Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator

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EXECUTIVE SUMMARY

Introduction

In 2003 the NYISO implemented an ICAP demand curve mechanism to establish market-responsive installed capacity (ICAP) prices to facilitate unforced capacity transactions between generators and load serving entities (LSEs). ICAP auctions under the demand curve mechanism have been designed to provide more stable sources of capacity revenues to generators, thereby promoting resource adequacy objectives over the long-term. The NYISO conducts monthly spot market auctions using the ICAP demand curves to establish unforced capacity (UCAP) requirements for utilities and other LSEs.

In March, 2004, NYISO retained Levitan & Associates, Inc. (LAI) to calculate new reference values for the ICAP demand curves to determine (i) the locational ICAP obligations for New York City (Zone J), (ii) the locational ICAP obligations for Long Island (Zone K) and (iii) the total statewide ICAP requirement. These ICAP reference values are based on the capital and operating costs of hypothetical gas turbine peaker additions located in the three regions in the 2005, 2006, and 2007 capacity years. In performing this analysis, we have assumed that investment in new gas turbine peaking capacity is rationalized as follows:

- Capacity, energy, and ancillary services from postulated gas turbine peakers can be "merchandised" at compensatory prices, *i.e.* sold at market-based prices that provide equity investors with a reasonable return on investment.

- The postulated peaker additions in Zone J, Zone K, and rest-of-state (ROS) incorporate gas turbine technology that best fits the load-following requirements of the zone.

- Engineering, construction, and operating responsibilities are properly allocated to credit-worthy parties.

LAI has assumed that the plants are financed on-balance sheet by a credit-worthy parent entity, using balance sheet debt and equity funds that reflect the risks of the project asset. The reference values reported in this study are expressed in levelized constant dollars for each of the three years. In other words, the reference values are the first value in a stream of capacity values that increase over time at the underlying 3% general inflation rate.

Plant cost and performance assumptions were calculated for "typical" plants within each of the three regions: Zone J, Zone K, and ROS. These assumptions are purposely not site-specific, but do reflect the key cost components that differentiate the total installed cost of new capacity in each region. The capital costs we derived incorporate vendor quotes and commercial intelligence supplied by DMJM+Harris, a leading engineering firm with substantial gas turbine experience, particularly in New York City and Long Island. LAI has supplemented that information with in-house data regarding gas and electric interconnection costs, operating costs and other components of total project capitalization.[1]

We calculated ICAP reference values for 2005 under three distinct calculation assumptions and compare them to the 2004 values.[2] Case I only captures plant capital and fixed operating costs. Cases IIa and IIb include net energy and ancillary service revenues, and therefore reflect LAI's forecast of peaker dispatch factors by zone under our forecast of hourly market energy prices. From a method standpoint, LAI derived the net revenues on both a deterministic and probabilistic basis:

- Case I just considers capital and fixed operating costs; the net revenues recoupable from the sale of energy and ancillary services are not included.

- In Case IIa, we include net revenues on a deterministic basis, where load is treated as a fixed construct. Energy prices are inherently less volatile, thereby reducing net revenues realized by peakers as well as the overall level of plant dispatch.

- In Case IIb, we include net revenues on a probabilistic basis, where load is treated stochastically using Monte Carlo analysis in order to simulate the impact of uncertain load conditions and other market uncertainties on energy prices. Increased energy price volatility increases peaker dispatch, thereby increasing net revenues derived from energy sales and decreasing required capacity revenues.

The table below indicates the 2003 and 2004 NYISO values and the 2005 values calculated by LAI under the three cases.[3] The LAI values were based on peaker ratings at ISO (*i.e.* 59°F) conditions. We did not attempt to adjust our results to account for differences between summer and winter plant demonstrated maximum net capacities (DMNC), nor did we translate the estimated ICAP reference values into UCAP values.

Table 1 – Summary of Reference Values
($/kW-yr)

Location	2003 Levelized Gas Turbine Cost	2004 Values With Phase-In	2005 Values Calculated by LAI		
			Case I	Case IIa	Case IIB
Zone J	$159	$130	$176	$152	$128
Zone K	$139	$114	$155	$148	$135
ROS (7FA)	$ 85	$ 60	$116	$116	$109

[1] Plant cost and performance assumptions were presented by LAI to the ICAP Working Group in prior stakeholder meetings held on April 22 and May 27, and incorporate a number of modifications and refinements based on constructive feedback from Working Group participants.

[2] LAI uses the term "reference values" generally to include the previous 2003 estimates of the levelized capital and fixed operating costs of a gas turbine (*i.e.* without phase-in adjustments), the values actually used to establish the 2003 and 2004 demand curves (*i.e.* with phase-in adjustments), and the 2005-2007 values calculated by LAI.

[3] The 2003 and 2004 values were presented at the February 13, 2003 NYISO Management Committee Meeting.

Both the deterministic and probabilistic scenarios presented in this report encompass complex market dynamics associated with large "discrete" blocks of generation added in New York City, Long Island, and, to a lesser extent, ROS. These results do not represent dispatch simulations where locational reserve margins are deemed "tight," *i.e.* at the NYCA Minimum Installed Capacity Requirement or the Locational Minimum Installed Capacity Requirement. Conducting simulations under tight conditions would invariably increase net revenues over the near-term and decrease reference values, particularly in Zones J and K when near-term resource additions are expected to push locational capacity above their minimum requirements.

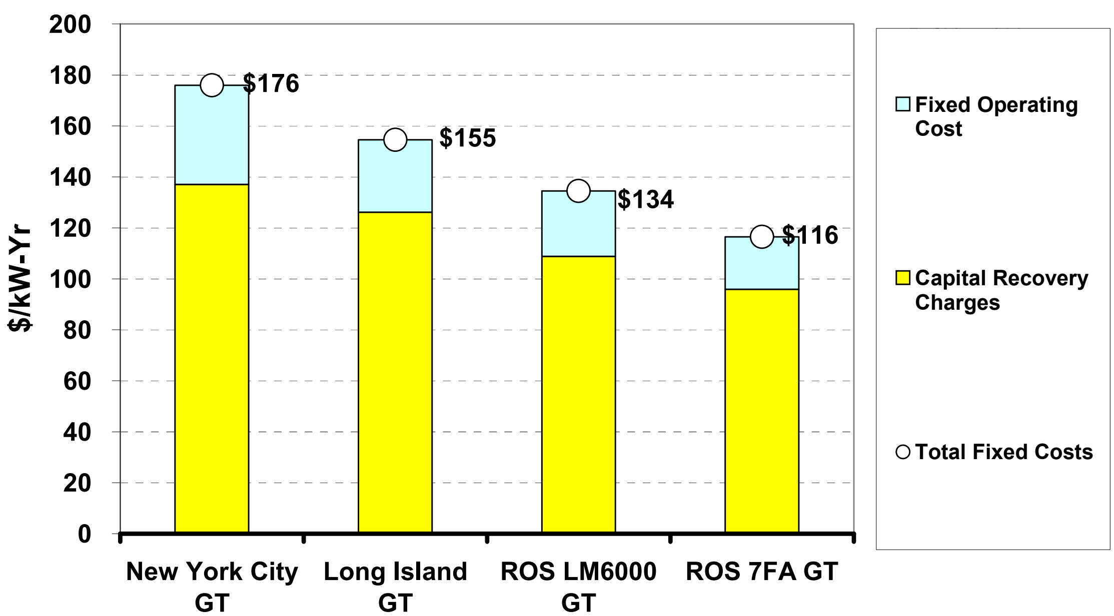
Case I – Capital and Fixed Operating Costs

LAI calculated reference values for 2005, 2006, and 2007, based on the capital costs that developers need to recover over the plant's economic life, plus fixed operating costs. This approach does not consider net revenues from energy and ancillary service sales. The resulting reference values shown in Figure 1 illustrate the contribution of the two cost components – capital recovery charges and fixed operating costs. Reference values for 2006 and 2007 increase at 3% per year.

- Our estimated 2005 reference value for Zone J of $176/kW-yr is 11% higher than the 2004 levelized value of $159/kW-yr.

- Our estimated 2005 reference value for Zone K of $155/kW-yr is 12% higher than the 2004 levelized value of $139/kW-yr. The Zone K cost is lower than Zone J due to a variety of factors, including lower construction costs, property taxes, and site lease costs.

Figure 1 – Case I Levelized Capacity Revenue Requirements – 2005



- The estimated reference value for an aeroderivative peaker project comprised of two GE LM6000 units (2xLM6000) in ROS is \$134/kW-yr, 14%-24% less than in Zones J and K, primarily as a result of lower construction costs. The 2004 ROS levelized value was not based on a 2xLM6000 plant and therefore is not comparable.

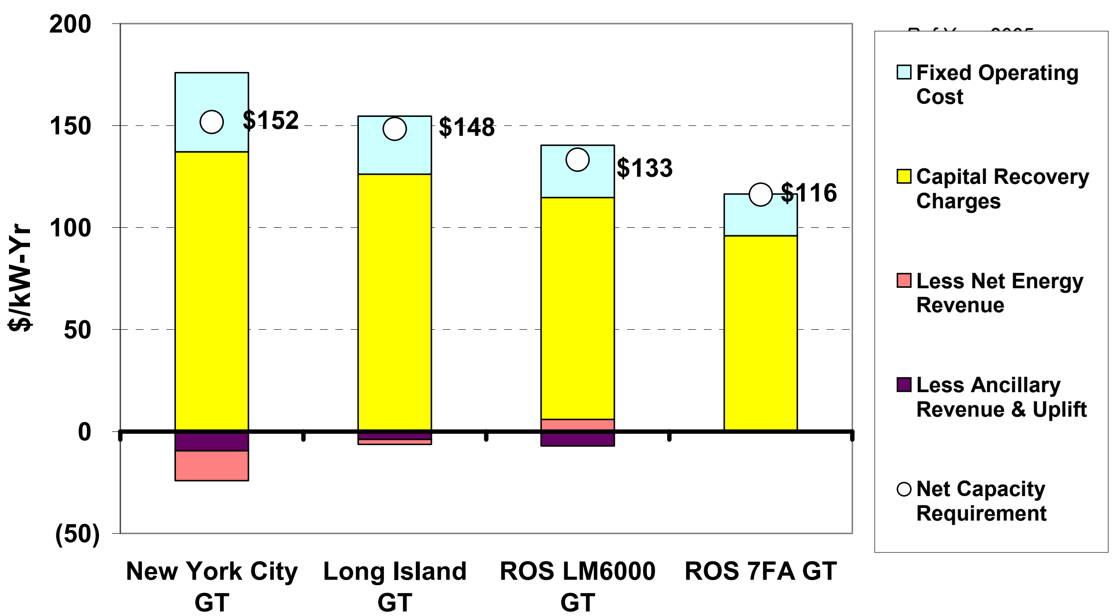
- The ICAP reference value for an industrial frame peaker project comprised of two GE 7FA units (2x7FA) plant in ROS is \$116/kW-yr, 13% less than a 2xLM6000 plant in ROS due to the lower unitized capital costs for the larger plant. Our estimated 2005 2x7FA ROS reference value is 36% higher than the 2004 levelized value of \$85/kW-yr, principally due to a higher estimated capital cost.

Case IIa – Capital and Fixed Operating Costs plus Net Revenues – Deterministic

LAI calculated net energy and ancillary service revenues likely to be earned over the expected peaker plant life using a chronological dispatch simulation model. In order to more accurately forecast the different levels of net revenues that contribute to the recovery of capital and fixed operating costs, we divided NYCA into five zones and included the surrounding markets of ISO-NE, PJM, Ontario, and Quebec. Zones J and K were modeled individually, and the ROS peakers were modeled in Zone GHI to avoid Central/East and UPNY/SENY transmission constraints.

The components underlying the Case IIa 2005 reference values are shown in Figure 2. These reference values include the Case I components of capital recovery charges and fixed operating costs, as well as the offsetting net energy and ancillary service revenues. Reference values for 2006 and 2007 increase at 3% per year.

Figure 2 – Case IIa Deterministic Levelized Capacity Revenue Requirements – 2005



- The gas turbine peakers in Zone J are expected to be dispatched at capacity factors ranging between 13%-15% over the forecast period when load is treated deterministically. The capacity factors decrease in 2006 after the new Poletti station, the repowered East River station, and the SCS Astoria project become operational. Upon retirement of the existing Poletti station in 2008, peaker capacity factors recover. Peakers in Zone J earn the largest net revenues from the sale of energy and ancillary services, thereby substantially reducing the levelized capacity revenue requirements by $24/kW-yr in 2005, increasing to $27/kW-yr in 2007.

- The peakers in Zone K are expected to operate at a 7% capacity factor in 2005 and decline to the 3%-4% range beginning in 2007. This decline is due to the anticipated start-up of the proposed Neptune transmission cable, Caithness Bellport, and other smaller scale combined cycle plants. Energy prices in Zone K are substantially reduced following this transmission and generation entry on Long Island. Hence, the net revenues realized by peakers on Long Island lower the Zone K levelized capacity revenue requirement by only $7/kW-yr.

- The 2xLM6000 peakers in ROS are forecasted to operate at a 3% - 8% capacity factor in the early years, and at higher capacity factors in the later years. In the deterministic load case, the peakers rarely run when the market price is above their energy bid, indicating that the peakers are either the marginal unit or dispatched for reserves. While daily startup costs are recovered through the production cost guarantee mechanism, net energy revenues can be approximately zero. Therefore the net revenues, including ancillary services, only reduce the levelized capacity requirement by $1/kW-yr to $2/kW-yr.

- The 2x7FA peakers in ROS are dispatched sparingly in the deterministic case due to the comparatively high heat rate and less flexible ramp rate relative to aeroderivative technology. The 2x7FA peakers in ROS would realize no net energy revenue and very little revenue from the ancillary services market. Hence, the Case IIa levelized capacity revenue requirement changes by no more than $1/kW-yr from Case I.

Case IIb – Capital and Fixed Operating Costs plus Net Revenues – Stochastic

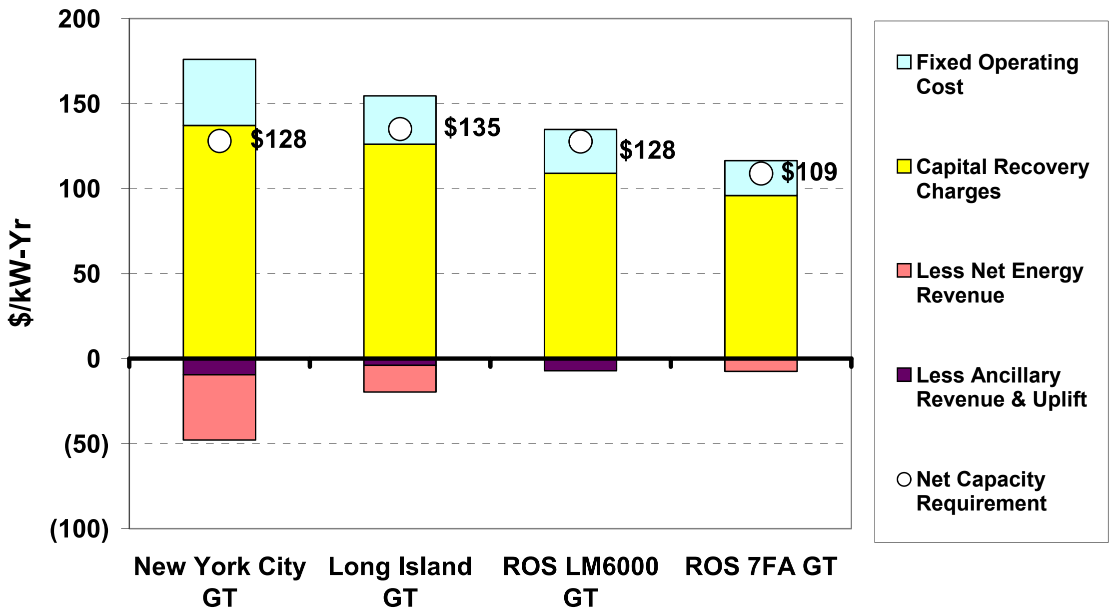
In Case IIb LAI forecasted net revenues with stochastic treatment of load to better forecast gas turbine dispatch and the occasional energy price spikes.[4] Varying the loads causes Special Case Resources (SCRs) to set the market energy price during a small number of hours each year, akin to including periods of extreme weather and system contingency events. Market energy prices increase compared to the deterministic case, as does peaker dispatch. LAI made the simplifying assumption that all generators would receive the higher market energy prices for all hours of operation, so that net energy revenues increase in all regions. As with the other cases, reference values for 2006 and 2007 increase at 3% per year from the 2005 values.

[4] In preliminary analyses LAI utilized "bid adders" to improve our deterministic forecast of gas turbine peaker dispatch and market energy price spikes; for this final report LAI utilized this stochastic methodology instead.

- The Zone J peaker capacity factors increase by 4% (*e.g.* from 15% to 19% in 2005), and net revenues double compared to Case IIa. Levelized net revenues increase from $24/kW-yr to $48/kW-yr for the 2005 reference year as a result of treating load stochastically, reducing the required levelized capacity revenues considerably.

- Zone K peaker dispatch increases from 7% to 10% in 2005, and by slightly larger amounts in later years (*e.g.* from 3% to 7% in 2026) compared to Case IIa. Levelized net revenues increase significantly, from $6/kW-yr (deterministic) in 2005 to $19/kW-yr (stochastic), reducing the required levelized capacity revenues by $13/kW-yr.

Figure 3 – Case IIb Stochastic Levelized Capacity Revenue Requirements – 2005



- ROS peakers experience the largest increase (in percentage terms) in net revenues compared to the almost insignificant net energy and ancillary service revenues in the deterministic case. The 2xLM6000 and 2x7FA plant capacity factors increase by only about 1% over the forecast horizon in Case IIb. However, both technology types earn a share of very high-priced energy revenues during the peak load hours. The 2xLM6000 levelized net revenue increases from $1/kW-yr to $6/kW-yr for the 2005 reference year, and the 2x7FA levelized net revenues increase from close to $0/kW-yr to $7/kW-yr.

Technology Choice

It was determined that a peaking plant consisting of two simple cycle LM6000 Sprint aeroderivative gas turbine units would be appropriate for Zones J & K, since all of the NYPA PowerNow! and virtually all of LIPA Fast Track units installed in the past few years utilized this technology. In ROS, either this 2xLM6000 plant or one consisting of two industrial

Frame 7FA gas turbines in simple cycle would be appropriate for peaking operation.[5] Both peaker configurations were assumed to operate on natural gas to avoid the capital costs of on-site liquid fuel storage and specialized combustion equipment. Average long-term performance data for these plants, based on vendor-supplied data, are provided in Table 2 below. These data include average levels of long-term performance degradation, and are expressed at winter and summer temperatures, as well as at ISO conditions.[6]

Table 2 – Gas Turbine Peaker Performance Data (with average long-term degradation)

Plant Type	2xLM6000			2x7FA		
Temperature	25°F	59°F	90°F	25°F	59°F	90°F
Net Capacity (MW)	97.7	96.0	83.7	351.6	326.4	293.0
Heat Rate (Btu/kWh)	9,528	9,739	9,961	10,635	10,809	11,127

LAI assumed that the 2xLM6000 plants would be able to operate at its full capacity of 96.0 MW (ISO rating). The same plants installed by NYPA and LIPA were limited to 79.9 MW, perhaps to expedite the permit approval process by avoiding the Article X permitting process then in effect. However, Article X expired on January 1, 2003. Whether or not an "Article X-type" environmental review process will be reinstituted in New York State is unknown at this time.

Capital Costs

LAI estimated the total capital cost of new peaker plants in the three regions with the assistance of DMJM+Harris. DMJM+Harris has substantial engineering, design, and construction management experience building generation projects using natural gas technology, including many gas turbine projects in Zones J and K.

LAI and DMJM+Harris obtained vendor quotes for the power island equipment and estimated the other cost categories based on experience and sample plant data. The other categories include owner's costs (permitting, legal services, owner's engineer, emission reduction credits, social justice, and financing), engineering & construction (labor, materials, on-site and off-site electric and gas interconnections), and startup & testing.[7] Our capital cost estimates are summarized in Table 3 below.[8]

[5] Although combined cycle plants would be expected to earn higher energy revenues, thereby lowering the requisite required capacity revenues, the NYISO ICAP manual specifies that the demand curve reference values be based on gas turbine peakers. Moreover, LAI's method of timing new additions to meet long-term load growth relies on both plant types having equivalent net capacity revenue requirements. Therefore ICAP demand curve reference values should be almost identical for these technologies.

[6] ISO (International Standards Organization) conditions are 59°F and 60% relative humidity at sea level; New York City's average temperature is about 55°F.

[7] Land costs were not capitalized; site lease costs were included as fixed operating costs.

[8] Some ICAP Working Group members expected the 2xLM6000 plant to be even more expensive relative to the 2x7FA plant. However, the 2xLM6000 plant is not limited to 79.9 MW in our study, thus lowering that plant's unitized capital cost, and our estimated cost of a 2x7FA plant is much higher than the Working Group's 2001 cost estimate of $413/kW.

Table 3 – Gas Turbine Peaker Capital Costs
(millions 2004 $)

Location Plant Type	New York City 2xLM6000	Long Island 2xLM6000	ROS 2xLM6000	ROS 2x7FA
Owner's Costs	$ 10.3	$ 9.2	$ 5.1	$ 16.9
Equipment	$ 41.5	$ 41.5	$ 41.5	$ 119.3
Construction	$ 61.2	$ 56.4	$ 45.7	$ 140.8
Startup & Testing	$ 1.0	$ 1.0	$ 1.0	$ 2.6
Total Capital Cost	$ 114.0	$ 108.1	$ 93.2	$ 279.7
/ Net Capacity (MW)	*96.0*	*96.0*	*96.0*	*336.5*
Unitized Capital Cost	*$ 1,188/kW*	*$ 1,126/kW*	*$ 971/kW*	*$ 831/kW*

The unitized capital costs in Table 3 are based on the net plant capacities at ISO conditions in "new & clean" condition ***before*** any performance degradation. The 2xLM6000 unitized costs indicate that constructing a peaking plant in New York City or Long Island is more expensive than an identical plant in the ROS, principally due to higher labor rates. The ROS data indicate that the much smaller 2xLM6000 plant is 17% more expensive than the 2x7FA plant on a unit cost basis, principally due to economies of scale. However, the LM6000 unit can achieve full load operation in ten minutes (allowing for higher emissions prior to operation of the selective catalytic reduction system) and is better suited to simple cycle operation, while the 7FA gas turbine takes longer to achieve full load and is more commonly used in combined cycle operation.

Fixed Operating Costs

LAI estimated the fixed operating costs that an owner would incur based on historical, publicly available plant data and confidential in-house plant data. As shown in Table 4, the most significant category is property taxes. Other fixed operating costs include the site lease, contract services, staffing, insurance, and general & administrative costs.

Table 4 – Fixed Operating Costs
(2004 $/kW-yr)

Location Plant Type	NYC 2xLM6000	Long Island 2xLM6000	ROS 2xLM6000	ROS 2x7FA
Property Taxes	$ 25.66	$19.06	$17.96	$15.54
Other	$ 12.05	$ 8.55	$ 6.99	$ 4.42
Total	$ 37.71	$27.61	$24.95	$19.96
Levelized 2005 Values ($/kW-yr)	$38.85	$28.44	$25.69	$20.55

Net Revenues

Reference values for Cases IIa and IIb include the net contribution (*i.e.* after fuel and variable operating costs) toward capital cost recovery from energy and ancillary services. LAI forecasted the expected net revenues using MarketSym, an advanced chronological dispatch simulation model. The hourly operation of the NYISO market, along with the surrounding markets in New England, PJM, Ontario, and Quebec, were simulated to capture the effect of bulk power flows across the transmission lines between neighboring market areas. NYISO was divided into five zones in order to depict relevant congestion effects across in-state transmission interfaces that give rise to energy price differentials. Zone J and Zone K were modeled individually. We selected a combined GHI zone to calculate the net revenues for a gas turbine peaker in ROS to avoid the Central/East and UPNY/SENY transmission limitations. Ancillary service revenues for the 2xLM6000 plants were based on the value of providing Ten Minute Non-Synchronous Reserves (TMNRR), while the 2x7FA revenues include Thirty Minute Reserves (TMR).

Supply Assumptions

LAI initialized the generation supply mix based on the NYISO 2004 Gold Book. We included SCRs that contribute to meeting ICAP throughout the forecast period. Near-term supply resources that are operating or are currently under construction were added, as well as resources that have entered into or won competitive solicitations for long term Power Purchase Agreements (PPAs). LAI used our in-house Entry Model to add sufficient supply resources in the long-term to maintain the minimum locational ICAP requirements for Zone J and K and the required NYCA reserve margin. Announced plant retirements were removed from the supply mix. Based on our in-house Attrition model, LAI does not foresee additional retirements over the long-term.

Load Assumptions

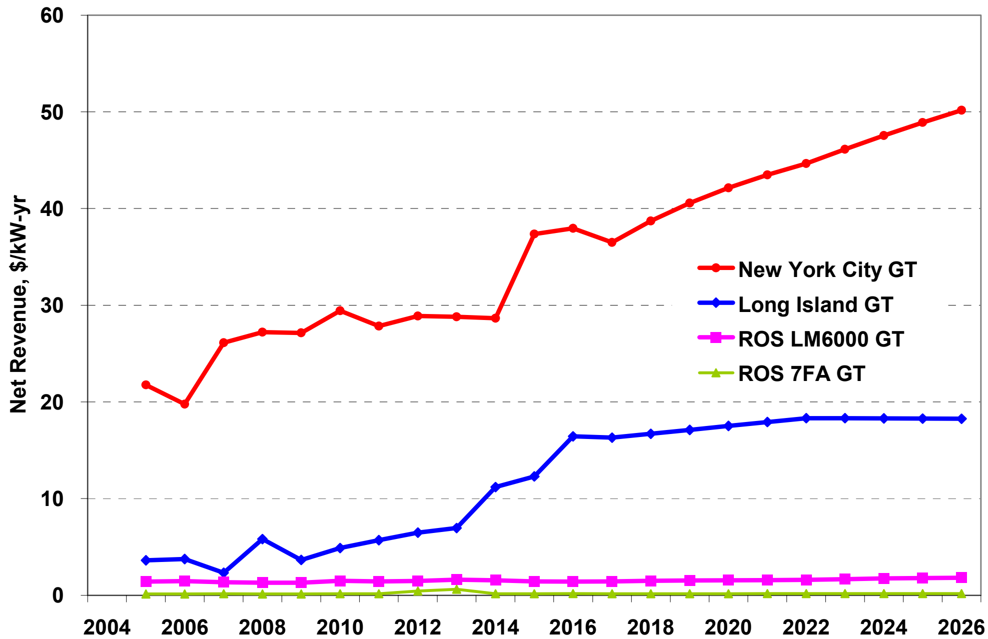
All of our dispatch simulation runs utilized the 2002 hourly load profiles for the NYISO zones. These profiles provide a useful range of peak and off-peak loads and have been utilized for other NYISO resource adequacy studies. Long-term changes in peak load and annual energy were taken from the 2004 Gold Book and extrapolated through 2026.

Deterministic versus Stochastic Treatment of Load

Gas-turbine peakers earn significant revenues during a small number of operating hours that have unusually high prices. Indeed, the quick-start capabilities of the LM6000 units make them especially valuable in the Real Time Market when energy prices sometimes skyrocket for brief intervals. Although the 2002 load profile includes typical peak loads, it does not include the day-to-day volatility necessary to estimate the potential energy revenues of peakers that operate at the upper end of the merit order stack. Volatility of market energy prices is largely driven by fuel (especially gas) price volatility during winter months and by load volatility throughout the year. However, gas price volatility also raises plant operating costs, thereby tempering a peaker's ability to derive premium profits from energy sales. Therefore, we focused our stochastics on load for purposes of deriving net revenues on a probabilistic basis.

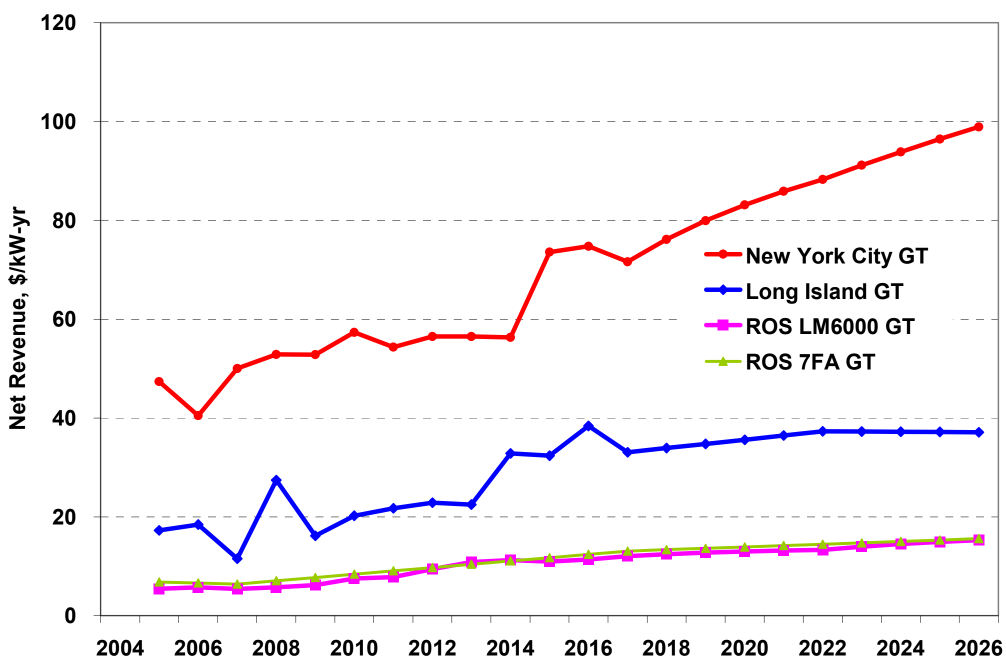
Net energy revenues for peakers in Zone J are higher than in other zones and increase significantly over the forecast horizon under both the deterministic and stochastic treatment of load. LAI believes the Zone J load profile is the fundamental reason. Unlike the load shapes for the other zones, Zone J has a greater percentage of hourly loads that are close to the peak load, and is the only zone with an increasing load factor, making peaker operation profitable during many more hours over the forecast horizon.

Figure 4 – Case IIa Deterministic Annual Net Revenues



Case IIb reference values were calculated by conducting fifty Monte Carlo iterations for three selected years using normal distributions around the daily load forecasts for the five NYISO zones. Figure 4 illustrates Case IIa peaker net revenues with deterministic treatment of load, and Figure 5 illustrates Case IIb net revenues with stochastic treatment.

Figure 5 – Case IIb Stochastic Annual Net Revenues



Levelization

The last step in this assignment was to calculate the levelized capacity revenue requirements for gas turbine peakers net of energy and ancillary service revenues. LAI levelized the capacity revenue requirements using the cost of equity for merchant peakers. Project financing of merchant power plants no longer appears to be viable, and long-term PPAs may not be available under the competitive market design. Therefore we assumed that a parent company would provide the debt and equity capital, the costs of which reflect the risks of a rational merchant plant investment, assuming a properly functioning ICAP mechanism that provides appropriate and stable ICAP revenues. Given the demise of the merchant financing market, it is not possible to determine the cost of capital with precision. Based on discussions with commercial bank lenders and financial advisors, however, we believe that a 50%/50% debt/equity ratio is reasonable, with an interest rate of 7.5% for 20 year debt, and a 12.5% (after-tax) equity rate of return.

Demand Curve Analysis

LAI conducted an analysis of the demand curves resulting from our calculations by testing the economic incentives for a supplier to withhold capacity to maximize revenues, and by calculating the total cost of ICAP to the regional market. Total ICAP costs were calculated with and without postulated withholding, as well as under alternative zero crossing points.

Our analysis provides only the theoretical maximum impact on the revenue of a supplier with a representative portfolio, and the region's cost of a hypothetical withholding scenario, but reasonable conclusions can be drawn from the our assessment of policies related to management of the ICAP spot market. The Case I, Case IIa, and Case IIb 2005 ICAP demand curves are illustrated in the following three figures, along with the 2004 demand curves (prior to the summer DMNC adjustment). At this point we have no recommendation to change the zero crossing point; any recommendation should be based on analyzing the final 2005 reference values and actual supply bid data.

Figure 6 provides the current and 2005 ICAP demand curves for the NYCA market based on the 2x7FA plant (which was selected for ROS because it has a lower capacity revenue requirement than the 2xLM6000 plant). Due to a higher estimated capital cost than incorporated in the current demand curve, the Case I and Case IIa demand curves (which are virtually identical) have a significantly steeper slope. The stochastic results in Case IIb lower the reference value and the demand curve slope slightly, but would still significantly increase the slope of the NYCA demand curve.

Figure 6 – NYCA Demand Curves – 2004 and 2005 Deterministic and Stochastic

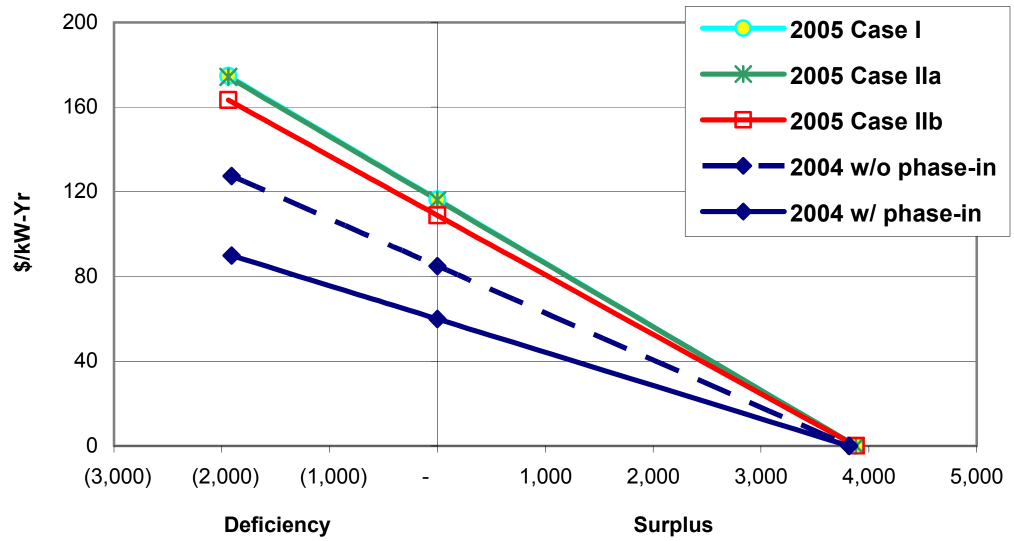
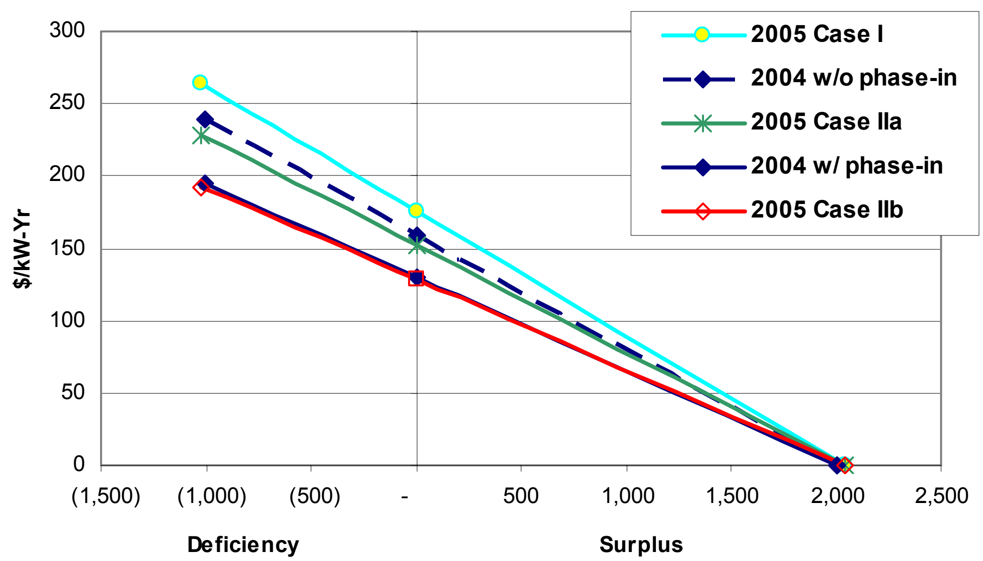


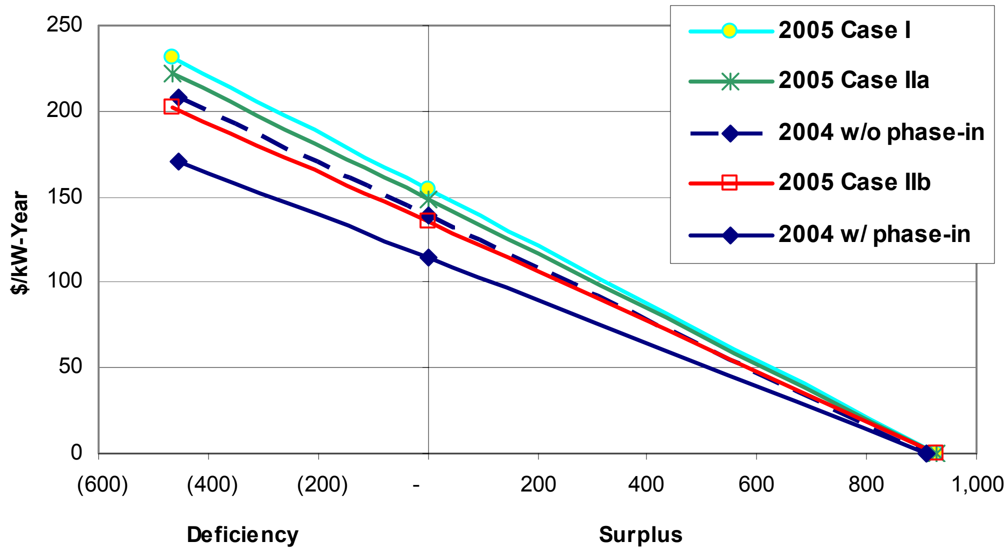
Figure 7 depicts the 2004 and 2005 demand curves for Zone J. Moving from the current reference value of $130/kW-yr (with phase-in) to $152/kW-yr in Case IIa would make the demand curve steeper. Utilizing the Case IIb value of $128/kW-yr would have minimal effect on the demand curve. Our withholding analysis indicates that Zone J provides significant incentives for suppliers to withhold and that such withholding would have significant impact on price and total cost of ICAP, assuming all ICAP was priced at the ICAP reference value.

Figure 7 – Zone J Demand Curves – 2004 and 2005 Deterministic and Stochastic



The calculated 2005 demand curves for Zone K for Case I and Case IIa are more steeply sloped than the current demand curve. The current Zone K demand curve is identical to the calculated 2005 demand curve for Case IIb. Due to the nature of the Zone K capacity market (*i.e.* essentially all capacity is procured under a long-term contract by a single buyer), we did not conduct a withholding analysis of that market.

Figure 8 – Zone K Demand Curves – 2004 and 2005 Deterministic and Stochastic



1 GAS TURBINE ASSUMPTIONS

The gas turbine assumptions in this section of the report, particularly capital cost data, were developed with the assistance of DMJM+Harris, an engineering consulting firm specializing in energy and other industries. DMJM+Harris has a diverse staff of engineers, designers, construction specialists, and other professionals, and provided program and construction management services to both NYPA and LIPA for their LM6000 gas turbine peaker projects.[9] DMJM+Harris is also working on the two LM6000 projects in Freeport, Long Island, and the NYPA Poletti combined cycle project in New York City. The gas turbine peaker assumptions are based on "typical" plants within each region and are not site-specific.

TECHNOLOGY CHOICE

The ICAP demand curves are based on the localized, levelized cost of a gas turbine peaker for NYC, LI, and ROS. There have been many gas turbine installations in NYC and LI over the past few years that have consisted of one or two aeroderivative units (typically GE LM6000) per site. Gas turbine peaker projects in ROS were proposed during the same period using industrial frame GE 7FA units. One peaker project at the Indian Point site was originally designed with eight aeroderivative units and was later amended to two 7FA units, but this project appears to have been cancelled. Another project at Torne Valley was originally designed as a combined cycle plant and was changed to a peaker, also using 7FA units. Both of these projects appear to have been cancelled. In PJM, a number of frame 7FAs were installed in simple cycle at the Lakewood (two units; site is permitted for three units) and Rock Springs (four units; site is permitted for six units) plants. Based on this information, we have made the following technology assumptions:

- In NYC and LI we assumed a peaker plant would consist of two LM6000 aeroderivative units. Since Article X expired on January 1, 2003, and there is no indication that a new Article X will be approved in the near term, we did not limit the 2xLM6000 peaker plant output to less than 80 MW. [10]

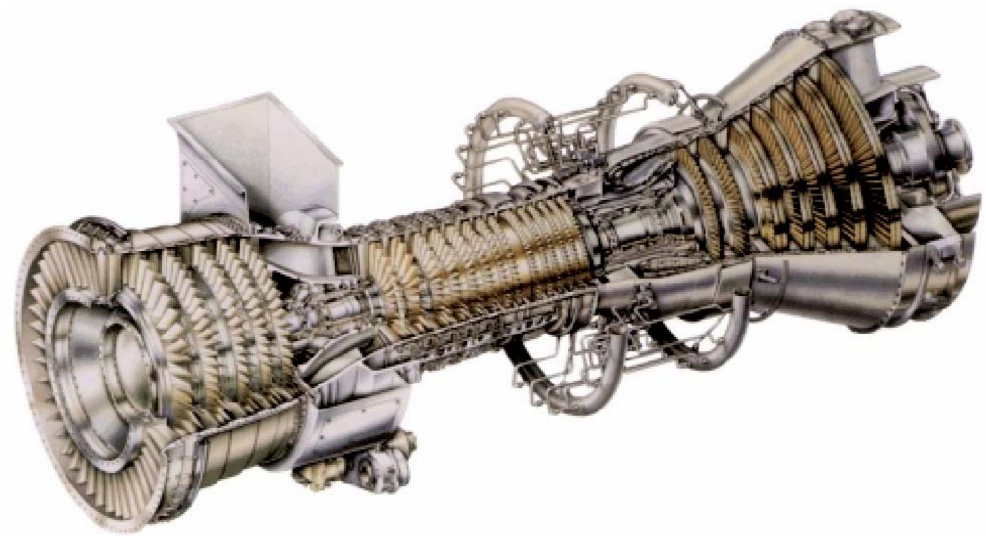
- In ROS future peaker units could be either aeroderivative or industrial frame units. Therefore we calculated costs and performance values to model both a two LM6000 plant and a two industrial Frame 7FA plant in ROS.

According to GE the "standard" LM6000 package has evolved to incorporate Sprint technology, *i.e.* spray inter-cooling at the low-pressure and high-pressure compressor sections. Sprint appears to be a cost-effective technology that increases plant output and improves efficiency during hot weather conditions. We have confirmed that all of the 2001 PowerNow! LM6000 gas turbines installed by NYPA incorporate Sprint technology. We have also confirmed that all of the LM6000 gas turbines installed for LIPA in their Fast Track Summer 2002 Project incorporate Sprint technology, as does the Village of Freeport project.

[9] DMJM+Harris's gas turbine experience is provided as Appendix A.

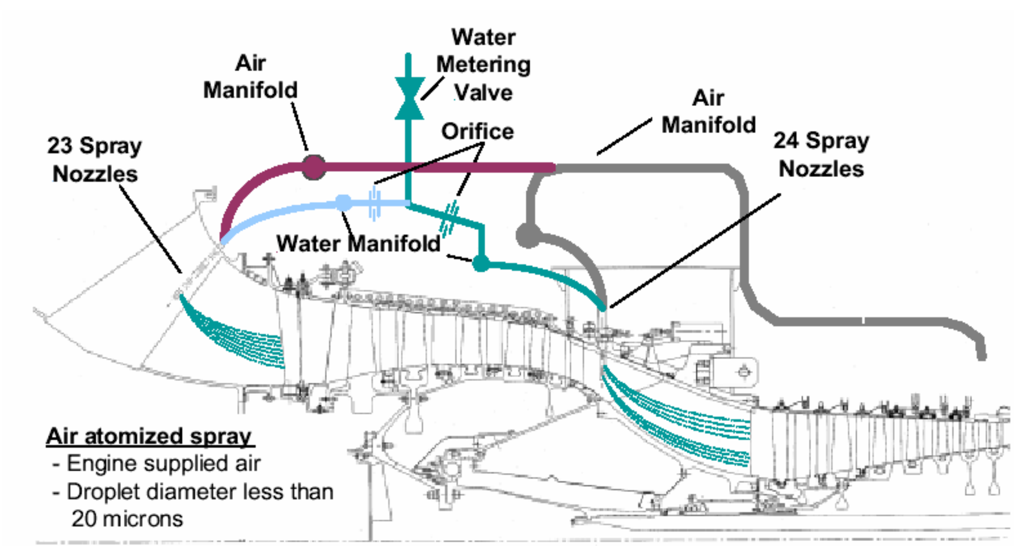
[10] If Article X were reinstated, it is impossible to forecast what, if any, effect there would be on project definition, since the size threshold may be different than 80 MW.

Figure 9 – LM6000 Cutaway Diagram



The 2xLM6000 or 2x7FA installations would be configured with single fuel (natural gas) capability since it is costly to install specialized combustion equipment and either fuel oil storage or a pipeline connection to a site for a peaker that operates at a low capacity factor. All of the NYPA PowerNow! LM6000 units in Zones J and K are gas-only, while all of the LIPA Fast Track LM6000 units in locations with gas service are gas-only.[11] Both the 2xLM6000 and 2x7FA plants would be designed so that each unit could operate independently but have certain common/shared balance-of-plant (BOP) systems such as gas compression, compressed air, de-mineralized water, ammonia systems, electrical systems, etc.

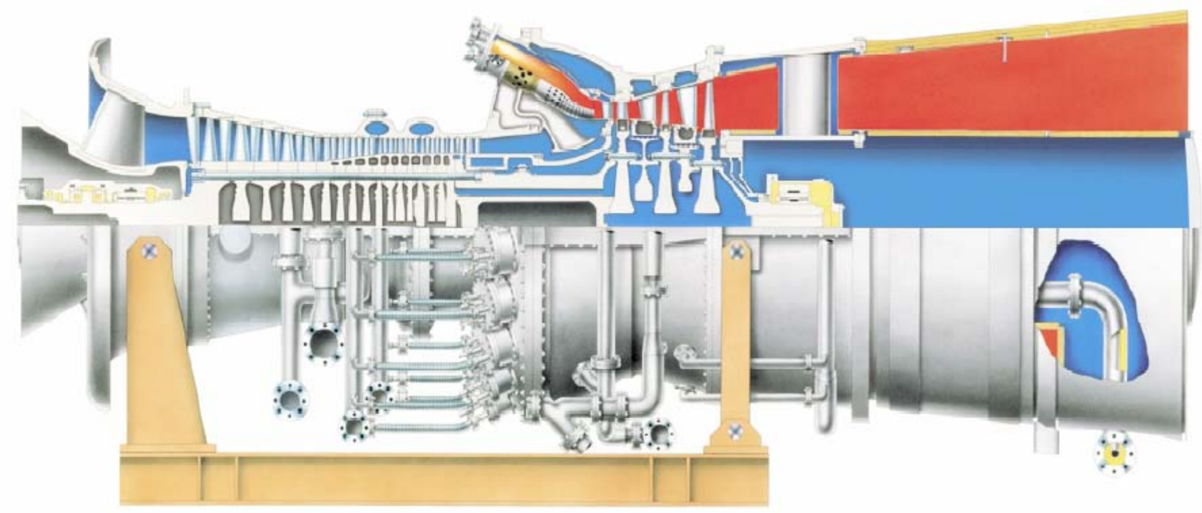
Figure 10 – Sprint Cross Section



[11] Gas service is not available in the Shoreham area where there are two LM6000 units that operate on fuel oil. Another LIPA unit at Jamaica Bay, using Pratt & Whitney FT-8 technology, relies on fuel oil.

The design of the LM6000 unit allows it to achieve full load operation within 10 minutes. The selective catalytic reduction system (discussed below) takes considerably longer to warm up (estimated at 15-35 minutes, depending on ambient temperature) and become operational. Provided that air permit conditions incorporate provisions to accommodate potential short-term exceedances of applicable emission standards during start-up, the LM6000 can provide TMNSR in the NYISO ancillary services market.[12] Although many recently constructed LM6000 units do not provide TMNSR, very few plant types can provide this needed service. Having the ability to provide TMNSR does not materially increase the plant's capital cost. Therefore we have assumed that 2xLM6000 plants would provide TMNSR.[13] The 7FA is an industrial frame unit that requires some degree of preparation before a start-up can be attempted, and can usually achieve full load simple cycle operation within thirty minutes, enabling it to provide TMR.

Figure 11 – Frame 7FA Cutaway Diagram



EMISSION CONTROLS

Both types of peaker plants would be fitted with selective catalytic reduction and oxidation catalysts to control NO_x and CO emissions to meet current state and federal standards.

- It is anticipated that the LM6000 units would utilize water injection to control NO_x in the combustion area and would not be a major source of criteria pollutants. Therefore the units would not trigger the requirements of New Source Review (NSR), including the requirement to obtain emission reduction credits (ERCs) in non-attainment areas.[14]

[12] The applicable federal requirement at 6NYCRR 201-1.4 allows for such flexibility.

[13] Our assumption is consistent with the 2003 State of the Market Report, New York Electricity Markets, April 2004, pages 37-40.

[14] To remain under the applicable NSR thresholds, these plants would likely have to incorporate enforceable operating hour limits in their air permits as was employed by the 2002 LIPA Fast Track units.

- We estimate that emissions from the 7FA units would exceed the applicable thresholds for NSR for moderate non-attainment areas, and would be required to obtain ERCs for NO_x and VOCs at the appropriate ratio.[15]

PERFORMANCE

We have used the following performance assumptions based on vendor specifications and actual operating experience.[16] In all cases we assume that the gas turbines operate on natural gas year-round. The performance of both types of gas turbines (aeroderivative and industrial frame units) is affected by ambient air temperature and by long-term degradation. The cost and performance impacts of the inlet chillers were not included for the gas turbines. Performance degradation over time is usual and unavoidable, and is addressed through periodic equipment maintenance, replacement, and unit overhauls. The Sprint water injection feature of the LM6000 gas turbine allows that unit to compensate for capacity degradation; these units are still subject to efficiency degradation.[17] The capacities and efficiencies of both types of gas turbines deteriorate as ambient temperature rises, and improve as ambient temperatures fall.

The data in Table 5 and Table 6 provides capacity and heat rate data, respectively, for the 2xLM6000 and 2x7FA plants. The first table begins with vendor-supplied gross plant capacity and subtracts station loads (also referred to as internal or parasitic plant loads) to calculate net capacity with the plant in new and clean condition. We then factor in long-term average capacity degradation to arrive at long-term net capacity. The second table begins with vendor-supplied heat rates at the lower heating value (LHV) of gas that has to be adjusted by a factor of 1.11 to higher heating value (HHV), the basis for actual gas purchases. We then factor in station loads and long-term average efficiency degradation to estimate the quantity of gas required.[18] Both tables provide performance data at ISO conditions, as well as at representative summer and winter temperatures.

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[15] All of New York State is classified moderate non-attainment for VOCs and NOx, except for New York City, Long Island, Westchester, Orange and Rockland Counties, which are severe non-attainment. The offset ratio for VOCs and NO_x in moderate non-attainment areas is 1.15:1.

[16] Vendor data is provided as Appendix B.

[17] According to a study prepared by GE, an LM6000 with Sprint water injection can compensate for loss of high pressure efficiency, the largest component of performance degradation over time.

[18] NYPA reports slightly higher actual heat rate experience for their LM6000 units, but this may be due in part to station loads imposed by inlet air chillers or operation at less than full capacity.

Table 5 – Peaker Plant Capacity
(MW)

Plant Type	2xLM6000			2x7FA		
Temperature	25°F	59°F	90°F	25°F	59°F	90°F
Gross Capacity	99.7	98.0	85.4	369.8	343.4	308.2
- Station Load	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Net Capacity	97.7	96.0	83.7	362.4	336.5	302.0
- Avg LT Degradation	0.0%	0.0%	0.0%	3.0%	3.0%	3.0%
LT Net Capacity	97.7	96.0	83.7	351.6	326.4	293.0

Table 6 – Peaker Plant Heat Rate
(Btu/kWh)

Plant Type	2xLM6000			2x7FA		
Temperature	25°F	59°F	90°F	25°F	59°F	90°F
Gross Heat rate (LHV)	8,337	8,527	8,715	9,209	9,360	9,635
* HHV / LHV	1.11	1.11	1.11	1.11	1.11	1.11
Gross Heat Rate (HHV)	9,254	9,458	9,674	10,222	10,390	10,695
- Station Load	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Net Heat Rate (HHV)	9,439	9,647	9,847	10,426	10,597	10,909
- Avg LT Degradation	1.0%	1.0%	1.0%	3.0%	3.0%	3.0%
Net Heat Rate (HHV)	9,528	9,739	9,961	10,635	10,809	11,127

CAPITAL COST

The capital cost of a gas turbine peaking plant was derived by estimating the cost of each of the following components based on the best available data, including vendor quotes for the power island packages.[19] We assumed that the plant would be located on a greenfield site, since there is a very limited number of existing sites that could accommodate additional gas turbines. The individual values, along with the totals, are provided in Table 7 below.[20]

- Owner's Costs
  - Development – preliminary engineering, permitting, emission reduction credits, consulting, legal
  - Owner's engineer during construction
  - Financing – interest during construction

- Equipment
  - Power island – gas turbine, electrical generator, exhaust ductwork, selective catalytic reduction, exhaust stack
  - BOP – water treatment, gas compression & metering, electrical equipment
  - Spare parts

[19] Vendor quotes for the power island can vary significantly over time as demand patterns change. LAI and DMJM+Harris have not tried to correct for current conditions in the new gas turbine equipment market.

[20] Capital cost details are provided in Appendix C.

- Construction
  - Engineering & design services
  - Site preparation
  - Labor[21]
  - Construction materials – concrete, rebar, miscellaneous steel, backfill materials, and other non-generation items[22]
  - Electric connections (switchyard) and system upgrades[23]
  - Gas connection (metering station) and pipeline extension[24]

- Startup & Testing
  - Vendor & engineer equipment & system tests
  - Performance & completion tests
  - Staff training

Table 7 – Peaker Plant Capital Cost
(Millions 2004 $)

Location Plant Type	NYC 2xLM6000	LI 2xLM6000	ROS 2xLM6000	ROS 2x7FA
Owner's Costs	$ 10.3	$ 9.2	$ 5.1	$ 16.9
Equipment	$ 41.5	$ 41.5	$ 41.5	$ 119.3
Construction	$ 61.2	$ 56.4	$ 45.7	$ 140.8
Startup & Testing	$ 1.0	$ 1.0	$ 1.0	$ 2.6
Total Capital Cost	$ 114.0	$108.1	$ 93.2	$ 279.7
/ Net Capacity (MW)	*96.0*	*96.0*	*96.0*	*336.5*
Unit Capital Cost	*$ 1,189/kW*	*$ 1,126/kW*	*$ 971/kW*	*$ 831/kW*

The capital costs in Table 7 were escalated at 3% per annum to arrive at the capital costs for gas turbine peakers coming on-line in 2005 and for succeeding years.[25] LAI verified our estimates against publicly available cost data for similar peaking units.[26]

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[21] Labor costs are almost twice as high in NYC and LI compared to ROS.

[22] Other non-generation items include small buildings & enclosures, pavement & curbs, drainage systems, landscaping, conduit & raceway systems, cable, lighting, grounding cable, lighting & power panels, miscellaneous non-process mechanical systems (HVAC, plumbing, fire protection, lift stations, etc), security systems, and fencing.

[23] LAI's estimates are based in part on the June 14, 2004 Financial Settlement agreed to by the parties in FERC Docket EL02-125-000 regarding the allocation of system interconnection (*i.e.* upgrade) costs for class 2001 projects. LAI also considered confidential cost data from projects with which we are familiar, data from Working Group members, and the potential to recover a portion of any "headroom" from succeeding projects,

[24] LAI estimated a typical capital cost that would be incurred by the local distribution company or the interstate pipeline to extend the pipeline to the site.

[25] Fuel cost data in the EIA 2004 Annual Energy Outlook is based on an average long-term GDP price deflator of 2.9%; LAI rounded that value to 3% for this assignment.

[26] A detailed breakdown of capital costs, as well as comparisons to cost data for other gas turbine peaking plants that have been constructed in New York over the past few years, are provided as Appendix C.

The unitized capital cost for a 2xLM6000 plant in ROS is 17% more expensive than a 2x7FA plant. There are two important factors why the unitized cost differential between the two ROS plants is not larger – one factor lowers the unitized LM6000 plant cost, and the other raises the unitized 2x7FA plant cost:

- The outputs of all the NYPA and LIPA 2xLM6000 plants were limited to 79.9 MW, presumably to avoid Article X permitting treatment and thereby shorten the permit approval process. This capacity limit raised the unitized capital cost of a 2xLM6000 plant by 20% when compared to 96.0 MW net output (ISO rating).

- The unitized capital cost estimate of $831/kW for a 2x7FA plant is about double the cost previously utilized by NYISO for ROS. The 2003 and 2004 ICAP demand curves were based, in part, on a capital cost estimate of $413/kW that was derived from surveys of four New England combined cycle projects that were financed in 2001. The underlying data for these projects was not available in sufficient detail to evaluate the significant cost differential.

The estimated capital cost for the 2xLM6000 plant in Zone J is not much more expensive than the same plant in Zone K. This is consistent with NYPA cost data for their PowerNow! gas turbine plants that entered service in 2001. When the NYPA plant capacities are adjusted to remove the 80 MW limit per site, the unitized cost of the NYPA plants are $1,208/kW, within 2% of our Zone J cost estimate. The adjusted NYPA plant costs in Zone J were only 4% more expensive than the NYPA plant in Zone K, consistent with our capital cost estimates. Another LM6000 plant was constructed by the Jamestown Board of Public Utilities (BPU), but there are too many differences and uncertainties to make a valid comparison with our peaker estimates. The Jamestown plant was constructed at an existing plant site and includes a heat recovery steam generator for combined cycle operation but not selective catalytic reduction. In addition, the BPU was able to avoid gas pipeline expansion, site infrastructure, and interest during construction costs, and was able to provide much of the labor requirements instead of mobilizing an outside labor force.[27]

In general, it is difficult to compare the cost of simple cycle plants to combined cycle plants. Simple cycle plants avoid the steam turbine, water treatment, cooling, and other costs of combined cycle plants, but much of the site-related construction costs are required, as are permitting and other development costs. It is also difficult to adjust for the disparate sizes of the two types of plants. For example, the cost of the 500 MW NYPA Poletti combined cycle plant was quoted at $650 million, approximately $1300/kW, but it is not certain that the announced cost included all of the owner's internal costs, or what the cost would be for just the simple cycle portion. Similarly, SCS Astoria announced a $983 million financing package for its 500 MW plant, but a large portion is for costs specific to this project:

- Interest during construction is higher than usual due to its reliance on high-yield debt that must arranged at construction commencement.

[27] Refer to Appendix C for NYPA and Jamestown cost calculations.

- The project is burdened with the costs of shared facilities that will be allocated to a second 500 MW plant planned at the site.
- Air-cooled condensers will be required.

PERMITTING & CONSTRUCTION SCHEDULE

The time required to develop a peaker plant is largely dependent upon the complexity of the permitting process. Unless and until PSC Law Article X is reauthorized, all new generation projects, and not only projects less than 80 MW, are subject to New York's State Environmental Quality Review (SEQR). Separate air, water use and/or discharge, and other land use permits follow a parallel track, and must be obtained from the DEC, local authorities, and other agencies prior to the start of construction. There may be considerable time variation in the time expected to permit a project depending on numerous factors, including the potential for adverse environmental impact, the identity of the SEQR Lead Agency, market conditions and the motivation of the project developer, and community acceptance.

In the last few years, both NYPA and LIPA constructed PowerNow! and Fast Track projects (LM6000 units capped at 79.9 MW total output per location) and were able to expedite SEQR and complete all permitting in less than a year. In these instances, NYPA and LIPA were the project sponsors as well as the SEQR Lead Agency, and all projects were determined to have no significant adverse impact and were issued a Negative Declaration. However, projects which are more complex, have possible significant adverse impacts, require a full Environmental Impact Study, require a Title V air permit rather than a State Facility permit, involve other Lead Agency participants, or are subject to extensive public review, are likely to have more prolonged permit review periods. LAI is not aware of any projects less than 80 MW for which the applicant is not the SEQR Lead Agency, and which have achieved commercial operation in the last few years. A very limited number of such projects have received SEQR Negative Declarations and/or other state permits.[28] While the permitting schedule for these projects has exceeded two years, the delay may have been due, at least in part, to unfavorable market conditions.

Projects 80 MW and greater which were subject to Article X review have typically required two to three years to obtain Siting Board certification and obtain other DEC air and water permits.[29] This represents the period of time between submission of the Article X Pre-

[28] Several examples are in the public record: (i) NYC Energy, LLC proposed a 79.0 MW barge project near Kent Avenue, Brooklyn Navy Yard, in 1998. The project received a Conditional Negative Declaration in January 2000 and its Air Permit in December 2000. However, subsequent litigation filed by community groups delayed construction. (ii) Fortistar Power Marketing LLC proposed two 79.9 MW projects on Staten Island. Initial meetings with the DEC began in 2001. These projects received their Negative Declarations in November 2003, but other permits are still in review. (iii) Lockport Merchant Associates obtained a Negative Declaration from SEQR Lead Agency, the Lockport Industrial Development Agency, for a 79.9 MW project in May 2001. No other permit activity has been published by the DEC.

[29] The PSC tabulation of Article X Cases identifies 11 projects that have been certified as of March 11, 2004. Five projects were certified in approximately 2 years (East River Repowering, KeySpan Ravenswood, SCS Astoria, Spagnoli Road, and Wawayanda); two projects were certified in approximately 2½ years (Bowline and Brookhaven); and three projects were certified in approximately 3 years (Athens, Poletti, and Reliant Astoria). SCS Astoria submitted a pre-application report in August 1999, a formal application in June 2000, and received

application to the later of the Article X Certification date or the DEC permit issuance date. Generally, the Certification and the DEC permits are issued within a few weeks of each other. This two to three-year timeframe likely represents the maximum permit schedule for a new peaker plant.

Based on this information, it is reasonable to bracket the expected permitting timeframe for a new peaker to be between one and two years from the point of application submittal to the issuance of the permits. We also added in three-to-six months for preliminary engineering and permit preparation time prior to the actual permit application. We anticipate that the larger 2x7FA plant in ROS will be classified as a major source that will trigger additional permit requirements and extend the ROS development schedule to 2 years. Therefore, for the purpose of this analysis, it is reasonable to make the following schedule assumptions:

- Zones J & K – 27 month permitting plus 8 months construction
- ROS 2xLM6000 – 21 months permitting plus 6 months construction
- ROS 2x7FA – 24 months permitting plus 12 months construction

VARIABLE OPERATING COSTS

Aside from fuel, the principal variable operating cost of gas-fired simple cycle gas turbine is major maintenance accrual. Gas turbine vendors specify a hierarchy of maintenance activities based on equivalent operating hours, with starts and part load operation contributing in accordance with defined formulae. Maintenance intervals for hot gas inspections are typically about 8,000 hours, with significant additional work at 24,000 hours and full overhauls at 48,000 hours. Since peaking service involves only a small, unpredictable number of hours per year and several starts, the expense of these major maintenance events is typically accrued with starts and energy generated, rather than over elapsed time. The accrual of maintenance costs is a recognized component of variable cost in NYISO bidding for such units. Table 8 shows the variable operating and start costs used in the simulation model for each type of gas turbine

Table 8 – Variable Operating and Start Cost Assumptions

	2xLM6000	2x7FA
Variable Operating Cost (2004 $/MWh)	$3.00	$3.00
Fuel per Start (MMBtu)	32.0	577.4

FIXED OPERATING COSTS

Fixed operating costs for gas turbine peaking plants consist primarily of property taxes, staffing, contract services, insurance, site lease, and general & administrative expense. The bulk of maintenance costs for these plants is considered variable, and is accrued based on equivalent hours of operation as noted above. LAI has made certain simplifying assumptions for estimating fixed operating costs for this study, as described below.

Article X Certificate in November 2001. Another project, Bethlehem Energy Center, required 4 years, but that application was amended during the review process.

Property Taxes

Property taxes are the largest component of fixed operating costs for a gas turbine peaking facility located in New York State. Property taxes are generally the product of an assessed valuation and a tax rate. Assessment ratios and tax rates can vary substantially among locations and plant types. LAI based our estimated property taxes on three data sources:

- A survey of upstate power generation plants (none of which were peakers) indicates that 2003 tax bills ranged from $3.60/kW-yr to $31.08/kW-yr, with most falling between $8.75/kW-yr and $18.70/kW-yr.[30] The average for the surveyed units was $15.50/kW-yr. The survey does not specifically identify plants or their assessed values.
- A review of confidential proposals for new capacity in the downstate region indicates that property taxes (or payments in lieu of taxes) on new combined cycle generation in 2005 would average about $19/kW-yr.[31]

- A power plant owner provided confidential tax bill information for older gas turbines in New York City indicating an effective rate of $12.62/kW-yr. This was based on an assessed market value of $233/kW and an effective tax rate of 5.41%.[32] The effective rate for a new peaking plant would be much higher based on our estimated capital costs.

Based on this information, we estimated property taxes on a levelized basis in which a plant's tax bill is assumed to increase with inflation in each year through a combination of valuation and/or rate adjustments. Our estimates are very close to the source data described above. Table 9 below summarizes our assumptions for property taxes used in the levelization model.

Table 9 – Property Tax Assumptions

	NYC 2xLM6000	Long Island 2xLM6000	ROS 2xLM6000	ROS 2x7FA
Property Tax (2004 $ millions)	$2.25	$1.88	$1.78	$5.22
Levelized 2005 Value ($/kW-yr)	$26.43	$19.63	$18.50	$16.00

Staffing and Contract Service Costs

Modern peaking plants are designed to operate with a minimum level of permanent staffing. The LM6000 configuration envisioned has full remote start and shut-down capability, so personnel on site would only be required for routine minor maintenance. The 7FA configuration for ROS would normally have an operator on-site full-time during the operating season. Gas-fired peaking capacity is likely to be used primarily in the summer, when peak

[30] Confidential survey provided by Independent Power Producers of New York, May 13, 2004.

[31] Based on confidential in-house data.

[32] The official New York City tax rate for Class 3 property is 12.418% with an assessment ratio of 45% of market value, equivalent to an effective rate of 5.59%.

loads occur and natural gas prices are relatively low. LAI has estimated staffing costs for the four cases as shown in Table 10.

Table 10 – Staffing Cost Assumptions

	NYC 2xLM6000	Long Island 2xLM6000	ROS 2xLM6000	ROS 2x7FA
Year-around staff positions	1	1	1	1
Seasonal (half-year) positions	2	2	2	4
Equivalent full-time positions	2	2	2	3
Staff Cost (2004 $/position-yr)	$150,000	$150,000	$100,000	$100,000
Annual Cost (2004 $/yr)	$300,000	$300,000	$200,000	$300,000
Levelized 2005 Value ($/kW-yr)	$3.22	$3.22	$2.15	$0.95

A small, often-unmanned peaking plant would rely on contractors to provide a range of routine services such as security, cleaning, landscape maintenance, etc. Other services would include potable water, sewer, and electricity. These services are estimated as shown in Table 11.

Table 11 – Contract Services Assumptions

	NYC 2xLM6000	Long Island 2xLM6000	ROS 2xLM6000	ROS 2x7FA
Contract Services (2004 $/yr)	$300,000	$300,000	$250,000	$500,000
Levelized 2005 Value ($/kW-yr)	$3.22	$3.22	$2.68	$1.58

Site Lease Costs

It was assumed that the gas turbine peaker sites would be leased, so land costs are not included in the capital cost estimates. Table 12 shows assumptions for site land requirements, lease rates, and resulting unit costs for each case, based on our review of confidential plot plans and lease rate data.

Table 12 – Site Lease Assumptions

	NYC 2xLM6000	Long Island 2xLM6000	ROS 2xLM6000	ROS 2x7FA
Land Requirement (acres)	3.50	3.50	3.50	5.00
Lease Rate (2004 $/acre-yr)	$112,000	$19,000	$16,000	$16,000
Levelized 2005 Value ($/kW-yr)	$4.20	$0.71	$ 0.60	$0.25

Insurance and General & Administrative Costs

Assumptions for insurance costs and G&A costs (that would be provided by the parent company owner) are shown in Table 13 based on our review on in-house data.

Table 13 – Insurance and G&A Assumptions

	NYC 2xLM6000	Long Island 2xLM6000	ROS 2xLM6000	ROS 2x7FA
Insurance Cost (2004 $/kW-yr)	$1.65	$1.65	$1.65	$1.65
G&A Cost (2004 $/kW-yr)	$0.12	$0.12	$0.12	$0.12
Levelized 2005 Value ($/kW-yr)	$1.77	$1.77	$1.77	$1.77

2 METHODOLOGY

INTRODUCTION

LAI used MarketSym to conduct the electric market simulation analyses using the three-part bid method. MarketSym is an advanced chronological dispatch simulation model that we license from Henwood Energy Services, Inc. All of our important assumptions regarding MarketSym topology, transfer capacities, demand, and supply are described below. LAI has included supply projects that have achieved financial closing or have been selected in response to utility RFPs. We have not incorporated potential changes in market regulations that have not received final approval.[33]

Gas turbine peakers earn most of their revenues during the relatively small number of operating hours with high market energy prices. Indeed, the quick-start capabilities of the LM6000 units make them especially valuable during volatile price movements. Deterministic simulation models that utilize "deterministic" loads and calculate "typical" energy prices cannot capture gas turbine dispatch and revenues during periods of price volatility. Therefore we have stochastically simulated load for the five zones defined in our model.

MARKETSYM TOPOLOGY

LAI is modeling the NYISO and the surrounding markets of ISO-NE, PJM, Quebec, and Ontario in order to fully capture the plant dispatch and market-clearing price effects of scheduled transfers and economic energy flows. In order to further improve the accuracy of plant dispatch and market price forecasts, some of these markets are divided into sub-areas with defined transmission interface limits between them.

<u>NYISO</u> – New York is divided into eleven zones, A – K, reflecting transmission constraints among regions in the State. LAI combined these zones into five "super" zones to capture the necessary and critical detail for Zones J, K, and ROS:

- Zones A, B, C, D, and E are aggregated into the NY-West zone
- Zone F (the capital district) is a separate zone NY-F
- Zones G, H, and I are aggregated into NY-GHI zone
- Zone J (New York City) is a separate zone NY-J
- Zone K (Long Island) is a separate zone NY-K

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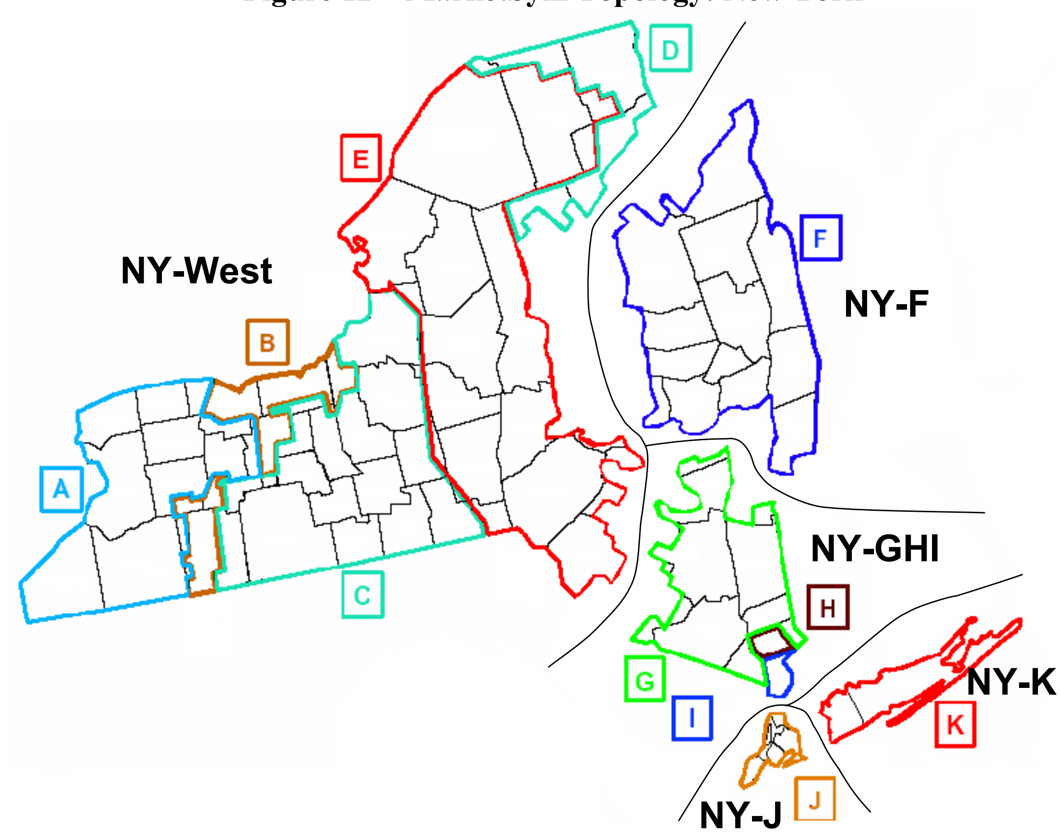
[33] SMD2, which will incorporate Real Time Commitment (RTC) and Real Time Dispatch (RTD), will co-optimize energy, reserves and regulation. The implementation of SMD2 is not expected to significantly alter any of our results, in particular our ancillary revenue estimates that we calculate as percentages of total energy payments.

Zones J and K were modeled separately because they have locational requirements and demand curves.[34] ROS was divided into three zones to capture the effects of the Central/East and UPNY/SENY interfaces.

PJM – LAI modeled the PJM market area as three zones:

- MAAC East - the eastern zone, east of the eastern MAAC interface, allows us to capture price differentials for transactions across the Neptune cable project
- MAAC West - the western zone, west of the eastern MAAC interface
- APS - PJM West

Figure 12 – MarketSym Topology: New York



ISO-NE – ISO-NE has divided the New England control area into thirteen sub-areas, defined by transmission constraints per the *"2003 Regional Transmission Expansion Plan"* (RTEP03). LAI has divided the New England control area into six sub-areas for this assignment:

[34] In New York City, LAI did not differentiate between the 138 kV and 345 kV transmission systems, since we did not seek to capture site-specific conditions for purposes of deriving reference ICAP values. Moreover, new entry of combined cycle plants added on the 138 kV system should alleviate many of the in-city transmission constraints, thereby equalizing energy price differential and relieving the dispatch requirements placed on peakers in the 138 kV load pockets.

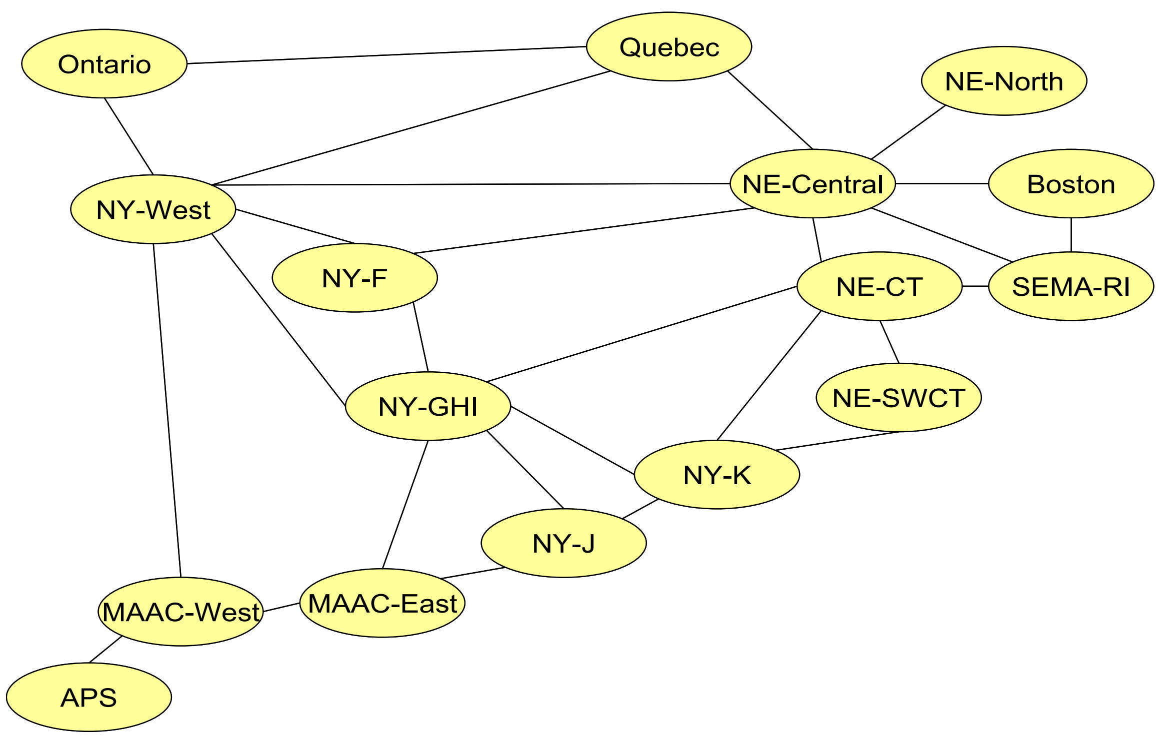
- Sub-areas BHE, S-ME and ME are aggregated into NE-North sub-area
- Sub-areas VT, WMA, CMA/NEMA, and NH are aggregated into NE-Central sub-area
- Sub-areas SEMA and RI are aggregated into SEMA-RI sub-area
- Sub-area Boston
- Sub-area SWCT (which includes NOR)
- Sub-area CT (excluding SWCT) allows us to capture locational pricing differentials for transactions across the Cross Sound Cable (CSC)

Quebec – The Quebec market was modeled as a single area that captures imports and exports with NYISO and ISO-NE.

Ontario – The Ontario market was modeled as a single area that captures imports and exports with NYISO.

The resulting MarketSym "topology" for this assignment is represented by Figure 13.

Figure 13 – MarketSym Topology for NYISO and Surrounding Systems



Transfer Limits

Transfer limits within market areas and between adjacent markets have been updated to reflect the latest available information from the following sources:

- NYISO Locational Installed Capacity Requirements Study Covering the New York Control Area (February 20, 2004)

- ISO-NE RTEP03 Report (November 13, 2003)
- PJM – MAAC FERC 715 Report

By using the NYISO study, LAI is utilizing the identical transfer limits used by NYISO to determine the locational ICAP requirements.[35] We have made the following assumptions regarding the CSC, Neptune (PJM / LI) and Line 1385 transmission cable projects. Other transmission projects under development (e.g. Empire Connection) are significantly more speculative and have not been included in this study.

- CSC, an existing dc tie between CT and Zone K, is fully operational at 330 MW net capacity by 2005.[36] While CSC has been the subject of a permit dispute, it appears that this dispute has been resolved. Energy flows across the CSC cable are assumed to be economically dispatched based on relative energy prices in CT and Zone K.

- The Neptune cable, a proposed dc tie between PJM and LI, was announced as one of the winners of LIPA's 2007 Supply RFP. Neptune is assumed to become operational in 2007 at 660 MW net capacity.[37] LIPA has announced its intention to obtain UDRs so that capacity purchased and de-listed in PJM will be treated as on-island capacity that count towards its locational ICAP requirement.

- Line 1385, an existing ac tie between SWCT and Zone K, will continue to be available for emergency transfers, consistent with its current usage.

LOAD DATA

Conducting dispatch simulations requires hourly load shapes that capture the full range of peak and off-peak loads for individual market areas. NYISO provided LAI with 2002 hourly load shapes for each of the eleven NYISO zones, a year that included high peak loads and good load variability.[38] LAI used the 2004 Gold Book annual peak and energy load forecasts for the eleven NYISO zones (which are non-coincident) and the coincident NYCA annual peak and energy load forecast for the years 2004 to 2013. LAI derived long-term growth factors to extrapolate the load forecast to year 2026. LAI's MarketSym model utilized the 2002 load shapes to the zonal peak and energy forecasts while satisfying the NYCA coincident load forecast. The MarketSym load data for the neighboring market areas was updated using the sources listed in Table 14 below

[35] Utilizing static transfer limit values is standard practice for long-run planning-type studies; it is impractical to calculate hourly values for a twenty-plus year forecast horizon.

[36] Converter and cable losses vary with power flow. The values used in this assignment are averages for the range of flows expected and are confidential.

[37] Converter and cable losses vary with power flow. The values used in this assignment are averages for the range of flows expected and are confidential.

[38] These are the same load shapes that were used in the Installed Reserve Margin (IRM) study and the Locational ICAP requirements study for 2004-2005 capability period.

Table 14 – Load Data Sources

Market	Data Source
ISO-NE	2003 Regional Transmission Expansion Plan (RTEP03) and 2003 Report of Capacity, Energy, Loads and Transmission (CELT)
PJM	2004 PJM Load Forecast Report
Ontario	10 Year Outlook: Ontario Demand Forecast (March 31, 2004)
Quebec	2004 Quebec Regular Forecast

NEAR-TERM ADDITIONS

Installed generation data for NYISO, ISO-NE, PJM, Quebec, and Ontario markets were taken from the sources listed in Table 15 below.

Table 15 – Sources of Installed Generation Data Information

Market	Data Source
NYISO	2004 Load and Capacity Data Report
ISO-NE	RTEP03 and 2003 CELT Report
PJM	2003 EIA 411 Filing
Quebec	NPCC
Ontario	NPCC

In addition to the generation facilities listed in these reports, we have added known resource additions (i.e. those under construction or that have been offered PPAs) and known retirements to bring those reports up to date. The near-term additions in New York with estimated in-service dates are listed in Table 16 below.

Table 16 – NYISO Near-Term Generation Additions (Summer MW)

Station Name	Zone	2004	2005	2006	2007
Keyspan Ravenswood	J	229			
Freeport GT1	K	40			
Freeport GT2 (Equus Power)	K	40			
Athens	F	1080			
East River Repowering (net)	J		288		
Poletti Station Expansion	J		458		
Bethlehem Energy Center	F		687		
Astoria Energy (SCS Astoria)	J			458	
New CC	K			80	
New CC	K				80
Caithness Bellport	K				286
Neptune	K				660

The known near-term generation retirements are listed in Table 17 below.

Table 17 – NYISO Near-Term Generation Retirements (Summer MW)

Station Name	Zone	2004	2005	2006	2007	2008	2009
Freeport 2-3	K	-15					
Waterside 6,8,9	J		-166				
Albany 1,2,3,4	F		-376				
Oceanside (LF)	K				-2		
Poletti 1	J					-855	
Yaphank (LF)	K						-3

Once specific additions and retirements are included, LAI tracks each market area's supply and demand balance, taking into account capacity imports and exports, and adds generic simple and combined-cycle additions to meet minimum reliability requirements as needed (explained in the next section).

LONG-TERM PLANT ENTRY / EXIT

LAI's forecast of ICAP values is based on fundamental supply and demand economic models of the LI, NYC, and ROS markets. We use two different models to forecast the capacity supply curve: an Attrition Model that analyzes the operating economics of existing plants and an Entry model that simulates the economic performance of hypothetical new plants.

Plant Entry

As market factors change, new generation is expected to enter the market while uneconomic generation is retired. LAI forecasts plant entry and exits in each market and sub-area using our proprietary in-house models. The plant Entry model assumes that all new generation will be gas-fired combustion turbines, either in simple cycle or combined cycle mode.

- Simple cycle gas turbines in Zones J and K are assumed to be LM6000 units (or equivalent aeroderivatives) that can provide TMNSR and are well suited to meet unexpected demand spikes in peaking service.

- Simple cycle gas turbines in ROS are assumed to be a mix of LM6000 and Frame 7FA units (or equivalent aeroderivative and industrial turbines) that are considerably larger but less expensive per unit of capacity.

- Combined cycle units are assumed to be industrial frame units, employing "F" or "G" technology that are best suited for thermodynamic efficiency, with heat recovery steam generators and steam turbine cycles. Combined cycle units in Zones J and K are more expensive to construct and are assumed to require air-cooled condensers instead of evaporative cooling systems.

LAI's capital cost estimates for plant entry are shown in Table 18 below.[39] The size of these plants is expressed under ISO conditions in new & clean condition (*i.e.* before long-term degradation) while dispatch simulation modeling incorporates average levels of long-term degradation. Over time, LAI expects these capital costs to escalate at the general inflation rate of 3% per annum.

Table 18 – New Plant Capital Costs (2004 $/kW)

	Simple Cycle (LM6000)	Simple Cycle (7FA)	Combined Cycle
ROS			
Size (net)	n/a	336 MW	519 MW
Total Capital Cost	n/a	$280 million	$467 million
Unit Cost	n/a	*$831/kW*	*$899/kW*
Zone J			
Size (net)	96 MW	n/a	519 MW
Total Capital Cost	$114 million	n/a	$688 million
Unit Cost	*$1,188/kW*	n/a	*$1,325/kW*
Zone K			
Size (net)	96 MW	n/a	519 MW
Total Capital Cost	$108 million	n/a	$637 million
Unit Cost	*$1,126/kW*	n/a	*$1,227/kW*

The quantity of new entry is determined by statewide and locational ICAP requirements. LAI included 784 MW of Special Case Resources (SCRs) in satisfying these ICAP requirements.[40] SCRs are defined as loads capable of being interrupted and distributed generators rated 100 kW or higher that are not directly telemetered. NYISO's most recent data indicates 784 MW of SCRs distributed throughout the control area as shown in Table 19 below. SCRs represent about 2.46% of the current NYCA supply. Over the long term LAI assumed that SCRs would continue to provide 2.46% of NYCA supply with the same zonal distribution.

Table 19 – Special Case Resources

Zones	Quantity	Percentage
NY-West (A-E)	578.4 MW	73.7 %
NY-F	37.6 MW	4.8 %
NY-GHI	4.7 MW	0.6 %
NY-J	153.8 MW	19.6 %
NY-K	9.8 MW	1.2 %

[39] The apparent similarity of capital costs for simple and combined cycle plants is explained by the higher unit costs of aeroderivative units and the favorable economies of scale to develop and construct a combined cycle plant. These capital cost estimates used in LAI's Plant Entry model are consistent with the capital cost data used to establish the NYISO ICAP Demand Curves.

[40] Emergency Demand Response Program (EDRP) is a companion program that allows registered interruptible loads and standby generators to participate on a voluntary basis and be paid for their ability to restore operating reserves. However, EDRP does not provide ICAP and does not contribute to meeting ICAP requirements.

As demand grows, LAI adds new capacity in the state when needed to maintain ICAP requirements. LAI recognizes that the locational ICAP requirements for Zone J & K are dependent upon the transmission system and inter-zonal transfer capacities. As load in those zones grow, the locational ICAP requirements will increase absent transmission expansions / improvements. Given that no such transmission projects are included in our forecast, we have calculated a reasonable estimate of the resulting locational ICAP requirements as shown in Table 20 below. These locational ICAP requirements determine the overall quantity of ICAP that we add for Zones J & K.

Table 20 – Estimated Change in Locational ICAP Requirements

	2003	2005	2011	2016	2021	2026
Zone J	80.0%	80.6%	81.9%	82.6%	83.4%	84.2%
Zone K	99.0%	99.3%	100.2%	100.8%	101.4%	101.9%

Once additional capacity is required to maintain the statewide or locational ICAP requirements, LAI's Plant Entry model calculates required capacity payments for the two types of new entrants, simple cycle and combined cycle, based on assumed financial values listed below. These financial values assume that the parent company of the project entity finances the project on-balance sheet. In today's market, we doubt that any merchant plants can be debt-financed on a non-recourse project basis. Project financing historically has required offtake agreements and some protection against uneconomic operating expenses. We do not see conditions in the bank or capital markets being conducive to merchant power plant financing on a non-recourse basis.

If the market capacity rate derived in our attrition analysis is higher than the required capacity rate determined by the entry model, then we assume that new generation displaces existing capacity. The type of new generation that is added corresponds to the lower of the simple and combined cycle required capacity revenues determined by the entry model, since that type of plant will provide a higher return on capital.[41] Both types of plants are added over time as their respective capacity revenue requirements converge, indicating that the ICAP demand curve reference points should be almost identical for these two technologies.

Plant Exit

The Attrition Model consists of a series of economic analyses to estimate the expected attrition of older, inefficient plants being displaced by new generators. Our analysis calculates the power revenues and operating expenses (including capitalized maintenance) for each at-risk generating unit in each year of the dispatch simulation. Our model assumes that a plant would be retired if it experienced an out-of-pocket cash operating loss of 10% or more for three consecutive years, *i.e.*, total revenues were 90% or less of fixed and variable operating costs. Recovery of sunk capital costs is not relevant to this analysis.

[41] A list of the long-term generation additions and actual versus target capacity requirements are provided as Appendix D.

STOCHASTIC ANALYSIS

In order to better forecast the operation of gas turbine peakers and the occasional energy price spikes during periods of high demand, LAI conducted a set of simulations in which load was treated stochastically. We statistically evaluated the pattern of daily average loads for each of the five zones we are modeling since the start of the competitive market to characterize the variation around mean values, and found that a 2-factor normal mean-reverting distribution provided a good fit for the data series.[42] We then used a Monte Carlo feature in MarketSym that varies the hourly loads in accord with the derived volatility and mean-reversion parameters, and ran MarketSym with the new load values. The hourly loads can change by up to 6%-7% during approximately 68% of the hours (*i.e.* one standard deviation). In order to obtain an acceptable distribution around the deterministic load values, we conducted fifty NYISO dispatch simulations for each month of three selected years, 2005, 2007, and 2017. We interpolated the results for intermediate years, and extrapolated the results for succeeding years.[43]

MARKET MITIGATION

The NYISO Tariff includes Mitigation Measures designed "to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the ISO Administered Markets, while avoiding unnecessary interference with competitive price signals."[44] NYISO would impose Mitigation Measures if the conduct is "significantly inconsistent with competitive conduct" and "would result in a material change in on one or more prices". Three types of generator conduct are considered to be inconsistent with competitive conduct and may warrant mitigation:

- Physical withholding
- Economic withholding
- Uneconomic production

The tariff establishes thresholds to be used in screening these behaviors, including separate tests for economic withholding in constrained areas such as the in-city area that are more stringent than those for unconstrained areas.

Our market simulation software includes a number of features that could be used to model some of these non-competitive behaviors, in particular, the capability to generate bids that are greater than the variable costs of the generators. However, we did not include any non-cost based bid adders for our analysis of peakers. Similarly, we did not specify any inputs that would simulate physical withholding or uneconomic production relating to a transmission constraint.

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[42] A normal distribution describes the randomly-generated daily volatility shocks applied to a load time-series. The mean-reversion reflects the market's tendency to return to typical long-term values.

[43] A technical discussion of the statistical analysis that defines these volatility parameters around daily load values is provided in Appendix E.

[44] NYISO FERC Tariff Attachment H.

LEVELIZATION CALCULATIONS

The last step in this assignment was to calculate the levelized capacity requirements for gas turbine peakers net of the energy and ancillary service revenues that we forecasted using MarketSym. LAI used the following structure to calculate the net capacity revenues required by a new peaker in any one year and for a particular zone:

Total Capital Charges
+ PV of Fixed Operating Costs
- PV of Net Energy Revenues
<u>- PV of Ancillary Service Revenues</u>
= PV of Net Capacity Revenue Requirements

spread over economic life in level constant dollars
= Levelized Net Capacity Revenue Requirement

LAI levelized the capacity revenue requirements using the cost of equity capital for the project. We assume a discount rate on nominal dollar cash flows equal to the after-tax equity rate of return.[45] As discussed earlier, LAI has assumed that project financing of merchant power plants is no longer viable and that long-term PPAs will generally not be available under the competitive market design. Therefore we assume on-balance sheet financing in which a parent company with an investment-grade credit rating utilizes debt and equity capital , the costs of which reflect the risks of the underlying investment, to fund the development and construction of new, rational gas turbine peakers.[46] The resulting financial assumptions are provided below:

Inflation rate – 3.0%
Construction debt rate – 5.0%
Permanent debt rate – 7.5%
Permanent debt term – 20 years
Debt / equity ratio – 50% / 50%
Plant depreciation –15 year MACRS
Income tax rate – 39.9% (combined federal & state)[47]
Equity rate of return – 12.5% (after-tax)

We have assumed a plant life of 20 years for this analysis to be consistent with the term of the permanent debt and based on our observation that there are many 20 year old gas turbine units

[45] While we could have assumed the average weighted after-tax cost of capital and ignore project-specific debt repayment, the results are virtually identical as demonstrated in Appendix E.

[46] Project debt financing with recourse to the parent company should not materially lower the project's cost of capital. First, lenders would require some compensation for merchant risk (*e.g.* recourse to the parent, mini-perm treatment of maturity, accelerated principal repayment terms, etc.), that would be imputed back to the parent. Second, the parent company funds used to provide project equity would be subject to more risk than equity used for consolidated investments, effectively raising the cost of project equity.

[47] The New York State corporate income tax rate is 7.5%%. For New York City (Zone J), the city income tax rate of 8.85% was also incorporated into an effective tax rate of 45.2%. We did not include the Metropolitan Transit Authority tax surcharge that would have a negligible effect on Zone J and K effective tax rates.

still in operation. While improvements in technology make newer units more efficient and competitive, older units can continue to play a role in maintaining system reliability.[48]

LAI has discussed the costs of capital with commercial bankers and financial advisors. The costs and other terms of the debt and equity must reflect the risks of a "rational" merchant power plant. Given the paucity of pure merchant project financings and the unique differences among plants, it is virtually impossible to precisely determine those capital costs. The assumed debt and equity assumptions are predicated on a number of important assumptions:

- Capacity, energy, and ancillary services from postulated gas turbine peakers can be merchandised at compensatory prices, *i.e.* sold at market-based prices that provide equity investors with a reasonable return on investment.

- The postulated peaker additions in Zone J, Zone K, and ROS incorporate gas turbine technology that best fits the load following requirements of the zone.

- Engineering, construction, and operating responsibilities are properly allocated to credit-worthy parties.

- Plant developers have the benefit of a properly functioning ICAP demand curve mechanism that provides appropriate and stable capacity revenues.

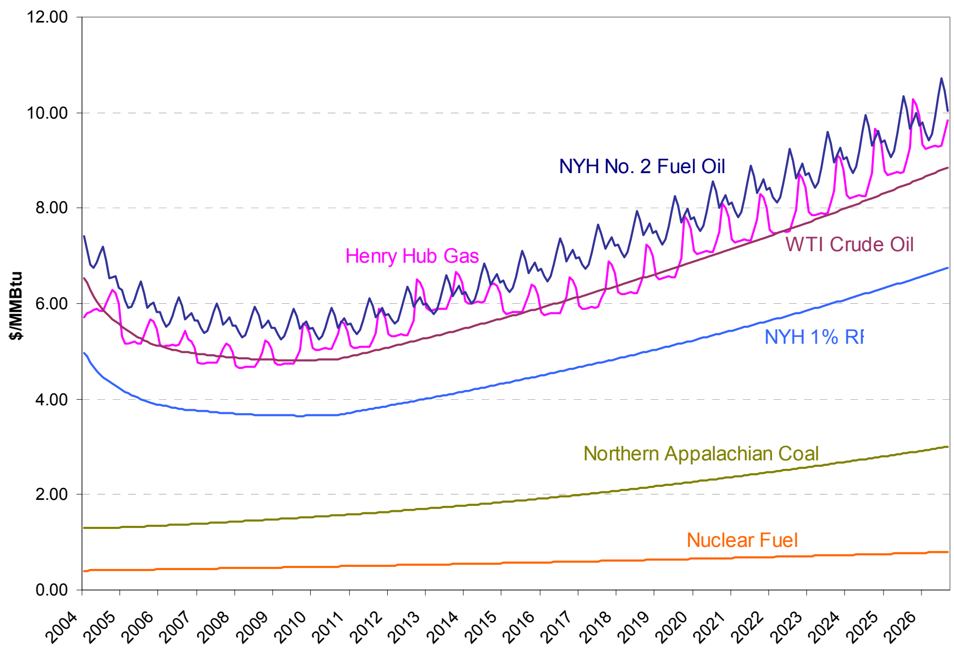
We are aware of certain cases in which higher equity returns were required to justify investments in merchant plants. However, many of these plants are in markets that have capacity surpluses and/or regulatory uncertainties or are otherwise "distressed," lowering expected revenues, increasing risks, and requiring higher equity returns. Moreover, winning bids for generating assets appear to utilize more aggressive assumptions, including lower equity return requirements. While we recognize that it may take some time for power markets to evolve to a rational equilibrium and for capital markets to become more comfortable lending to parents with merchant portfolios, we cannot foretell how long this process will take.

[48] The previous NYISO ICAP values were based, in part, on a study that utilized a 15 year project life.

3 FUEL PRICE FORECASTS

The forecasts of delivered fuel prices provide key factor inputs to MarketSym and therefore to the forecast of net energy and ancillary service revenues. As shown in Figure 14, for the forecast period 2004 through 2026, LAI has forecast basic fuel commodity prices: natural gas "into-the-pipe" at the Henry Hub, the trading point for NYMEX futures, fuel oil at New York Harbor (NYH), Appalachian coal, and nuclear fuel (U_3O_8). The forecast of underlying fossil fuel prices is linked to the price of the benchmark West Texas Intermediate (WTI) crude oil, a key driver of residual fuel oil prices, and, to a lesser extent, natural gas commodity prices. In the sections to follow, LAI addresses the sundry adjustments to basic commodity prices that have been made in order to account for the value of fuel delivered to the relevant pricing points utilized by MarketSym. Consistent with the EIA Annual Energy Outlook, LAI has incorporated a core inflation rate of 3.0% per annum in all economic forecasts performed for this analysis.

Figure 14 – Underlying Price Forecasts for Primary Fuels



NATURAL GAS PRICES

Gas Commodity Price

Our forecast of gas commodity prices into-the-pipe at the Henry Hub has two components:

- A near-term forecast of monthly gas prices based on NYMEX futures prices through December, 2005 (as of the close of trading on March 18, 2004).

- LAI's long-term gas price forecast using our in-house econometric model that considers U.S. drilling activity, EIA's 2004 Annual Energy Outlook forecast of WTI prices, and the gap between U.S. production and consumption.

Noteworthy long-term assumptions that define domestic gas production and consumption include:

- Annual domestic consumption grows at 0.5% per year from 21.8 trillion cubic feet (Tcf) in 2003 to 24.5 Tcf in 2026.

- U.S. production is assumed to grow slightly from 19.1 Tcf in 2003 to 19.6 Tcf in 2005, and then decline and remain steady at 19.2 Tcf through 2014.

- In 2015, U.S. production is assumed to increase to 19.8 Tcf, reflecting new gas production from Alaska / the Canadian Arctic into North American markets, after which production increases 0.5% per year.

Gas commodity prices are currently high relative to historical price levels due to tight supply conditions and the maturation of existing producing fields experienced by major gas producers in the Gulf Coast, Western Canada, and many other primary producing areas. Accelerated depletion rates have maintained upward pressure on commodity prices, increased gas price volatility, particularly during the heating season, and significant seasonality. LAI expects that commodity prices will gradually decline through 2008, reflecting additional demand destruction, increased liquefied natural gas (LNG) imports at existing terminals, and the start-up of Mackenzie Delta production in late 2007 / 2008. However, the maturation of producing fields portends a continuation of the recent trend toward accelerated depletion. That is, existing supply basins will continue to be depleted faster than new wells can produce, particularly in the Gulf Coast and Western Canadian Sedimentary Basin. A return to sustained upward pressure on commodity prices from 2009 through 2014 is therefore reflected in the forecast. New production from Alaska's North Slope and the Canadian Arctic, along with additional LNG imports via new terminals, will tend to moderate the increase in gas commodity prices over the long-term.

Interstate Pipeline Transportation

Natural gas basis differentials reflect the value of gas at various trading hubs relative to the Henry Hub. While the FERC authorized rate charged for interstate transportation services explains in part how basis sorts out across relevant pricing points, the value of transportation diverges substantially from cost of service rates. Relevant market dynamics from month to month must therefore be captured in defining the basis adder to underlying commodity prices across New York State, New England, PJM, and the Dawn hub in southern Ontario. The monthly basis differentials shown in Table 21 were developed based on our analysis of historical data over a sixty-three month period for six trading hubs of relevance in the present context. In our long-term forecast of delivered gas prices, monthly basis differentials were escalated at one-half the annual inflation rate and added to the Henry Hub commodity prices to calculate delivered monthly gas prices in New York and the surrounding regions.

Table 21 – Forecast of 2004 Monthly Gas Basis Differentials vs. Henry Hub ($/MMBtu)

	Transco Z6-NY	TETCO M3	IQT-Z2	Tennessee Zone 6	Dawn	Niagara
Jan	$2.64	$1.65	$1.97	$2.28	$0.05	$0.34
Feb	$1.24	$0.94	$1.12	$1.25	$0.28	$0.43
Mar	$0.60	$0.56	$0.57	$0.63	$0.33	$0.38
Apr	$0.42	$0.37	$0.36	$0.38	$0.19	$0.22
May	$0.31	$0.30	$0.29	$0.28	$0.13	$0.16
Jun	$0.36	$0.32	$0.30	$0.29	$0.10	$0.13
Jul	$0.40	$0.31	$0.30	$0.29	$0.03	$0.08
Aug	$0.40	$0.31	$0.31	$0.31	$0.08	$0.12
Sep	$0.32	$0.30	$0.29	$0.30	$0.15	$0.17
Oct	$0.37	$0.33	$0.32	$0.38	$0.17	$0.20
Nov	$0.44	$0.37	$0.37	$0.44	$0.20	$0.25
Dec	$1.94	$0.85	$0.79	$0.90	$0.07	$0.21

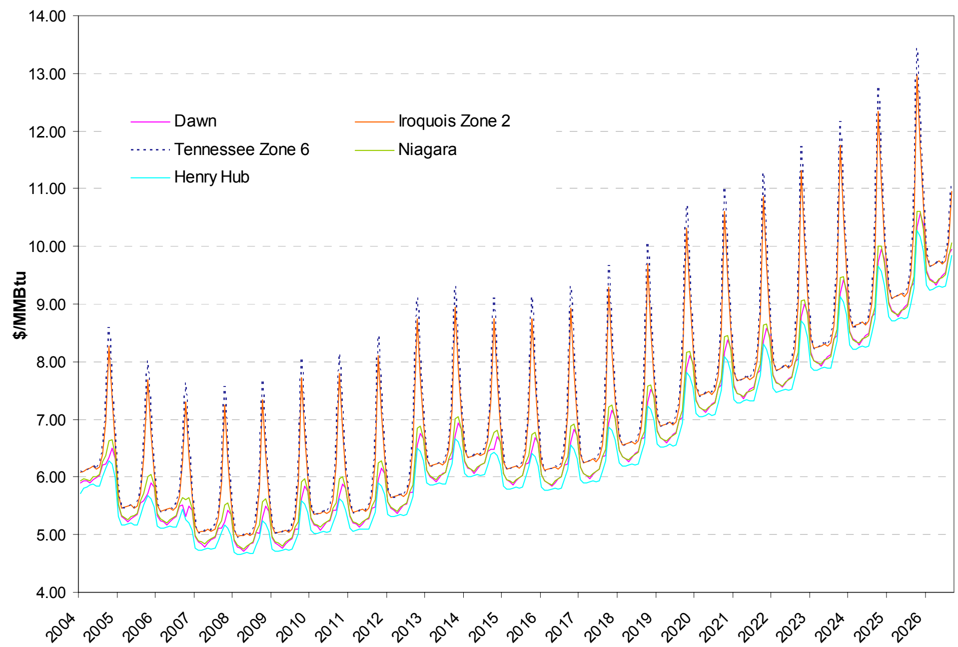
Specific basis differentials at each trading hub were used to forecast delivered gas prices for power plants in all relevant zones captured in our production simulation model. Table 22 indicates which basis differentials were used for each market region. For example, delivered gas prices to power plants in New York Zones A-E were calculated using basis differentials for the Niagara market center, delivered gas prices for some plants in New England use the Iroquois Zone 2 basis while other plants use Tennessee Zone 6 basis.

Table 22 – Relationship of Basis Differentials to Market Areas

	Transco Z6-NY	TETCO M3	IQT-Z2	Tennessee Zone 6	Dawn	Niagara
NY-Zones A-E						X
NY-Zone F			X			
NY-Zones G-I	X		X			
NY-Zone J	X					
NY-Zone K	X		X			
PJM-E	X	X				
PJM-W		X				
New England			X	X		
Ontario					X	
Quebec					X	

The seasonal pattern of basis differentials reflects the periodic winter price spikes that have characterized natural gas prices in recent years. The large number of gas-fired generation plants that have come on-line since the mid-1990s resulted in increased gas demand year-round. LAI forecasts that the recent seasonal price pattern shown in Figure 15 will continue over the forecast period with the most pronounced winter price spikes occurring at Transco Zone 6-NY, Tetco M3, Tennessee Zone 6, and Iroquois Zone 2.

Figure 15 – Natural Gas Prices at Selected Regional Trading Hubs



Local Gas Transportation

Many generators are directly connected to interstate pipelines and therefore do not require local transportation and balancing service from local distribution companies (LDCs). In New York State, however, most gas-fired generators are located behind the citygate and therefore do require local services. Many arrangements between generators and LDCs are defined under value-of-service principles. LAI has evaluated historical local transportation charges and has assumed that generators can negotiate with LDCs to avoid minimum bill provisions for the purpose of this assignment. We have estimated that gas-fired plants requiring local transportation service in ROS pay on average about $0.26/MMBtu during the heating season, November through March, and $0.10/MMBtu during the non-heating season, April through October. For plants requiring local transportation in New York City or Long Island, we have estimated the volumetric adder to be $0.19/MMBtu on a year-round basis. We have incorporated the $0.26/MMBtu winter adder and the $0.10/MMBtu summer adder for local transportation service for power plants requiring local transportation service in PJM and New England.

Imbalance Charges

Generators throughout New York generally pay fees to pipeline companies, LDCs, or gas marketers for balancing services to account for differences between the amount of natural gas confirmed and the amount of gas used for power production. Absent the procurement of balancing services, a generator is exposed to costly penalties applicable to the quantity of natural gas that is outside the daily tolerance level or "bandwidth." Some transportation providers doing business in New York State have received FERC approval to provide shippers with permissive daily swing capability to accommodate the cycling duty on natural-gas fired generation. Under FERC Order No. 637, interstate pipelines have increased incentives to rationalize the sale of line-pack, for example, through new services such as park and loan. Gas utilities are also able to sell innovative services that foster imbalance resolution, and trading among market participants provides a financial vehicle for generators to manage their exposure to imbalance penalties. The costs of these services are reasonably definable, and in our view, are includible in a generator's bid each day.

Gas utilities have received NYPSC authorization to cash-out daily imbalances based on a formula that is indexed to the incremental cost of gas in the market area. How much balancing service required by individual generators depends on location and expected plant dispatch, particularly during the heating season – the time when the interstate pipelines and the New York Facilities System generally run close to or at capacity limits. The potential high cost of pulling too much (overpull) or too little (underpull) gas out of the distribution network offers shippers strong economic motivation to conform to the daily tolerance limit. Other business considerations related to the number of power plants in an operator's portfolio, generator technology type, risk tolerance, and amount of firm versus non-firm transportation entitlements, also impact the quantity and pricing of balance services obtained by merchant generators in New York.

Surplus or deficiency imbalances for scheduling inaccuracies are resolved on a daily or a monthly basis. For generators directly connected to interstate pipelines, FERC tariff provisions govern the cash out of unauthorized overpulls or underpulls. When there is no congestion on pipelines, generators typically rely on the pipeline as a source of "swing" capacity at no incremental cost. However, during periods of congestion, particularly when a pipeline issues a Critical Flow Day Alert or an Operating Flow Order (OFO), the penalty for violating the daily balance requirement can be high. All such penalties are levied on a volumetric basis in relation to a preset tolerance range.

For generators that obtain transportation service from an LDC, the cost of imbalance resolution is set forth under existing NYPSC tariffs or negotiated contracts for balancing services.[49] What individual generators pay strictly for balancing service at the local level is not known with confidence for two reasons: first, the commercial arrangements are not in the public domain, and, second, balancing services are often bundled with other transportation services. During local system constraints, gas utilities often post OFOs. Like penalties levied at the interstate level, the penalty for violating the daily balance requirement is high, and are levied on a volumetric basis. In our experience, generators receiving gas from pipelines or through LDCs are knowledgeable of the tariff conditions governing imbalance resolution, and therefore have proper economic motivation to avoid these costly penalties or include an allowance in submitting their daily bids.

There are no "hard" commercial benchmarks regarding the quantity and pricing of balancing service for gas-fired generators. LAI therefore exercised professional judgment in incorporating a reasonable allowance for each zone in the market area. We note that peakers in New York City, Long Island, or ROS are dispatched most often in the heavy load hours, May through September**,** when pipelines and LDCs have the greatest ability to accommodate

[49] Con Edison provides local transportation and balancing services under its SC-9 tariff. KeySpan New York and KeySpan Long Island provide local transportation and balancing services under the SC-20 and SC-14 tariffs, respectively.

overpulls or underpulls. To account for imbalance charges by pipelines, LDCs, or gas marketers, we have included the following volumetric adders:

- $0.05/Dth for generators directly connected to interstate pipelines,
- $0.10/Dth for generators served by LDCs in ROS,
- $0.15/Dth for generators served by LDCs on the Long Island Facility System and the New York Facility System.

Intra-Day Premiums

Another issue that arises in the context of imbalance resolution is the cost of gas incurred by peakers in the RTM. Current nomination / confirmation cycles in the gas day do not dovetail with the nomination / confirmation cycles in the power day. Whereas the gas day extends from 10 a.m. to 9:59 am the following day, the power day extends from midnight to midnight. Generators called upon to provide load following and peaking requirements within the power day may need to obtain natural gas from the intra-day market, sometimes at significant cost premiums relative to day-ahead commodity gas prices (adjusted for basis). While liquidity levels in the intra-day market reported on the Intercontinental Exchange or Bloomberg are thin relative to liquidity levels in the day-ahead market, generators are well-positioned to recognize and then include the intra-day premia in their daily bids. Moreover, the bid-ask spreads in the intra-day market during the late spring, summer, and early fall are not remarkable. Although the bid-ask spreads in the intra-day market during cold snaps can be large, simulation results indicate that the amount of gas-fired generation from peakers during cold snaps is relatively low.

Peakers called on to dispatch in the RTM are free to reap profits from price spikes during brief intervals. The new park and loan and other load management services available in the marketplace can provide peakers with the flexibility to respond to market signals. No allowance for intra-day gas cost premium has been included in the derivation of energy prices and net revenues from energy sales in the RTM.

Lost & Unaccounted For

LDCs experience losses due to pipeline leaks, uses, and other causes. LDCs sometime report Lost & Unaccounted For gas in the 3-4% range. However, most power plants are located close to the citygate and are served on large diameter, higher-pressure distribution mains that experience lower-than-average system losses. A 1% allowance for Losses & Unaccounted For gas at the local level has been included in our forecast.

Fuel Taxes

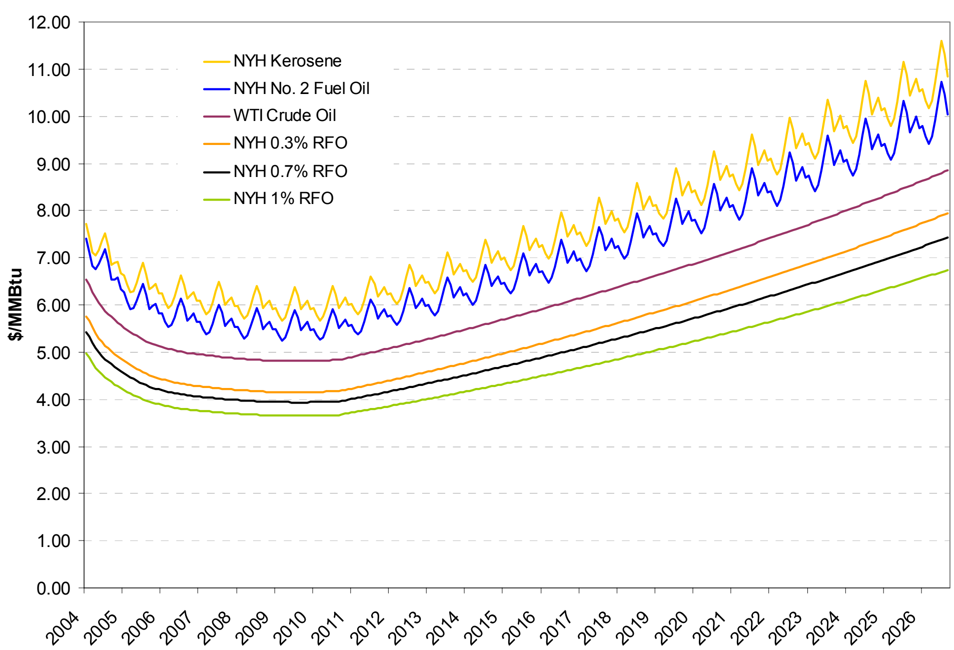
New York has a number of sales taxes that apply to fossil fuels. The New York petroleum business tax and the New York spill tax have been included in the cost of oil. Tax code revisions have eliminated several disparities with respect to gas purchased out-of-state versus gas purchased in-state. For example, the Gas Import Tax will be phased out in 2005 and was therefore omitted from the forecast of fuel prices. Natural gas deliveries to generating plants throughout New York State are subject to a 0.948% Gross Receipts Tax that is being phased out at the end of 2005, which was also omitted from the forecast of fuel prices. Lastly, we did not include a New York City 4% sales tax on fuel prices.

FUEL OIL PRICES

Market and cost factors, such as the price of crude oil, refining cost, the cost of substitutable fuels, and emissions limits, drive our forecast of fuel oil prices. Figure 16 illustrates our forecast of WTI and four NYH fuel oil products: 0.3% and 1% sulfur residual fuel oil (RFO), No. 2 fuel oil, and kerosene. The key assumptions in our forecast of fuel oil prices are as follows:

- The underlying WTI crude oil forecast is based on NYMEX future prices for WTI that shows prices decline for the next several years and the 2004 EIA long-term escalation rate for WTI crude oil prices thereafter.
- The NYH forecasts for 0.3% and 1.0% sulfur RFO, along with No. 2 fuel oil, are derived from econometric relationships with WTI crude. We have also included seasonality for No. 2 fuel oil prices based upon historical data.
- The forecasted price of kerosene, used at some peaker plants, was based on an analysis of the historic premium for kerosene over No. 2 fuel oil.

Figure 16 – New York Harbor Fuel Oil and WTI Crude Oil Price Forecasts



Delivered fuel oil prices in New York State reflect the New York Petroleum Business Tax and the New York Spill Tax. Fuel oil prices in New England and PJM are higher than NYH prices due to transportation costs, as shown in the following table.

Table 23 – Regional Fuel Oil Price Differentials from NYH Forecasts (2004)

Market	Residual Fuel Oil	No. 2 Fuel Oil
New York-Zone J	0.3% NYH + $0.47/MMBtu	NYH + $0.73/MMBtu
New York-Zone K	Varies by Facility[50]	NYH + $0.80/MMBtu
New York-ROS	1.0% NYH + $0.81/MMBtu	NYH + $0.88/MMBtu
PJM	0.7% NYH + $0.25/MMBtu	NYH + $0.27/MMBtu
New England	0.7% NYH + $0.30/MMBtu	NYH + $0.33/MMBtu

COAL PRICES

LAI's forecast of coal prices is utilized in two ways:

- We forecast regional coal prices using an in-house statistical model that is based on the historical relationships between the price of coal delivered to generating plants in Pennsylvania, underground mining productivity in Appalachia, and inflation. The price of coal delivered to Pennsylvania generating plants serves as a proxy for PJM delivered coal prices since Pennsylvania plants burn about half of all of the coal consumed for generation in PJM. The cost of coal delivered to plants in New York State and New England reflects the additional transportation cost differentials from PJM deliveries.

- Plant-specific coal prices for generation plants that report their delivered fuel prices using FERC Form 423 are escalated at a rate based on the econometric forecast described above.

In 2002, PJM delivered coal prices averaged $28.77 per ton ($1.20/MMBtu). The historical PJM delivered coal prices represent a mix of contract and spot pricing, with spot purchases accounting for approximately 20% to 25% of the total PJM coal deliveries. Our forecast of PJM coal prices reflects this mix. However, spot prices, while significantly more volatile than contract prices, provide a publicly available indicator of pricing trends. After a short-term spike in 2001, eastern spot coal prices began rising again in September 2003. By March, 2004 Northern Appalachian spot prices had reached $1.77/MMBtu and spot prices in Central Appalachia were over $2.00/MMBtu. The current spot price spike has been caused primarily by a tighter balance between supply and demand (after nearly two decades of excess capacity) and by other short-term (1 to 3 years) production and demand factors in the eastern coalfields. By comparison, Powder River Basin coal prices have been nearly flat since the end of 2001. Based on average coal transportation costs of about $7.00/ton for deliveries in PJM, we expect average PJM delivered coal prices to average $2.06/MMBtu in 2004 and $2.22/MMBtu in New York.

[50] For many RFO-fired plants in Long Island, LAI identified the grade of RFO burned; adders fell within the range of $0.50-0.75/MMBtu.

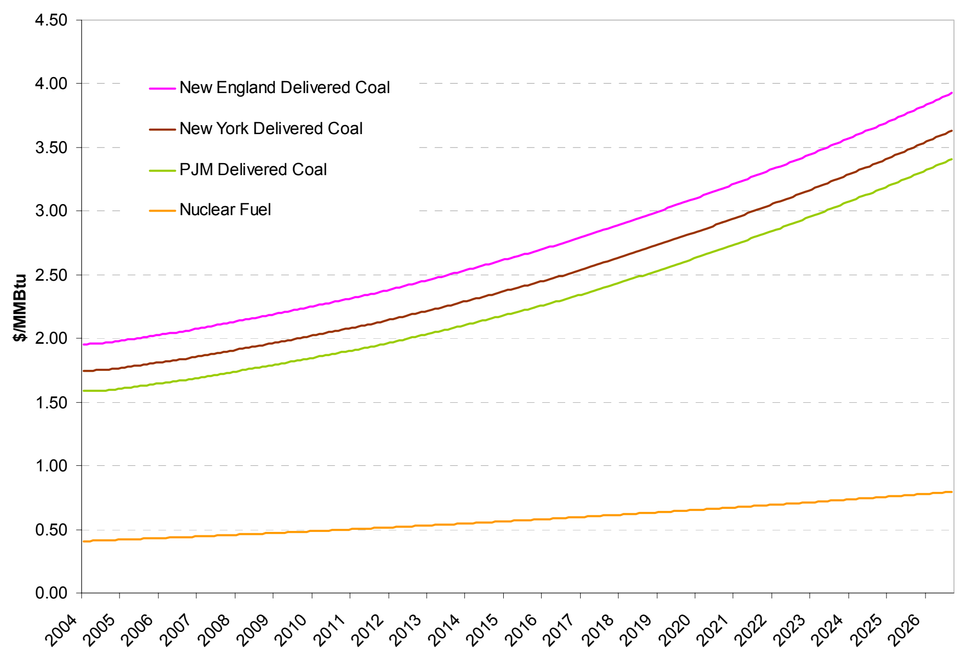
Delivered coal prices are forecasted to grow at about the rate of inflation through 2016, and somewhat higher than the rate of inflation over the remainder of the forecast period. For plants located in western PJM, western New York, or along the Atlantic coast that can receive shipments by water, competitive supplies from the Powder River Basin, Colombia, and Venezuela will exert some downward pressure on prices.

URANIUM PRICES

Uranium prices have been relatively stable in the \$10-\$12/pound of U_3O_8 range for the last several years. Given the anticipated decline in worldwide demand for uranium, prices are expected to remain relatively flat over the long run. Sufficient supplies of uranium and adequate fuel processing capacity should maintain fuel costs at nuclear plants in PJM, New York and New England at the equivalent of \$0.40/MMBtu (2004) throughout the forecast period. This price pattern reflects the impacts of the small number of new plants likely to be built worldwide and the recent trend in plant decommissioning in some industrialized countries.

The following chart shows the price forecasts for coal and uranium in PJM, New York, and New England. Plant-specific coal price data as reported in FERC Form 423 are not included in the chart.

Figure 17 – Coal and Uranium Fuel Forecasts



U.S. EMISSIONS LIMITS AND ENVIRONMENTAL COMPLIANCE COSTS

The Clean Air Act (CAA) establishes national standards for air quality and authorizes the EPA to promulgate regulations to achieve those standards. In part due to the regional transport of pollutants, much of the eastern U.S. has not attained national air quality standards. The

EPA and many individual states have implemented market-based cap-and-trade programs that establish state-wide NO_x and SO_2 allowance budgets, representing the total amount of the pollutant that can be emitted by all of the affected sources in the state. The allowances are allocated, or, in some cases, auctioned, annually among all of the sources in the budget program. Generators can meet their budgeted allocation by reducing emissions or by purchasing allowances from other generators. LAI tracks the emission rates and allowances for major fossil-fueled plants in PJM, NYISO, and ISO-NE. Generator bid prices in our chronological dispatch simulations reflect the opportunity costs for NO_x and SO_2 allowances – unused allowances are counted as a negative cost, because generators can sell those allowances at market rates.

SO_2 Allowance Price Forecast

EPA's Phase II Acid Rain state budgets for SO_2 were established by allocating SO_2 allowances to each affected unit at an emission rate of 1.2 pounds of SO_2/MMBtu of heat input, multiplied by the unit's baseline heat input. Federal Phase II Acid Rain provisions became effective in 2000. New York State has been in the vanguard of improving air quality. In 1999, Governor Pataki announced that fossil fuel-fired generators in New York would be required to further reduce SO_2 and NO_x emissions to protect sensitive regions of the state, such as the Adirondacks and the Catskills, from the deleterious impacts of acid rain. New York State's Acid Deposition Reduction Program (ADRP) became effective on May 17, 2003.[51] The SO_2 reductions under this program will be implemented in two phases, starting on January 1, 2005 and January 1, 2008. In January 2004, the EPA proposed to further ratchet down air emissions from electric generators to achieve air quality standards. The proposed Clean Air Rules of 2004 would further reduce SO_2 emissions in 28 states and D.C. in 2010 by approximately 50% below Phase II Acid Rain levels, with another 15% reduction by 2015.[52]

We assume that existing coal and RFO plants will meet their SO_2 budget allocation through the use of compliance coal or low sulfur RFO (0.7% sulfur or less), by operation of flue gas desulfurization systems, or by acquiring allowances from the market. Our forecast of SO_2 allowance prices shows a gradual decline from \$276/ton in 2004 to \$138/ton in 2011 as energy producers adjust their operations by implementing new technologies to reduce emissions, in advance of the initial Clean Air Rules deadlines. After 2011 SO_2 allowance prices are forecast to increase with inflation as shown in Figure 5.[53]

NO_x Allowance Price Forecast

LAI's NO_x allowance price forecast reflects the costs of meeting increasingly stringent NO_x emission limits, coupled with the expected proliferation of NO_x budget programs across the Northeast. The Ozone Transport Commission (OTC) member states (all New England, New York, New Jersey, Delaware, Maryland, Pennsylvania, and Washington D.C.) have been

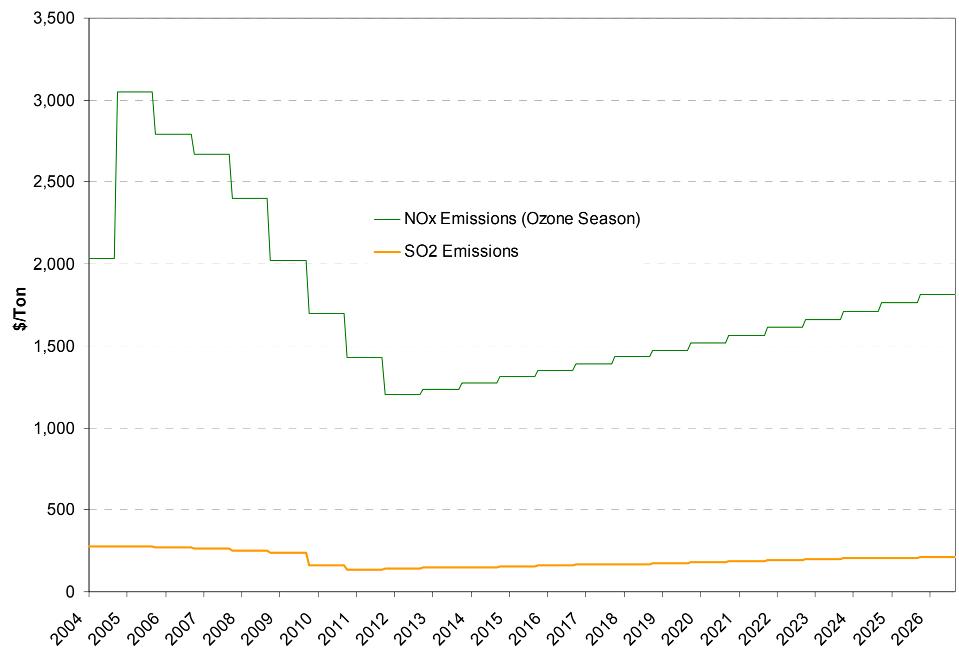
[51] 6 NYCRR Parts 237 and 238

[52] The states subject to the SO_2 and NO_x provisions of the proposed Clean Air Rules of 2004 are AL, AK, DE, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MN, MS, MO, NJ, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI, and DC. CT is only subject to the ozone-season provisions of the NOx rules.

[53] Market prices for SO_2 are reported by EvoLution Markets and Cantor-Fitzgerald brokerages.

subject to a NO_x budget "cap and trade" program since 1999. The OTC program limits the total emissions from affected units in each state during the ozone season, May 1- September 30. The most recent NO_x budget reductions were implemented in May 2003.

Figure 18 – Emissions Allowances Price Forecast



Two other regional trading programs, the federal Section 126 final action and the NO_x State Implementation Program (SIP) Call, will affect additional states that were not previously subject to the OTC NO_x budget program.[54] In New York, the NO_x provisions of the ADRP will impose ozone and non-ozone season caps beginning in October 2004. The proposed federal Clean Air Rules of 2004 would also implement a year-round cap on NO_x in the 28 affected states, including New York, starting in 2010, with additional reductions in 2015.

The emission limit used to calculate the NO_x SIP call budgets, the annual ADRP budgets, and the first phase of the 2004 Clean Air Rules is 0.15 lb NO_x/MMBtu, which represents approximately an 85% reduction from uncontrolled NO_x emissions for most large coal-fired power plants. The second phase of the 2004 Clean Air Rules would establish a baseline annual budget based on a 0.125 lb/MMBtu emission rate. In our forecast (Figure 18 above), NO_x allowance prices reflect the average prices reported for recent OTC trades for the current year (2004) and for allowances to be used through 2008.[55] We assume that NO_x allowance prices will continue to decline to the marginal cost of removal beyond 2008, as the remaining uncontrolled plants install emissions control technologies in anticipation of 2010 and 2015 deadlines. After 2012, NO_x allowances are projected to increase at the rate of inflation. At

[54] States and districts covered by the NO_x SIP Call are AL, CT, DC, DE, IL, IN, KY, MA, MD, MI, NC, NJ, NY, OH, PA, RI, SC, TN, VA, WV. States and districts covered by the Section 126 final rule are DC, DE, IN, KY, MD, MI, NC, NJ, NY, OH, PA, VA, WV.

[55] Market prices reported by Cantor Environmental Brokerage and Evolution Markets as of March, 2004 for OTC allowances.

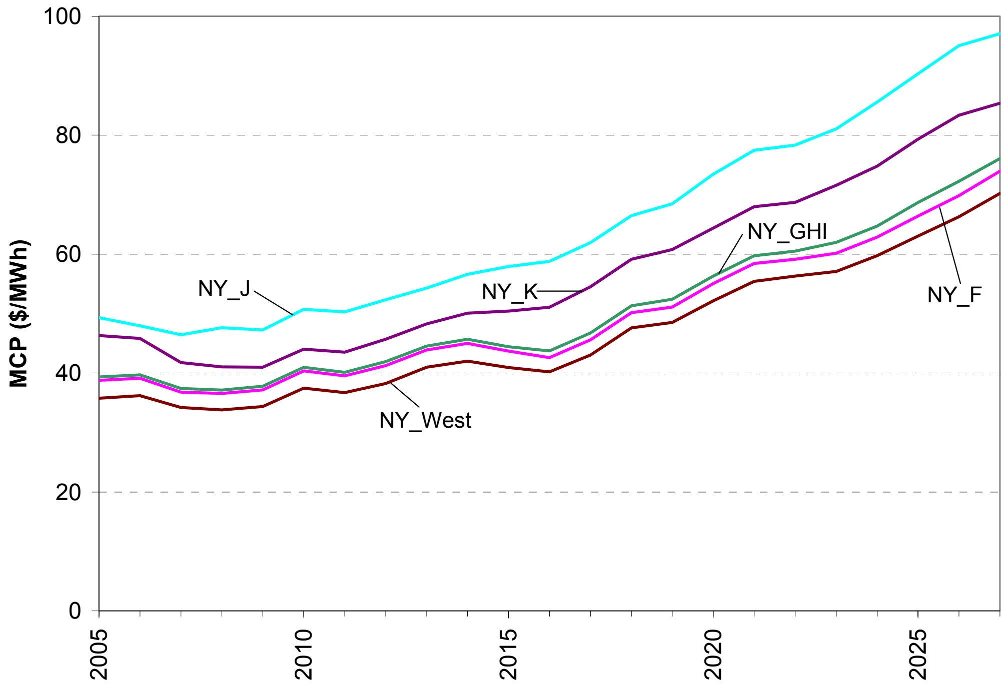
this time, a separate market for non-ozone season (October-April) NO_x allowances has not developed, and little public information is available regarding market prices. Although ozone-season allowances cannot be traded with non-ozone season allowances, generators can manage fuel burns and emissions inter-seasonally to minimize environmental compliance costs. The same marginal cost of control technologies and the same target emission rates apply to the ozone and non-ozone seasons. Therefore, we expect that the price of non-ozone season NO_x allowances will follow the same trend as the ozone season allowances.

4 DISPATCH SIMULATION RESULTS

ENERGY PRICES BY REGION

In order to calculate the contribution toward capital cost recovery from net energy and ancillary services, LAI forecasted the expected net revenue realized by a peaker over a twenty year horizon. Projected fuel costs and related market dynamics, in particular, new entry and plant attrition effects, are addressed in the previous sections of this report. To forecast hourly energy prices and the dispatch of gas turbines, LAI used MarketSym (in concert with proprietary plant entry, attrition, and other in-house models) to simulate the hourly operation of the NYISO and surrounding markets.

Figure 19 – Annual Average Market Energy Price Forecast / Deterministic



We found the following energy price patterns for the five NYISO zones we modeled:

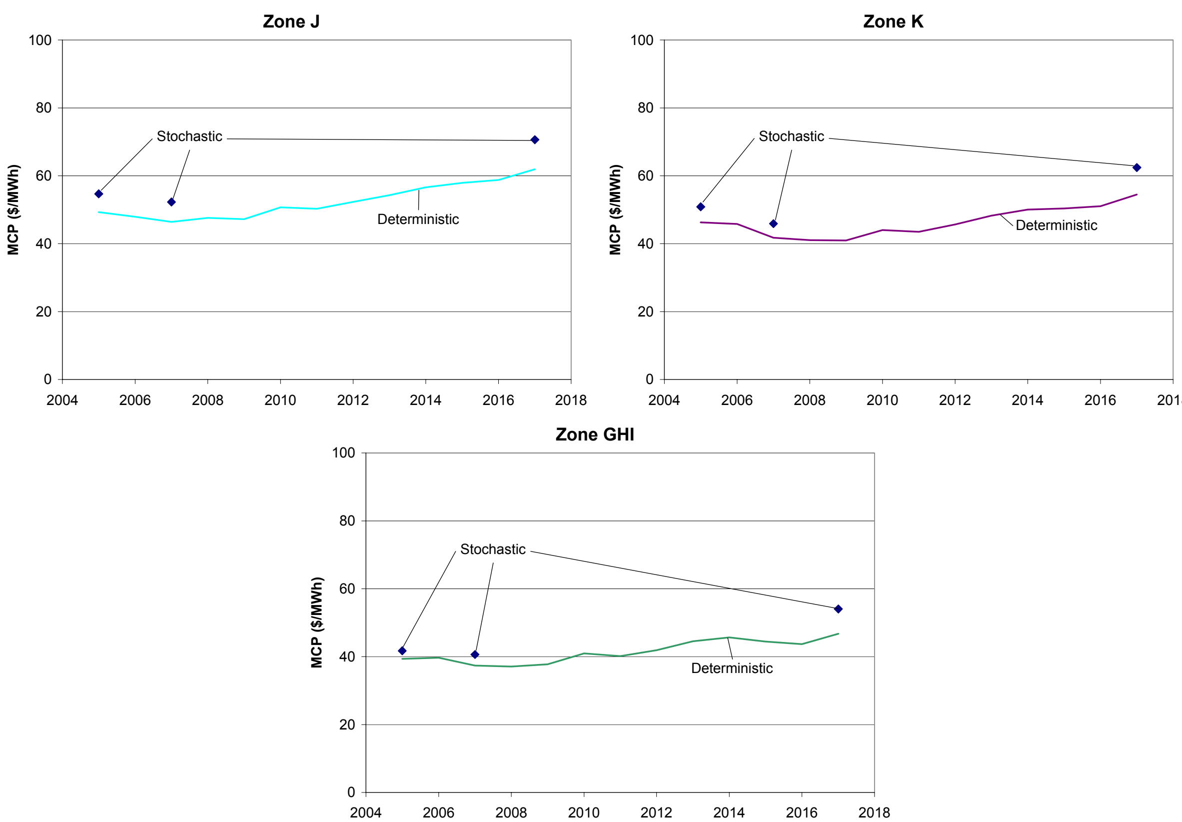
- Energy prices were highest in Zones J and K, as expected. Zone J prices are expected to decrease slightly through 2007 as new resources are added in-city, and then increase gradually over time.

- Energy prices in Zone K are close to Zone J in 2005 and 2006, and then decline in 2007 as a result of substantial anticipated resource additions relative to load.

- Energy prices in Zones F and GHI are almost identical and are below Zones J and K over the forecast horizon. Prices in NY-West (Zones A-E) remain consistently below Zones F and GHI.

The next three figures indicate the changes in average market energy prices from Case IIa in which we treated load deterministically, and Case IIb in which load for the selected years was treated stochastically. Case IIb market energy prices reflect market volatility, akin to including periods of extreme weather and system contingency events, and are higher than Case IIa. The increase in average market energy prices was greatest in 2017 for all of the zones, due in large part to a greater proportion of hours in which SCRs (and other high-priced resources) set the energy price. In Zone J SCRs set the energy price 13-14 hours/year in 2005 and 2007, and 34 hours/year in 2017. SCRs in Zone K had a very similar pattern. In Zone GHI SCRs set the energy price 11 hours/year in 2005 and 2007, and 29 hours/year in 2017. Although generators scheduled in the DAM may be entitled to higher RTM prices only for incremental operating hours, LAI made the simplifying assumption that all generators would receive the higher Case IIb energy prices for all operating hours.

Figure 20 – Annual Average Market Energy Price Forecasts (Case IIa deterministic and Case IIb stochastic values)



FORECAST OF PEAKER DISPATCH

LAI modeled "proxy" gas turbine peakers in Cases IIa and IIb to forecast expected unit dispatch and the associated gross energy revenues realized during the hours when the peakers were expected to operate. Net energy revenues reflect the cost of natural gas on a delivered basis, emissions allowances and other non-fuel variable operating costs. LAI modeled peakers in each of the three ROS areas. The most favorable location was GHI and therefore we have not included results for the other two ROS areas (A-E and F). Our modeling results, by region, were as follows:

- LAI estimates that the Zone J 2xLM6000 plants will have a 15% capacity factor under Case IIa deterministic conditions in 2005, and a 19% capacity factor under Case IIb stochastic conditions. Actual NYISO energy data indicate that the ten NYPA gas turbines in New York City operated at a 24.3% capacity factor in 2002 and 16.2% in 2003.[56] Thus NYPA's actual experience is largely consistent with LAI's stochastic capacity factor estimates.

- The Zone J capacity factors are forecasted to decline to about 13% in 2006-2007 in Case IIa, and to 16% in Case IIb. The decline in plant dispatchability is explained by the addition of 1,538 MW of new combined cycle plants that can be efficiently cycled: 250 MW at Ravenswood came on-line in 2004, 500 MW at NYPA's new Poletti station and an incremental 288 MW at Con Edison's repowered East River plant are assumed to come on-line in 2005, and 500 MW at SCS Astoria in 2006.

- On Long Island the 2xLM6000 peakers are forecasted to operate at 6%-7% capacity factors under Case IIa and 9%-10% under Case IIb in 2005-2006. While this level of peaker dispatch is lower than the historical value of 12.3% in 2003, it can be explained in part by the assumed commercialization of the Cross Sound Cable. When the cable became operational on August 15, 2003, it had a noticeable impact on LIPA gas turbine operations.[57]

- Under deterministic conditions the 2xLM6000 ROS plant is forecast to operate at 3%-7% capacity factors during the first ten years of our forecast. The capacity factor increases by up to 2% under stochastic conditions.

- The 2x7FA plant is almost never dispatched due to its higher heat rate. Under deterministic conditions the expected capacity factor is close to zero, and in the stochastic case it averages about 1% over the forecast horizon.

ANCILLARY SERVICE REVENUES

LAI derived the quantity of ancillary service revenue allocable to gas turbine peakers based on the plants' technology characteristics and seasonal dispatch determined in MarketSym. The LM6000 plants are assumed to bid into the TMNSR market, thereby receiving a share of total TMNSR payments by NYISO. The 7FA plants are assumed to bid into the TMR market and receive a share of those revenues. TMNSR can be provided by aeroderivative and jet-type (also quick-start) units, internal combustion units, and pumped storage facilities. TMR

[56] Data was obtained from the 2003 and 2004 Gold Books.

[57] The LIPA gas turbines were scheduled to operate at a 6.3% average capacity factor in the DAM during the first four months of 2003 before CSC was in service, and at a 2.8% capacity factor in the first four months of 2004 when CSC was in service. In contrast, the scheduling of the NYPA gas turbines varied very little, from 3.3% to 2.8%, for the same periods.

can be provided by a variety of units, including industrial frame gas turbines, provided they have not been dispatched and have capacity available to offer.

LAI determined total TMNSR and TMR payments as percentages of total energy payments using confidential NYISO data for 2003. We calculated the total payments for TMNSR and TMR over the forecast horizon based on the forecasted changes in total energy payments for the NYISO zones. We also calculated the total potential supply of TMNSR and TMR available from all generating units capable of providing the particular service. The unit revenue for TMNSR and TMR was then derived by dividing the total payments by the total potential, and we allocated the payments to the LM6000 and 7FA units based on their share of the potential supply.

- Total TMNSR payments in 2003 (including lost opportunity costs as provided by NYISO) were \$7.2 million, and we estimate that these TMNSR payments will increase to \$8.3 million in 2005.[58] There is about 4900 MW of potential supply that can provide this ancillary service, so the average unit revenue is \$1.69/kW-yr in 2005. Thus a 2xLM6000 plant in ROS, for example, would receive \$136,000 in 2005, and amounts that will vary in proportion to estimated energy revenues in future years.

- Total TMR payments in 2003 were \$2.0 million, and we estimate that these TMR payments will increase to \$2.3 million in 2005. There is just over 5900 MW of potential supply that can provide this ancillary service, so the average unit revenue is \$0.39/kW-yr in 2005. Thus a 2x7FA plant in ROS, for example, would receive \$109,000 in 2005, and amounts that vary in proportion to our estimated total energy revenues in future years.

NET REVENUES

The different shapes of the net revenue curves in Figures 21 and 22 for the three regions result from differences in the local capacity mix, load growth, and load shape. The capacity mix changes occur yearly through 2017, after which the curves are smoothed in five year blocks. The high net revenue values in Zone J, and the large rate of revenue growth after 2017 relative to the other two regions, results from differences in the regional load factors. Based on the 2002 hourly load data, Zone J has the highest percentage of hours close to the peak load and based on the 2004 Gold Book forecast it is the only zone that has an increasing load factor. Thus Zone J has more hours when the most expensive units must operate, making peaker operation profitable in a growing number of hours.

Peakers in Zone J have the highest forecasted level of net energy and ancillary service revenues. Under Case IIb conditions with stochastic treatment of load, peakers in Zone J are forecasted to earn \$40/kW-yr to \$60/kW-yr for the first ten years. These results are generally

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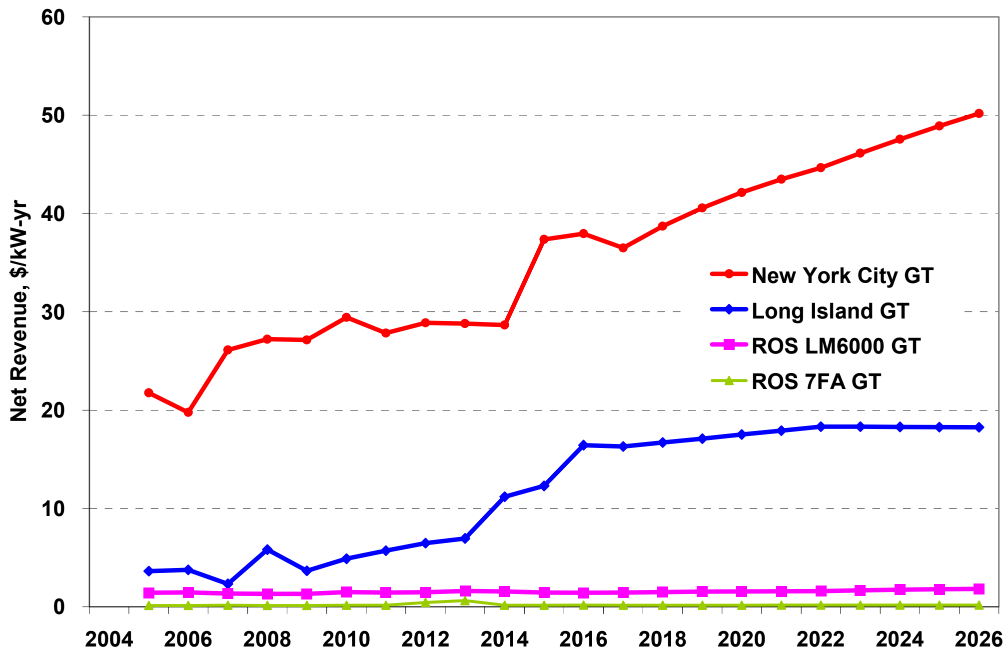
[58] 2003 TMNSR and TMR payments are based on the 2003 LBMP (non-bilateral) energy payments and may differ from the NYISO settlement reconciliation values. TMNSR prices declined in mid-2003 and appear to have remained at relatively low levels through the first few months of 2004. We understand that TMNSR prices may be even lower under SMD2, but we have not tried to estimate the resulting impacts.

consistent with the 2003 Market Monitoring Report[59] in which gas turbine peakers (with a 10,500 Btu/kWh heat rate) on the 345 kV system in the Zone J Day-Ahead Market were estimated to have earned approximately $50/kW-yr in 2002 and $40/kW-yr in 2003, ignoring any reduction due to intra-day gas cost premiums.[60]

Figure 21 – Case IIa Deterministic Gas Turbine Peaker Net Revenues

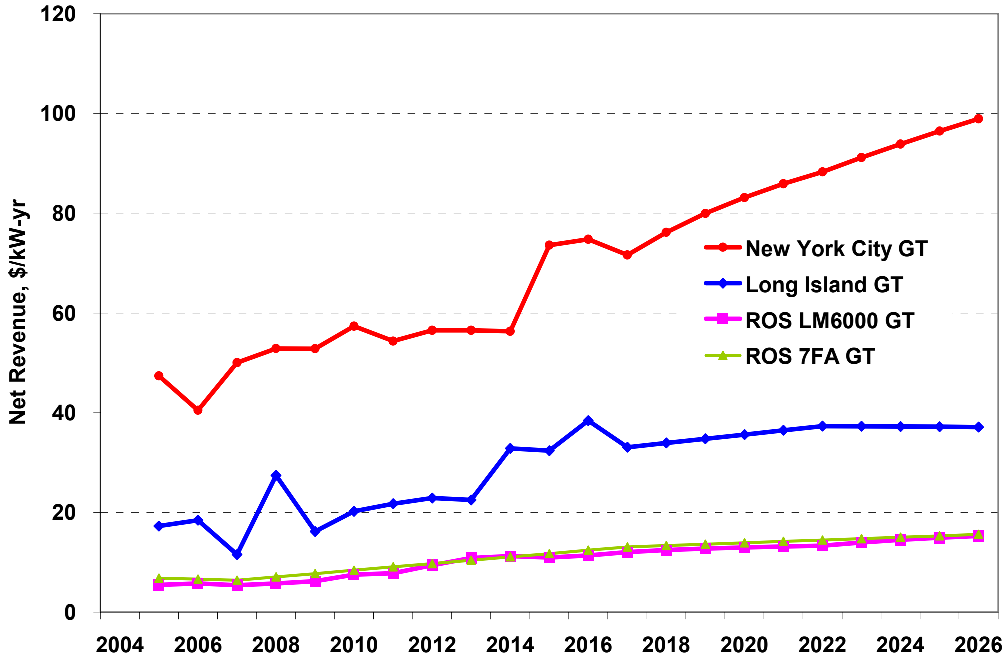


The ROS LM6000 and 7FA peakers are forecasted to earn $6/kW-yr to $12/kW-yr under Case IIB conditions for the first ten years. These results are also generally consistent with the 2003 Market Monitoring Report in which gas turbine peakers in the Capital Zone were estimated to have earned a fraction of the energy revenues earned in Zone J during 2002 and 2003, again ignoring any reductions due to intra-day gas cost premiums.

[59] 2003 State of the Market Report, New York Electricity Markets, April 2004, pages 37-40.

[60] Intra-day premiums are discussed in the previous section of this report. According to the Market Monitoring Report, gas turbine peakers on the 138 kV system in Zone J were estimated to have earned approximately $80/kW-yr (ignoring intra-day gas cost premiums), but the higher prices in these load pockets should dissipate as new capacity is added in the next two years.

Figure 22 – Case IIb Stochastic Gas Turbine Peaker Net Revenues



The next set of figures illustrates capacity factors, net revenues, and capacity revenue requirements, organized for each of the three cases defined for this study.

Case I – Capital and Operating Costs without Net Revenues

Figure 23 – Capacity Revenue Breakdown – 2005

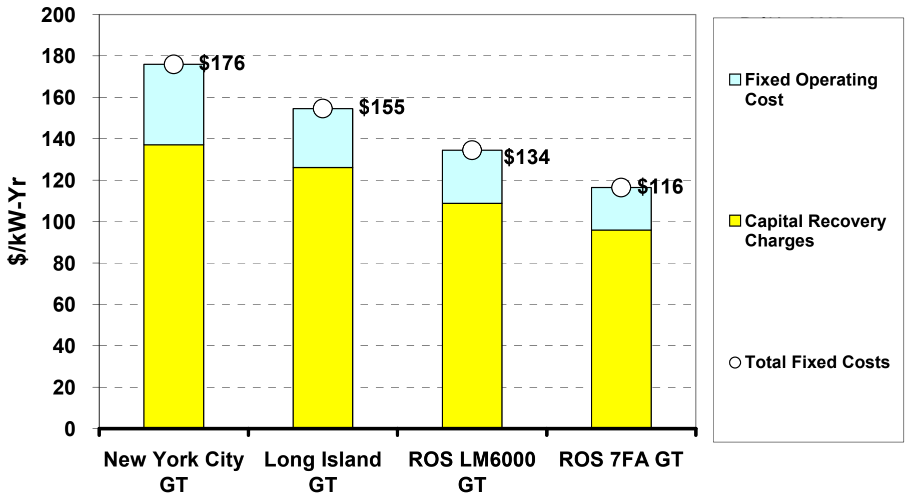
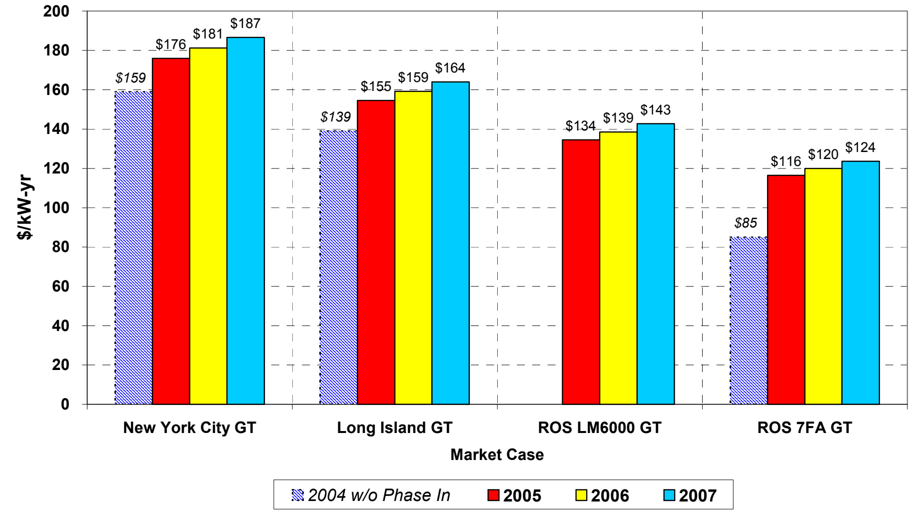


Figure 24 – Capacity Revenue Requirement Results



Case IIa – Capital and Operating Costs plus Net Revenues / Deterministic

Figure 25 – Gas Turbine Annual Capacity Factors

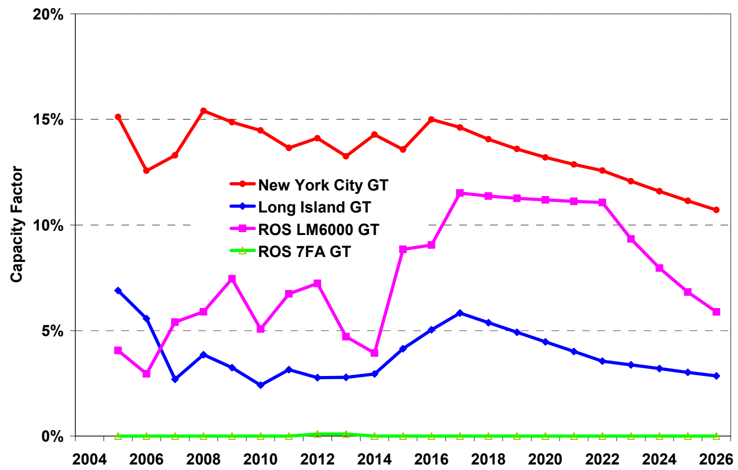


Figure 27 – Capacity Revenue Breakdown – 2005

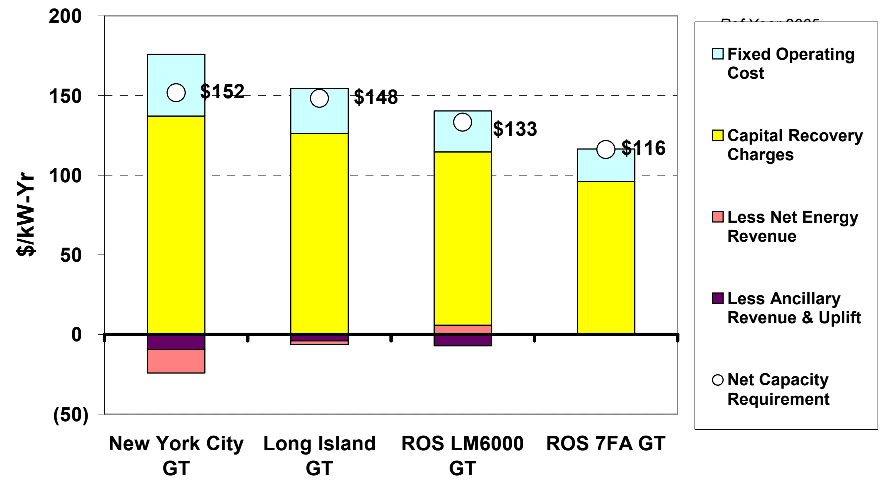


Figure 26 – Gas Turbine Annual Net Revenues

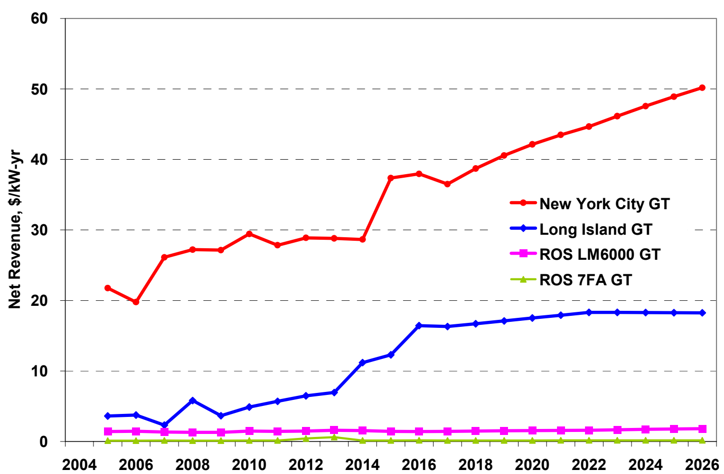
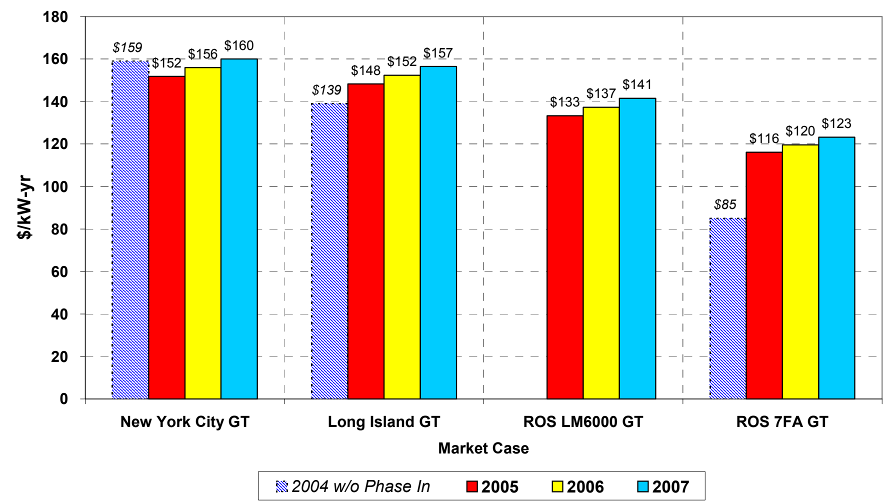


Figure 28 – Capacity Revenue Requirement Results



Case IIb – Capital and Operating Costs plus Net Revenues / Stochastic

Figure 29 – Annual Capacity Factors – NYC and LI

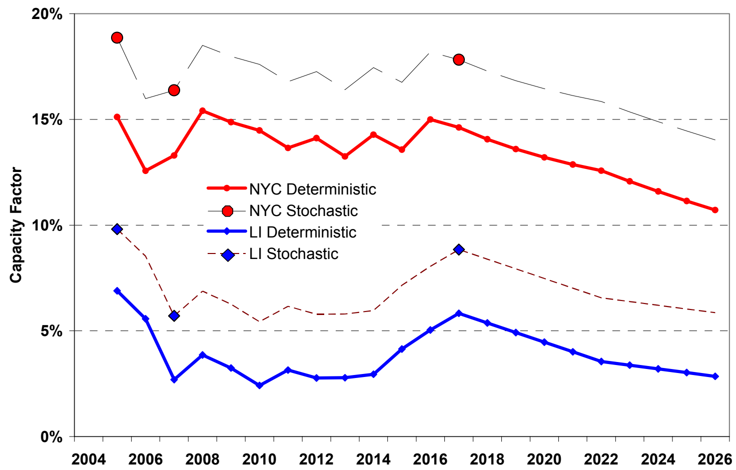


Figure 31 – Annual Net Revenues – NYC

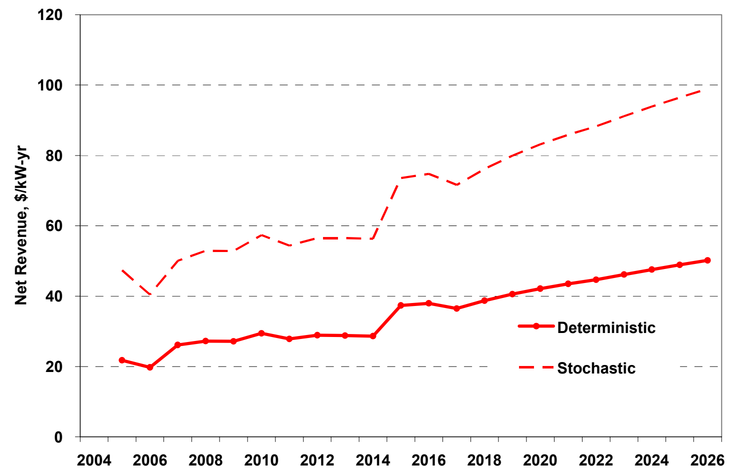


Figure 30 – Annual Capacity Factors – ROS

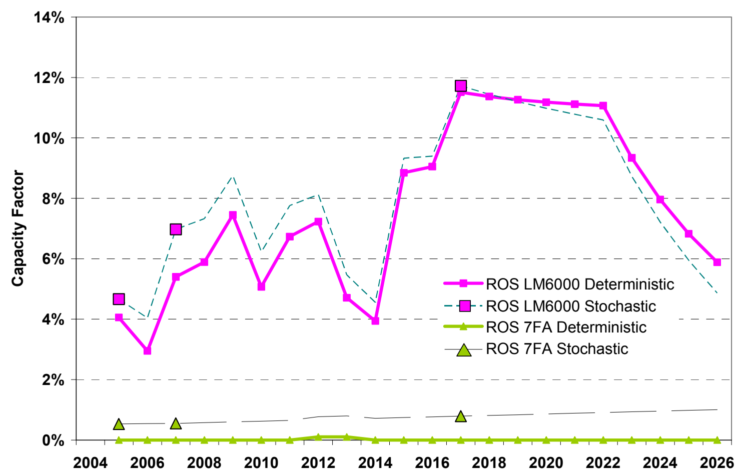
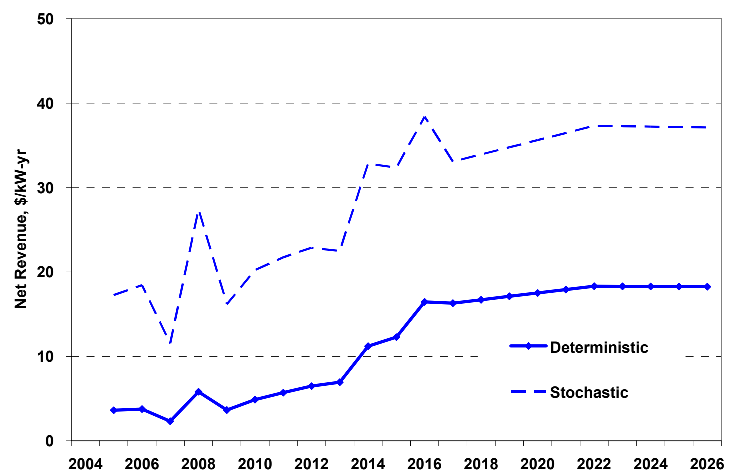


Figure 32 – Annual Net Revenues – Long Island



Case IIb – Capital and Operating Costs plus Net Revenues / Stochastic

Figure 33 – Annual Net Revenues – ROS (LM6000)

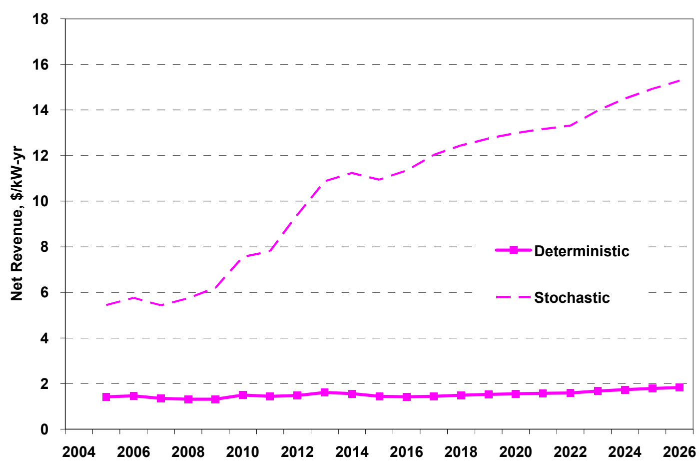


Figure 34 – Annual Net Revenues – ROS (7FA)

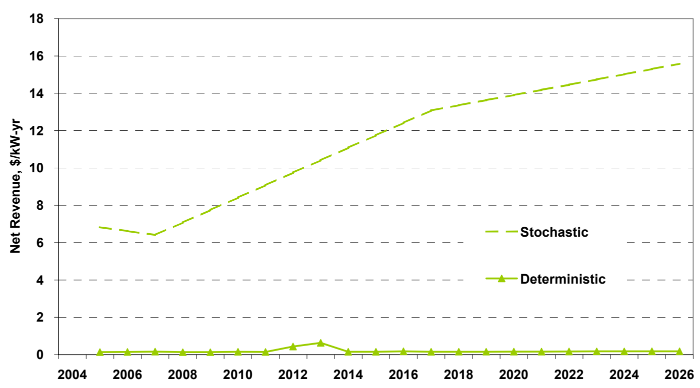


Figure 35 – Capacity Revenue Breakdown – 2005

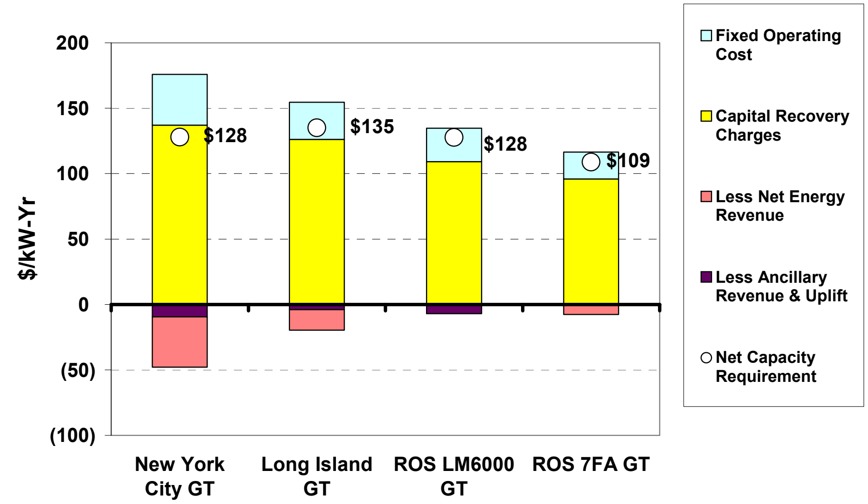
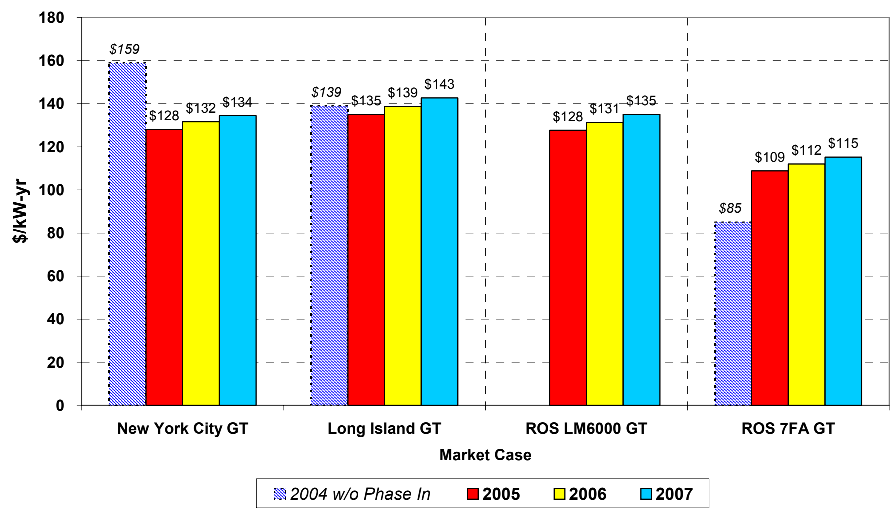


Figure 36 – Capacity Revenue Requirement Results



5 DEMAND CURVE ANALYSIS

From a broad perspective, the ICAP demand curve mechanism was developed to achieve a number of complementary objectives:

- Facilitate unforced capacity transactions between generators and LSEs.
- Reduce volatility in the ICAP markets and, in turn, provide reasonable expectations of income to generation facility owners.
- Reduce the ICAP market's vulnerability to the exercise of market power.
- Reward excess generation enhanced reliability and price stability benefits.
- Recognize the declining marginal benefit of additional generation.

In this section of our report we construct and analyze the demand curves based on the calculated reference values. The analysis represents, in part, a continuation of general inquiry first conducted by David Patten, Independent Market Advisor, which was later adopted and extended by Mike Cadwalader of LECG Consulting, in work for transmission owners (TO). The analysis describes the incentives for a supplier to withhold capacity (to rationally maximize ICAP revenues), the total cost of ICAP (including and excluding a limited withholding behavior scenario), and the impact of alternative zero crossing points on total cost of ICAP for all three cases and regions. Our assumptions and analysis are based on economic theory and are not intended to depict the motivation or actions of individual market participants.

CURRENT 2004 DEMAND CURVES

In the figure below, we illustrate the current 2004 ICAP demand curves across the three distinct ICAP regions, prior to the summer DMNC adjustment, on a percentage basis.[61] The slopes of the three demand curves are similar. The NYCA demand curve has a much lower reference value of $60, but also a lower zero-crossing point 12% above the statewide capacity requirement.[62] The Zone J and Zone K curves have higher reference values of $130 and $114, respectively, and common zero-crossing points 18% above the locational requirements.

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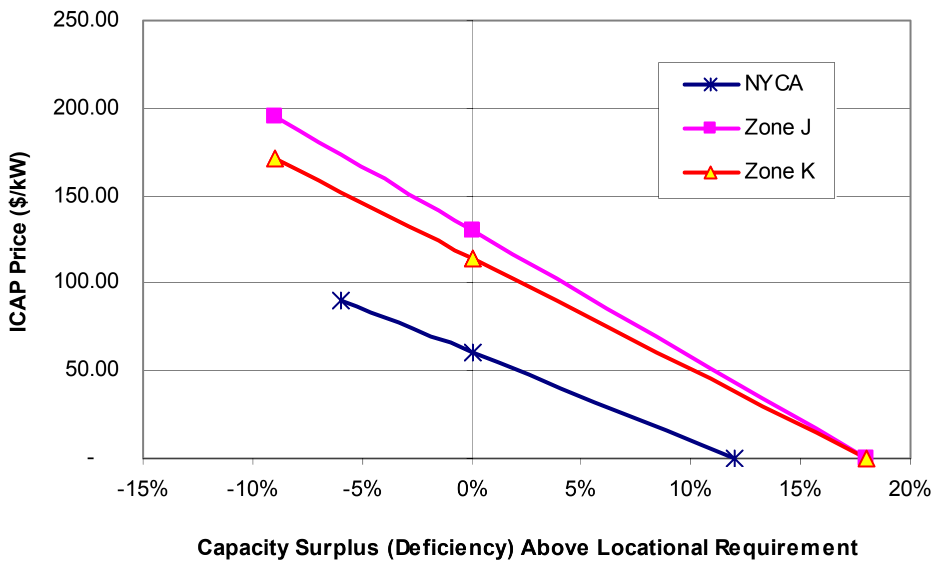
[61] The phase-in was incorporated to limit LSE exposure to ICAP prices and is expected to expire next year.

[62] The NYCA reference values shown throughout this section are based on the 7FA technology because it is less expensive than the LM6000 technology.

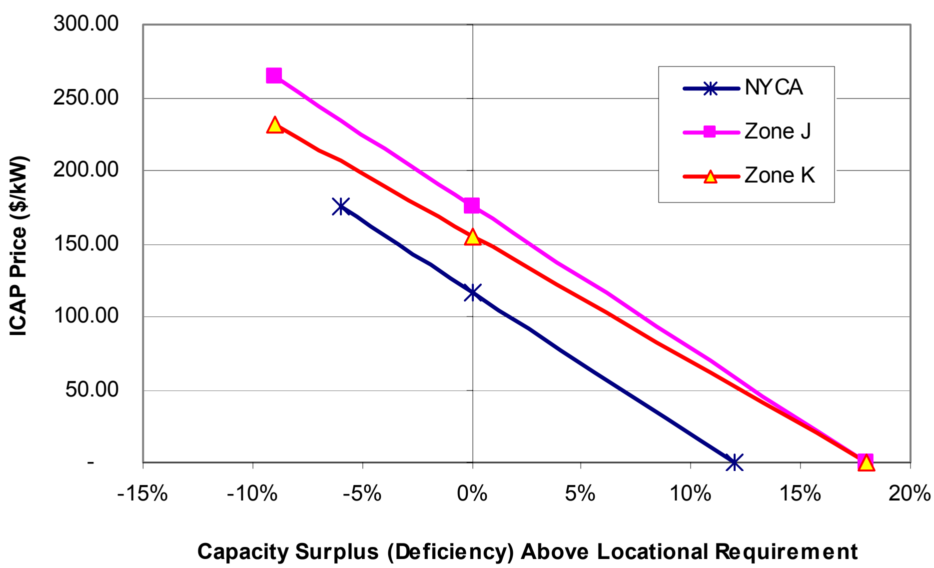
Figure 37 – Current 2004 ICAP Demand Curves (with phase-in)



CASE I – CAPITAL AND FIXED OPERATING COSTS

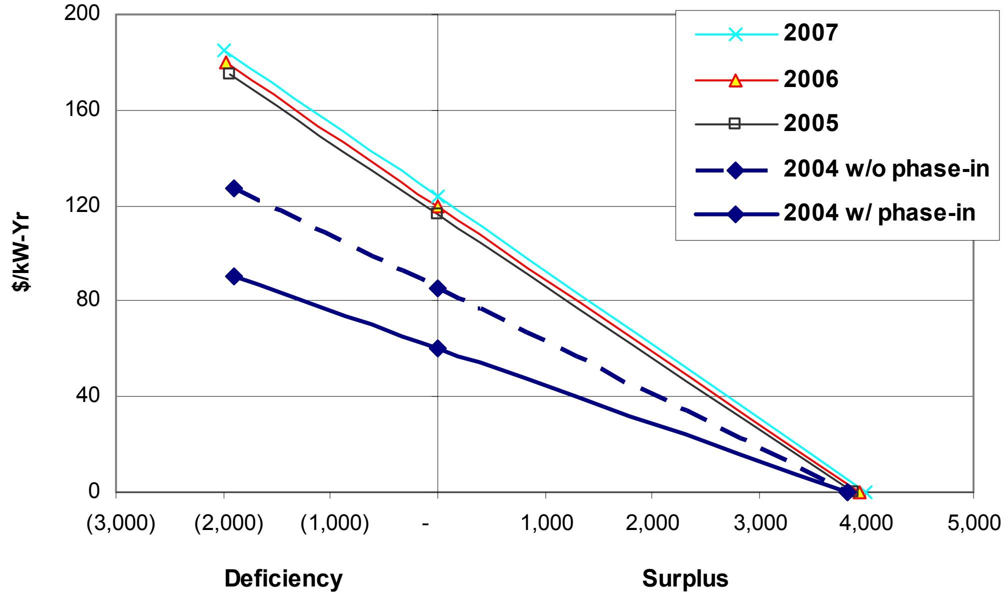
In the following figure, we show the same graph for 2005, based on Case I assumptions (*i.e.*, without net revenues). The Zone J and Zone K curves are higher than the current demand curves (with phase-in). However, the calculated NYCA reference values are significantly higher than current values, principally due to higher capital costs for the 7FA technology than previously utilized in ROS.

Figure 38 – Case I – 2005 ICAP Demand Curves



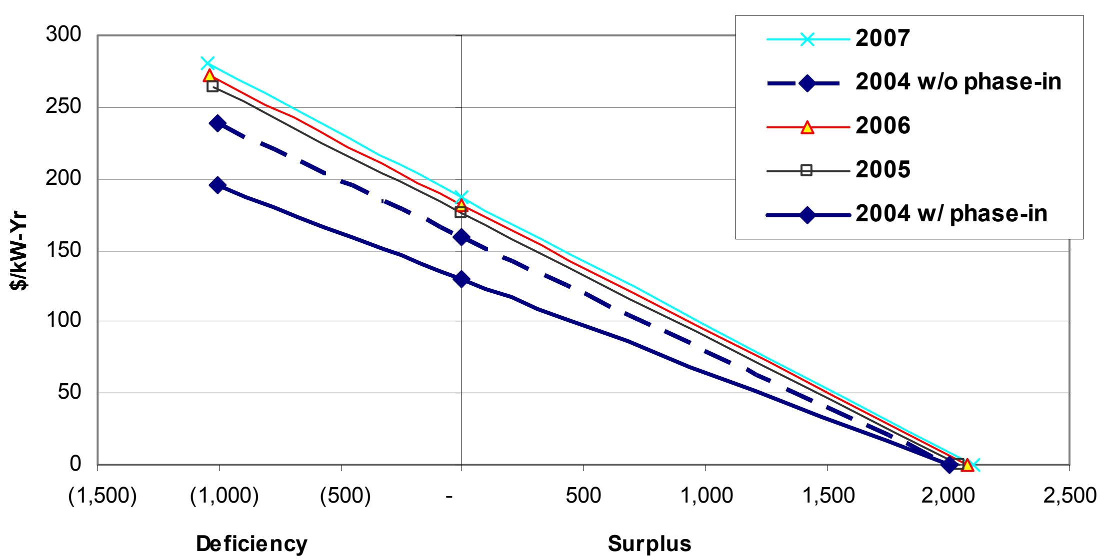
The following three figures compare 2004 reference values to the calculated Case I values for the 2005 – 2007 period. As seen in Figure 39 for NYCA, the new reference values increase the slope of the demand curve much more than for Zones J and K.

Figure 39 – Case I – NYCA Demand Curves, 2004 - 2007



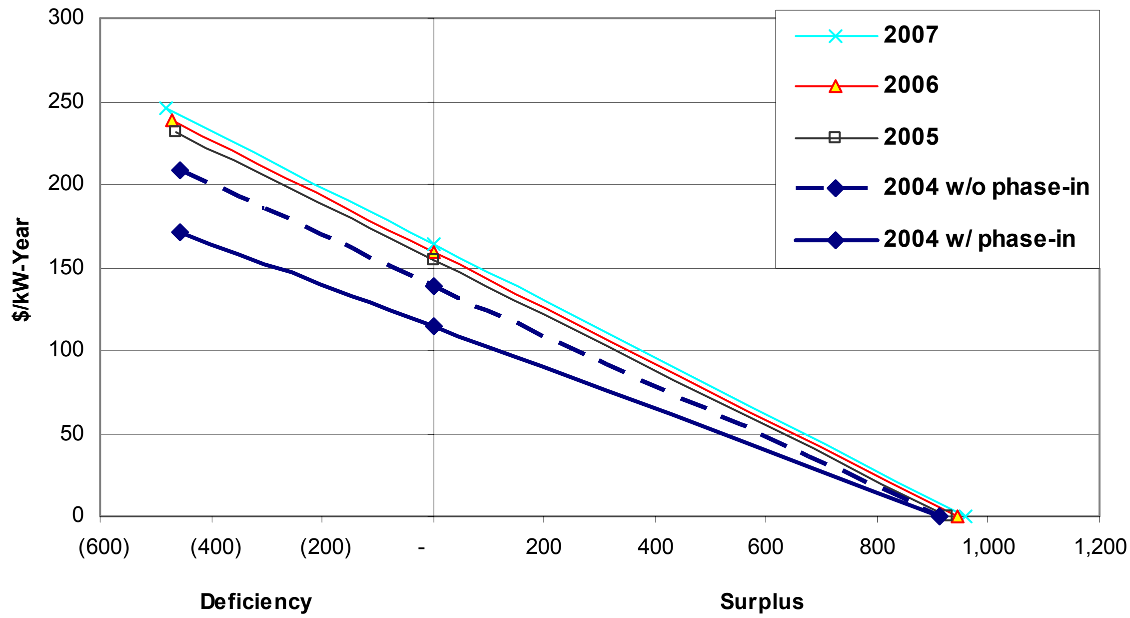
The Case I reference values for Zone J for the 2005 - 2007 period are modestly greater than the current reference value as shown in Figure 40. The slope of the demand curve does not change significantly.

Figure 40 – Case I – Zone J Demand Curves, 2004 - 2007



The projected Case I demand curves for Zone K have slopes that are steeper than the current demand curve as shown in Figure 41.

Figure 41 – Case I – Zone K Demand Curves, 2004 - 2007

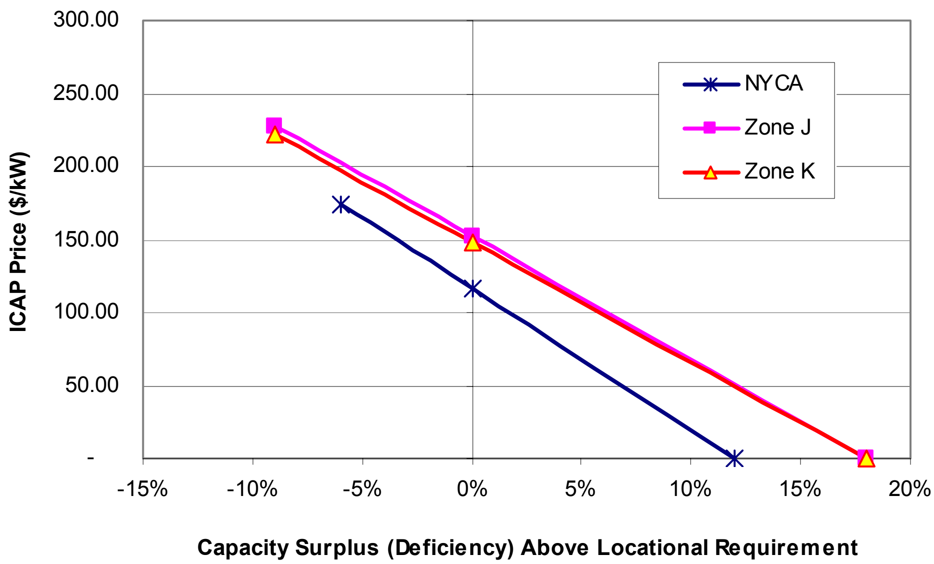


CASE IIA – CAPITAL AND FIXED OPERATING COSTS PLUS NET REVENUES – DETERMINISTIC

In Figure 42, we illustrate the Case IIa demand curves for the 2005 ICAP year in which we include the contribution of net energy and ancillary service revenues under deterministic treatment of loads. The NYCA and Zone K demand curves are based on higher reference values than the current demand curves, and thus have steeper slopes. The forecasted Zone J reference values is lower than the current value due to larger net revenues, resulting in a slight flattening in the slope of the demand curve.

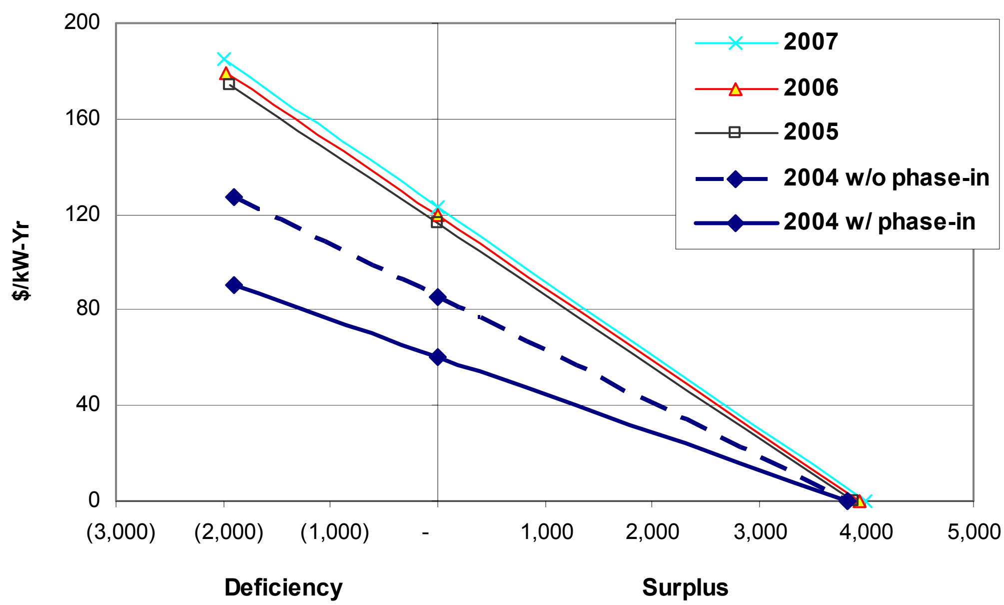
Compared to Case I, the NYCA reference value changes insignificantly ($0.31/kW-yr) under the Case IIa assessment due to the very limited operation and net revenues of the 2x7FA plant. The Zone J reference value drops significantly (14%) under the net revenue assessment, from $176/kW-yr to $152/kW-yr. The Zone K reference value dropped modestly (4%) under the net revenue assessment, from $155/kW-yr to $148/kW-yr.

Figure 42 – Case IIa – ICAP Demand Curves, 2005



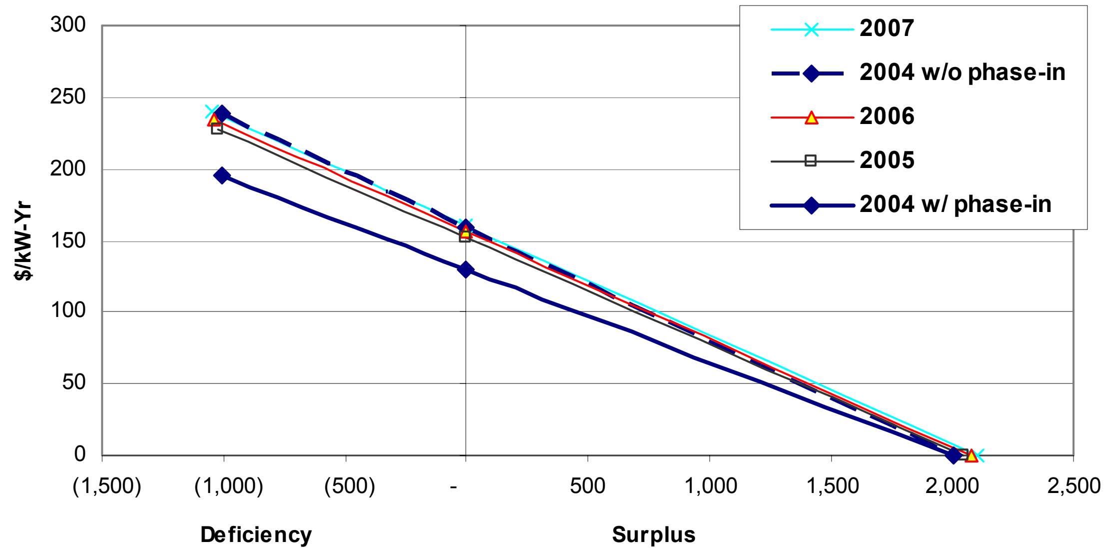
The following three figures compare current reference values to the Case IIa values calculated by LAI for the 2005 – 2007 period. As seen in the first graph for NYCA, the new reference values increase the slope of the demand curve much more than for J and K.

Figure 43 – Case IIa – NYCA Demand Curves, 2004 - 2007



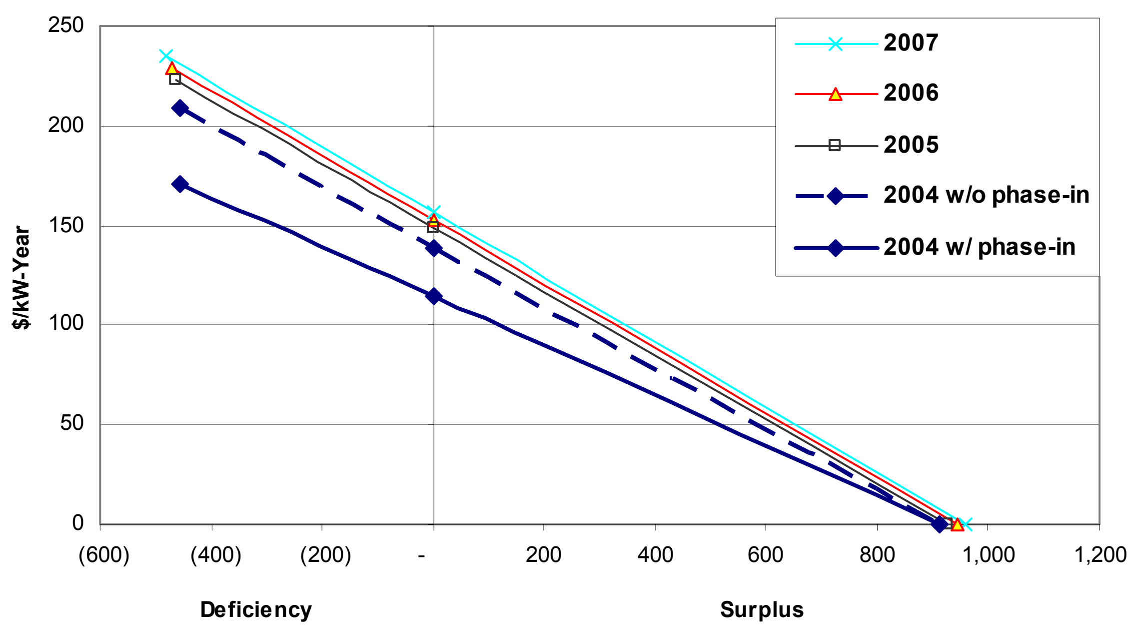
The reference values for the Zone J region for the 2005 – 2007 period are very similar to the current reference values, without the phase-in, as shown in Figure 44. Reference values increase from the current value of $130/kW-yr to $152/kW-yr in 2005, with further increases to $160/kW-yr by 2007.

Figure 44 – Case IIa – Zone J Demand Curves, 2004 - 2007



The projected reference values for the Zone K region are well above the current reference value (with phase-in) of $114/kW-yr as shown in Figure 45.

Figure 45 – Case IIa – Zone K Demand Curves, 2004 - 2007



Incentives to Withhold

Following a review of a variety of technical analyses on ICAP markets and demand curve functionality, LAI structured our analysis based on research conducted by LECG, as issued in a May 5, 2004, report to New York transmission owners.[63] LAI assessed the incentives an ICAP supplier has to withhold and estimated the resulting impacts on ratepayers. The supplier's portfolio was tested in 5% increments, and the withholding impact was calculated based on a complete removal of that portion of a supplier's portfolio from the ICAP market.

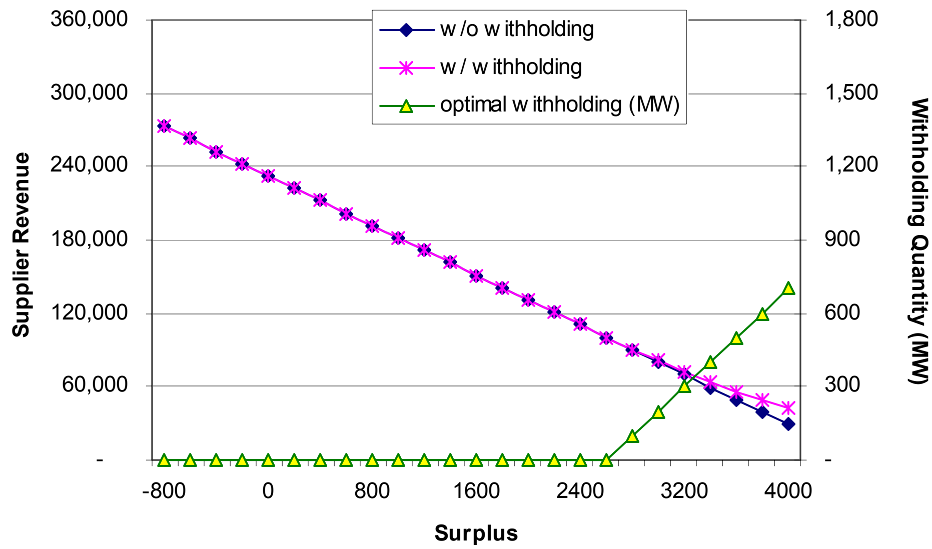
The following three figures assess the incentive a supplier would have to withhold capacity based on various levels of capacity surplus in the regional market in order to optimize revenue. The supplier was assumed to have 2,000 MW in the NYCA region and 1,000 MW in the Zone J region. The analysis only assessed portfolios within regions, not portfolios across regions (*e.g.*, NYCA and Zone J combined).

Insofar as nearly all generation on Long Island is covered contractually by the Long Island Power Authority (LIPA), LAI did not conduct the withholding analysis for Zone K. KeySpan Generating Company owns and operates the vast majority of capacity on Long Island. KeySpan has a long-term, cost-based contract with LIPA governing the sale of capacity and energy to LIPA. Thus, nearly all of the Zone K capacity is procured by LIPA. We understand that, some of the new capacity that will be constructed on Long Island under PPAs with LIPA will be merchant capacity. However, this merchant capacity will be very small in relation to total installed capacity in Zone K. For this reason, assessing incentives to withhold on Long Island does not appear worthwhile.

In Figure 46, we show the maximum revenue a 2,000 MW supplier could generate with and without withholding practices at various levels of ICAP surplus in the NYCA market. The left-hand axis indicates the supplier's revenue (i.e. portfolio quantity not withheld multiplied by the ICAP clearing price). The right-hand axis indicates the portion of the supplier's portfolio withheld. As shown, there is minimal incentive to withhold in the NYCA market, and only then, at very high levels of surplus (when ICAP prices diminish to near-zero).

[63] Memorandum to TO Members of ICAP Working Group from Mike Cadwalader, May 5, 2004.

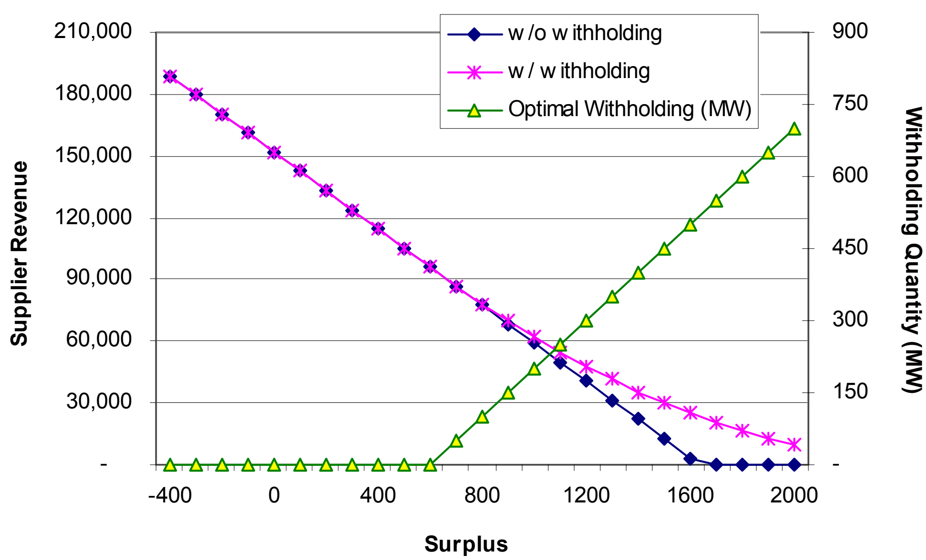
Figure 46 – Case IIa – Supplier Incentive to Withhold ICAP – NYCA, 2005



In Zone J, the incentive to withhold is more pronounced. At a locational surplus of 700 MW or more, a supplier with an in-City portfolio of 1,000 MW could withhold capacity to maximize revenue. The supplier has an economic incentive to increase his withholding practices as the regional surplus increased. Absent withholding, at an approximate surplus of 1,600 MW the price of ICAP would diminish to near-zero.

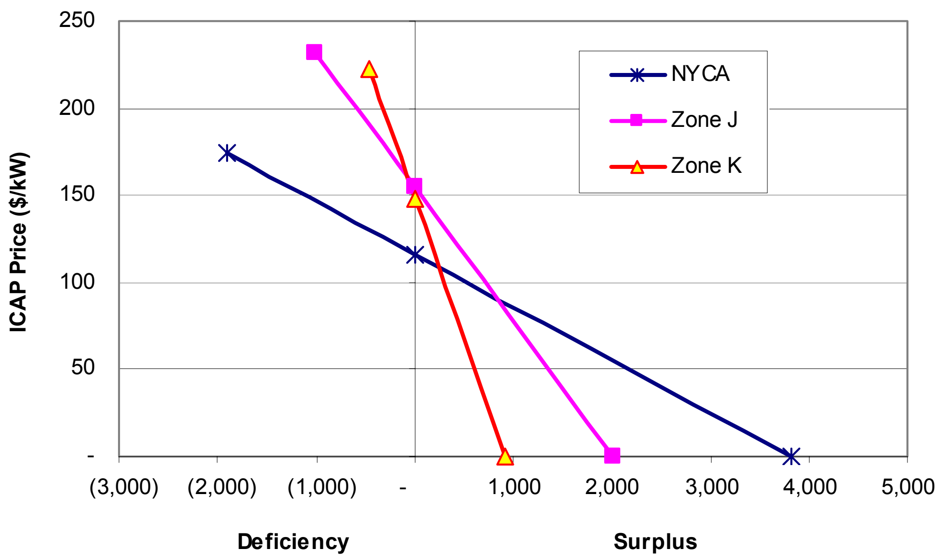
A large percentage of Zone J capacity retains a limit on the maximum ICAP price it can receive. The ICAP cap limits the capacity price sold by the three entities that bought the existing Con Edison units to \$8.75/kW-month (\$105/kW-year). In our withholding example for the Zone J region, withholding never causes prices to rise above that level.

Figure 47 – Case IIa – Supplier Incentive to Withhold ICAP – Zone J, 2005



Another way to assess the impact of the demand curves is the slope, representing the ratio of change in price divided by the change in MW. The proposed Zone J demand curve under Case IIa has a slope of -9.27%. That is, for every 100 MW increase in Zone J capacity surplus, the regional price of ICAP declines by $9.27/kW-yr. In contrast, NYCA has a Case IIa slope of -2.54%. The Zone K market has a slope of -16.14%, which if not constrained by long-term contracts, would provide significant incentive for a supplier to withhold capacity to maximize revenue. The following figure shows the slopes of the demand curves on a per-MW basis, as opposed to a percentage basis, as depicted in Figure 44.

Figure 48 – Case IIa – ICAP Demand Curves (per MW Basis), 2005



The slope of all Cases and regions is provided in the following table. The steeper the slope, the greater the price impact due to changes in supply.

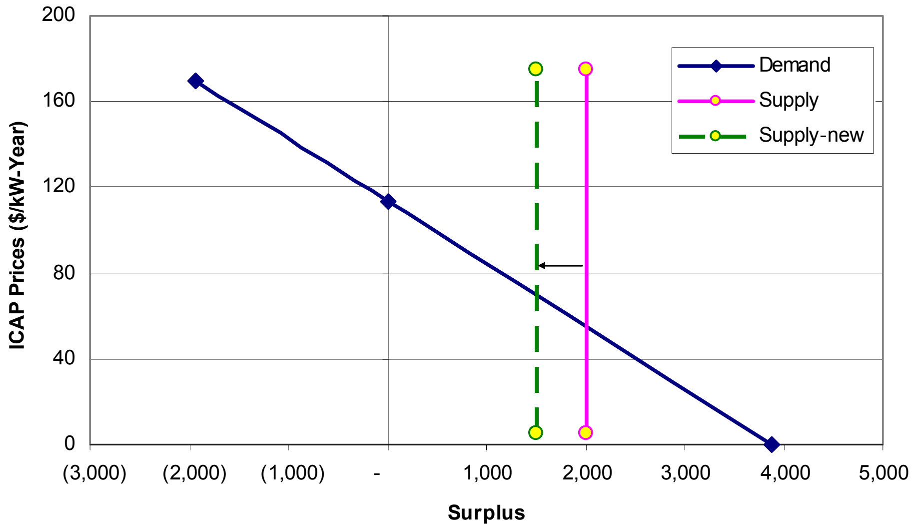
Table 24 – ICAP Demand Curve Slopes, All Regions and Cases

	Case I	Case IIa	Case IIb
NYCA	-2.54%	-2.54%	-2.38%
Zone J	-10.75%	-9.27%	-7.82%
Zone K	-16.83%	-16.14%	-14.70%

Total Cost of ICAP

The total cost of ICAP was determined for each region under Case IIa and Case IIb conditions. In our model, we make one significant assumption. Because we have no specific knowledge of the shape of the supply curve, we assume it is vertical where it intersects the demand curve. That is, for every MW withheld from the market, we assume that it meets the demand curve exactly 1 MW higher up the demand curve. This concept is illustrated graphically in Figure 49, where a 500 MW facility is "withheld" from the NYCA market. By assuming the supply curve is vertical at the point of intersection with the demand curve, the change in ICAP price and the incentive to withhold referenced in this report represents the ***theoretical maximum*** given the size and capability to withhold of an individual supplier.[64]

Figure 49 – Assumed Shape of Supply Curve at Point of Intersection



The following three figures depict the total ICAP cost by region, with and without withholding by a single supplier of 2,000 in the NYCA market and 1,000 MW in the Zone J market under Case IIa assumptions. LAI did not conduct a withholding and total ICAP cost analysis for Zone K, since essentially all of the capacity is procured under a long-term contract by a single buyer, virtually eliminating withholding opportunities. Figure 50 indicates the impact of the specified withholding scenario for NYCA. At a 0 MW surplus, where all ICAP is priced at the Case IIa reference value, the total cost of ICAP in the NYCA region is $4.43 billion.[65]

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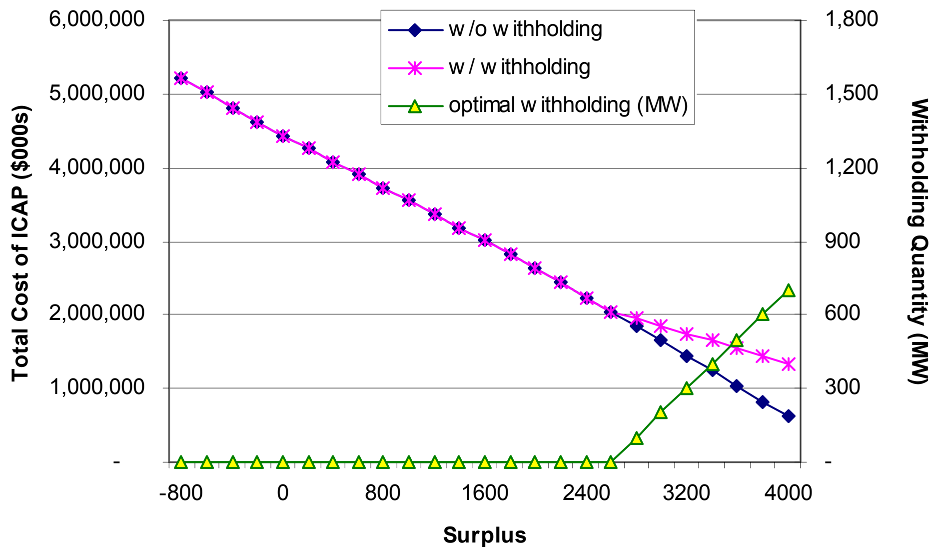
[64] A more thorough assessment of withholding impacts using the actual supply curves and the approved 2005 ICAP demand curves may be warranted.

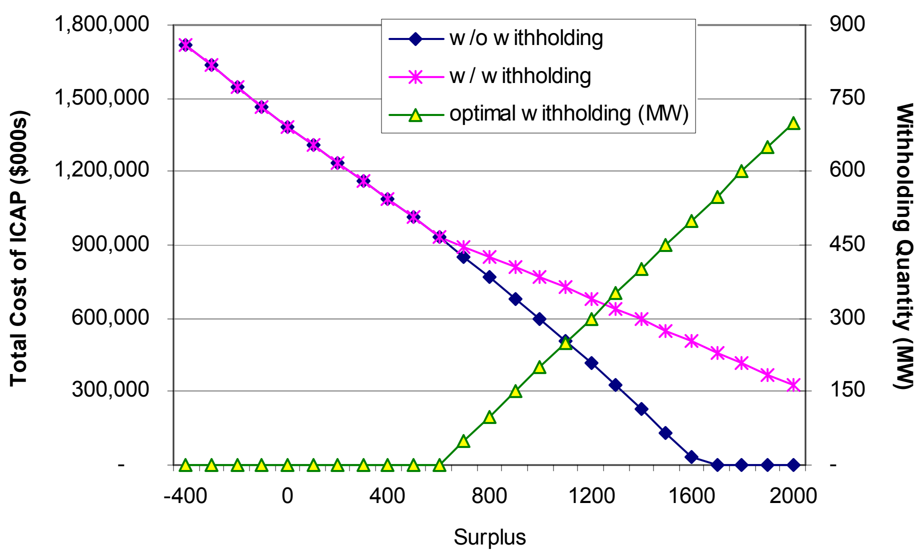
[65] It is important to note that the stated assumptions (*i.e.*, that there is no surplus and all ICAP is priced at the reference value) do not represent the current market environment. Accordingly, readers of this report should not presume that the revised ICAP demand curves will necessarily cause a radical run-up in the price of ICAP in NYCA.

Figure 50 – Case IIa – Total Cost of ICAP – NYCA, 2005



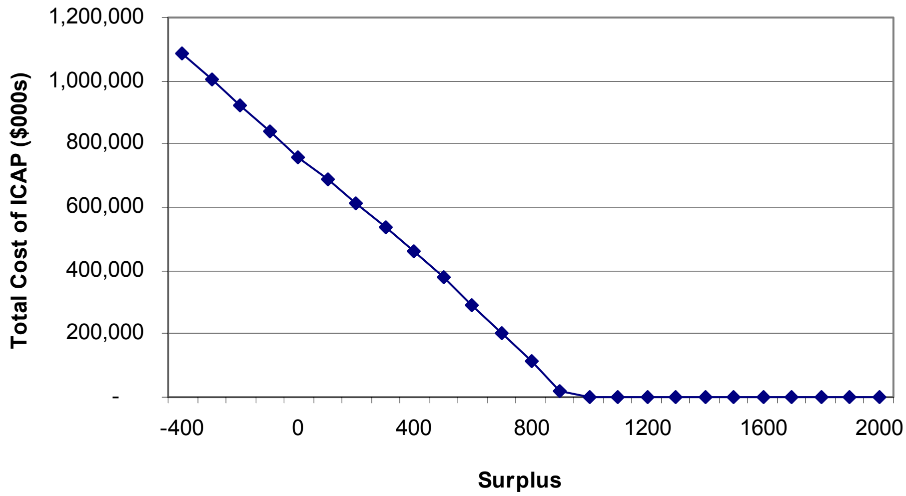
In Zone J, the total cost of ICAP (again, at a 0 MW surplus) is $1.38 billion, as shown in Figure 51. Based on the limited exercise of assessing withholding opportunity by a single supplier with a portfolio of 1,000 MW, the total cost of ICAP can be greatly influenced by physical withholding practices.

Figure 51 – Case IIa – Total Cost of ICAP – Zone J, 2005



In Zone K, the total cost of ICAP at a 0 MW surplus, is expected to cost $757 million in 2005, as shown in Figure 52.

Figure 52 – Case IIa – Total Cost of ICAP – Zone K, 2005



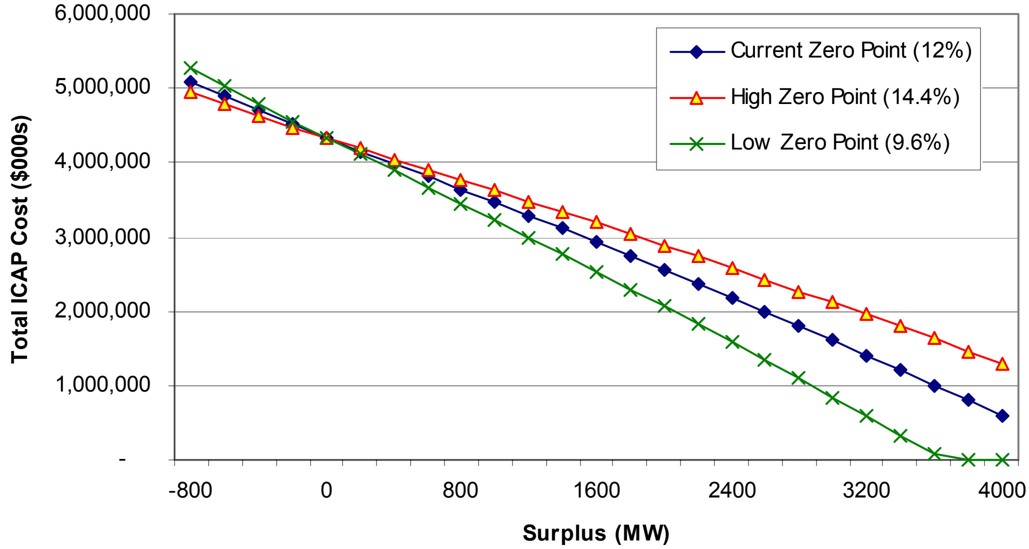
Alternative Zero Point Options

LAI assessed the total cost of ICAP under a range of zero point crossings – the point where the demand curve meets the $0 value on the X axis. In the following five figures, we assess the impact of alternative zero crossing points (bracketed around the base case) on the three regional markets under non-withholding and withholding scenarios. The withholding scenarios, as discussed above, are based on withholding opportunity by a single supplier, 2,000 MW in size for the NYCA region and 1,000 MW in size for the Zone J region. Zone K is excluded from the withholding assessment.

The bracketed alternative zero crossing points are set at 20% above and below the locational and state-wide capacity requirements. For example, the NYCA demand curve is currently based on a zero crossing point equal to a 12% incremental reserve margin (*i.e.*, 112% multiplied by the 118% reserve requirement defined by the New York Reliability Committee). For purposes of this analysis, LAI assessed zero crossing points of 80% and 120% of the 12% incremental reserve margin, equal to zero crossing points at reserve margins of 9.6% and 14.4%, respectively. For the Zone J and Zone K regional analyses, the 20% brackets are applied to the 18% locational reserve requirements, creating low and high alternative cases of 14.4% and 21.6%, respectively.

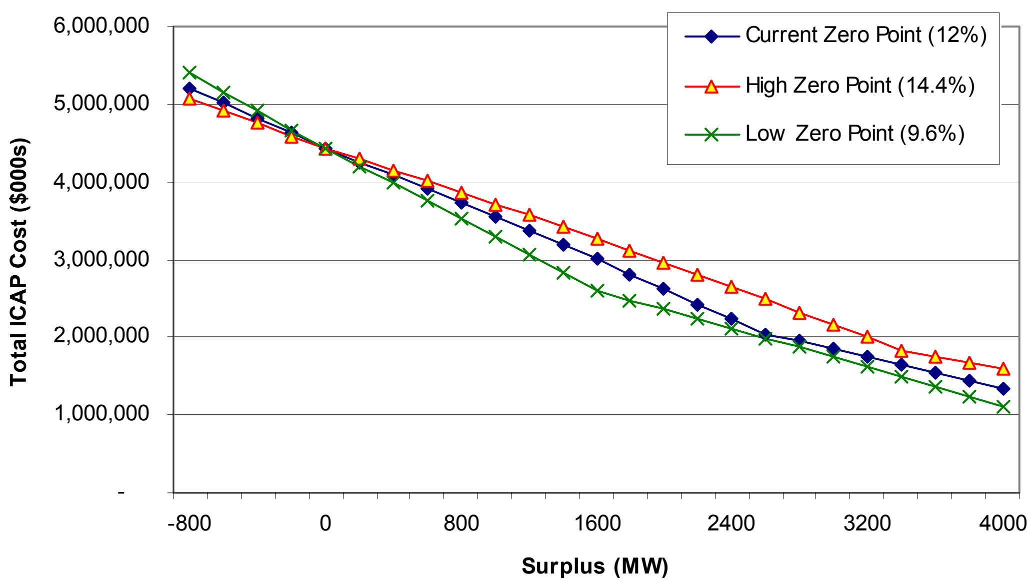
As seen in Figure 53, the total ICAP cost for NYCA is dependent on the zero crossing point and the ICAP surplus level in a given year. The High Zero Point case produces a lower total cost of ICAP (relative to the Current and Low Zero Point cases) during periods of ICAP deficiency, but higher overall cost during periods of ICAP surplus.

Figure 53 – Case IIa – Total Cost of ICAP at Alternative Zero Crossing Points, No Withholding – NYCA, 2005



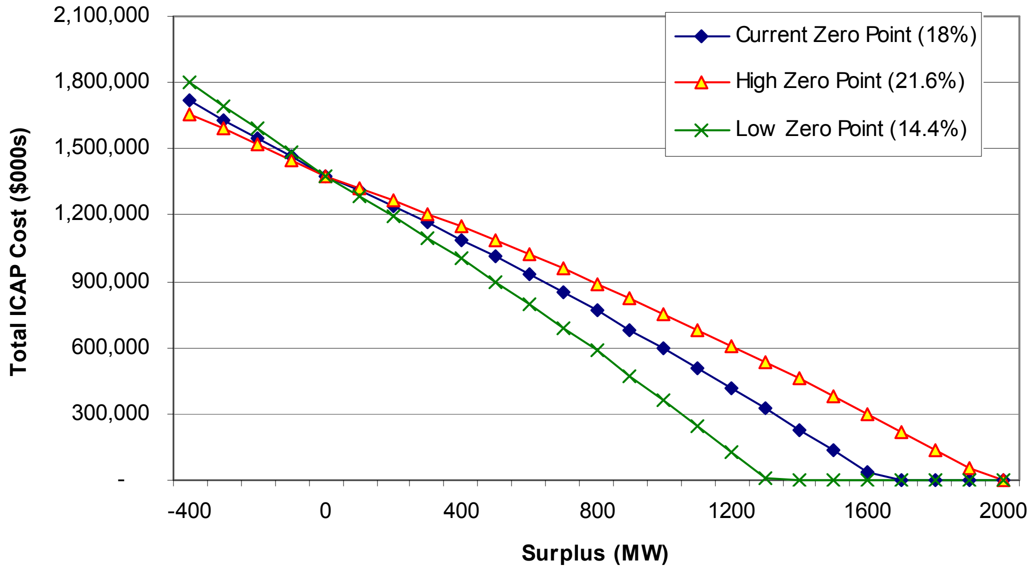
If withholding is considered, there is less variation in the results of alternative zero crossing points. The high zero point alternative is still the most expensive, but at various levels of surplus, the low zero point case and the current zero point case produce very similar results.

Figure 54 – Case IIa – Total Cost of ICAP at Alternative Zero Crossing Points, Withholding – NYCA, 2005



The same analysis for Zone J produces similar results. As seen in Figure 55, under a scenario of no withholding, the three alternatives produce very distinct total ICAP costs at various levels of surplus and deficiency.

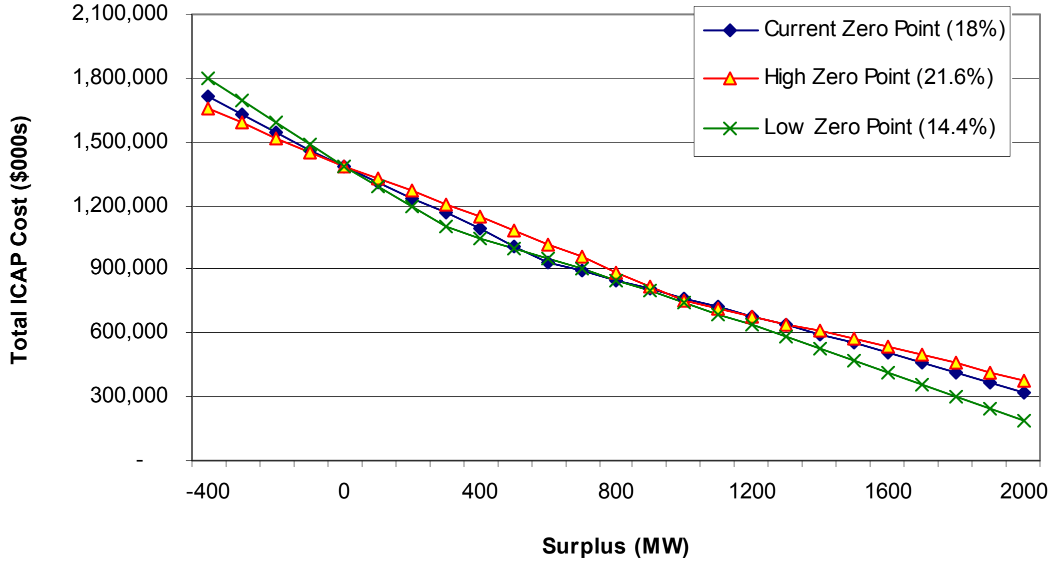
Figure 55 – Case IIa – Total Cost of ICAP at Alternative Zero Crossing Points, No Withholding – Zone J, 2005



If withholding is considered, the alternative zero crossing points produce similar total ICAP costs in Zone J. Given the wide variation in actual supplier portfolios, the uncertainty with respect to regional surplus, and the uncertainty in the quantity of supply that can be withheld from the market, it is difficult to define statistically significant conclusions from the overlapping curves.[66] Given the expected additions of SCS Astoria, NYPA Poletti, and Con Edison's East River repowering, the Zone J market will have a capacity surplus during the 2005 – 2007 analysis period, but it is difficult to determine where on the X axis the region's deficiency/surplus disposition is likely to fall.

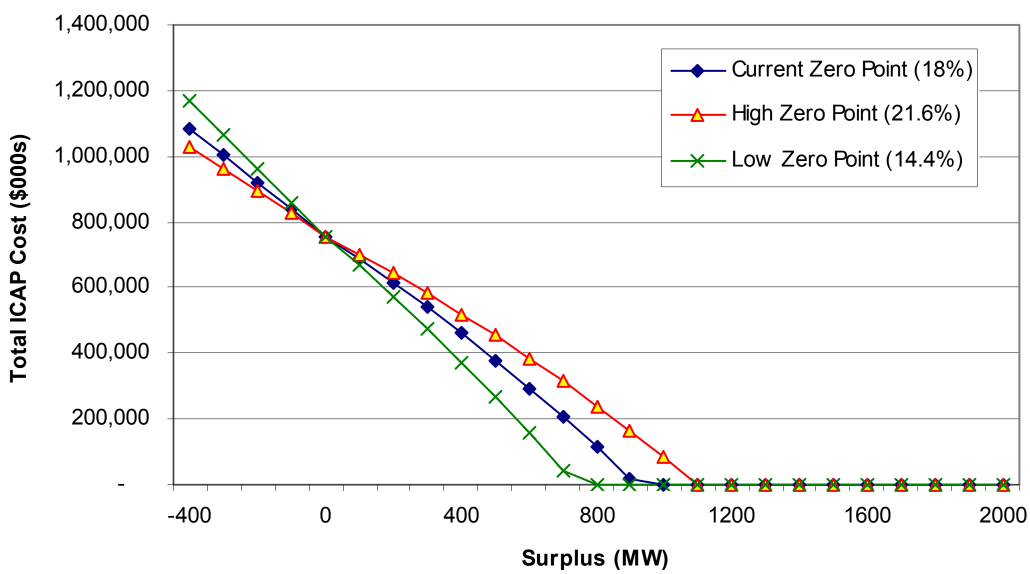
[66] Additional analysis on these critical market issues needs to be completed before this assessment could be used as the basis for altering the basic mechanics of the demand curve.

Figure 56 – Case IIa – Total Cost of ICAP at Alternative Zero Crossing Points, Withholding – Zone J, 2005



In the Zone K regional market, under the scenario of no withholding, the base and alternative curves produce straight lines at steep slopes. As explained earlier, opportunities for withholding in Zone K are minimal, and no withholding was considered for this market.

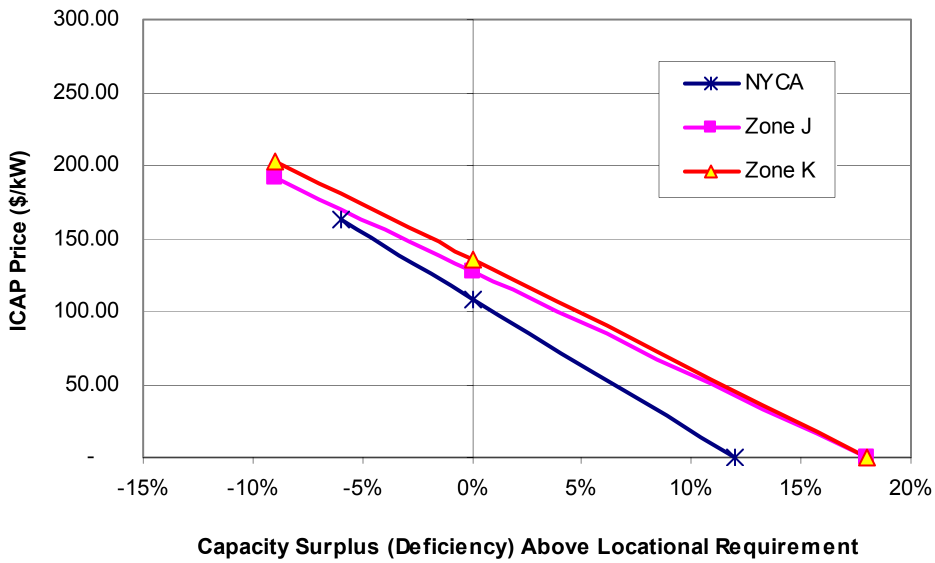
Figure 57 – Case IIa – Total Cost of ICAP at Alternative Zero Crossing Points, No Withholding – Zone K, 2005



CASE IIB – CAPITAL AND FIXED OPERATING COSTS PLUS NET REVENUES – STOCHASTIC

Figure 58 depicts the ICAP Demand Curves for all regions under Case IIb conditions for 2005. Case IIa and Case IIb include the contribution of net energy and ancillary service revenues to calculate net revenue requirement attributable to the capacity market, but load was treated stochastically in Case IIb.

Figure 58 – Case IIb – ICAP Demand Curves, 2005



The following three figures compare current ICAP demand curves to the calculated Case I, Case IIa, and Case IIb demand curves for 2005. As seen in Figure 59, the Case IIb stochastic treatment of loads leads to higher net energy revenues in NYCA, and thus a lower capacity reference value and associated demand curve than Cases I and IIa. Due to the very limited net energy and ancillary revenues attributable to a 2x7FA facility, the lines for 2005 Case I and Case IIa are essentially identical.

Figure 59 – All Cases – NYCA Demand Curves, 2004 - 2005

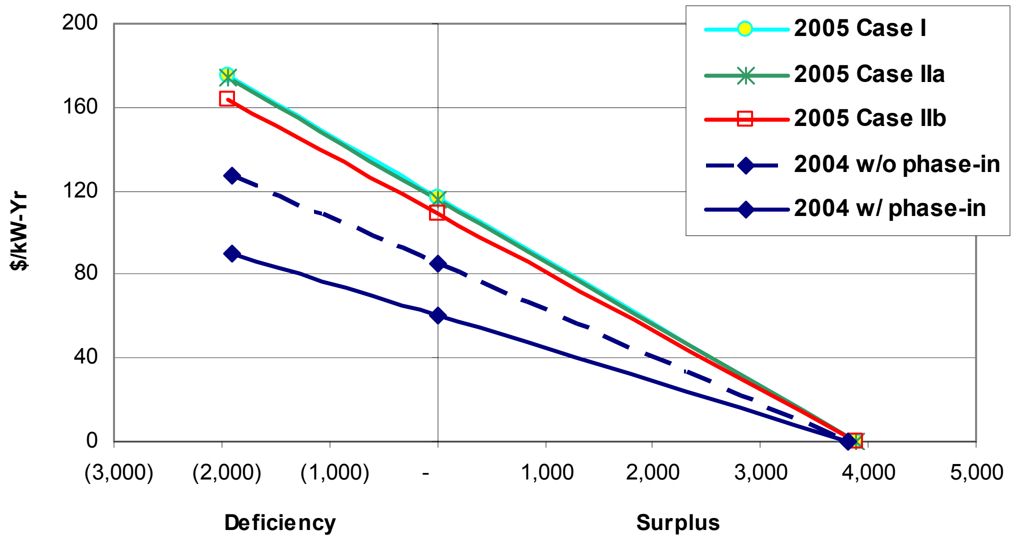
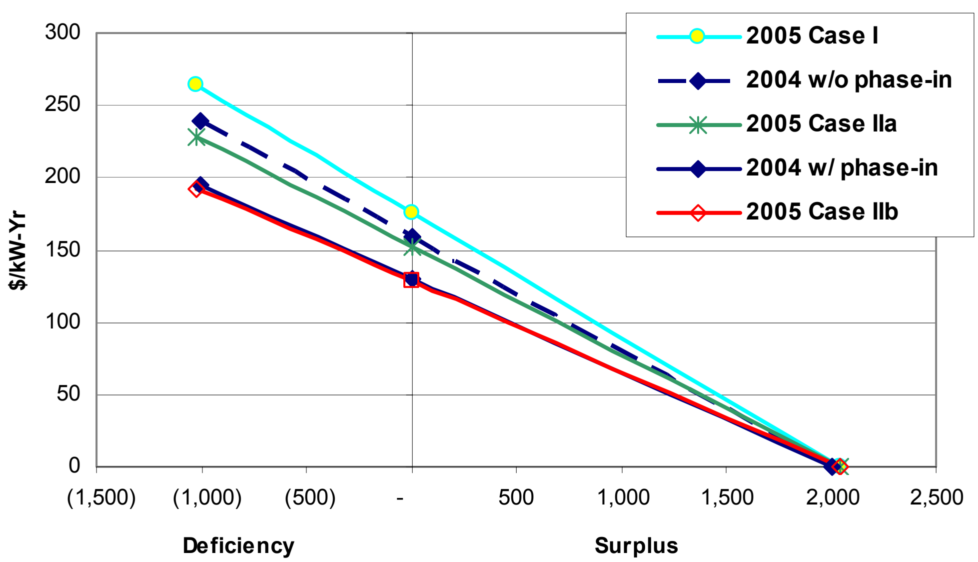


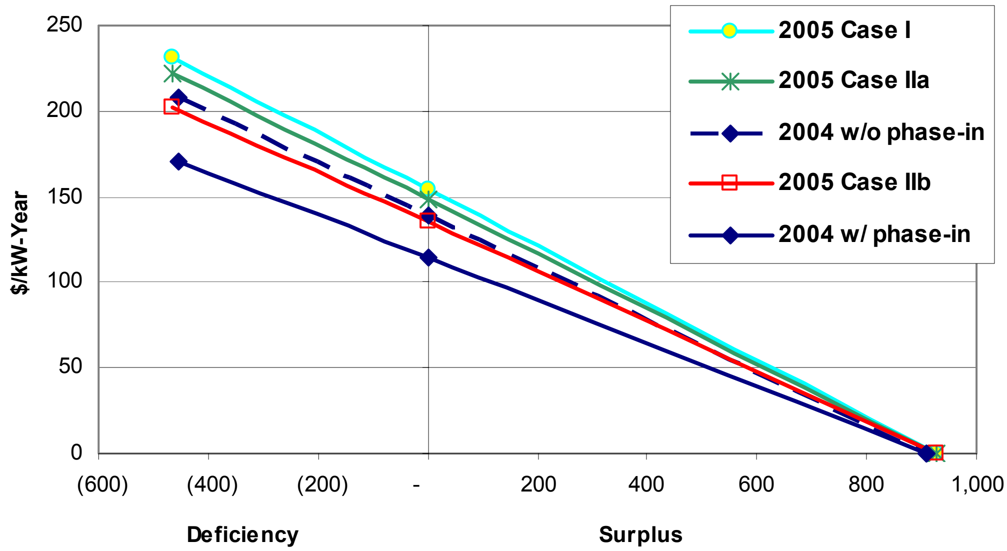
Figure 60 depicts the 2005 demand curves for Zone J calculated by LAI against the current ICAP demand curves. The Case IIb analysis produces a significantly lower demand curve, due to the enhanced net revenues of a peaking facility during periods of volatile market conditions.

Figure 60 – All Cases – Zone J Demand Curves, 2004 - 2005



The Case IIb analysis produces a slightly lower demand curve for Zone K, as depicted in Figure 61. Results are tightly bunched, indicating no dramatic swings from the current demand curves to any of the tested Cases, although Case IIb produces a lower ICAP demand curve for Zone K.

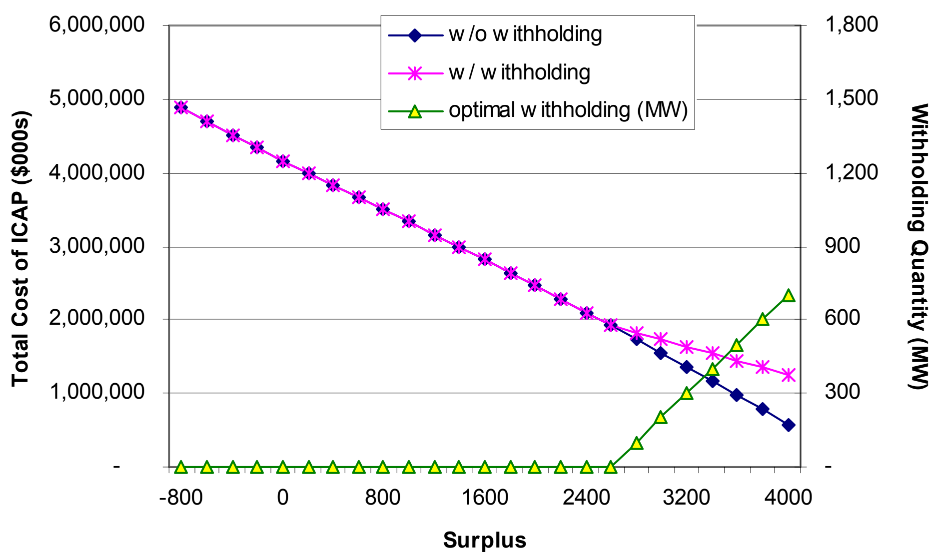
Figure 61 – All Cases – Zone K Demand Curves, 2004 - 2005



Total Cost of ICAP

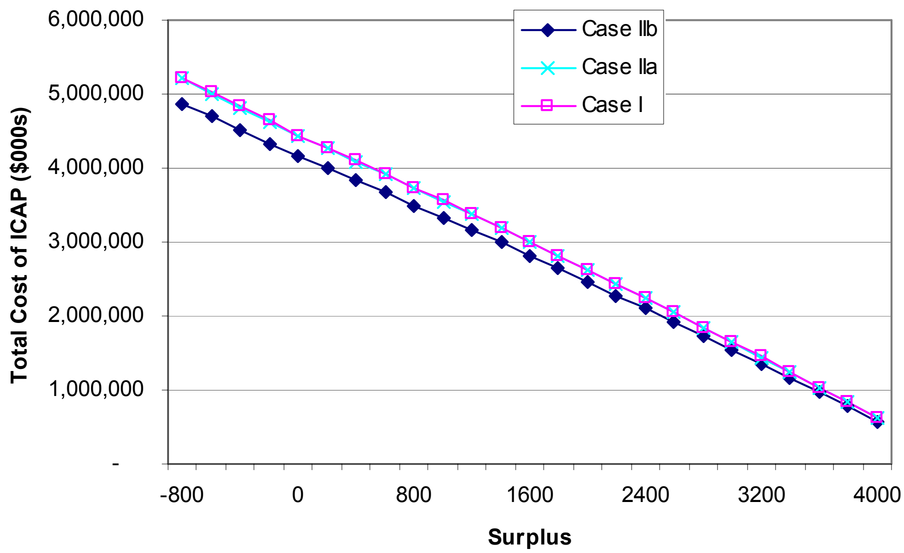
The following figures depict the total ICAP cost under LAI's Case IIb analysis by region, with and without withholding by a single supplier. Additional figures also compare the total cost of ICAP (excluding withholding) for all cases assessed in order to allow a straightforward comparison. Figure 62 indicates the impact of the specified withholding scenario for NYCA. At a 0 MW surplus, where all ICAP is priced at the Case IIb reference value, the total ICAP cost in NYCA is $4.04 billion in 2005.

Figure 62 – Case IIb – Total Cost of ICAP – NYCA, 2005 (w/ Withholding)



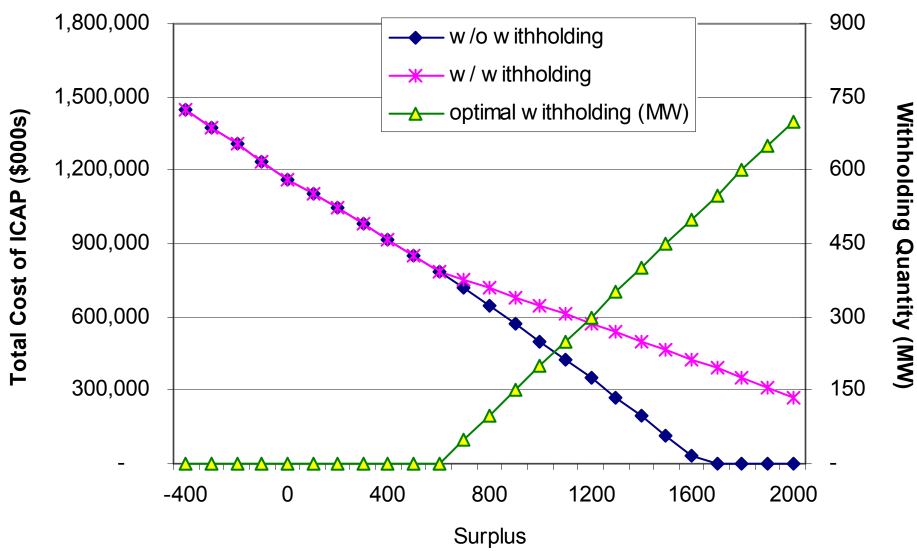
The following figure depicts the total ICAP cost for NYCA under the Demand Curves calculated for the three cases as defined in this analysis. As seen in the graph, Cases I and IIa provide almost exactly matching results. Case IIb lowers the ICAP demand curve, and thus the total ICAP payments for NYCA across the entire X-axis of deficiency / surplus positions.

Figure 63 – All Cases – Total Cost of ICAP – NYCA, 2005 (No Withholding)



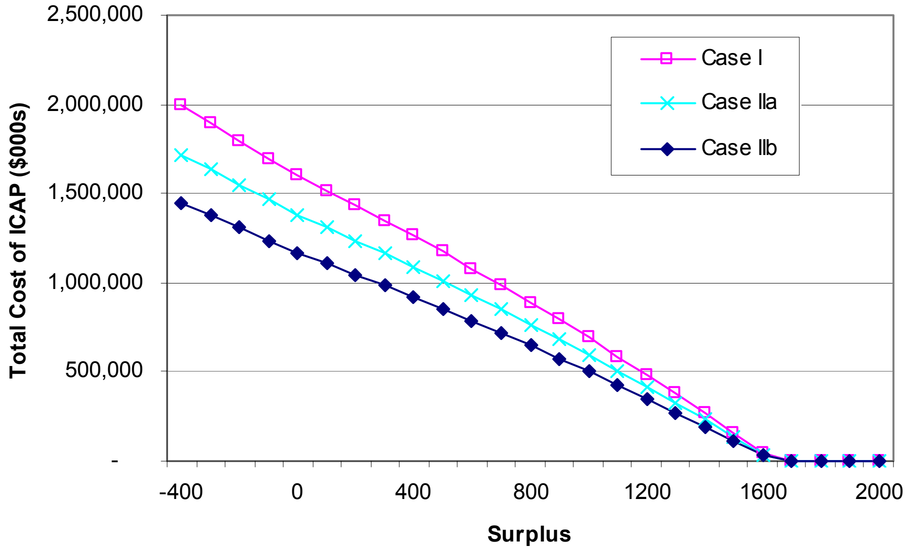
In Zone J, the total cost of ICAP at a 0 MW surplus is $1.16 billion in 2005. Based on the limited exercise of assessing withholding opportunity by a single supplier with a portfolio of 1,000 MW, the total cost of ICAP can be greatly affected by withholding practices.

Figure 64 – Case IIb – Total Cost of ICAP – Zone J, 2005



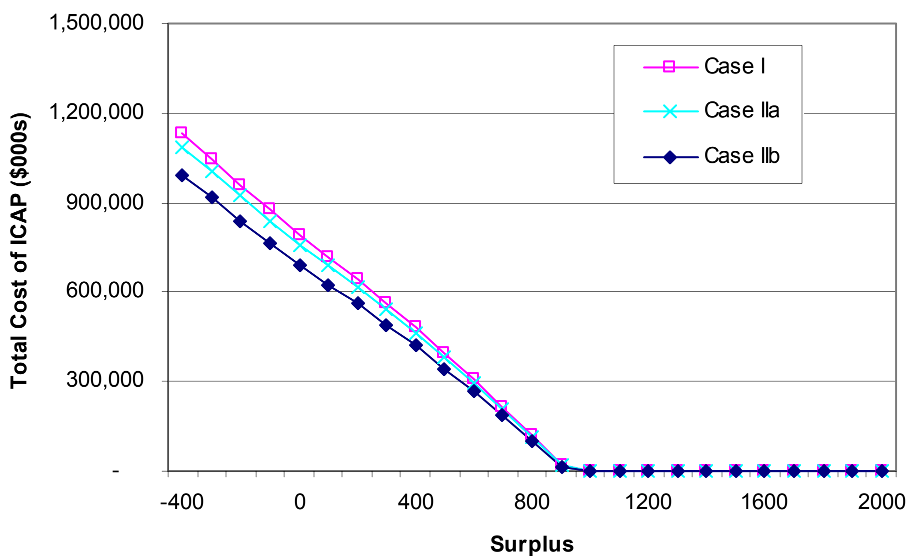
The following figure depicts the total ICAP cost for Zone J under the demand curves calculated for the three cases as defined in this analysis. As seen in the graph, each case produces different results. Case IIb has the lowest ICAP demand curve.

Figure 65 – All Cases – Total Cost of ICAP – Zone J, 2005 (No Withholding)



In Zone K, the total cost of ICAP at a 0 MW surplus is expected to cost $682 million in 2005, excluding the potential for withholding. The following figure depicts the total ICAP cost for Zone K under the demand curves. As seen in the graph, all three cases produce very similar results. Case IIb results in the lowest ICAP demand curve.

Figure 66 – All Cases – Total Cost of ICAP – Zone K, 2005



The total ICAP cost, by case and for each region, is summarized in the table below. The values are based on a 0 MW surplus, without the consideration of withholding.

Table 25 – Total ICAP Cost (0 MW Surplus, No Withholding)

	Case I	Case IIa	Case IIb
NYCA	$ 4.44 B	$ 4.43 B	$ 4.15 B
Zone J	$ 1.60 B	$ 1.38 B	$ 1.16 B
Zone K	$ 0.79 B	$ 0.76 B	$ 0.69 B

Conclusions

Case IIb consistently produces lower reference values and shallower ICAP demand curves across the three regional markets assessed. Our analysis provides only the theoretical maximum impact on the supplier's revenue and the region's total ICAP under withholding. That being said, reasonable conclusions can be drawn from the assessment of alternative zero crossing points and other policies related to management of the ICAP spot market:

- Suppliers with sizable portfolios will have real incentives to withhold capacity from the spot market auction process, particularly in Zone J due to the concentration of generation resources.

- As the level of regional surplus increases, the incentive to withhold and the impact of withholding on the total cost of ICAP increases. However, these impacts are reduced as the total cost of ICAP decreases with incremental surplus capacity.

- At this point we do not advocate any alteration in the zero-crossing points used to define the demand curves for a range of reasons:

    - As seen in Figure 54 and Figure 56, withholding opportunities can obscure the differences in alternative demand curves. Steeper demand curves (*i.e.*, with smaller zero-crossing points) provide greater incentive for suppliers to withhold and thus can lead to increases in total capacity costs. Shallower demand curves (*i.e.*, with higher zero-crossing points) provide lower incentive for suppliers to withhold and thus can lead to relatively lower total capacity costs.

    - Because the analysis looked only at a single, hypothetical supplier in each locational market, region-wide conclusions would be subject to considerable uncertainty. We recommend a more complete and rigorous analysis of likely suppliers and their combined impact on regional capacity markets under alternative zero-crossing point options.

    - A comprehensive review of alternative zero-crossing points needs to consider the long-term capacity market impacts. For example, an alternative zero-crossing point may appear to reduce total capacity costs in the near term after withholding is considered, but, the revised demand curve may alter retirement and entry decision criteria for existing and proposed units, respectively.