1. CONCEPTUAL FRAMEWORK FOR ASSESSING PIPELINE ADEQUACY

Assessing the ability of the gas delivery infrastructure to meet future gas demands for electricity generation requires understanding:

- The range of potential gas requirements for electric generation under various electric load conditions.

  How this range is affected by electric load growth and the addition of new electric generation capacity.

  The extent to which potential gas requirements for electric generation can be met with various levels of gas delivery capacity.

  The economic determinants of generators' fuel use decisions.

  The economic determinants of available gas deliverability and future pipeline capacity expansions.

- Potential causes of gas shortages stemming from supply and demand imbalances that prevent the minimum gas demand needed to meet electric load from being supplied.

This chapter begins with a conceptual discussion of each of these issues and then outlines the framework with which each is addressed in this study. For readers unfamiliar with the gas and electricity infrastructure in New York State, background information is provided in Appendix A.

1.1 DETERMINANTS OF GENERATOR GAS DEMANDS

Gas is burned by several different types of electric generators in the NYCA

  Steam Generators – which use either gas or residual oil to fire boilers (approximately 11,000 MW). The majority of gas-capable NYCA steam units have the ability to burn gas or residual oil (commonly referred to as "dual-fuel" units), while a small portion (approximately 560 MW) are only capable of burning natural gas.

- Combustion Turbines – which use either gas or distillate oil (approximately 2,800 MW).

- Combined Cycle Gas Turbines – which use either gas or distillate oil (approximately 3,100 MW).

The generators and their primary and secondary fuels are listed in the *Load & Capacity Data* Report, commonly referred to as the "Gold Book."[11]

The extent to which gas-capable generators (either those units that can only burn gas, or units that can burn either gas or oil) will be dispatched to meet electric loads and their resulting gas demands are determined primarily by the mix of generators available to sell into the electric market, fuel prices facing each type of generator, operative environmental regulations including the cost of emissions allowances, and the demand for electricity. These factors combine to form a demand curve, or range of potential gas demands for each generator. Where in that range the actual demand will fall is a function of the gas price (including both commodity and transportation costs), the price of residual oil, the price of distillate oil and the resulting economic decision of the generation owner.

To illustrate this decision, consider the following simple example. If a generator is able to obtain delivered gas at a relatively low price, it will be willing to sell into the electric market at a correspondingly low output price, which is reflected in the generator's bid into the market. If electric demand is such that this bid is below the market clearing electric price, the generator will be dispatched and, as a result, contribute to the aggregate demand for gas. If delivered gas is only available at a much higher price such that if the unit burns gas, its dispatch cost will be above the dispatch cost of other, nongas units that are available as substitutes, the owner will not be willing to sell its output at the market clearing price and the generator will either not run or will burn a lower-cost fuel.

This example shows the two types of decisions made by the operators of gas-capable generators. First, they will choose to burn whatever fuel is available at the lowest cost. Second, they will choose whether or not to sell into the electric market at the market-clearing price. If delivered gas prices are low, more gas-fired generators will run and dual-fueled units will opt to run on gas. When the gas price is high relative to oil, dual-fuel units will opt to burn oil to the extent it is available and gas-fired units without the ability to burn alternative fuels may be displaced by oil-burning units.

Such economic decisions by generators in New York have led to substantial variation in the mix of gas and oil used for generation. This variation in fuel mix is illustrated in Figures 1 and 2, which show fuel prices and the corresponding amount of gas and oil burned by dual-fueled steam units in eastern New York. The red line on Figure 1 represents the gas price and the blue line represents the oil price. Each bar shows the total amount of gas and oil burned; the dark portion on the bottom represents oil and the lighter portion on top represents gas. These data show two interesting facts. First, these units have burned substantial amounts of both gas and oil during all seasons of the year, implying that some gas has been available in the winter and that oil has been economically attractive during some summer months. Second, the graph shows that when gas

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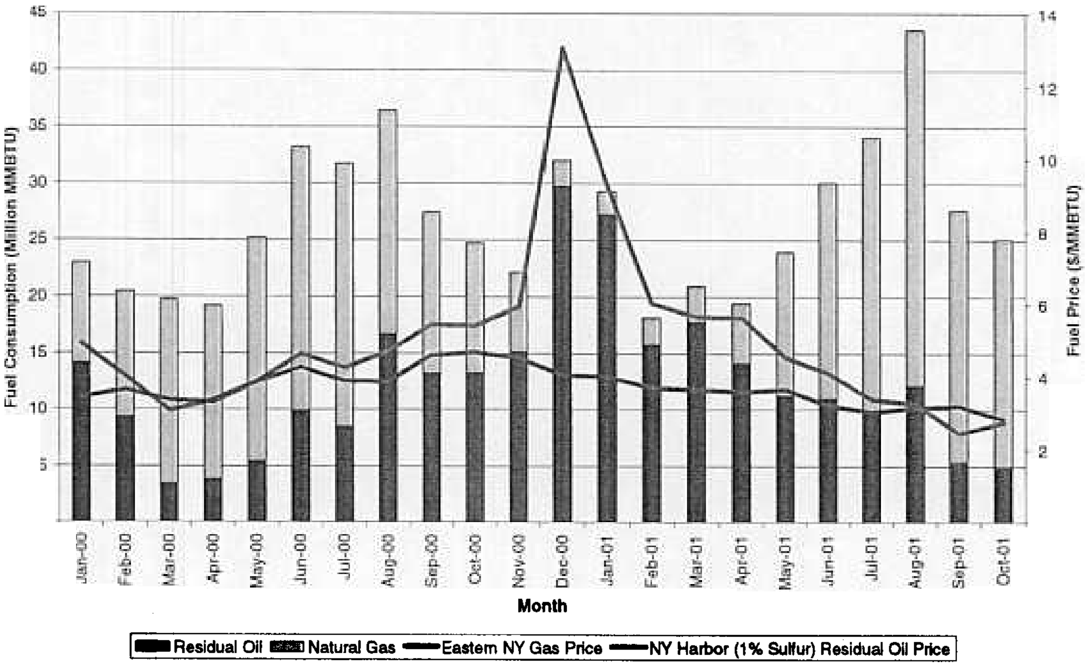
[11] This report is prepared by the NYISO and filed with the New York State Energy Planning Board in compliance with the regulations pursuant to Section 6-106 of the New York State Energy Law.

prices have risen, as in late 2000 and early 2001, generators have made the economic decision to burn oil.

Figure 1

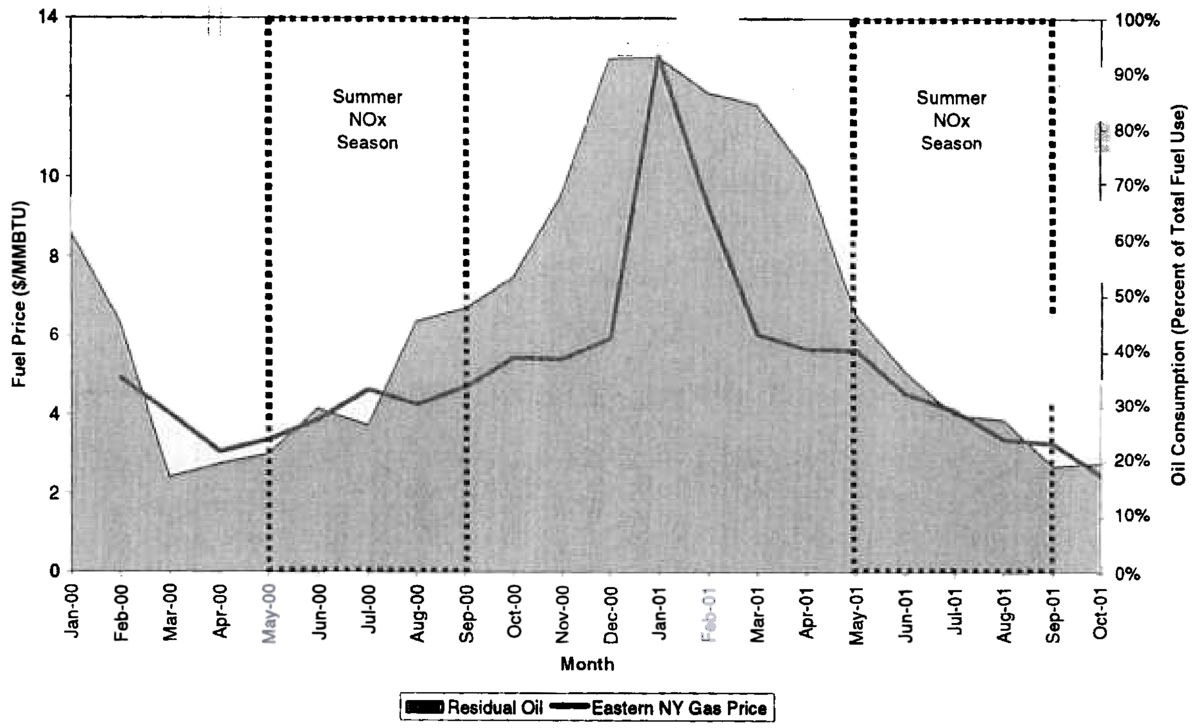
Historical Fuel Prices and Fuel Mix in Dual-Fueled Steam Units
Eastern New York 2000-2001



This economic decision to burn oil when gas prices rise can be clearly seen in Figure 2, which shows oil as a percentage of total fuel burn in dual-fuel units. These historical data illustrate that New York generators have made economic decisions to burn oil when gas prices have been high, even during periods when environmental regulations make it costly to burn oil. When gas prices were at their highest level at the end of 2000, more than 90 percent of the fuel used in dual-fueled steam units was residual oil. Furthermore, substantial amounts of oil were burned even during the summer months, when nitrogen oxides (NO_X) regulations apply.

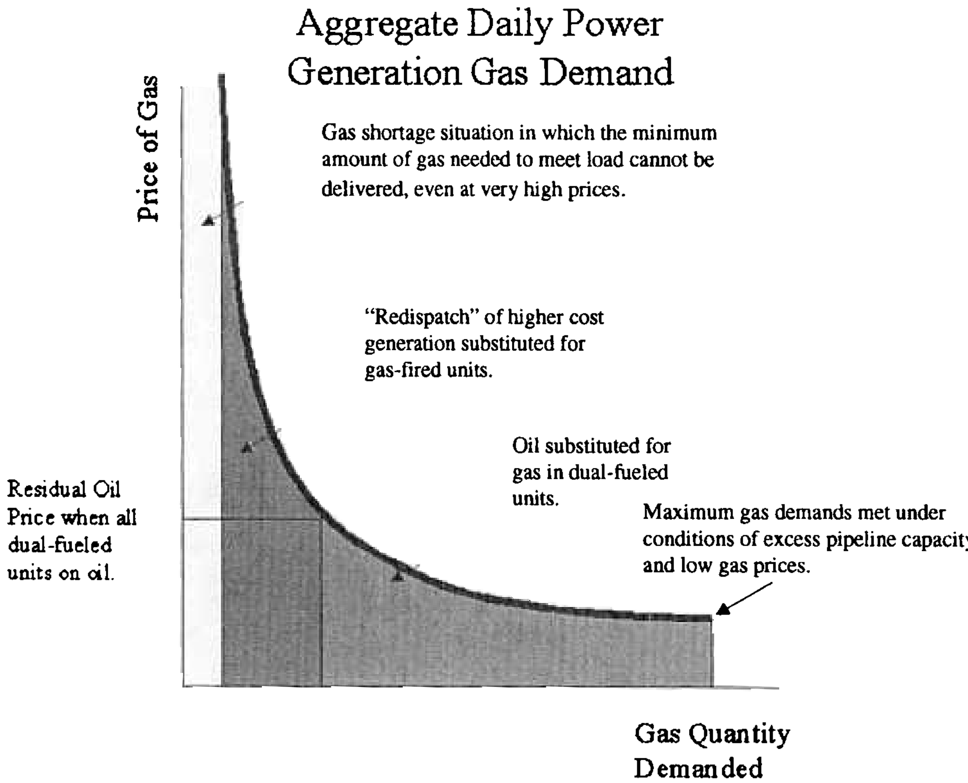
Figure 2

Oil Consumption as a Percentage of Total Fuel Use among Dual-Fueled Steam Generators
Eastern New York State 2000-2001



The range of potential gas demands among generators and the economic decisions about fuel use made by plant operators can be conceptualized in a demand curve, as depicted in Figure 3.

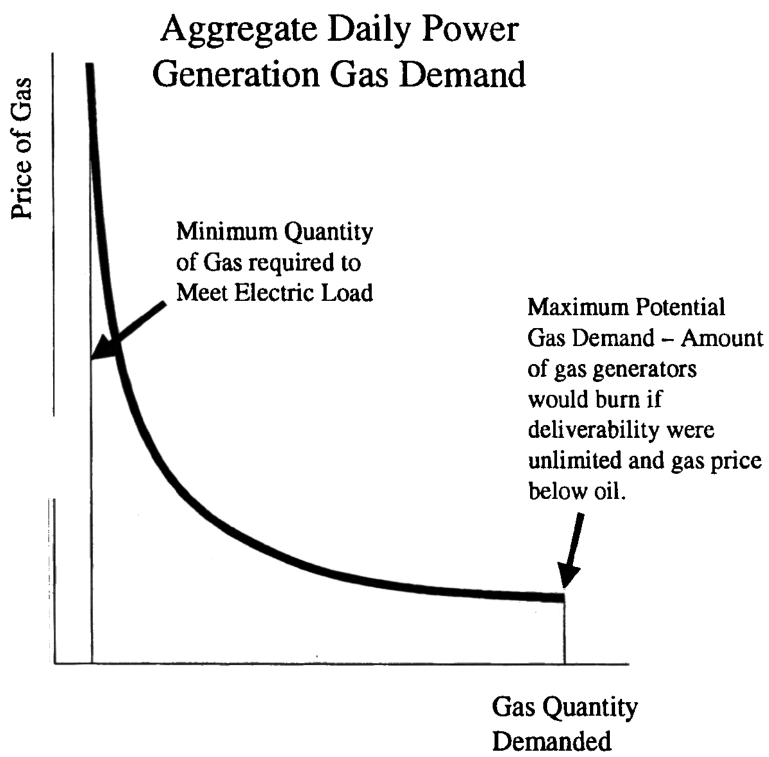
Figure 4



First, when the gas price rises to the cost of burning residual oil (including any related environmental costs), dual-fueled steam units will substitute residual oil for gas. If the gas price increases enough, residual-oil-burning steam units will become more economic than gas-fired, combined-cycle units (CCs) and gas demands will be further reduced as these units are displaced. This displacement represents a different form of substitution; buyers in the electric market turn to substitutes for gas-fired generation. Additional substitution occurs if the gas price rises above the level at which all residual-fired units are dispatched, as higher-cost, non-gas-fired units, such as oil-fired peakers or imports from other areas (which may include high fees for losses or wheeling), will be more economic than gas-fired CCs and displace additional gas demands.

If the delivered gas price rises very high and the quantity demanded by generators still exceeds the available supply of gas, a shortage exists and electric loads will not be met. A sustained imbalance between gas supply and generators' demand occurs when gas demands are in or near this region for some period or periods during the year, even under normal electric and gas operating conditions (extreme circumstances that lead to such shortages will be addressed in a later, contingency analysis, phase of this study). Note, however, that the economic responses of generators to changes in the gas price may create periods when generating units, which would run on gas if supply were abundant and the price low, either do not run or switch to oil. Such periods do not represent shortages or sustained mismatches between supply and demand. Rather, they simply reflect the market outcome and the economic decisions made by competitive

Figure 3



The end points of the demand curve define the range of potential gas use. The point at the far right corresponds to a situation where the delivered gas price is relatively low, so that gas-fired generators are dispatched before oil-burning units and dual-fueled units opt to burn gas. Throughout this report, we refer to this point as "maximum potential" or "unrestricted" gas demand. The far left end of the demand curve represents the minimum amount of gas that is needed to meet electric loads. If electricity supply is sufficiently tight that load cannot be met without gas-fired units, the owners of these units will be willing to pay a higher price for gas, which they can then recover through higher electric prices (*e.g.*, California gas and electricity markets in the winter of 2000–2001). As delivered gas prices rise, substitutes become more attractive and the quantity of gas demanded by generators drops from its maximum potential level. This substitution is depicted in Figure 4.

generators—the type of market response illustrated by New York generators in the historical data shown in Figures 1 and 2.

The amount of gas-fired generation that is needed to meet electric loads, and for which a shortage in the gas market will occur if its gas requirements are not met, will vary with load and generator availability. During high load times, the minimum amount of gas-fired generation required will be higher, which means more gas supply is needed to avoid shortages (*i.e.*, the size of the yellow area in Figure 4 is highest in peak load periods). During lower load periods, it may be the case that no gas-fired generation is needed, so that the demand curve for gas actually touches the price axis (y-axis) and the yellow region disappears. Similarly, minimum gas requirements will increase and decrease with the amount of nongas generation that is on outage.

Because this study is focused on the ability to meet future gas demands, which occur in years when new power plants are expected to be in operation, it is also important to understand how new gas-fired, CC units will affect the range of potential gas demands. As CC units are added, they have two counteracting effects on gas demands. First, because theses units are predominantly fueled by gas and are relatively efficient, they will tend to displace more costly generation, some of which is not gas-fired. As a result, under many load conditions, new CCs will increase maximum potential gas demands. For example, consider the summer peak period in eastern New York. Much of the installed generating capacity is needed, including oil-fired steam units and many oil-fired gas turbines (GTs). When more CC capacity is in place and gas is available at a low price, the oil-fired steam units and GTs will not need to run as much, meaning their generation, which is oil-fired, will have been replaced by gas-fired CCs, increasing both the total potential gas demand for electric generation. If the high-cost, oil-fired units whose generation is displaced by new CCs are retired, the minimum gas requirements for the electric generation sector will also increase.

The second effect of adding new CCs is a consequence of their relative efficiency. Because CCs are able to generate at a lower heat rate than steam units or simple cycle turbines (peaking units), if all else is equal, having them available may lower the minimum gas requirements for meeting electric load. For example, suppose that 100 MW of gas-fired generation is needed to meet electric demands for an hour. If a GT with a 10,500 Btu/kWh heat rate supplies this 100 MW, 1,050 MMBtu of gas will be needed for that hour. However, if a CC with a 7,000 Btu/kWh heat rate is available, it can supply the necessary 100 MW while burning only 700 MMBtu of gas.

1.2 DETERMINANTS OF GAS SUPPLY AND TRANSMISSION CAPACITY FOR GENERATION

The economic decisions by generators purchasing fuel provides a means by which gas suppliers can effectively ration limited delivery capacity. If delivery is not constrained, competition among gas transportation suppliers will keep prices relatively low so that generators (and other gas purchasers) will be able to buy as much gas as they want at a relatively low price that reflects only the commodity and incremental transportation costs of gas (but no additional margin). However, if pipeline capacity is fully utilized so that deliverability to additional gas customers is constrained, delivered gas prices will rise to ration limited delivery capacity. The market will reach equilibrium when the delivered price is just high enough that gas demands fall to the level that can be supplied when the gas delivery system is fully utilized.

Several factors, including the economics of building pipeline expansions, seasonal variation in nonpower gas demands, and institutional and regulatory factors make it unlikely that maximum potential gas demands for electric generation will always be fulfilled. Generators could contract for firm delivery capacity and avoid fluctuations in the availability and price of transportation. However, the existing incentives for generators generally do not favor buying firm gas transportation capacity. The lack of incentive for generators to buy firm transportation capacity in turn prevents pipelines from building the full amount of additional capacity that would be needed to serve generators' full potential demands.

Although the largest driver of forecasted growth in natural gas demand over the next decade is the electric power generation sector, the economic interests of the owners of new power plants are not always aligned with the pipelines' interest in expanding pipeline capacity. Clearly, in the long run, new power plants will require new pipelines (or pipeline expansions) to supply their fuel. However, in the short term, many generators can acquire adequate capacity in the active secondary market, at a cost that is often much lower than the costs of firm capacity on a pipeline expansion or new pipeline.

The traditional dual-fuel steam electric generation units in New York have burned gas when it was available and the price was economic. Experience indicates that gas has been readily available in the summer and randomly available in the winter (depending on weather). As discussed in the previous section, these units have switched between gas and oil as dictated by economic conditions.

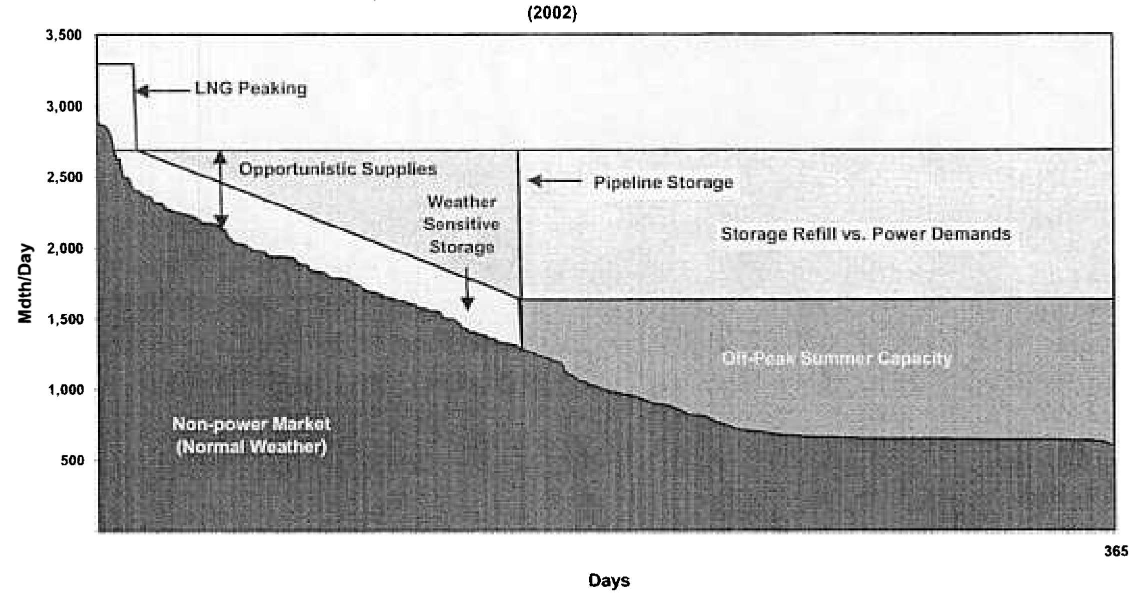
In contrast, the new CC units being installed throughout the Northeast have been designed to be primarily fired by gas (with occasional distillate oil backup for some projects and no backup capability for others). The plants that have environmental permits to burn distillate oil as an alternate fuel to gas are typically restricted to no more than 720 hours of distillate operation per year. As New York (and the Northeast in general) is a winter-peaking gas area, there is generally substantial surplus pipeline capacity in the summer, although some of this capacity is necessarily used to fill winter storage needs. Given their operational efficiency, the CCs would reasonably expect to be dispatched ahead of the large installed base of steam electric units as long as their efficiency advantages (generally around 50 percent) were not offset by a price disadvantage relative to residual fuel oil (the same 50 percent).

There are different "risks" associated with relying on the secondary market for pipeline capacity instead of contracting for firm gas transportation service. The secondary released capacity market is often not firm, with capacity being subject to recall by its longer-term owner. In the primary pipeline direct market, the firm contract holder is the primary owner. However, the time when the power plant may be most interested in assuring that it is dispatched (and thereby requiring fuel) is in the peak summer months when it is likely that the spark spread or "profit" for a MWh would be the highest. This is the same time that the pipeline capacity is most likely to be available and at lowest cost. During the peak winter months, electric prices are typically lower, gas pipeline capacity is more expensive (if available at all), and the generator's MWh "profit" will be at its lowest.

This seasonal fluctuation in pipeline utilization and available capacity is illustrated in Figure 5.

Figure 5

Gas Capacity Available to Downstate LDCs
(Non-power Market and Generation Market)
(2002)



The chart shows a load duration curve for the nonpower generation market.[12] The relatively steep initial portion of the curve is due to the short period of very cold weather that occurs in a normal winter. Over the course of the winter, the daily demands for gas rise as the temperature falls. Utilities plan for this seasonal increase in load by purchasing storage services. Such storage services provide supplies that are much closer to the market than general pipeline supply by virtue of the supplies having been transported from the production areas to the market areas during the lower demand periods in the summer. During a normal weather year, LDCs in New York serve their firm customers and transportation customers[13] with firm pipeline supplies supplemented by winter storage services and local LNG supplies.[14]

[12] A load duration curve represents the daily deliveries to a market segment (in this case, the entire market, excluding power generation), ranked from the peak day send-out to the lowest daily delivery.

[13] Transportation customers are those customers that elect to only purchase delivery services from an LDC for gas that they have independently purchased from a third party. Either the third party or the customer is responsible for getting the gas delivered to the LDC's city gate facilities, where the LDC accepts the gas and delivers it to the customer's facility.

[14] The LNG supplies in NY are liquefied from pipeline supplies in the summer and placed into storage for the winter. It represents a very high deliverability source for a short period of time (approximately five days at the maximum withdrawal rates). Given the long time it takes to refill the storage tanks, it is generally only available for one cycle during the year.

The utilization of storage is a function of the weather and the relative economics of the cost of gas in storage compared to other alternate sources of supply. As such, LDCs must contract for sufficient gas to meet extreme weather conditions (*i.e.*, a "design winter") in order to meet their "obligation to serve." Given that design winters are rare occurrences, some of the capacity planned for use in such circumstances may then be "available" at other times. During random days in the winter, the weather may be relatively mild. Under such conditions, the pipeline capacity that would normally have carried the storage gas to market may alternatively be used to bring spot gas purchases to power plants if the economics are favorable. In very mild winters such as that in 2001–2002, these conditions may emerge quite often. We have labeled this capacity as "opportunistic supplies" for the power markets. It is important to note that power generators are not the only candidate for this capacity, as an LDC may elect to inject gas into storage to extend their storage supplies, sell the capacity and gas to "off-system" customers, or to interruptible customers within the LDC.

For generators that have dual-fuel capability (and the environmental permits to burn oil), the randomness of these supplies does not constitute a problem (except for a possible economic one). However, there is risk associated with counting on these supplies because the occurrence of a design winter[15] could effectively remove all such supplies from the spot market for the winter's duration. While electric generators face the risks that they will be unable to generate since these "opportunistic" supplies would not be available on the spot market, their "lost profits" are likely to be small. Relatively high delivered gas prices coupled with relatively low electricity prices result in winter spark spreads that are typically small.

When the winter season is over, two blocks of potential pipeline capacity open up for power generators—off-peak summer capacity and storage refill capacity. The off-peak summer capacity is typically available for most of the summer at prices that are often quite favorable. This capacity provides a substantial portion of the capacity that is used by generators for the summer. In addition, there is the capacity that is typically used to refill storage fields in the summer. The availability of this capacity is not assured but rather depends on several conditions.

If the previous winter was quite cold, then the storage fields (or local LNG facility) may be effectively depleted—requiring a substantial amount of injection over most of the summer (as injection rates are lower than withdrawal rates). Given the need for LDCs to have adequate supplies to meet their firm delivery obligation in the winter, low storage inventories in the spring create considerable pressure on the market to utilize a portion of the gas transmission capacity to refill the storage fields. High gas and transportation prices may create some reluctance to do this, but as the summer wears on, the need to replenish the supplies becomes stronger.

High storage inventories at the end of the winter heating season (such as currently exist) can free up the pipeline capacity market a great deal, augmenting the off-peak market substantially. This same situation occurs whenever the storage market slows down. It is the availability of this

[15] A design winter is a winter that is significantly colder than a normal winter (*i.e.*, 10 to 15 percent colder on average than the normal winter. The normal winter is generally based on 30-year averages.

transportation capacity at very low costs (when gas prices are also often low) that supports the high demand for gas by generators in the summer. The fact that gas prices and gas transportation costs are often at their lowest when electric prices are at their peak allows generators to earn substantial margins without the need to contract for firm gas pipeline capacity.

Since gas transmission capacity is typically available at low costs when it is most valuable to generators (summer) and typically unavailable when it is least valuable (winter), there is little incentive for the generator to contract for firm gas transmission capacity. However, without firm capacity contracts in hand, a pipeline is unlikely to receive FERC approval for the project. It is only when a generator perceives that the pipeline market will be sufficiently "tight" when it would be profitable for the generator to run, that the generator would enter into a firm agreement for its overall gas transmission capacity. Otherwise, a generator would likely opt to rely heavily on the secondary market or, as is the case for one of the new generation projects in New York, contracting for less than 50 percent of their total gas requirements.

This divergence of interests makes pipeline expansion projects problematic, particularly in the Northeast where there is substantial existing oil-fired electric generating capacity that would be available to meet electricity demand when gas prices are high and/or gas deliverability is restricted. In the event that the contracts are in hand, most pipeline projects can be in place in a timely fashion. Thus, over the long term, there is unlikely to be any systemic shortages of gas for the power sector, from an economic perspective. However, we would expect that this "economic" amount of gas transmission capacity would, necessarily, result in situations where the delivered price of gas rises to levels that make it economic to meet electricity demands with oil-fired generation instead of gas-fired generation.

Given that gas transmission capacity is available on a short-term spot basis (*i.e.*, released capacity), merchant electric generators have little incentive to purchase firm gas transmission capacity unless the expected costs are similar (adjusting for the relative risks). To date, in the NYCA, market-released capacity during the summer months has been readily available at costs below those that would be paid to obtain firm service directly from the pipeline. For example, for the first quarter of 2002, the average discount on Tennessee Gas pipeline was 36 percent of the full tariff rate.[16]

1.3 FRAMEWORK FOR ANALYSIS

Because both generator gas demands and pipeline/LDC deliverability are determined to a large extent by the amount of new generating capacity that is added and the extent of pipeline expansions, we have modeled a range of electricity and gas expansion cases. Because of the economic and regulatory uncertainty surrounding the addition of new gas and electric infrastructure, this study does not explicitly address the amount of new gas or electric capacity

[16] Source: Tennessee Gas pipeline Web site for released capacity.

that is needed or is likely to be built in New York.[17] Rather we determine whether any of the scenarios analyzed leads to a sustained imbalance between gas demand by electric generators and gas delivery capacity.

Our study framework also recognizes that the ability to burn oil in electric generators has been and continues to be important to the reliable operation of the New York electric system. A substantial amount of oil has been used to meet electric loads both in the winter months, when gas supplies to electric generators have been limited, and in the summer to comply with reliability rules (in order to protect against the sudden loss of gas supply to New York City). The importance of oil is that it provides an alternative, locally stored fuel option, or "local Btu storage." Even in the absence of any electric load growth and/or generating capacity additions, pipeline capacity would not be sufficient to allow electric demands to be met if the ability to store and burn oil for electric generation were substantially diminished.

Recognizing the importance of local Btu storage, we have assumed that electric generators will be able to burn oil at a scale comparable to historical levels. We are then able to estimate gas use and the extent to which oil needs to be burned in various electric capacity addition and pipeline expansion scenarios. This approach identifies a range of combinations of local Btu storage and gas delivery capacity that are sufficient to meet the fuel supply needs of the electric system and illustrates the resulting trade-off between local fuel storage and pipeline capacity.
The goal of our analysis of generator gas demands and the corresponding deliveries by pipelines and LDCs is to identify:

- For each generating capacity scenario, the range of potential gas demand for generation and where in that range actual deliveries will fall under various pipeline expansion scenarios.

- Whether conditions exist under which gas delivery capacity is so limited that a shortage results because minimum gas requirements for meeting electric load cannot be fully supplied.

  The number of days on which the maximum potential gas demands for electric generation can be met and the percentage of the total annual potential demands that are met.

Our approach utilizes separate models for the electric and gas systems. Consistent equilibrium solutions are obtained by iterating between the two models. The General Electric Multi-Area Production Simulation (GE MAPS) model is used to simulate operation of the Northeast regional electric system.[18] The New York gas transportation system is modeled using a GRIDNET-based

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[17] All of the electric capacity expansion scenarios exceed the NYCA locational and statewide installed capacity requirements. In addition, the MAPS modeling accounts for required spinning and non-spinning operating reserves.

[18] The GE MAPS model is a Multi-Area Production Simulation (MAPS), which simulates the hourly operation of the electric generation and transmission system, including the impacts of transmission constraints and operating reserve requirements. The model minimizes the total system cost of meeting forecasted electricity demands given key economic and engineering assumptions (*e.g.*, fuel costs, heat rates, etc.) for electric generating units.

model. The appendices to this report provide more detailed descriptions of both models, along with an overview of the gas and electric infrastructures serving New York.

Our iterative modeling approach begins with estimating the maximum potential gas demands for each day of the year using the GE MAPS model. The MAPS model performs an hourly commitment and dispatch of the electric system, assuming that gas-fired generators are able to purchase gas at a relatively low price (below that of residual oil) and obtain their full, or maximum potential, unrestricted demands.

The hourly fuel demands for each electric generating unit are summed by day to obtain the corresponding daily demands, which are fed into the gas model. The gas model is then dispatched to see what portion of the maximum total potential gas demands can be met, given pipeline and LDC deliverability. If the maximum potential gas demands cannot be met, generating units are recommitted and/or redispatched using the GE MAPS model or, in the case of dual-fuel steam units, simply switched to oil until the level of gas demands matches available gas supplies for each gas delivery node.

If there are any days when the gas system is unable to meet the minimum gas requirements for generation (*i.e.*, if all non-gas-fired generating capacity is in operation and gas-fired generation must then operate to meet electric load in any electric load pockets), those days are identified as a shortage situation in which electric load cannot be met.

This approach allows us to identify:

- Maximum potential amount of gas that generators would consume if deliverability were never constrained.

  Days on which these full, unrestricted demands will not be met and some redispatch to oil-fired units or units in another location will be required.

  The total amount of gas and oil burned in each pipeline/capacity addition scenario.

  The amount of pipeline capacity expansion needed to fully meet maximum potential gas demands.

- The number of days during which CCs are likely to run on gas under various levels of pipeline expansion.

The detailed modeling results for each generating unit can be aggregated (over time and by geographic area) to characterize overall gas and electric system performance.