	2,648	2,899	2,857
Upstate East						
R/C/I	266	276	270	276	272	264
Electric Gen.	324	462	418	235	199	89
Total	590	738	688	511	471	353
Downstate						
R/C/I	2,750	3,002	2,989	2,979	3,345	3,230
Electric Gen.	932	672	1,067	1,023	403	1200
Total	3,682	3,674	4,056	4,002	3,748	4,430
Statewide Total						
R/C/I	5,570	5,842	5,814	5,819	6,472	6,322
Electric Gen.	1,364	1,318	1,669	1,342	646	1318
Total	6,934	7,160	7,483	7,161	7,118	7,640

For the modeling scenario that examined the re-powering of existing downstate power plants that burn heavy (No. 6) oil as an alternate fuel, the analysis revealed an overall slight increase in gas demand for electricity generation relative to the Reference Case. While more gas-fired capacity will result from replacement of older residual oil burning capable generation units, the new gas-fired generation capacity will be much more efficient combined-cycle power plants. However, there is a substantial shift in the use of gas for electric generation with a significant decrease in the upstate regions, offset by a significant increase downstate.

The "Much Colder Than Normal Weather" scenario assumes that weather conditions from the extremely cold 1976-1977 winter period occur in the forecast years. Overall forecast peak day gas demand was lower than in the Reference Case. The analysis showed a sharp increase in residential and commercial peak day demand relative to the Reference Case which assumes normal weather. However, in response to the high gas prices generated by the model forecast electric generation demand for gas decreased significantly across the State.

The combination scenario examined the much colder than normal weather conditions of the 1976-1977 winter, the retirement of the Indian Point nuclear facilities, and repowering of residual oil burning power plants to burn natural gas. The results for the combination case show an overall peak day demand greater than any other scenario examined. The residential and commercial peak day demand is slightly lower than the much colder than normal scenario, while electric generation demand for natural gas is more than double the levels from the much colder than normal scenario. The increase in electric generation gas demand occurred downstate where electric generation gas demand nearly tripled from the levels shown in the colder than normal scenario, while upstate electric generation gas demand decreased.

The modeling results for these five cases with respect to the utilization of pipeline capacity available to serve that demand are shown in Table 3.[41]

Table 3. Peak Day Pipeline Utilization

Peak Day Pipeline Utilization						
	Reference Case		IP Retirement	Re-Powering	Colder than Normal	Combination
	2009	2018	2018	2018	2018	2018
	Peak Day	Peak Day	Peak Day	Peak Day	Peak Day	Peak Day
Millennium	90 %	98 %	100 %	100 %	94%	100%
Algonquin	100 %	100 %	100 %	100 %	100%	100%
Tennessee to downstate	86 %	100 %	100 %	100 %	82%	100%
Iroquois to downstate	99 %	56 %	55 %	83 %	80%	100%
Texas Eastern	100 %	100 %	100 %	100 %	100%	100%
Transcontinental to downstate	100 %	100 %	100 %	100 %	100%	100%

[41] The table shows peak day pipeline utilization for the pipelines serving the capacity constrained downstate market area.

The modeling results for the Reference Case show that most of the interstate pipelines serving New York are now operating at or near full capacity on a peak day,[42] and it is expected that in 2018 there will be unmet peak day demand.[43] For reliability purposes, adding additional pipeline capacity for downstate peak day needs would be advisable.

The RIAMS 2018 peak day analysis results reflect flow on the Iroquois pipeline into Long Island at levels below available pipeline capacity under most scenarios. Those results are a function of a projected reduction in supply from Canada flowing into the Iroquois delivery point at the Canadian border and a projected shift in gas demand for power generation.[44]

The RIAMS model results indicate that there will be a certain level of unmet gas demand in each of the scenarios examined. The level of unmet gas demand is determined for New England and New York combined, and the model indicates the share of that unmet demand expected in both areas. However, the model cannot precisely define how much of the unmet demand will impact New England versus New York. The model shows gas flowing to meet demand in a way that maximizes value by minimizing the cost of delivering gas to customers. Given the uncertainties of the RIAMS results, considering the total unmet demand as being allocated entirely to the electric sector provides an upper boundary of natural gas demand curtailments to the electric sector. Table 4 summarizes the projected unmet demand from all sectors for both New York only and New York and New England combined.

Table 4. Projected Total Unmet Natural Gas Demand in 2018

Projected Total Unmet Natural Gas Demand in 2018 (MMcfd)		
Scenario	**New York Only**	**New York and New England Combined**
Reference Case	60	300
IP Retirement Scenario	140	600
Re-Powering Scenario	170	530
Much Colder than Normal Scenario	40	400
Extreme Combination Scenario	375	900

[42] The downstate utilities report that on a peak day they are fully utilizing their available pipeline capacity.

[43] For the Reference Case scenario, the 2018 projected unmet gas demand for New England and New York total approximately 300 MMcfd of which about 56 MMcfd is in New York consisting of about 31 MMcfd in the Electric generation sector and about 25 MMcfd for the combined residential, commercial, and Industrial sectors.

[44] The model results suggests that if the Iroquois pipeline capacity to Long Island is to be fully utilized, then additional pipeline capacity would be needed on domestic pipelines to bring gas to Iroquois.

The modeling scenario where the Indian Point Nuclear power plant is retired and replaced by a gas-fired power plant shows pipeline flows similar to the Reference Case with most pipelines very full on peak days.[45] Total unmet gas demand in New York increases to approximately two times that in the Reference Case.[46]

For the modeling scenario that examined the re-powering of existing downstate power plants that burn heavy (No. 6) oil as an alternate fuel, the analysis shows a significant decrease in gas demand upstate, offset by a significant increase downstate. Total unmet gas demand is slightly lower than in the Indian Point retirement case.[47]

The much colder than normal scenario forecasts total unmet demand at levels less than the Indian Point retirement and repowering scenarios, but greater than the unmet demand reflected in the Reference Case.[48] However, only about 10 percent of the unmet demand is projected to occur in the New York market area.

The combination scenario indicates a higher unmet demand of about 900 MMcfd, of which about 375 MMcfd occurs in the New York market area.[49] About 330 MMcfd or nearly 90 percent of the New York unmet demand is in the downstate region.

Additional MAPS modeling was conducted for the Reference Case, Indian Point Retirement Scenario, and the Repowering Scenario to assess the impact of this unmet demand to the electric system.[50] Electric generators were made unavailable based on the unmet demand schedule from RIAMS and adjusted to account for uncertainties of the unmet demand allocation between New York and New England and among sectors within New England. Table 5 summarizes the unmet demand modeled in MAPS.

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[45] This scenario assumed the 2,000 MW nuclear capacity was replaced with 2,500 MW of natural gas capacity to reflect differences between the availability rates of generation technologies. The 2,500 MW capacity was used to serve as an upper bound for natural gas demand. The electric system Indian Point Retirement IPM model results, however, reflect a lower natural gas capacity replacement at Indian Point but additional resources throughout the State based on its least cost economic optimization. The hypothetical 2,500 MW plant was assumed to be served by Algonquin and Millennium Pipelines.

[46] For the Indian Point retirement scenario, the projected unmet gas demand for New England and New York total approximately 600 MMcfd of which 140 MMcfd is in New York consisting of about 100 MMcfd in the Electric generation sector and about 40 MMcfd for the combined residential, commercial, and Industrial sectors.

[47] For the re-powering scenario, the projected unmet gas demand for New England and New York total approximately 530 MMcfd, of which 170 MMcfd is in New York, consisting of about 120 MMcfd in the electric generation sector and about 50 MMcfd for the combined residential, commercial, and Industrial sectors.

[48] For the much colder than normal scenario, the projected unmet demand for New England and New York totals about 407 MMcfd, of which 39 is in New York, consisting of about 14 MMcfd in the electric generation sector and about 24 MMcfd for the combined residential, commercial, and industrial sectors.

[49] For the combination scenario, the projected unmet demand for New England and New York is approximately 893 MMcfd, of which 375 MMcfd is in New York, consisting of about 227 MMcfd in the electric generation sector and about 148 MMcfd in the combined residential, commercial, and industrial sectors.

[50] Similar analysis will be completed for the much colder than normal scenario and the combination scenario.

Table 5. Projected Total Unmet Natural Gas Demand in 2018

Total Unmet Demand Modeled in MAPS to Assess Impact to the Electric System	
Reference Case	254 MMcfd
Indian Point Retirement Scenario	504 MMcfd
Re-Powering Scenario	413 MMcfd

The additional MAPS modeling indicates that some electric load would not be served due to insufficient gas delivery capacity.[51] On an annual basis, this unserved electric load would be considered negligible, given the level of precision of the model and modeling assumptions. However, if this unmet demand all occurred on the same day, the impact to the electric system may be significant. Further analysis will continue to assess the magnitude and the impacts to the electric system from this unserved electric load due to insufficient natural gas delivery capability.

As described above, the RIAMS model's ability to delineate the unmet demand between New York and New England is limited. Ultimately, contractual rights to move gas will control what will actually happen in the real world. For example, replacement of the Indian Point nuclear plant with a gas-fired generator will create a significant increase in base load gas demand. While the existing interstate pipelines may be able to meet that demand during parts of the year, delivery of the gas assumed in the model, as available to Indian Point, may well be pre-empted by customers with superior transportation rights on the pipeline. Meeting a new significant base load gas demand year-round would require the addition of upstream pipeline capacity that is not represented in the model and the costs for this have not been accounted for.

One possible way to address the unmet demand in both New England and New York could be through a backhaul on existing pipelines of new incremental gas supply delivered downstream of New York and/or New England load centers. For example, customers (LDCs) could contract for firm, increased send-out from LNG import terminals in New England or eastern Canada. However, this approach assumes commitment to an adequate and reliable gas supply to those terminals. In reality, there may be many factors that may limit the deliverability of LNG supply, including availability, weather, and economics.

[51] The modeling process is based on economic dispatch and does not take into account the NYISO gas-electric coordination protocols between gas pipelines and generators that are designed to help identify possible winter and summertime natural gas curtailment conditions and establish a process for generators to seek emergency gas supplies if necessary.

6 *Infrastructure Issues*

6.1 Pipeline Expansions of Gas Capacity to New York State and the Northeast

Incremental pipeline capacity will be needed to meet growing natural gas loads in the New York and northeast regions. The natural gas system, particularly into the New York downstate area (New York City and Long Island), has physical capacity constraints that need to be addressed. As new pipeline capacity is built into the region it will increase deliverability, flexibility, and reliability of the gas system and will help reduce the cost of gas into the region. Another very important benefit to be considered is that new interstate pipeline capacity could increase the diversity of gas supply to the region. For example, a new pipeline may provide access to new supply basins, such as the developing Marcellus Shale. A new pipeline connection may also expand the diversity of the pipeline capacity that serves the downstate region, a potentially critical security and reliability consideration.

6.2 Recently Completed Pipeline Projects

As shown in Table 6, over the past two years, there were several natural gas pipeline infrastructure projects completed in the region. Six of the projects provide additional pipeline capacity directly into the New York market. The newly constructed Millennium Pipeline in conjunction with the Empire Connector, Ramapo Expansion, Market Access Expansion, and the 08/09 Expansion projects have provided New York with a significant amount of new natural gas pipeline capacity. The Millennium Pipeline originates in the Corning area, where it interconnects with the new Empire Connector pipeline, and terminates at an interconnection with the Algonquin pipeline in the Ramapo area. The Millennium Pipeline was put in service in 2008 and has added a total of 525 MMcfd of incremental capacity to access Canadian supplies, through the Empire Connector, and storage services along both the Millennium and Empire lines. The Millennium Pipeline serves markets along its route through the lower Hudson Valley, and provides incremental capacity of 300 MMcfd to New York City and Long Island markets through the newly expanded Algonquin (Ramapo Expansion) and Iroquois (Market Access and 08/09 projects) pipelines. Future construction of pipeline capacity upstream of Corning to interconnect with Millennium would enable new supplies from the west to reach New York markets.

Table 6. Recently Completed (2007 to 2009) Major Northeast Pipeline Expansions

Recently Completed (2007 to2009) Major Northeast Pipeline Expansions			
Project	**Pipeline Company**	**Description**	**Year In-Service**
Leidy to Long Island	Transcontinental	Expanded capacity to the Long Island, NY market by 100 MMcfd.	2007
Northeast ConneXion	Tennessee	Expanded capacity to the New England market area by 150 MMcfd.	2007
Empire Connector (Northeast 07 Project)	Empire Pipeline	New pipeline that interconnects Empire's existing pipeline with the new Millennium Pipeline near Corning, NY. 250 MMcfd.	2008
Millennium Pipeline (Northeast 07 Project)	Millennium	New Pipeline from Corning, NY to Ramapo, NY. 525 MMcfd of new capacity.	2008
Ramapo Expansion (Northeast 07 Project)	Spectra/Algonquin	Upgrade of Algonquin's facilities to interconnect with Millennium at Ramapo, NY to expand Algonquin's capacity by 325 MMcfd.	2008
Market Access Expansion (Northeast 07 Project)	Iroquois	Upgrade of Iroquois' facilities to receive additional volumes through Algonquin and expand capacity by 100 MMcfd for delivery to Hunts Point, NY.	2008
08/09 Expansion	Iroquois	Upgrade of Iroquois' facilities to receive volumes from Algonquin and expand capacity by 200 MMcfd (Phase I & II, 175 MMcfd, Phase III 25 MMcfd) for delivery to Long Island, NY.	Phase I 2008; Phase II 2009
Maritimes & Northeast Phase IV	Maritimes & Northeast	Expands Maritimes & northeast facilities in Maine by 418 MMcfd to receive natural gas from the planned Canaport LNG facility in Saint John, NB.	2009
Dominion Cove Point Pipeline Expansion	Dominion	Expands pipeline facilities in PA by 700 MMcfd to transport new supply from Dominion Cove Point LNG facility expansion in Cove Pt., MD.	2009
Northern Bridge	Spectra/Texas Eastern	Expansion of Texas Eastern to provide 150 MMcfd of new takeaway capacity from REX at Clarington, Ohio. To Oakford/Delmont, PA.	2009
Rex East	Rockies Express	1,678 mile Rockies Express (REX) pipeline will provide 1.8 Bcfd of new pipeline capacity from the Rocky Mt. supply region to interconnection points with pipelines in Ohio and northeast.	2009

Another project that provides new capacity directly to the New York market is the Leidy to Long Island expansion on the Transcontinental Gas Pipeline Corp. (Transco) pipeline system. The Leidy to Long Island project involved construction of 15 miles of 20-inch pipeline and related improvements that

expanded Transco's pipeline system by 100 MMcfd. The project is based on a 20-year binding precedent agreement executed by Transco and National Grid (former KeySpan Energy Delivery).[52]

6.3 Proposed Pipeline Projects

The level of pipeline construction in the northeast is likely to increase in the next few years. Pipelines are proposed to bring Rocky Mountain gas supplies to northeast markets, through interconnections with, and expansions of, the major pipelines serving New York area markets. These pipeline expansions will also provide access to supplies from the Marcellus Shale, providing a significant source of supply close to the market area. Two major pipelines are also proposing new delivery points directly into the constrained downstate market area. Several of the planned projects are competing for the same market, and not all of the projects will be constructed and put into service. The projects that are ultimately certified and constructed will enhance the State's access to supplies to meet future loads and will be critical to ensuring reliable competitively priced supplies to New York in the future. The additional capacity provided by the completed projects will help address the concerns highlighted by the modeling results discussed above.

6.4 REX and Related Projects

The recently completed 1,700 mile Rockies Express (REX) pipeline will provide up to 1.8 Bcfd of new pipeline capacity from the Rocky Mountain gas supply region to interconnection points with other interstate pipelines in Ohio.

However, additional pipeline capacity will be needed to bring the Rockies supply further east and northeast from the REX terminus at Clarington, Ohio. Several competitive pipeline proposals are under consideration. National Fuel Gas Company has proposed a 324-mile pipeline to deliver Rockies gas from Ohio to Corning, New York, while Texas Eastern Transmission Company's Northern Bridge, Time III and TEMAX expansions would provide incremental capacity from Ohio to Oakford, Pennsylvania, and to Station 195 on the Transco system near Delta, Pennsylvania. Another proposed outlet for increased supplies from the Rockies is Williams Companies' proposed Rockies Connector Pipeline, which would extend approximately 250 miles, connecting its Transco Station 195 in York County, Pennsylvania, to the eastern terminus of the Rockies Express in Ohio. Also Iroquois' MetroExpress project will provide additional capacity to move Rockies' supplies to northeast market centers. The owners of the Rockies Express Pipeline have also proposed extending the pipeline further east to Linden, New Jersey. The expanded capacity of many of the listed projects can also be used to access gas supplies in the Appalachian region such as the Marcellus Shale production. There may be additional pipeline projects proposed as production from the Marcellus Shale is further developed. Table 7 on the following page lists the major planned pipeline projects to serve the northeast.

[52] A precedent agreement is a contract between a pipeline company and its customer(s) for the purchase of firm pipeline capacity on a proposed pipeline. The agreement lays out all the terms and conditions of the capacity purchase which generally become effective upon the in-service date of the pipeline.

Table 7. Planned Northeast Pipeline Projects

Project	Pipeline	Description	Status/Est. in Service
East to West Expansion	Spectra/ Algonquin	Expansion of Algonquin pipeline in New England to bring new LNG supplies into northeast markets.	Filed at FERC 2010
Time III	Spectra/ Texas Eastern	60 MMcfd expansion from Oakford/Delmont, PA. to Transco pipeline's Sta. 195 near Delta, PA.	Filed at FERC Nov. 2010
TEMAX	Spectra/ Texas Eastern	Expansion of Texas Eastern to provide 395 MMcfd from REX at Clarington, OH to interconnection with Transco pipeline's Stat. 195 near Delta, PA.	Filed at FERC Nov. 2010
MetroExpress	Iroquois	Expansion of existing facilities to provide additional capacity to receive new Rockies supply at existing delivery points on the Iroquois system.	Proposal under development 2010 – 2011
West to East	National Fuel Gas	Pipeline from REX at Clarington, OH to Corning, NY. Capacity 550 – 750 MMcfd.	Proposal under development 2010 – 2011
300 Line Expansion	Tennessee	Tennessee plans to expand its existing 300 line to provide an additional 300 MMcfd of capacity to transport new Appalachian supplies to PA, NY, and northeast markets.	FERC Pre-filing 2010 – 2011
Northeast Connector	Williams/ Transco	Expansion of Transco from Sta. 195 to its Zone 6 delivery points in NJ and NY markets. Will facilitate bringing additional Rockies supply from Texas Eastern's TEMAX project and will also be used to access Marcellus Shale supplies.	Proposal under development Nov. 2012
Rockies Connector	Williams/ Transco	New pipeline from REX at Clarington, OH. Across southern PA to interconnect with Transco's mainline at Sta. 195.	Proposal under development 2013
Planned New Pipeline Delivery Points into the New York City Market Area			
Rockaway Delivery Lateral	Williams/ Transco	Pipeline from Transco's offshore system in the Lower NY Bay to interconnect with National Grid on the Rockaway Peninsula. Capacity of 647 MMcfd.	FERC Pre-Filing 2012
Lower Manhattan Lateral	Williams/ Transco	Pipeline from Transco's system in northern NJ to an interconnect with Con Edison in lower Manhattan.	Proposal under development 2012 – 2013
NJ – NY Extension	Spectra/Texas Eastern	Pipeline from Texas Eastern's facilities near the existing NY delivery station at Goethals into NJ and crossing the Hudson River to interconnect with Con Edison in lower Manhattan.	Proposal under development 2012 – 2013

6.5 New Pipeline Delivery Points into New York City Market Area

Both National Grid and Consolidated Edison have identified a need to add delivery capacity into their respective New York territories. In addition, the distribution system's ability to absorb additional interstate pipeline deliveries at a particular point must be considered in planning interstate pipeline capacity additions. Consolidated Edison has identified a need to add delivery capacity in lower Manhattan as the optimal point. National Grid has identified a need to add delivery capacity in the Jamaica Bay (Rockaway Peninsula) area.

Transco has proposed a new delivery pipeline lateral from its offshore pipeline in the Lower New York City Bay to an interconnection with National Grid facilities on the Rockaway Peninsula.[53] Transco is also considering a new pipeline lateral from its pipeline in northern New Jersey to interconnect with Consolidated Edison's facilities in lower Manhattan. Texas Eastern Transmission is considering a similar proposal by extending its system from its existing Goethals delivery point in Staten Island to a new delivery point with Consolidated Edison in lower Manhattan. The two competing lower Manhattan Pipeline proposals are preliminary and have not been filed with FERC. Only one of the lower Manhattan projects will be built and before proceeding with final plans, either pipeline will need a commitment from Consolidated Edison or other potential customers, e.g., LDCs, gas producers, or electric generators, for a sufficient level of capacity to make the project economical. Consolidated Edison is in the process of evaluating the merits of each proposal.

New delivery points at those New York City market locations would significantly relieve existing capacity constraints, increase the reliability of the gas system and reduce both the volatility of spot market gas prices in the downstate market and the delivered price of natural gas into that market. Additional pipeline capacity into the downstate region would provide a direct benefit to not only the natural gas ratepayers but also to electric ratepayers. Therefore, mechanisms for having all beneficiaries share the cost of these expensive pipeline capacity additions should be explored.

LNG Expansions

New natural gas infrastructure is being developed in the northeast related to new or expanded LNG facilities. In 2008, Algonquin placed in service a 16-mile pipeline link to the new Northeast Gateway LNG terminal offshore Massachusetts. Maritimes & Northeast Pipeline is expanding its facilities in New England in order to connect its system to gas supply from the Canaport LNG facility in Saint John, New Brunswick that received its first shipment of gas in June 2009. The Neptune LNG project located offshore near Gloucester, Massachusetts is expected to be ready to deliver re-gasified LNG into Algonquin's pipeline facilities by the spring of 2010. Dominion has also completed construction of a pipeline expansion that would provide for deliveries of re-gasified LNG from the Cove Point LNG terminal expansion to Dominion's South Point market center in central Pennsylvania. There are also proposals for two LNG terminals in Maine.[54] While these LNG projects and associated pipeline expansions would not directly serve the New York market, they would provide additional gas supplies and capacity to the northeast region which may free supplies and capacity to New York.

In addition there are three proposals to build LNG facilities off shore of the New York and New Jersey market areas: Safe Harbor Energy (New York), BlueOcean Energy (New Jersey), and Liberty Natural Gas (New Jersey). Safe Harbor has filed an application for its proposal with the Maritimes Administration; BlueOcean Energy and Liberty Natural Gas have not made a filing and are still in the planning stages. If built, these projects would interconnect with the interstate pipeline systems that have delivery points into the New York City market area through construction of new pipeline laterals. Any new LNG import facilities located either within New York's coastal zone or in a location such that would have a reasonably foreseeable effect on New York's coastal resources, must be fully consistent with New York's Coastal Management Plan, as authorized under the federal Coastal Zone Management Act of 1972 as well as all applicable environmental and safety laws and regulation.

[53] FERC. *Pre-filing Docket PF09-8*. 2009. http://www.ferc.gov/industries/gas/indus-act/pre-filing/fy-2009.pdf

[54] The two proposed Maine LNG projects, Downeast LNG and Calais LNG, have made FERC filing and pre-filing applications, respectively.

A large volume of imported LNG entering the northeast market close to load centers would increase the competiveness of the market, reduce price volatility, and could lower prices.

6.6 Infrastructure Siting

The planning, regulatory approval process and construction of new pipeline or LNG facilities is difficult and can take many years, particularly in the northeast. For example, the Millennium Pipeline project's application was first filed with FERC in December 1997. The project experienced significant delays due to major issues involving routing and environmental concerns. In December 2001 and September 2002, Millennium received FERC approval. However, the Department of State (DOS) determined that construction of the pipeline was inconsistent with the Coastal Zone Management Act. Millennium filed an amended application with FERC that addressed DOS's concerns in August 2005, received final FERC approval in December 2006, and subsequently received authorization to begin construction in June 2007. The project was constructed and put in service in December 2008, over 11 years after it first filed its FERC application.

The Broadwater LNG project proposed to be located offshore Long Island was publicly announced by Broadwater Energy in November 2004 and filed with FERC in January 2006. It took over two years for the project to receive FERC approval; however, it did not receive the necessary Coastal Zone Management Act approval from New York due to inconsistency with State coastal policy. Subsequently, the U.S. Department of Commerce denied an appeal by Broadwater and upheld New York's coastal zone ruling.

7 Conclusions

- Demand for natural gas is expected to increase over the planning horizon. In the Reference Case, gas demand is expected to increase on a statewide basis in the residential and commercial sectors and remain essentially flat in the industrial and electricity generation sectors. Most of the increase is expected to occur in the capacity constrained downstate area. Supply is expected to be adequate to meet demand.

- The capacity of interstate pipelines to transport sufficient commodity to meet New York's increasing demand for natural gas is a concern, particularly for the downstate area. Additional pipeline capacity will be needed to continue to reliably meet demand.

    - Peak day modeling results for the Reference Case show that the available pipeline capacity in the downstate area is essentially fully utilized during peak day demand periods throughout the forecast period.

    - Assuming Indian Point 2 and 3 are retired and replaced by a 2,500 MW gas-fired power plant shows pipeline flows similar to the Reference Case with most pipelines very full on peak days.[55] Gas demand for electricity generation increases substantially downstate, and declines somewhat in the upstate east area. Total unmet gas demand in New York increases to approximately two times that in the Reference Case.

    - Assuming the re-powering of existing downstate power plants that burn heavy (No. 6) oil as an alternate fuel, the analysis revealed an overall slight increase in gas demand for electricity generation relative to the Reference Case. While more gas-fired capacity will result from replacement of older residual oil burning capable generation units, the new gas-fired generation will be much more efficient combined-cycle power plants. However, there is a substantial shift in the use of gas for electricity generation with a significant decrease upstate, offset by a significant increase downstate. Total unmet gas demand is slightly lower than in the Indian Point retirement case.

    - Assuming much colder than normal weather, the overall forecast peak day demand was lower than that produced by the Reference Case. The analysis showed a sharp increase in residential and commercial peak day demand relative to the Reference Case which assumes normal weather. However, in response to the high gas prices generated by the model, forecast electric generation demand for natural gas decreased significantly across the state. Total unmet demand is forecast to be at levels less than the Indian Point

[55] It is very important to recognize that the model shows gas flowing to meet demand in a way that maximizes value by minimizing the cost of delivering gas to customers. However, contractual rights to move gas will control what will actually happen in the real world. For example, replacement of the Indian Point nuclear plant with a gas-fired generator will create a significant increase in base load gas demand. While the existing interstate pipelines may be able to meet that demand during parts of the year, meeting such a significant increase in base load gas demand year round would require the addition of upstream pipeline capacity that has not been accounted for.

retirement and repowering scenarios, but greater than the unmet demand reflected in the reference case.

- Assuming much colder than normal weather conditions coupled with the retirement of the Indian Point nuclear facilities, and repowering of residual oil burning power plants to burn natural gas, the modeling indicates an overall peak day demand greater than any other scenario examined. The residential and commercial peak day demand is slightly lower than the results of the much colder than normal scenario. In contrast electric generation demand for natural gas is more than double the levels from the much colder than normal scenario. The increase in electric generation demand for natural gas occurs downstate where electric generation demand for natural gas nearly tripled from the levels shown in the colder than normal scenario, while upstate electric generation demand for natural gas decreased. The combination scenario indicates a higher unmet demand of about 900 MMcfd, of which about 375 MMcfd occurs in the New York market area. About 330 MMcfd or nearly 90 percent of the New York unmet demand is in the downstate region.

- Additional modeling is needed to more fully understand important aspects of the adequacy of the gas delivery system serving the State and to more fully capture the interdependence of the natural gas system and electric systems.

  - Further analysis is needed to assess the magnitude and the impacts to the electric system resulting in unserved electric load due to insufficient natural gas delivery capability.

  - The models assume that all elements of the gas system, such as pipelines, compressors and production facilities, will operate dependably as designed. The vulnerability of the State to pipeline or compressor failures has not been assessed and should be examined as part of a separate contingency analysis.

- Consolidated Edison and National Grid have identified needs to add delivery capacity into their respective downstate New York territories. In addition, there are certain constraints within the distribution system in the downstate area that must be considered in planning interstate pipeline capacity additions.

  - Planned pipeline additions for new delivery points into the downstate market area, if built, would significantly relieve existing capacity constraints, increase the reliability of the gas system and reduce both the volatility of spot market gas prices in the downstate market and the delivered price of natural gas into that market.

  - The addition of new delivery points into the downstate market would directly benefit not only the natural gas ratepayers, but also downstate electric ratepayers. Therefore, mechanisms to have all beneficiaries share the cost of these expensive pipeline capacity additions should be explored.

- The State should take specific steps to encourage investment in natural gas infrastructure, including LNG facilities that are sited, constructed, and operated as to be fully consistent with

applicable State and federal environmental and safety laws and regulations,[56] that could supply future downstate requirements consistent with the State's planning objectives by: (i) providing project developers rigorous, pre-application, all-agency evaluations of State and local project siting, environmental and safety concerns, and (ii) maximizing agency coordination during permitting proceedings.

[56] As discussed in Section 6.5, there are several proposed LNG import projects that could serve New York State. Such projects could provide some of the same benefits, such as the addition of a new gas supply source that could have the effect of diminishing price volatility.