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

NERA
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I. Executive Summary

In 2003, the NYISO implemented an Installed Capacity ("ICAP") Demand Curve mechanism. The ICAP Demand Curve is used in the ICAP Spot Market Auction conducted for each month. The ICAP Demand Curves act as bids for capacity in the ICAP Spot Market Auctions.

The NYISO updated the Demand Curves in 2004 for the 2005/06, 2006/07 and 2007/08 Capability Years. That update was based upon an independent study conducted by Levitan & Associates, Inc. (LAI), input from the NYISO Market Advisor and input from market participants. The Demand Curve process calls for the Demand Curves to be updated every three years. The NYISO retained NERA Economic Consulting (NERA) assisted by Sargent & Lundy LLC (S&L) to perform an independent Demand Curve parameter update study applicable to Capability Years 2008/09, 2009/10 and 2010/11.

NERA was responsible for the overall conduct of the study and led the effort with respect to formulating the financial assumptions, estimating energy and ancillary services net revenues and developing the recommended Demand Curves. S&L was primarily responsible for developing construction cost estimates, operating cost data and plant operating characteristics. NERA and S&L collaborated to identify the potential technology choice for each region[1].

In considering the study, the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff") was the primary guide. In particular, we relied on Section 5.14.1(b) of that Tariff. That section of the Tariff specifies that the update shall be based upon and consider the following:

- the current localized levelized embedded cost of a peaking unit in each NYCA Locality and the Rest of State to meet minimum capacity requirements;

[1] The Demand Curve process calls for a Demand Curve for New York City (NYC), Long Island (LI) and the New York Control Area (NYCA). NERA and S&L developed the net cost of new entry for NYC, LI, the Capital Region, the Central Region and the Lower Hudson Valley. For the NYCA the Capital Region has been used. The Lower Hudson Valley estimate is for informational purposes only. ROS is the term used herein to refer to supply in the part of the New York Control Area that does not include the New York City and Long Island Localities.

- the likely projected annual Energy and Ancillary Services revenues of the peaking unit over the period covered by the adjusted ICAP Demand Curves, net of the costs of producing such Energy and Ancillary Services, under conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity requirement;

- the appropriate shape and slope of the ICAP Demand Curves, and the associated point at which the dollar value of the ICAP Demand Curves should decline to zero; and

- the appropriate translation of the annual net revenue requirement of the peaking unit determined from the factors specified above, into monthly values that take into account seasonal differences in the amount of capacity available in the ICAP Spot Market Auctions.

The Tariff further specifies that:

> "a peaking unit is defined as the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable."

The most significant issue affecting the 2007 Demand Curve update is the choice of peaking technology. It is clear that the Services Tariff requires the update to identify the peaking unit with the lowest fixed costs and highest variable costs that is economically viable. This unit will not necessarily be the lowest "net-cost"[2] unit under current conditions. It is possible that a more expensive capital cost unit with a lower variable or operating cost would have a lower net cost. For example a combined cycle unit may have a lower net cost as a result of higher energy net revenues. The Tariff, however, does not call for the lowest net-cost unit. Rather, it requires that the update be based upon the net-cost of the lowest capital cost and highest operating cost unit that is economically viable.

As part of this study, we assumed that only a unit that could be practically constructed in a particular location would qualify. We further assumed the Tariff to apply to reasonably large scale generating facilities that are standard and replicable, which excludes dispersed generators and special case resources.

[2] Net-cost refers to the difference between the annual fixed cost and annual energy and ancillary service net revenues.

This study examines four types of units, which between them represent two technology options. The first technology options are frame units –Frame 7EA and Frame 7FA. These are large scale combustion turbines with low capital costs and high operating costs. They are relatively inflexible with respect to starts and stops. The second are aeroderivatives – the LM6000 and LMS100. These are more flexible combustion turbines, but have higher per kilowatt capital costs than frame units and have lower operating costs.

A review of these units showed the following:

1. The Frame 7FA has lower capital and operating costs than the Frame 7EA. The LMS100 currently has lower capital and operating costs than the LM6000. However, it is not clear that this will continue to be the case for the LMS100.

2. In comparison to the LMS100 the capital cost of the Frame 7FA is lower and the operating cost is higher.

3. The Frame 7FA would not practically be constructed as a peaking unit in the Lower Hudson Valley, NYC or LI. This is the case because in those particular locations a selective catalytic reduction (SCR) would be required to avoid severe operating restrictions and when operated in simple cycle mode; the Frame 7FA exhaust temperature is too hot for an SCR. Hence, a Frame 7 is not a practical choice in the Lower Hudson Valley, NYC and LI regions.

4. There are uncertainties with respect to the costs of the LMS100. Only one LMS100 plant is in operation. The unit appears to offer a combination of capital and operating costs somewhere between that of a traditional peaking unit and a combined cycle unit. Currently, only General Electric offers a unit like the LMS100, and it faces no direct competition. The base equipment price has risen by 7% in three months, while LM6000 equipment costs have remained stable, which makes it very difficult to predict where the equipment will be priced during the 2008/09 – 2010/11 period. Therefore, the assessment that the LMS100 has a lower capital cost than the 2008/09 LM6000 may not be robust. Manufacturer price increases could lead to the LMS100 price rising to the point where the LMS100 installed cost exceeds that of the LM6000. Manufacturer price decreases could lead to the price of the LM6000 declining below that of the LMS100. At this point in the LMS100 life cycle it is too early to know if the LMS100 will

render the LM6000 obsolete, except where its smaller size is required, as the LMS100 will continue to have lower capital and operating costs, or whether as the LMS100 gains experience and acceptance, the prices will adjust so that LM6000 has a lower capital cost to offset its heat rate disadvantage

In the 2004 Demand Curve update, the NYISO used a Frame 7FA for its NYCA Demand Curve and a LM6000 for the NYC and LI Demand Curves. The LMS100 was not available at that time. In order to put the current update into perspective, below is a comparison between the costs used in 2004 and the current update holding technology constant.

Table I-1

Demand Curve Values at Reference Point:

Values for Capacity Years 2007/08 and 2008/09

		2004 Update for 2007 2008 dollars/kW-year			*2007 Update for 2008 2008 dollars/kW-year*		
		Annual Fixed Cost	Energy and AS Net Revenues	Net Costs	Annual Fixed Cost	Energy and AS Net Revenues	Net Costs
ROS	Frame 7	94.79	20.70	**74.09**	110.47	7.31	**103.16**
NYC	LM6000	191.76	52.30	**139.46**	244.82	56.42	**188.40**
LI	LM6000	168.88	41.40	**127.48**	214.19	73.90	**140.29**

We present the values above in 2008 dollars as the curve will be stated on that basis. As can be seen above, all else equal, the Demand Curve would increase significantly. This is the result of a combination of factors including:

1. an increase in construction and equipment costs resulting from market conditions;

2. a change in the carrying charge methodology that effectively shortens the 20 year amortization period used in the prior study but that in NYC is offset by a lower effective property tax rate assumption; and

3. for LI these are partially offset by significant increases in estimated energy and ancillary services net revenues, while for ROS generators the energy and AS net revenues have decreased.

A comparison of the installed cost per ICAP kW and the effective amortization period used is presented below.

Table I-2

Capital Costs and Amortization Periods

Values for Capacity Years 2007/08 and 2008/09

		2004 Update 2008 dollars		*2007 Update 2008 dollars*	
		Installed Cost per ICAP kW ($/kW)	Amortization Period (Years	Installed Cost per ICAP kW ($/kW)	Amortization Period (Years)
ROS	Frame 7 x 2	666	**20**	689	**14.5**
NYC	LM6000 x 2	1,322	**20**	1,582	**13.5**
LI	LM6000 x 2	1,253	**20**	1,484	**18.5**

Holding technology and the Demand Curve zero crossing point constant, the levelized cost would increase in all regions by more than inflation. This is attributable to increased construction costs and increased recognition of merchant risk through the use of shorter amortization periods.

As discussed above, the LMS100 has emerged as a technology alternative. The LMS100 currently has lower capital and lower operating costs than the LM6000, but as previously discussed, that situation may not be robust.

Table I-3

Demand Curve Values at Reference Point:
Values for Capacity Years 2007/08 and 2008/09

		2004 Update for 2007 *2008 dollars* Annual Fixed Cost	Energy and AS Net Revenues	Net Costs	*2007 Update for 2008* *2008 dollars* Annual Fixed Cost	Energy and AS Net Revenues	Net Costs
ROS	Frame 7 x 2	94.79	20.7	**74.09**	110.47	7.31	**103.16**
NYC	LM6000 x 2	191.76	52.3	**139.46**	244.82	56.42	**188.40**
	LMS100 x 2				190.64	64.89	**125.75**
LI	LM6000 x 2	168.88	41.4	**127.48**	214.19	73.90	**140.29**
	LMS100 x 2				165.93	89.98	**75.95**

The LMS100 has a relatively efficient heat rate (9100 BTU/kWh HHV) and, hence, is able to capture very significant energy net revenues. All the results discussed to this point reflect the existing zero-crossing points or slopes. The issue of Demand Curve slope will be addressed later. The methodology integrates slope and cost as higher slopes increase merchant risk.

We recognize that continuity is important to the Demand Curve process. Since the recommendations we are making herein incorporate several major changes, we will review and explain the rationale behind each major change.

New Technology – The LMS100 has emerged as a technology alternative. While the LM6000 has an extensive application in electricity generation, with more than 200 in commercial operation, the LMS100 is a relatively new machine with little operating history. The only unit in commercial operation, installed in 2006, is located at Basin Electric Power Cooperative's Groton Generation Station in Groton, South Dakota; a second unit is under construction and slated for operation in June 2008. Discussions between S&L and Basin Electric indicate that the unit has been operating without any recurring issues or major problems other than a generator bearing replacement with reliability trending up. S&L has made a site visit to Basin Electric and is monitoring performance.

As discussed in Section II, LMS100 units are planned for NYC and have been offered as a market-based solution to the NYISO's request for reliability solutions.

The uncertainty in the LMS100 cost and performance estimates for this report should not be technically different from those of the LM6000. Major components of the LMS100 technology are based on both Frame 6 and LM6000 designs. The gas turbine in the LMS100 has over 100 million hours of operating experience in both aircraft engines and industrial applications. The construction process and requirements for the LMS100 are similar to those of either frame or aeroderivative units; hence, the contingency factor in the cost estimates need not be increased. There is no known technical basis for excluding the LMS100 from consideration at this time. Nonetheless, actual LMS100 performance is not demonstrated by a vast experience base, though some merchant generators may be willing to take the LMS100 technology risk. As discussed above, the LMS100 has a substantially lower heat rate than the LM6000 and faces no direct manufacturing competition. Equipment prices have increased recently and there is no way to tell whether or not such increases will continue and if introductory pricing was promotional. If the equipment price continues to escalate and if LM6000 demand falls and LM6000 prices drop, the LMS100 could become more expensive in installed costs terms than the LM6000. The Demand Curve has been developed for both the LM6000 and LMS100 in areas of the state where it is not practical to install a Frame 7 FA.

Construction Costs – Construction costs changes, while significant, are explainable and reflect market changes. LM6000 and Frame 7 FA construction costs have increased by more than inflation, but these result from increases in material and construction costs that are well known. In fact in early July, the New York Times reported on the equipment price increases[3]. These increases have been captured though the date that the estimates were prepared in the mid-second quarter of 2007. The corresponding LMS100 costs are derived from LM6000 figures due to similarities in site requirements and construction methods.

Carrying Charges – The 2004 update used a 50/50 capital structure with a debt cost of 7.5% and an equity cost of 12.5%. The current update uses very similar costs – i.e., 50/50 capital structure with a debt cost of 7.0% and an equity cost of 12.0%. However, the previous study used a 20-year amortization period for all regions. In the current study we introduce a new methodology that

[3] Wald, Matthew L., Cost Surge for Building Power Plants, New York Times, July 10, 2007.

determines the amortization period considering the risk of excess capacity, other risks which we discuss later and the Demand Curve zero crossing point or slope. The result, given no change to the Demand Curve slope, is a reduction in the NYC amortization period to about 13.5 years, in the ROS to about 14.5 years, and in Long Island to about 18.5 years. This increases carrying charges. The difference by region reflects the risk difference resulting from the slope of the Demand Curve and the slope of the energy and ancillary service net revenue function. We believe that this change in method is necessary as the method used ties together the risk and the zero crossing point of the Demand Curve and provides for an internally consistent consideration of the Demand Curve slope, which affects risk, and the amortization period. As there exists a bias towards excess capacity, a steeper slope requires a higher carrying charge to compensate for lower prices in excess capacity periods. In both studies, the capital structure and cost of capital reflect a sound company with moderate risk and an investment grade rating. The Demand Curve is predicated on more risky merchant development.[4] Hence, not having increased the cost of capital to allocate for merchant risk, we believe that it is necessary to reflect merchant risk in the cost and do so through a shortening of the recovery period.[5] We would recommend that the method used to develop the Demand Curve be made a permanent feature of the Demand Curve update process.

The Services Tariff specifies the localized levelized cost be used, but not does not specify the amortization period to be used in levelization. The method we have used to develop the levelized cost explicitly considers the revenue diminution that will be experienced in periods of excess capacity and determines the amortization period so that a new entrant would just recover costs given such revenue diminution. This is done to ensure that the demand curve provides sufficient revenue to be able to attract entry when capacity is needed.

<u>Energy and Ancillary Service Revenues</u> – The estimates that we use here for NYC energy net revenues are similar to those in the last update. For LMS100 facilities we use energy revenues on the 345 kV system as the units may be too large for location in areas where they could obtain load

[4] The tariff calls for the localized levelized embedded cost. We interpret levelized to mean levelized using parameters that reflect the risk of merchant generation or generation that will face spot market prices.

[5] For the LMS 100 for LI, the amortization period is actually increased to 22.5 year. The method has been consistently applied. The relatively high level of LMS 100 net energy revenues on LI and the fact that such revenues are not sensitive to reserve margin, results in a lower level of merchant risk for this unit on LI than that implied by a 20 year amortization period.

pocket prices. We obtain significantly higher energy revenues on Long Island than in New York City. This is consistent with price data which show LI energy prices to exceed prices in NYC. Compared to the 2004 update we obtain lower net energy revenues in ROS. We believe that the decrease upstate is caused by explicitly modeling the maintenance related start-up costs of the Frame 7 units. Except for statistical adjustments to correct net revenues for reserve levels, the energy net revenues we use are reflective of those that realistically could have been achieved over the past 3.5 years as they are based on actual prices for the past 3.5 years. This lends objectivity to the estimates. The statistical analyses demonstrated that the system changes in New York City (e.g., the addition of roughly 1,000 MW of combined-cycle capacity) had a very minor impact on energy prices. Hence, we did not explicitly adjust for this change, but capture its effect through the reserve margin variable. It is possible that any effect in part is obscured by improvements in the pricing algorithm which raise prices.

Our original intent was to develop the estimates of energy and ancillary service net revenues using a Monte Carlo representation of weather and fuel prices over the next three years. This proved not to be possible. Extensive and detailed calculations were done to reflect the operating constraints of the combustion turbine equipment and the interactions between real time and day-ahead prices. These calculations were not feasible in a Monte Carlo model that treated weather and fuel price probabilistically. Hence, the energy net revenues we have developed reflect actual weather and gas prices over the past 3.5 years and reflect a detailed modeling of realistic equipment operation and day-ahead and real time market interactions.

Demand Curve Development – The Demand Curves were developed explicitly analyzing risks. Risks that could reasonably be considered to be symmetrical have no impact on expected value and were not considered in the risk analysis. Risks that were not symmetrical were analyzed in a Monte Carlo risk analysis model described later in the report and made available to market participants in executable form.

The model recognizes that the NYISO has in place planning and response procedures to prevent capacity from falling short. Hence, over time, there should be a bias toward surplus capacity conditions. If there is expected to be surplus capacity, the Demand Curve must be adjusted to reflect the fact that over time the expected clearing price would be below the target reserve point.

Absent such an adjustment, the Demand Curve would not produce adequate expected revenues to recover cost and would not induce the proper level of investment. Additionally, historically there has been a real decline in generating plant costs reflecting technical progress and we would expect future Demand Curves to reflect this decline. As the current Demand Curve is set considering revenue that will accrue to generators in the future, it is necessary to account for this decline.

The model we have developed to set the Demand Curve accounts for these factors. As an example, the effective real levelized carrying charge developed from the risk analysis and used to set the Demand Curve reference point is 13.57-14.17% for NYC and 15.36% for NYCA. NYCA is higher because the Demand Curve has a steeper slope (crossing at 12% rather 18% above the reference). Over 20 years, the non-risk-adjusted carrying charges would be 12.95% for ROS and 12.41% for NYC. Hence, the risk adjustment has a significant impact on the levelization of construction cost and on the Demand Curve. The carrying charge difference between the 30-year values can be viewed as the merchant risk. The merchant risk premium for NYC is also lower because in the first 11 years, new generation in NYC pays no property taxes. Full property taxes are not paid until year 16. This enables more revenue to go toward the return of and return on capital. The 30-year levelized carrying charges are 11.20% for ROS and 11.18% for NYC.

The table below translates the carrying charge used to determine the basis point premium in weighted average cost of capital (WACC) over 20 years and 30 years.

Table I-4

Translation to Basis Premium

		Carrying Charge	WACC Premium on 20-Year Amortization	WACC Premium on 30-Year Amortization
ROS	Frame 7 x 2	15.36%	241	416
NYC	LM6000 x 2	14.17%	176	299
	LMS100 x 2	13.57%	116	239
LI	LM6000 x 2	13.31%	36	211
	LMS100 x 2	12.30%	-65	110

To reemphasize, all values discussed to this point use the current Demand Curve slope. However, when using the risk model, the slope of the Demand Curve has a measurable influence on the levelization and the Demand Curve reference point. With a bias toward excess capacity, a steep slope requires a higher reference point if there is to be an expectation of full cost recovery. In surplus capacity periods, the Demand Curve will clear below the reference price, and if there is a steep slope, revenues will decline more rapidly than if there is flatter slope. To provide the same expected revenue over the life of the investment, a higher reference point must accompany a steeper slope. For example, if the NYC x-intercept was applied to the NYCA Demand Curve, the reference value would fall by $7.15 per kW-year.

In the 2004 update, the Demand Curves slopes were reviewed. The review concluded that the zero crossing points of 112% for NYCA and 118% for NYC and LI be retained. However, the review did find that steeper curves provide greater incentive to withhold and that shallower curves can lead to lower total capacity costs because the reduced incentive to withhold and lower price more than compensate for the higher level of purchase. The incentive to withhold was identified as greatest in Zone J as the result of greater concentration in Zone J. The slope is both a function of the zero crossing point and the CONE at the reference capacity level. The higher the reference CONE, the greater the slope for the same zero crossing point. Given the recent controversy over potential withholding in NYC spot capacity auctions and mitigation issues, we do not recommend increasing the slope by moving the zero crossing point closer to the origin. If the LMS100 is selected and the zero crossing point is kept at 118%, the slope will stay approximately the same. If the LM6000 is selected as the peaking unit, maintaining the 118% zero crossing point will increase the Demand Curve slope. That slope is already creating controversy with respect to withholding. Hence we recommend retaining the 118% zero crossing point. However, we do not recommend moving the zero crossing point beyond 118% as it is reasonably clear that capacity has little value at or beyond that point.

The LI market is different than the other two regions because it has one dominant load serving entity with most supply under contract. Thus, maintaining the zero crossing point at 118% would be reasonable.

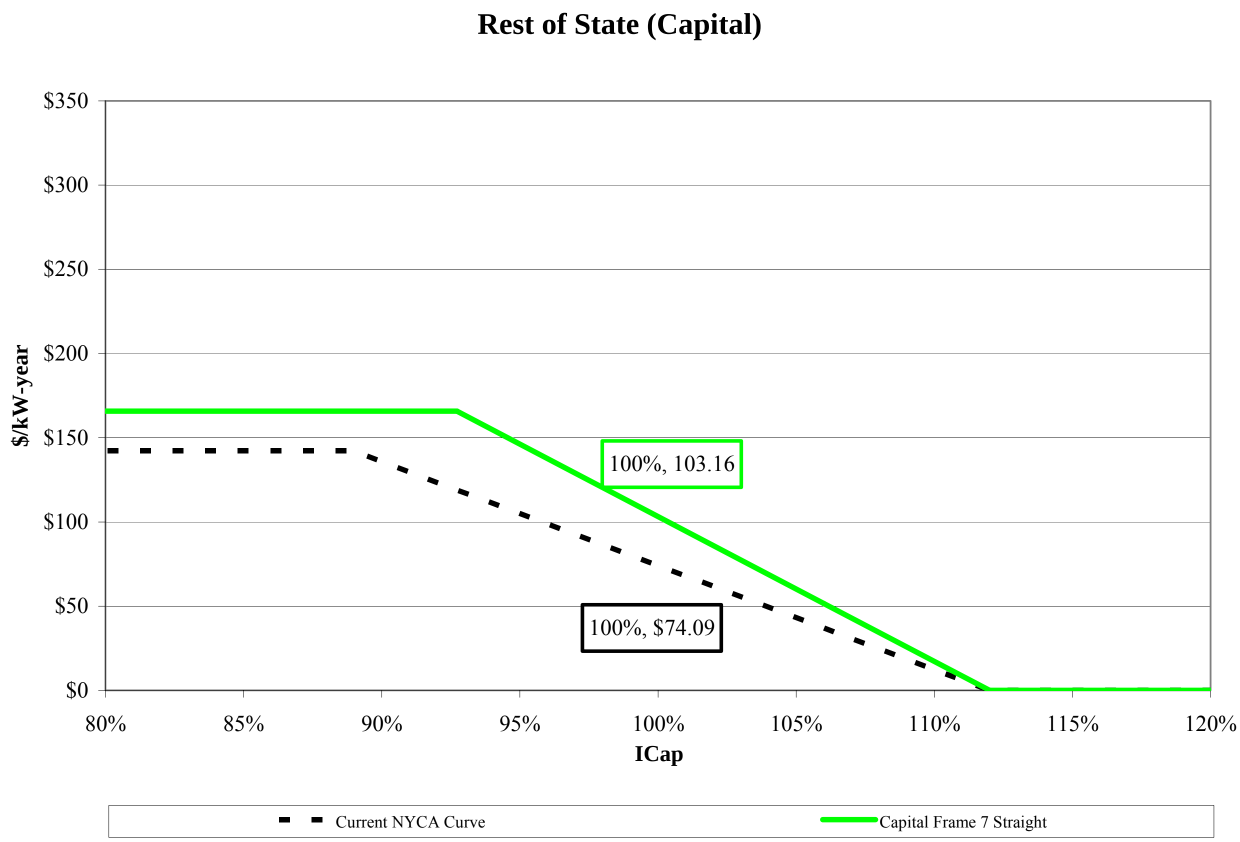
There is no reason why the Demand Curve must be a single straight line from the maximum value of 1.5 times the reference point to the zero crossing point. We also examined a "kinked" Demand Curve. This type of curve has a relatively lower slope (i.e. it is flatter) from the reference point and becomes steeper (hence the kink) at a point close to the zero-crossing point. There are pros and cons to such a curve. On the pro side, it reduces the reference point because it reduces the impact of a modest capacity excess which is the most likely condition. However, this does come at a cost. The incentive to add capacity during a shortage condition is reduced as the curve is flatter on both sides of the reference point. It also reduces the incentive to withhold when total capacity falls into the flat segment of the curve. Further, by going to the zero crossing point more quickly, it will eliminate capacity payments if there are chronic large excesses when such payments would persist, albeit at low levels, versus a single flatter curve that crosses zero further from the reference point.

According to the Services Tariff, the Demand Curve is not based on the lowest net-cost unit, but on the net-cost of an economically viable unit with the lowest fixed cost and highest operating (or variable) cost. Therefore, if a baseload unit were to be installed it is possible that it could cause a surplus of capacity and, due to greater efficiency, it could be profitable without capacity revenue. Under the single slope Demand Curve which extends well beyond the reference point, customers may pay capacity payments even when such surpluses develop and capacity revenue is not needed to induce entry. Under a kinked Demand Curve, payments will decline to zero faster and capacity payments are more likely to be eliminated if they are not required to induce entry by baseload plant. However, this effect could be offset by a higher incentive to withhold capacity if supply falls into the steeply sloped area of the kinked Demand Curve. Hence, a kinked Demand Curve is likely to be effective only when capacity withholding is prohibited or mitigated. Further, a Demand Curve that declines to zero more rapidly could lead to mothballing and retirement of less efficient existing capacity. We have developed a kinked Demand Curve for each region in addition to traditional curves. The kinked curves have a first segment that extends from the reference point to a point 33% above the reference level. The curve kinks at six percent above the reference level and descends to zero at 12% above the reference level. This slope would drop the reference price for NYCA by about 12.4% and would drop the NYC reference price by about 7.3%. In return for the lower reference price and quicker drop to zero, prices would decline less sharply during the periods of modest surplus that are the most likely conditions and rise less steeply during shortage conditions.

We do not recommend kinked Demand Curves for two reasons. First, there is a very strong incentive to withhold when supply conditions are close to the kink. Second, the interaction between winter capacity and the kink is complex and has not been analyzed. A kink around 106%, could easily force prices in the winter down to near zero. This would need to be offset by an increase in the reference value. However, it would add uncertainty and create the strong potential for setting a curve that either systematically over- or under-compensated generators. We would not recommend looking again at a kinked curve, until the summer/winter adjustment is stable and more time can be dedicated to analyzing the combined effects of withholding, the summer/winter adjustment and potential excess capacity. While a kink further out, say at 110% may be feasible, by that point, the impact of the kink is likely to be very small.

In making the Demand Curve recommendation, we have been influenced by the value of stability. The zero crossing points are reasonable and there is no compelling reason for a change. Given the significant changes in construction cost, we believe that changes to the zero crossing point that do not provide for a clearly better Demand Curve are not warranted. In developing the demand curves using the probabilistic approach we recognize that there is likely an effective floor price as below some price it does not make sense for all capacity to offer in the market. We tested and implemented an effective floor price as high as $36 per kW-year. Experience shows that even with relatively large surpluses, the clearing prices in spot auctions does not drop to zero and all available capacity is not sold. The ROS or NYCA market has cleared at below $36 per KW year in the past. We note that a floor of $36 per KW year has no material impact on the demand curve.

Recommended Demand Curves – The recommended Demand Curves are presented below. For each region the chart shows the current Demand Curve, the 2008/09 recommendation for a single segment Demand Curve and the current curve. Both LM6000 and LMS100 curves are shown for NYC and LI.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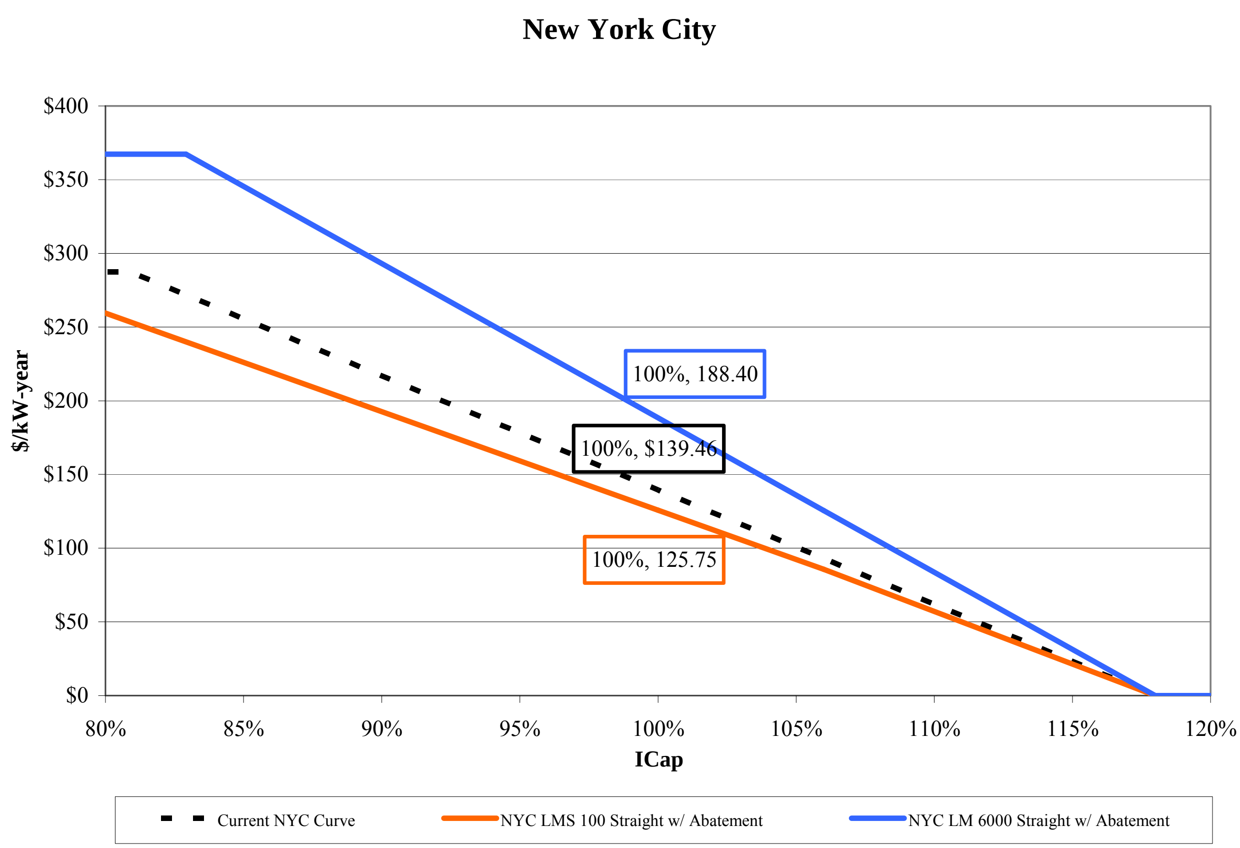
100%
105%
110%
115%
120%
ICap
Current NYCA Curve
Capital Frame 7 Straight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$300
$250
$200
$150
$100
$50
$0
$/kW-year
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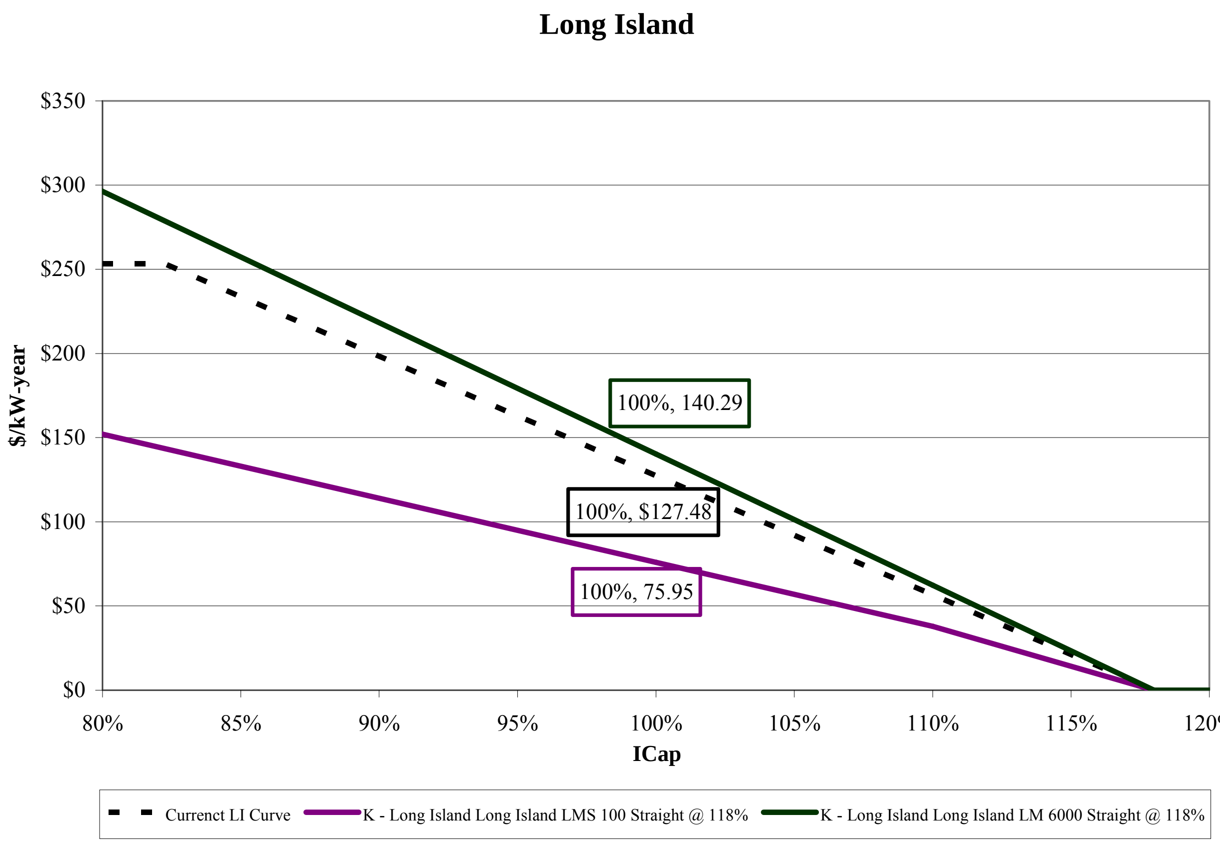
100%, $139.46
100%, 125.75
80%
85%
90%
95%
100%
105%
110%
115%
120%
ICap
Current NYC Curve
NYC LMS 100 Straight w/ Abatement
NYC LM 6000 Straight w/ Abatement



Mitigation Impacts – The analyses described above have been conducted assuming that markets are strictly mitigated and that withholding incentives are weak and/or withholding is not effective as a result of mitigation. This assumption, while not strictly true, is reasonable for NYCA and Long Island. To be realistic, given that this assumption is not strictly true, we have examined an effective price floor of $36 per kW-year, and found that it had no impact. As recent controversy indicates, withholding may be a greater concern for New York City. If it was assumed that, despite a tendency for moderate excess capacity to exist in NYC, generators could effectively maintain the minimum spot capacity auction price at the Divested Generators Owners' (DGOs) price cap of $105 per kW-year, the reference value for the LM6000 would remain virtually unchanged, as the demand curve is well above that level. The reference value for LMS100 would decline from $125.75 as at that level the curve that we analyze would often clear below the DGO price cap of $105 per KW year. We are not presenting a curve with an assumption that the price in NYC could be maintained at $105 per KW as such a curve it is not particularly meaningful. The curve would be well below the $105 per KW price cap level and would not impact the clearing price under the assumption that there is sufficient concentration to maintain the clearing price at that level.

II. Technology Choice and Construction Cost

The installed capacity (ICAP) Demand Curve is derived from the levelized cost of a hypothetical new peaking unit at various locations throughout the state of New York. The reference peaking facility is a gas-fired combustion turbine operating in simple-cycle mode. A range of combustion turbine options, based upon recent peaking applications and design requirements, were evaluated at each location. The levelized cost analysis described in this section accounts for the location-specific factors affecting the total capital investment, the cost inputs and economic parameter inputs for the levelized cost analysis, and the annual operating cost and performance characteristics for each technology.

Levelized costs generally refer to the capital-related carrying charges, operation and maintenance (O&M), and fuel costs incurred over the plant operating life. For the ICAP Demand Curve analysis, costs are divided into variable costs (those that vary with operation) and non-variable (fixed) costs. The Demand Curve analysis uses the fixed cost components, consisting of the capital-related carrying charges, property taxes, insurance, and fixed O&M. Variable costs, consisting of fuel and variable O&M, are used to develop net energy and ancillary service revenues in NERA's econometric model of NYISO market prices. Once the levelized annual fixed costs for the unit are established, they indicate a reference point in the Demand Curve at which the net revenues from the energy and ancillary service markets offset the fixed costs. Input assumptions for the cost components are described in the following subsections.

A. Tariff Requirements

The Services Tariff states that the periodic review of the ICAP Demand Curves shall assess "the current localized levelized cost of a peaking unit in each NYCA Locality and the Rest of State to meet minimum capacity requirements." The Services Tariff defines a peaking unit as "the unit with technology that results in the lowest fixed costs and the highest variable costs among all other units' technology that are economically viable."

It is clear from the Tariff language that the requirement is to identify the lowest fixed cost, highest variable cost peaking unit that is economically viable. This unit will not necessarily be the lowest "net-cost" unit under current conditions. It is possible that a more expensive capital cost unit with a lower variable or operating cost would have a lower net cost. For example, a combined-cycle unit may have a lower net cost as a result of higher energy net revenues.

The Tariff, however, does not call for the lowest net-cost unit. Rather, it requires that the update be based upon the net-cost of the lowest capital cost and highest operating cost unit that is economically viable. For the purposes of this study, we assume that only a unit that could be realistically constructed in a locality would qualify. We also assumed the Services Tariff to apply to reasonably large scale generating facilitates that are standard and replaceable. This excludes dispersed generators and special case resources.

B. Alternate Technologies Examined

In conducting the study, two types of peaking units were examined and, within each type, two technologies.[6]

The first type was the heavy-duty frame units: the 7EA and 7FA. These are large-scale combustion turbines oriented to industrial applications with lower capital costs (on a $/kW basis) and higher operating costs (on a $/MWh basis). Maintenance costs are affected by the duty cycle experienced in operations. As a unit is subjected to more stops and starts, the time between major overhauls decreases. Nitrogen oxide (NO_X) emissions are reduced by equipping the units with dry low NO_X (DLN) combustors. Selective catalytic reduction (SCR) technology for NO_X control cannot be used

[6] The peaking units examined in this study are manufactured by GE Energy. The selection of these units was based on the units that were studied in the last Demand Curve Review and the comments and suggestions of ICAP Working Group members during the conduct of the study. Based on data from Platts, approximately 56% of combustion turbine capacity in the U.S. and 56% of combustion turbine capacity in the New York Control Area was manufactured by GE. There are several competing manufacturers and models for E and F frame machines and aeroderivatives. The units chosen for the study have representative cost and performance characteristics of similar products from other manufacturers. The choice of frame and aeroderivative units in this study does not constitute a recommendation from Sargent & Lundy to choose any specific manufacturer and models for projects in the New York Control Area.

because exhaust gas temperatures in simple-cycle mode exceed 850°F, above which the catalyst is damaged irreversibly. The efficiency of frame units can be improved by configuring units in a combined-cycle mode, where the exhaust of one or more units is directed to a heat recovery steam generator, which drives another steam turbine. This configuration was not included in the study.

The second type studied was aeroderivatives: the LM6000 and LMS100. These are derived from aircraft engines and have operating characteristics that better match the needs of aircraft owners. Aeroderivatives are more efficient (lower heat rate) and are maintained based on hours of operations regardless of the number of starts and stops, but have higher capital costs (on a $/kW basis). NO_X emissions can be reduced by injecting water into the combustion zone; however, aeroderivative exhaust temperatures are low enough to permit use of SCR for NO_X control.

1. 7EA

The General Electric Frame 7EA combustion turbine unit has been on the market since 1976 with over 750 units in service. The 7EA fleet has accumulated tens of millions of service hours and is recognized for high reliability and availability in both simple-cycle and combined-cycle operation. The baseload 7EA gas turbines have been averaging 95%+ availability with 98%+ reliability. The 7EA is used in a wide variety of power generation, industrial and cogeneration applications. It is uncomplicated and versatile; its medium-size design lends itself to flexibility in plant layout; and can be readily converted from simple cycle to combined cycle without major modifications to the machine. With its fuel handling equipment, advanced bucket cooling, thermal barrier coatings and a multiple-fuel combustion system, the 7EA can accommodate a full range of fuels. It is designed for dual-fuel operation and able to switch from one fuel to another while the turbine is running under load or during shutdown.

2. 7FA

General Electric's installed fleet of more than 500 'F' technology combustion turbines has reached 10 million hours of commercial operation in power plants worldwide. The F technology combustion turbines were introduced in 1988. The 7FA combustion turbine, with a nominal rating of 170 MW, is capable of operating on 100% natural gas or 100% diesel fuel. DLN combustors reduce NO_X emissions. Water injection is used for NO_X control in the combustion process when firing diesel fuel. The wide range of power generation applications for the 7FA gas turbine include combined cycle, cogeneration, simple-cycle peaking and integrated gasification combined cycle (IGCC) in both cyclic and baseload operation with a wide range of fuels. The reliability of the 7FA gas turbine has been consistently 98% or better.

3. LM6000

Since the introduction of the LM6000 into GE's aeroderivative combustion turbine product line, GE has produced more than 300 units, of which more than 200 are in commercial operation. The turbine has a 12-month rolling average engine availability of 96.8% and engine reliability of 98.8%, based on more than 3.1 million operating hours. The LM6000 is a dual-rotor, "direct drive" combustion turbine, which was derived from GE's CF6-80C2, high-bypass, turbofan aircraft engine. The combustion turbine reduces NO_X emissions levels by using a single annular combustion system with water injection to limit the formation of NO_X during the combustion process. For this study, the LM6000 was configured with SPRINT™ (Spray Inter-cooled Turbine) technology to significantly enhance power.

4. LMS100

The LMS100 is a General Electric aeroderivative combustion turbine that combines the technology of heavy-duty frame engines and aeroderivative turbines to provide cycling capability without the maintenance impact experienced by frame machines; higher simple-cycle efficiency than current aeroderivative machines; fast starts (10 minutes); and high availability and reliability. The LMS100™ system, developed by General Electric in 2004, combines the 6FA compressor technology with CF6®/LM6000™ technology. The low-pressure compressor (LPC), based on the 6FA, pumps 1.7 times the LM6000™ airflow. The airflow enters an intercooler, which reduces the temperature of the airflow before it enters the high-pressure compressor (HPC). Consequently, the HPC discharges into the combustor at ~250°F (140°C) lower than the LM6000™ aeroderivative gas turbine. The combination of lower inlet temperature and less work per unit of mass flow results in a higher pressure ratio and lower discharge temperature, providing significant margin for existing material limits and higher efficiency. The HPC airfoils and casing have been strengthened for this high-pressure condition.

Unlike the other technologies, the LMS100 is a relatively new machine with little operating history. The only unit in commercial operation is located at Basin Electric Power Cooperative's Groton

Generation Station in Groton, South Dakota. The unit has been in commercial operation since July 2006. The unit has been operating without any recurring issues or major problems other than a generator bearing replacement, with reliability trending up and availabilities in the upper 80 percent range. As of April 22, 2007, there have been 584 hours of operation and 107 starts[7]. Basin Electric has begun construction on a second unit, which is slated to be in service in June 2008[8]. GE reported to S&L in May 2007 that at least 13 other units have been sold: 2 in Canada and 11 in California. There are published reports of additional LMS100s planned at other locations in North America. A recent NYISO report identified five LMS100 units in the interconnection queue[9].

The uncertainty in the LMS100 cost and performance estimates for this report are not different from those of the LM6000. As discussed previously, major components of the LMS100 technology are based on both 6FA and LM6000 designs. The CF6 gas turbine in the LMS100 has over 100 million hours of operating experience in both aircraft engines and industrial applications. The construction process and site requirements for the LMS100 are similar to those of either frame or aeroderivative units; hence, the contingency factor in the cost estimates need not be increased. Therefore, there is no known technical basis for excluding the LMS100 from consideration.

Equipment prices for the LMS100 are difficult to predict in the short term. Quoted equipment prices for the LMS100 have increased 7% over three months during the course of this study. The lower heat rate of the unit could support a higher price for equipment without unduly suppressing demand. Other equipment manufacturers have not yet introduced models with competing features and capabilities of the LMS100. In the long run, competition from other manufacturers will limit price increases. Until competition emerges, it is possible that there will be additional equipment price increases.

[7] Personal communication, GE Energy, May 24, 2007.

[8] POWER, July 2007, p. 12.

[9] The 500 MW Astoria Repowering Project was one of eight market solutions reported in NYISO for "The Comprehensive Reliability Plan 2007: A Long Term Reliability Assessment of New York's Power System," First Draft, June 29, 2007.

5. Comparison

The key characteristics of the four technologies evaluated for this study are shown below. The direct costs are the costs typically within the scope of engineer, procure, and construct (EPC) contracts, and do not include owner's costs, financing costs, or working capital and inventories.

Table II-1 Key Characteristics of Evaluated Technologies

	Heavy-Duty Frame Technologies		Aeroderivative Technologies	
	7EA	**7FA**	**LM6000 Sprint**	**LMS100**
Capacity of a 2-Unit Addition	165	330	99	200
Total Cost ($m)	120-150	199-240	91-135	171-237
Total Cost ($/kW)	720-930	500-720	920-1,360	860-1190
Heat Rate (Btu/kWh HHV)	12,000	10,700	9,700	9,100
Pressure Ratio	12.6:1	16:1	29:1	42:1
Mass Flow (lb/sec)	640	980	290	470
Exhaust Temperature (°F)	998	1,114	826	770
Water Use (gpm)	15	30	50	60
Land Requirement (acres)	3.5	3.5	3.5	3.5
Voltage Support (MVARs)[10]	41.8	82.7	24.5	49.8

The direct cost ($/kW) and heat rate data show that the 7FA had lower capital and operating cost than the 7EA, and that the LMS100 had lower capital and operating cost than the LM6000.[11] The 7FA has lower capital and higher fuel and operating costs than the LMS100. Appendix 1 shows more detailed information on the cost and performance characteristics of the LMS100, LM6000,

[10] Based on 90% Load, ISO Conditions (59F, 60% RH, 14.7 psia), Evaporative cooling, 0.85 Power Factor

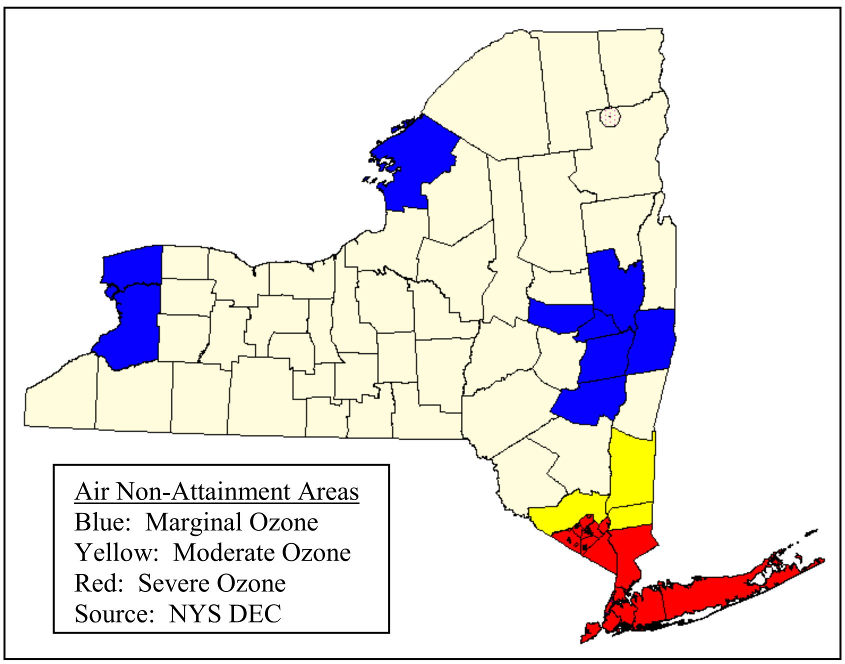
[11] However, as noted above, there is uncertainty over the price of LMS100 equipment. Should the manufacturer increase the LMS100 equipment price relative to the LM6000, to capture the benefits of the lower LMS100 heat rate, this could change.

and 7FA technologies. The following section addresses the impact of emissions limitations on technology choice.

C. Technology Choice by Region

All four technologies are considered to be a major source subject to Title V regulations (operating permits) and because they are subject to Title IV Acid Rain (applies to each generator that is greater than 25 MW in capacity). The chart below shows the status of ozone nonattainment areas in New York State[12]. The amount of emissions that triggers meeting the Lowest Achievable Emissions Rates (LAER) is 25 tons per year (NO_X) in New York City, Long Island, and two counties of the lower Hudson Valley (Westchester and Lower Rockland). The threshold is 100 tons per year in other locations. SO_2 emissions are not significant from turbines using natural gas, and there no longer are carbon monoxide attainment issues in New York.

Figure II-1 — Ozone Nonattainment Areas in New York State



The table below shows estimates of the maximum annual hours of operation for the 7FA without an SCR and the LMS100 with and without an SCR. Use of an SCR on a simple-cycle 7FA is not

[12] Personal communication, NYS DEC, February 5, 2007.

economically or, at the present time, technically practical. S&L is not aware of any simple-cycle 7FA gas turbines with an SCR. Current, proven, SCR catalyst has a maximum operating temperature of approximately 850°F. [13] [14] 7FA gas temperatures are in excess of 1100°F (see table above). To reduce the temperature entering the SCR to 850°F, approximately 1,000,000 lb/hr of dilution air (at 59°F) would be required. The total flow entering the SCR would result in approximately 30% increased size of the SCR. Costs would increase due to the larger SCR, dilution fan, dilution ductwork and dampers, and associated controls. The dilution air fan would be about a 2 MW addition to the auxiliary power load. This additional auxiliary power, in addition to reducing unit output, increases the net heat rate by around 150 Btu/kWh.

Table II-2 — Estimated Maximum Annual Hours of Operation for 7FA, LMS100, and LM6000

		25 Ton Limit (downstate)		100 Ton Limit (upstate)	
	NOx emissions (lbs/hr)	Maximum Annual Hours	Maximum Capacity Factor	Maximum Annual Hours	Maximum Capacity Factor
7FA w/o SCR	74	678	8%	2,712	31%
LMS100 w/o SCR	101	494	6%	1,975	23%
LM6000 w/o SCR	45	1,111	13%	4,444	51%
7FA w/SCR	Not Practical	N/A	N/A	N/A	N/A
LMS100 w/SCR	8	6,250	71%	8,760	100%
LM6000 w/SCR	5	8,760	100%	8,760	100%

A 7FA without an SCR sited downstate would be severely restricted in operating hours, but could be operated upstate with a capacity factor as high as 31%. Operation of an LMS100 or LM6000 with an SCR would not be restricted at all upstate, and not significantly affected by annual operating limits downstate.

Operation of a simple cycle 7FA as a peaker with a 25 Ton Limit on NO_x emissions would result in very low allowed hours of operation. Hence, we considered it impractical to construct a 7FA as a peaker in the Lower Hudson Valley, New York City, or Long Island. In those regions, either the LMS100 or the LM6000, both with an SCR, can be operated as peaking units without environmental restrictions on operating hours.

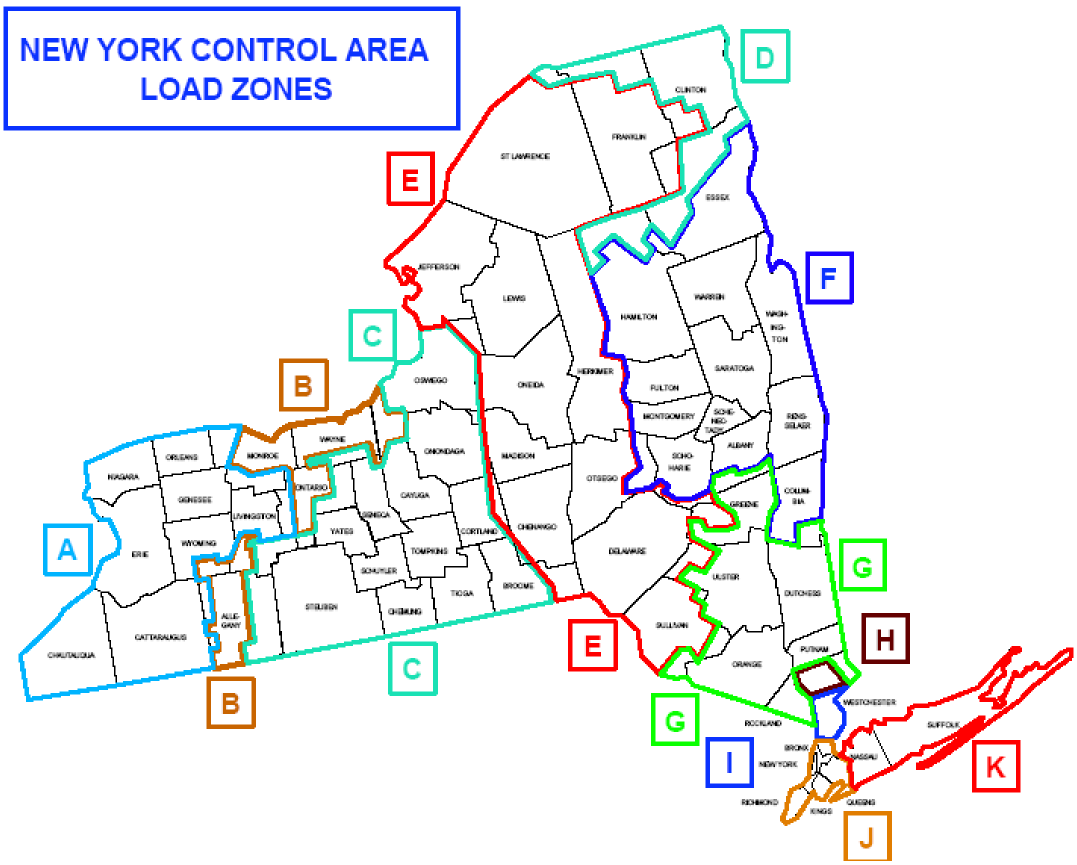
[13] US. Environmental Protection Agency, Air Pollution Control Technology Fact Sheet, EPA-452/F-03-032

[14] GE Power Generation, "Gas Turbine NO_x Emissions Approaching Zero—Is it Worth the Price?" GER4172, September 1999.

D. Construction Schedule and Costs

Cost estimates were prepared for the construction of a new greenfield two-unit simple-cycle combustion turbine peaking plant at each of five New York load zones: C, F, G, J, and K. Figure II-2 shows the location of these zones.

Figure II-2 — Map of New York Control Area Load Zones



These estimates reflect plant features typically found in modern peaking facilities and are intended to reflect representative costs for new plants of their type, in year 2007 dollars. The estimates are conceptual and are not based on preliminary engineering activities for any specific site. The estimates reflect projects awarded on an EPC basis, with combustion turbines and SCR systems (if included) purchased directly by the owner. Scope includes all site facilities for power generation and distribution, including a 230-kV switchyard. With no specific sites chosen for the hypothetical peaking unit of this study, a 230-kV switchyard was chosen as a compromise. Transmission systems covering small geographic areas are generally lower voltage, such as 115kV or even lower, but a peaking unit could be interconnected at a higher voltage.

1. Principal Assumptions

The key assumptions are discussed below.

a. Technology and SCR Systems

Pursuant to the discussion in the previous section, estimates were prepared using LM6000 and LMS100 technologies with an SCR at Zones G, J, and K, and with LM6000, LMS100, and 7FA technologies without an SCR in Zones C and F. SCRs are assumed to meet a NO_X emissions limit of 2.5 ppm. CO catalyst has not been included.

b. Greenfield Conditions

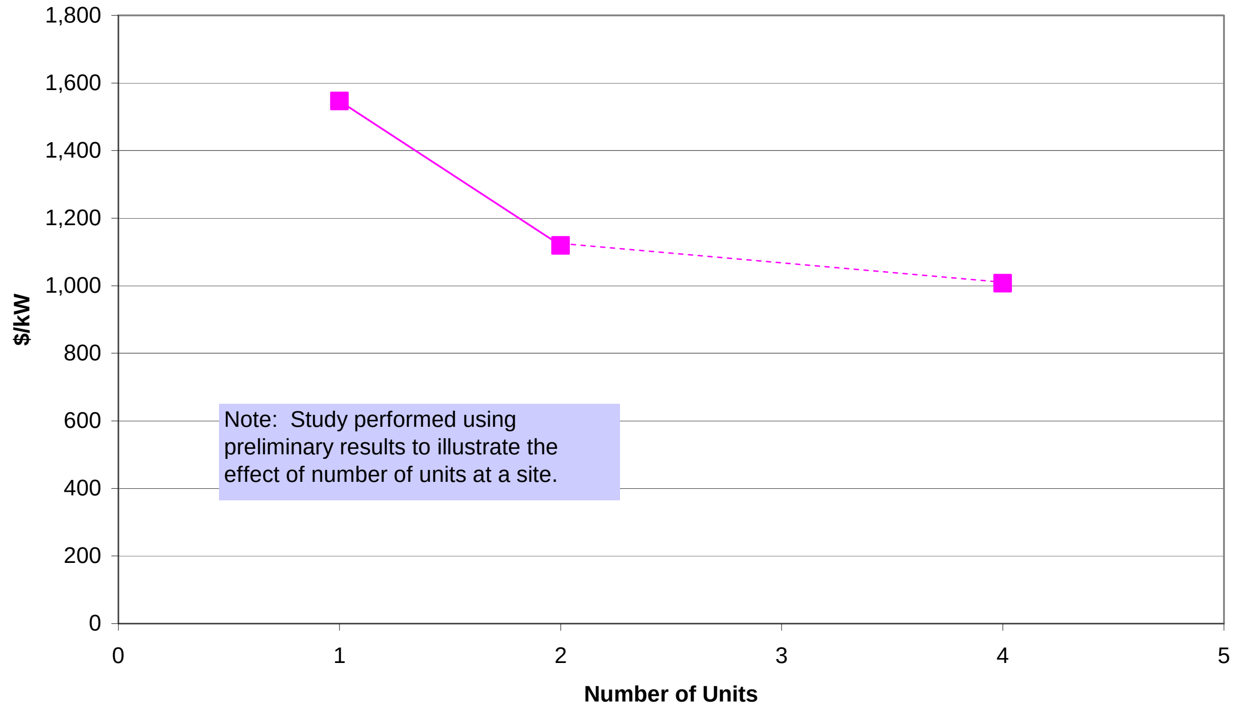
A new entrant peaking unit could be installed less expensively at an existing site where already-constructed common facilities may be utilized. Although such brownfield sites exist, the number of these is limited. The study is based on a greenfield site conditions to incorporate all of the normally expected costs to develop a new entrant peaking plant. Land and water requirements for greenfield conditions are summarized in Table II-1.

c. Number of Units

The cost per kilowatt of new capacity is reduced if multiple units are constructed and share the burden of the common facility costs. A comparison study of one, two, or four units was conducted and shows that a two-unit addition is a reasonable tradeoff between the higher cost of adding only a single unit, and the lumpier addition of four units to system capacity. Figure II-3 shows that a two-unit addition is 72 percent of the cost of a one-unit addition, and 11 percent more than the cost of a four-unit addition.

Figure II-3 — Direct Cost as a Function of Number of Units

(Zone J Results for LM6000)



d. Inlet Air Cooling

Inlet air evaporative cooling (the intercooler for the LMS100) was assumed for all technologies because it increases capacity. Dry cooling was assumed for the intercooler for the LMS100. Inlet air chillers were not included in the configuration due to cost considerations.

e. Dual vs. Single Fuel

The capability to burn natural gas or fuel oil reduces the risk of not having peaking capacity available when needed due to fuel supply interruption, and adds capital cost while lowering operating costs. However, current NYISO and NY Public Service Commission rules do not require dual-fuel capability. Gas availability is more likely a problem in the winter when reliability is less an issue. In New York City, Consolidated Edison Service Classification No. 9 appears to require dual fuel capability to qualify for Power Generation Transportation Service[15]. Con Ed reported to S&L in July 2007 that dual fuel capability is negotiated on a site specific basis, and is not always required[16]. Given the possibility that a new peaking unit in New York City may be required to have

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[15] Consolidated Edison Company of New York, Service Classification No. 9, Transportation Service (TS), Leaf 266.

[16] Personal communication, Consolidation Edison, July 5, 2007.

this capability, dual fuel capability has been assumed for Zone J. Firing only with natural gas was assumed for Long Island (Zone K) and Rest of State.

f. Gas Compression

Fuel gas compressors have been included based on a local supply pressure of 200 psig.

g. Contingency

Contingency is added to cover undefined variables in both scope definition and pricing that are encountered within the original scope parameters. Contingency should always be treated as "spent money." Examples of where it is applied would include nominal adjustments to material quantities in accordance with the final design, items clearly required by the initial design parameters that were overlooked in the original estimate detail, and pricing fluctuations like the recent run-up in copper prices. A contingency of 10% was applied to the total of direct and indirect project costs.

h. Basis for Equipment, Materials, and Labor Costs

All equipment and material costs are based on S&L in-house data, vendor catalogs, or publications. Labor rates have been developed based on union craft rates in 2007. Costs have been added to cover FICA, fringe benefits, workmen's compensation, small tools, construction equipment, and contractor site overheads. Work is assumed to be performed on a 50-hour work week by qualified craft labor available in the plant area. Labor rates are based on Onandaga County for Zone C, Albany County for Zone F, Dutchess County for Zone G, New York County for Zone J, and Suffolk County for Zone K. A labor productivity adjustment of 1.38 has been applied to Zones J and K and 1.05 for other zones. Materials costs are based on data for Syracuse in Zone C, Albany in Zones F and G, New York City in Zone J, and Riverhead in Zone K.

i. Miscellaneous

Black start capability has not been included. Spread footing foundations without foundation piles were assumed. Use of rental trailer-mounted water treating equipment was assumed. Potable water is available from a municipal supply. Wastewater treatment is not included; contaminated wastewater will be collected locally for tanker truck disposal. A control/administration building is included.

2. Capital Investment Costs

Capital investment costs for each peaking unit option include direct costs, owner's costs, financing costs during construction, and working capital and inventories:

— Direct costs are costs typically within the scope of an EPC contract. These costs are estimated in detail in Appendix 1.

— Owner's costs include items not covered by the EPC scope such as owner's development costs, oversight, legal fees, financing fees, startup and testing, and training. On the basis of data extracted from recent independent power projects, these costs have been estimated as 11% of direct capital costs. In addition, social justice costs were estimated to be $1,000,000 for the LM6000 and $2,000,000 for the LMS100 in NYC, $375,000 in LI for either technology, and $275,000 in ROS for all three technologies.

— Financing costs during construction refer to the cost of debt and equity required over the periods from each construction expenditure date through the plant in-service date. These costs have been calculated from the monthly construction cash flows associated with the capital cost estimates in Appendix 1, and the cost of debt and equity presented in Section F.2. A 20-month construction period is assumed, with cash flows peaking in the 14^{th} month. Over 70% of the total cash flow occurs in the second half of the construction period.

— Working capital and inventories refer to the initial inventories of fuel, consumables, and spare parts that are normally capitalized. It also includes working capital cash for the payment of monthly operating expenses. On the basis of recent independent power projects, these costs have been estimated as 2% of direct capital costs.

Capital investment costs for each location and combustion turbine option are summarized below in Table II-3.

Table II-3 — Capital Investment Costs for Greenfield Site (2007 $)

	NYC 2 x LM6000 With SCR	**NYC 2 x LMS100 With SCR**	**Long Island 2 x LM6000 With SCR**	**Long Island 2 x LMS100 With SCR**	**LHV 2 x LM6000 With SCR**	**LHV 2 x LMS100 With SCR**
Direct Costs	113,354,000	199,123,000	106,870,000	189,976,000	92,757,000	168,473,000
Owner's Costs	13,468,000	23.903,000	12,129,000	21,274,000	10,479,000	18,805,000
Financing Costs During Construction	5,771,000	10,148,000	5,415,000	9,612,000	4,697,000	8,522,000
Working Capital and Inventories	2,267,000	3,982,000	2,137,000	3,800,000	1,855,000	3,369,000
Total	134,860,000	237,156,000	126,551,000	224,662,000	109,788,000	199,169,000
Net Degraded ICAP MW	87.56	188.72	87.57	188.75	87.06	187.59
$/kW	$1,540	$1,257	$1,445	$1,190	$1,261	$1,062

	Albany 2 x LM6000 No SCR	**Albany 2 x LMS100 No SCR**	**Albany 2 x GE 7FA No SCR**	**Syracuse 2 x LM6000 No SCR**	**Syracuse 2 x LMS100 No SCR**	**Syracuse 2 x GE 7FA No SCR**
Direct Costs	77,497,000	146,187,000	170,437,000	76,615,000	144,665,000	168,694,000
Owner's Costs	8,801,000	16,355,000	19,023,000	8,703,000	16,189,000	18,833,000
Financing Costs During Construction	3,926,000	7,396,000	8,621,000	3,882,000	7,319,000	8,533,000
Working Capital and Inventories	1,550,000	2,924,000	3,409,000	1,532,000	2,893,000	3,374,000
Total	91,774,000	172,862,000	201,490,000	90,732,000	171,066,000	199,434,000
Net Degraded ICAP MW	86.69	186.74	300.30	86.19	185.61	298.72
$/kW	$1,059	$926	$671	$1,053	$922	$668

E. Other Plant Costs

Other costs associated with each peaking unit option include fixed O&M costs, variable O&M costs, and fuel costs. These costs are estimated in detail in Appendix 1, Table A-2. The basis for these estimates is described in the following subsections.

1. Fixed O&M Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance). Design-related costs were derived from a variety of sources, including the State-of-the-Art Power Plant Combustion Turbine Workstation, v 7.0, developed by the Electric Power Research Institute (EPRI) and data for existing plants reported on Federal Energy Regulatory Commission (FERC) Form 1. The resulting cost assumptions are summarized in Table II-4.

Table II-4 — Fixed O&M Assumptions (2007 $)

	NYC and Long Island 2 x LM6000	NYC and Long Island 2 x LMS100	ROS 2 x LM6000	ROS 2 x LMS100	ROS 2 x GE 7FA
Average Labor Rate, incl. Benefits ($/hour)	$62.00	$62.00	$50.00	$50.00	$50.00
Operating Staff (full-time equivalents)	4.00	4.00	4.00	4.00	4.00
Maintenance Staff (full-time equivalents)	3.00	3.00	3.00	3.00	3.00
Routine Materials and Contract Services	$237,000	$305,000	$237,000	$305,000	$365,000
Administrative and General	$206,000	$206,000	$206,000	$206,000	$206,000

Other fixed operating costs are described below and summarized in Table II-5.

a. Site Leasing Costs

Site leasing costs are equal to the annual lease rate ($/acre-year) multiplied by the land requirement in acres. These values used were from the Levitan & Associates, Inc. (LAI) study, escalated by inflation.

b. Property Taxes and Insurance

Property taxes are equal to the unadjusted property tax rate for the given jurisdiction, multiplied by an assessment ratio, and multiplied by the market value of the plant. The assessment ratio is the percentage of market value applied in the tax calculation. The property tax rates and assessment ratios for this analysis were selected as typical values currently in effect for jurisdictions in each location, as follows:

NYC: (City of New York website), Class 4 Property (10.059%) x 45% assessment ratio = 4.53% effective rate. Power plant equipment that is not rate regulated by the public service commission should be treated as general commercial real property (Class 4).[17]

LI: According to Suffolk County website, each town sets its own property tax rate. The limit on the effective rate is 1.5% in the county, but villages have a 2.0% limit, and towns have no limit. An effective value of 2.00% was chosen as representative for LI.

ROS: From the wide range of values posted for Ulster County (Hudson Valley) and Onondaga County (Syracuse area) on their websites, a typical rate and assessment ratio of: 4.0% and 50%, respectively, were chosen for a 2.00% effective rate.

If the facility is a Qualified Empire Zone Enterprise, a property tax credit may apply, based on a formula that considers job creation, wages and benefits or investments made in the zone. For this analysis, it was assumed that most new combustion turbine facilities would not qualify for this credit.

Under the Industrial and Commercial Incentive Program (ICIP) in New York City, the project is granted a property tax exemption for the first 11 years, followed by a 20% decline in the exemption each year for four years, with full taxes due in the 16th year and thereafter. A New York State court

[17] In the Matter of Astoria Gas Turbine Power, LLC v. Tax Commission of City of New York, 857 N.E.2d 510 (2006)

has ruled that power plants in New York City qualify for the program as commercial improvement work. The continuous renewal of the ICIP in future years is assumed.

Insurance costs are estimated to be 0.30% of the initial capital investment, escalating each year with inflation, on the basis of actual data for recent independent power projects.

Property taxes and insurance are commonly considered to be part of the carrying charge rate because their value is directly related to the plant capital cost. The LAI report includes these items as part of the fixed O&M. The carrying charge rates in Section II.F.3 of this report are derived both with and without property taxes and insurance.

Table II-5 — Other Fixed Operating Cost Assumptions (2007 $)

	NYC	Long Island	ROS
Land Requirement (acres)	3.50	3.50	3.50
Lease Rate ($/acre-year)	122,000	21,000	17,000
Property Tax Rate	10.059%	2.00%	4.00%
Assessment Ratio	45.00%	100.00%	50.00%
Effective Property Tax Rate	4.53% *	2.00%	2.00%
Insurance Rate	0.30%	0.30%	0.30%

* The effective rate excluding the ICIP property tax exemption granted during the first 15 years of operation.

2. Variable O&M Costs

Over the long-term operating life of a peaking facility, the largest component of variable O&M is the allowance for major maintenance expenses. Each major maintenance cycle for a combustion turbine typically includes regular combustion inspections, periodic hot gas path inspections, and one major overhaul. For the aeroderivative units, GE recommends a major maintenance overhaul every 50,000 factored operating hours. For the frame units, major overhauls are every 48,000 operating hours or 2,400 factored starts, whichever occurs first. Normal operating hours and normal starts are factored, that is, increased to account for severe operating conditions. For example, operating hours are factored for operation on fuel oil instead of natural gas and starts are factored as a result of trips or emergency starts. For peaking duty, major maintenance intervals thus tend to be hours-based for the aeroderivative units and starts-based for the frame units.

Since major maintenance activities and costs are spaced irregularly over the long-term, the cost in a given year represents an annual accrual for future major maintenance. The average variable O&M cost for major maintenance is thus equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored operating hours between overhauls, divided by the unit capacity in megawatts. Other variable O&M costs are directly proportional to plant generating output, such as unscheduled maintenance, SCR catalyst and ammonia, water, and other chemicals and consumables. SCR is required in ozone non-attainment areas, which applies to all study locations except Albany and Syracuse. The GE 7EA cannot be equipped with an SCR because the hot-side gas temperature is too high. Variable O&M assumptions for each turbine model and location are summarized in Table II-6.

Table II-6 — Variable O&M Assumptions (2007 $)

	NYC, Long Island, & Lower Hudson Valley **2 x LM6000**	**NYC, Long Island, & Lower Hudson Valley** **2 x LMS100**	**ROS** **2 x LM6000**	**ROS** **2 x LMS100**	**ROS** **2 x GE 7FA**
Major Maintenance Interval (Operating Hours)	50,000	50,000	50,000	50,000	48,000
Major Maintenance Interval (Factored Starts)	N/A	N/A	N/A	N/A	2,400
Cost of Parts Required for Complete Major Maintenance Interval *	5,257,000	14,200,000	5,257,000	14,200,000	26,360,000
Man-Hours Required for Complete Major Maintenance Interval *	2,496	6,700	2,496	6,700	17,760
Unscheduled Maintenance ($/MWh)	0.75	0.75	0.75	0.75	0.51
SCR Catalyst and Ammonia	0.90	0.90	N/A	N/A	N/A

	NYC, Long Island, & Lower Hudson Valley 2 x LM6000	NYC, Long Island, & Lower Hudson Valley 2 x LMS100	ROS 2 x LM6000	ROS 2 x LMS100	ROS 2 x GE 7FA
($/MWh)					
Water ($/MWh)	0.07	0.07	0.07	0.07	0.01
Other Chemicals and Consumables ($/MWh)	0.17	0.17	0.17	0.17	0.02

* Includes combustion inspections, hot gas path inspections, and major inspection required, on average, for one complete interval.

3. Fuel Costs

The fuel costs for each peaking unit option are derived from the delivered price of fuel in each region, the net plant heat rate, and the plant dispatch. Fuel prices are derived on a statistical basis, using the historical correlation between daily New York gas costs by location and load and electricity price, as presented in Section III. The statistical approach is used to capture the effects of extreme conditions in the electricity markets on daily and seasonal gas prices. This approach incorporates fuel prices that are consistent with the hours of the year the peaking unit is actually dispatched.

The fuel price forecasts in Section III account for the transportation cost differences by location. These prices are tied to commodity pricing at delivery points in New York from a major interstate pipeline system that transports natural gas from producing regions along the U.S. Gulf Coast. Local fuel transportation charges were added to the price at the nearest trading point. The applicable local transportation rates include ConEd PSC No. 9-Gas (Leaf 277) for New York City and Keyspan PSC No. 1-Gas, Service Classification No. 14 (Leaf 189) for Long Island. In those two regions, the total delivered fuel price to an end user for interruptible service is the sum of the following:

- Texas Eastern Transmission Market Area 3 (TET-M3) or Transco Zone 6 Price
- System Cost Component
- Marginal Cost Component
- Value Added Charge
- Taxes

— Imbalance Charges

The System Cost Component, Marginal Cost Component, Value Added Charge, and Taxes are all subject to a minimum monthly bill that is based upon a 50% capacity factor. According to discussions with representatives from ConEd and Keyspan, the Imbalance Charges are minimal in the day-ahead market. Those same representatives indicated that firm transportation service is not commonly provided because of the prohibitive costs of system reinforcement. Interruptible service gives ConEd and Keyspan the right to curtail gas supply up to 720 hours per year. The risk of gas supply interruption is greatest in the winter months when electric system reliability is less of an issue.

Local fuel transportation charges for the rest of state were estimated from data for various existing plants in the Northeast. The estimated rates for each study region are summarized in Table II-7.

Table II-7 — Fuel Transportation Charges (2007 $)

	NYC	Long Island	ROS
Gas Transportation Service ($/mmBtu) *			
System Cost Component	0.100	0.100	—
Marginal Cost Component	0.092	0.140	—
Value Added Charge	0.005	0.005	—
Taxes	0.007	0.008	—
Pipeline Demand Charges ($/mmBtu)	—	—	0.400
Pipeline Commodity Charges ($/mmBtu)	—	—	0.002

* The minimum bill must be based on a capacity factor of 50%. For a peaking unit, the effective $/mmBtu cost is thus higher than the indicated rates.

The net plant heat rates and start-up fuel consumption rates for each peaking unit option are summarized in Appendix 1, Table A-2.

The modeling of the peaking unit dispatch in connection with the derivation of energy and ancillary service revenues, and the associated fuel consumption and costs, are discussed in Section III.

F. Development of Real Levelized Carrying Charges

Capital investment costs are converted to annual capacity charges using annual carrying charge rates. The annual carrying charge rate multiplied by the original capital investment yields the annual carrying charges. Carrying charges typically include all annual costs that are a direct function of the capital investment amount: principal and interest payments on project debt, equity returns, income taxes, property taxes, and insurance. The assumptions used for property taxes and insurance were discussed in Section II.E.1.b. Income tax and financing assumptions are presented in the following subsections.

1. Income Tax Assumptions

Income taxes are a significant component of carrying charge rates. A portion of these charges must be grossed up to account for the income taxes due on plant revenues such that the desired return on equity is achieved. Income taxes include the federal corporate tax rate of 35.00%, the New York State corporate tax rate of 7.50%, and the New York City income tax rate of 8.85%. The composite tax rate is the sum of these rates, reduced by the portion that is deductible from taxable income. Income tax assumptions for each region are summarized in Table II-8.

Table II-8 — Income Tax Assumptions

	NYC	Long Island and ROS
Federal Tax Rate	35.000%	35.000%
State Tax Rate	7.500%	7.500%
City Tax Rate	8.850%	0.000%
Composite Tax Rate *	45.628%	39.875%

* Federal tax rate + state tax rate + city tax rate – [federal tax rate x (state tax rate + city tax rate)], to account for the deductibility of state and local taxes from federal taxable income.

2. Financing Assumptions

The financing of the plant is assumed to have a 50:50 ratio of debt to equity for a financially healthy merchant generator with a BBB credit rating. NERA has found this capital structure to be consistent with Standard & Poor's classification of merchant generation as "Business Position 8" under its ratings criteria with a mid-BBB rating target debt ratio of 47.5%. NERA has estimated the cost of equity to be 12.0% from the capital asset pricing model (CAPM) using a risk-free rate of 4.73%, an equity beta of 1.0, and an equity risk premium of 7.10% (4.73 + 1.0 x 7.10 = 11.83). The beta of 1.0 is consistent with observed equity betas for existing merchant generators. The equity risk premium is the Long Horizon Equity Risk Premium from 1926 to 2005 (Ibbotson Associates, *Stocks, Bonds, Bills and Inflation 2006 Yearbook*). The risk-free rate is the 20-year treasury yield and the estimated cost of debt is 7.00%, which is consistent with recent yields on corporate bonds rated Baa by Moody's (Source: http://www.federalreserve.gov /releases/h15/update/).

Financing assumptions for each region are summarized in Table II-9. The values are identical for each region except for the after-tax weighted average cost of capital, which is lower in New York City because of the city income tax. The costs of debt and equity are shown on a nominal basis and a real basis. Real rates are derived by removing the inflation component of 2.70%, and are subsequently used to calculate the real weighted average cost of capital (WACC) and the real levelized carrying charge rates.

Table II-9 — Financing Assumptions

	NYC	Long Island and ROS
Equity Fraction	0.500	0.500
Debt Fraction	0.500	0.500
Cost of Equity (nominal)	12.00%	12.00%
Cost of Debt (nominal)	7.00%	7.00%
Cost of Equity (real)	9.06%	9.06%
Cost of Debt (real)	4.19%	4.19%
Weighted Average Cost of Capital *		
Before-Tax (nominal)	9.50%	9.50%
After-Tax (nominal)	7.90%	8.10%
Before-Tax (real)	6.62%	6.62%
After-Tax (real)	5.67%	5.79%
Amortization Period (years)	15.5	11.5

Tax Depreciation **	15-year MACRS	15-year MACRS
Inflation Rate	2.70%	2.70%

* (Equity Fraction x Cost of Equity) + (Debt Fraction x Cost of Debt), before tax; and (Equity Fraction x Cost of Equity) + [(Debt Fraction x Cost of Debt) x (1 – Composite Tax Rate)], after tax.

** Federal tax code schedule (Modified Accelerated Cost Recovery System or MACRS) for a simple-cycle combustion turbine, adjusted for residual depreciation if the amortization period is less than 15 years.

While the LAI study used a constant 20-year amortization period across all regions, this study introduces a new methodology developed by NERA that determines a separate amortization period for each region. The difference by region considers the risk of excess capacity, the slope of the Demand Curve, and the slope of the energy and ancillary service net revenue function. This change in method ties together the risk and the slope of the Demand Curve and provides for an internally consistent consideration of the Demand Curve slope, which affects risk, and the amortization period.

3. Levelized Cost Results

For each case, the annual carrying charges were calculated over the amortization period. Annual carrying charges are equal to the sum of the following components:

— **Principal.** Based upon mortgage style amortization.

— **Interest.** Equal to the cost of debt multiplied by the loan balance for the given year.

— **Target Cash Flow to Equity.** Equal to the initial equity investment multiplied by an annuity factor over the amortization period, using the cost of equity as the annuity rate.

— **Income Taxes.** Calculated by the formula: [t/(1-t)] x [Target Cash Flow to Equity + Principal – Annual Tax Depreciation], where t = Composite Tax Rate. Annual tax depreciation is based on 15-year MACRS depreciation in accordance with the federal tax code for a simple-cycle combustion turbine.

— **Property Taxes.** The effective property tax rate multiplied by the original capital investment amount, escalating year with inflation.

— **Insurance.** The insurance rate multiplied by the original capital investment amount, escalating each year with inflation.

Annual carrying charge rates on a hypothetical $1,000,000 capital investment are derived in Appendix 2, Table B-1. Carrying charges derived on this basis result in the specified target cash flow to equity, as verified by the income statement shown in Table II-10.

Table II-10 — Income Statement

	Carrying Charges
minus	Tax Depreciation
minus	Interest
=	Taxable Income
minus	Taxes
minus	Principal
Add back	Depreciation
=	**Target Cash Flow to Equity**

The levelized carrying charge is equal to the annual carrying charges over the amortization period converted to an annuity using the after-tax WACC. In other words, the annual carrying charges are considered to be "revenue requirements" that are discounted at the after-tax WACC. The LAI study used the cost of equity as the discount rate on the principle that project-specific debt is already included in the revenue requirements. It states that the after-tax WACC would be used only if the debt components were removed from the revenue requirements. The LAI study also uses the cost of equity as a discount rate for the fixed O&M, property taxes, and insurance costs.

We believe, however, that the after-tax WACC is an appropriate discount rate for the entire annual revenue requirements, including all debt-related components. In theory, a discount rate should depend upon the riskiness of a future stream of payments. Greater risk or uncertainty in those payments would justify a risk premium that would raise the discount rate. Conversely, lower risk would justify a lower discount rate. The LAI study, however, effectively applies a higher discount rate (the cost of equity) to payment streams that have relatively lower risk (the debt components and the depreciation tax shield). This contradiction arises because revenue requirements, not cash flows, are being discounted. Leveraged cash flows are inherently riskier than unleveraged cash flows, but the same logic does not apply to revenue requirements.

The real levelized carrying charge rates as a function of amortization period are summarized in Table II-11. For additional clarity, the rates were derived both with and without property taxes and insurance, since these items are sometimes classified as part of the fixed O&M.

Table II-11 — Real Levelized Carrying Charge Rates

	NYC with ICIP	NYC without ICIP	LI and ROS
Levelized Carrying Charge Rates – with Property Taxes and Insurance:			
10-year amortization	17.16	21.69	18.57
15-year amortization	13.75	17.85	14.85
20-year amortization	12.41	15.87	12.95
25-year amortization	11.65	14.74	11.87
30-year amortization	11.18	14.03	11.20
35-year amortization	10.86	13.56	10.75
Levelized Carrying Charge Rates – Without Property Taxes and Insurance:			
10-year amortization	—	16.86	16.27
15-year amortization	—	13.02	12.55
20-year amortization	—	11.04	10.65
25-year amortization	—	9.91	9.57
30-year amortization	—	9.20	8.90
35-year amortization	—	8.73	8.45

The ICIP property tax abatement in New York City has a significant effect on the carrying charge rates. Over the 15-year amortization period, the ICIP reduces the levelized carrying charge rate by 23%. There are several reasons for a change of this magnitude:

- — Under the ICIP, the normal property tax bill is not phased in until year 16, which is after the 15-year amortization period;
- — Without the ICIP, the effective property tax rate for New York City is 4.53% compared to 2.00% elsewhere, as indicated in Section II.E.1.b;
- — Property taxes escalate with inflation due to valuation and/or rate adjustments. This is the assumption also used in the LAI report. Without the ICIP, the relatively high property taxes in New York City are constant in real terms through the entire amortization period.

In addition to the effects of region and property taxes and insurance, the sensitivity of the carrying charge rates over a range of amortization periods (10 to 35 years) and for higher costs of debt and equity (base case, base case + 200 basis points, and base case + 400 basis points) are shown in Appendix 2, Table B-2.

III. Estimating Energy Net Operating Revenues

The next task is to estimate the annual net operating revenues of our hypothetical peaker. The net operating revenues are not to be based on any estimate of actual future supply and demand balances, however, but are required by the Tariff to be based on “conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity requirement.[18]

A. Overview of Approach

We have used historical data from 5/1/2003-12/31/2006 to benchmark the operation of the NYISO system. We then statistically estimate the effect of various cost drivers, including installed reserve margin, on the observed zonal LBMP values. This statistical model allows us to conceptually vary any causal variable to create an estimate of price under future conditions. At this point, we have an estimate of prices under the specified Services Tariff conditions.

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We then use these prices to dispatch the hypothetical unit, calculating both day-ahead and real-time energy revenues. In so doing we must create a hypothetical strategy for this unit and make decisions as to the degree of foresight the unit operator will have in choosing between commitment to the day-ahead market versus opportunistic behaviour in the real-time market. In addition, we must be mindful of real operating constraints on the unit with regards to start-up cost and start times. These calculations are carried out by zone.

We should note that we considered and rejected the other prominent competing method for estimating net operating revenues, namely production cost modelling. There are two prominent problems with this approach. The first is that production cost modelling does not mirror actual price experience. Production cost models by their very nature tend to understate actual electric prices, since they reflect a system which always behaves optimally and never has to adjust for unexpected contingencies in real time. These adjustments have real costs, and these costs are often substantial. The second problem is that for practical purposes, production cost models must be run at expected conditions and cannot be run as a system actually runs, *i.e.* with widely varying gas prices, weather and demand conditions and transient transmission irregularities. The effect of these things are not linear, particularly under peak conditions and thus do not average out.

Thus, our approach assumes that the best evidence on what electric prices will be is what electric prices have been, adjusted where possible for known changes.

We should note that there is no perfect method to generate these results. Indeed, implicit in the tariff statement is the notion that net revenue estimation is the part of demand curve estimation most subject to error – this is why we use peaking units rather other units, since in a balanced system, all optimal new generating equipment will yield the same net demand curve value. Because the net revenue calculation is a hypothetical abstraction, we strive to model the important parts of the problem to the best of our ability, but recognize that there are numerous small effects which are unmodelled and which, by the law of large numbers, should roughly cancel one another out. Excessive focus on particular small issues raise the possibility of an unbalanced look at the problem in which the noise generating by the estimation process exceeds the signal generated. Consequently, the generation of net revenue estimates, while scientific, nonetheless calls for a good deal of judgment, as does almost any hypothetical modelling exercise.

B. Data

The hourly day-ahead and five-minute zonal LBMPs are publicly available at the NYISO website, as are zonal loads. These were augmented by daily gas prices taken from Bloomberg (Texas Eastern Transmission M3 price for all but New York City and Long Island, and by Transco Z6 prices for NYC and Long Island) which were then linearly interpolated across non-trading days. Temperatures were taken from data supplied by NOAA. Long Island and New York temperatures were taken from JFK airport. Upstate temperatures were taken at Albany Airport. The final addition was a series of excess purchases of capacity, by month, supplied by the NYISO in three capacity zones, New York City, Long Island, and the New York Control Area. These began in May 2003. Gas transportation costs were taken from Table A-2, except in New York City. For New York City, the Transco Z6 prices were raised by 4 percent to reflect fuel taxes and another 20 cents/MMBTU for local transportation.

The use of the period from May 2003 to December 2006 was chosen to sample over a wide range of conditions in input prices, cost drivers (*e.g.* weather) while staying reasonably close to the present structure of the market. In particular, this period covers the time of the implementation of scarcity pricing in the NYISO which sharply increases prices on occasion.

C. Statistical Estimation

The fitting of a statistical equation to predict electricity prices is a reasonably straightforward exercise. Electricity price in any hour in any zone is determined by the intersection of offers to supply power and the estimated (if day ahead) or actual (if real time) demand for power, adjusted for limitations, if any, of the transmission system to minimize total resource costs. The supply curve of electricity is largely fixed, but moves somewhat from hour to hour as transmission conditions change, the availability of units change, and from other transient factors, *e.g.* temperature. If, as a first approximation, we regard the supply curve is fixed, then varying demand traces out the supply curve. Thus, our estimation strategy is to use load to identify the supply curve while varying the supply curve from hour-to-hour to reflect underlying technical supply differentials. The remainder of unmeasured effects, which are substantial, are left as residuals in the underlying model. Thus,

$LBMP_{hz}$ = f(NY Load, Zonal Load, Attributes of Hour h, Attributes of Zone z, Gas Price, Reserve Margin, Temperature) + ε

The complete specification is given in Appendix 3. The standard indicia of model fit are quite good. The basic regression model explains about 83 percent of the underlying variation in electric prices. This implies that given the zone, the hour, the NY and zonal load, Gas Price, reserve margin and temperature, we can capture about 83 percent of the variation in electricity price around its mean. The remaining 17 percent of the variation that is unexplained are implicitly accounted for by a combination of variables excluded from the estimation process; these might include levels of outages, transient system conditions among other qualitative and quantitative factors.

With one exception, all causal factors work as expected. Thus, for example, price increases as load increases, and increases faster the more load increases[19]. Prices are generally higher on the weekends and in the shoulder months (adjusting for load differences) to reflect outage patterns on deferrable maintenance. Higher temperatures cause higher prices, even adjusting for load, due to degraded performance of units. Finally, prices fall as reserve margins rise, with one exception: for reasons that are not entirely clear, prices on Long Island do not seem to be negatively related to reserve margin. Indeed, the only effect discernible is a small positive effect, which contradicts the expected economic relationship. Consequently, we have assumed that price on Long Island is essentially unrelated to observed reserve margin and we use estimated net revenues over the last 3½ years to estimate annual day-ahead net operating revenues.

D. Price Prediction

The Services Tariff requires conditions at or slightly above target margins. In the period observed margins were usually substantially in excess of the target margin. Thus, to estimate what prices would have been at the required Services Tariff conditions, we can recalculate prices using the statistical equation to calculate the change in prices attributable to a shrinking (or growth) of the observed reserve margin holding all other factors constant. We should note in particular that holding all other factors constant necessitates holding the unmeasured factors constant as well.

[19] This follows from the strongly positive effects on the cube of load.

Thus, we do not set the error terms (which reflect the unmeasured factors) to their average level of zero, but allow them to take whatever value they actually took in the data.

In essence, then, we choose as a base the actual conditions prevailing over the sample period, adjusting only for reserve margin. The use of this historic period is in many ways preferable to forecast the future. First, the last three-and-one-half years are broadly representative of patterns which are expected in the future in any case. We have periods of relatively low demand and relatively high demand as well as hot and cool summers. In any case, there is no particular reason to expect net price formation to follow any different path.

Gas prices average around $8/MMBTU over the study period, which is reasonably close to currently observed forward prices for natural gas over the forecast period, although current quotes are slightly higher. This does not matter very much for the calculation of peaker net revenues, however, since higher levels of gas prices tend to translate into roughly unchanged levels of net revenues for a peaking unit, since both revenues and costs rise in approximately the same amount[20].

We have examined other adjustments to make to the supply curve as well. For example, the methodology would allow us to adjust for transmission additions to Long Island from the 660 MW Neptune project. In the limit, we could regard this project as essentially reducing load by 660 MW year-round on Long Island. Again, owing to the odd distribution of prices on Long Island, we see very little effect on peaking prices on Long Island from the Neptune cable.

E. Hypothetical Dispatch

We have assumed that the unit is bid into the day-ahead market at a price which reflects the observed daily gas price and observed variable O&M. If taken, the unit runs in those hours and earns an operating net revenue equal to the difference between price and cost. We separately count starts and reduce net operating revenues by a start-up gas cost. In practice, units are virtually never taken more than once per day.

[20] Note that this is a statement about the average gas price levels. In extreme conditions, for a variety of reasons, prices are higher than a direct gas price comparison might suggest. This effect has been included in the modeling.

In line with the engineering assumptions, we have assumed that the overhaul maintenance costs are captured in a variable O&M value, which implies that the maintenance is largely hours of operation, not starts per se. This assumption is not appropriate for the Frame 7 units upstate which run at capacity factors far more consistent with a dollars per start criterion. We have used $20,000 per start to reflect the various possibilities for these units. In the day-ahead market, any block of operating hours which fail to earn back this startup cost earn zero net revenues, reflecting either a rejection of the unit in that block of hours for day-ahead operation, or inclusion with a production cost guarantee to bring the unit to zero net revenues.

In the hours in which the unit is not dispatched in the day-ahead market, it considers operation in the real time market. We have examined real time operation under several different alternatives, all of which yield similar results.

We have taken the five-minute real time zonal prices and carry out the following algorithm. First, we calculate operating net revenues for each unit in each zone if it ran at that price, using daily gas prices just as in the day-ahead calculations. We group these five-minute operating net revenues into continuous hours of operation and treat these as homogeneous units.

We next adjust for start-up time. If the unit was operating day-ahead in the previous hour, we allow it to continue running without an incremental start if the operating profit from the real-time price is positive, and allow it to continue running as long as the real-time profit is positive. If however, the unit was not running in the first hour of positive net revenues, we again allow it to continue running for contiguous blocks of profitable operation, but subtract start-up fuel costs and reduce the expected net revenue in the first hour by 50 percent in NYC and Long Island to reflect a 30 minute start-up time and by 1/6 upstate to reflect a ten minute start time for all but the Frame 7 which has a 30 minute start. If the total value of the contiguous block is positive, we book those hourly net revenues. We have tried numerous different strategies for dispatch in the real time market and all yield similar results. The approach used here has two major simplifications. First, we assume sufficient foresight to predict a profitable block of hours as soon as a profitable opportunity arises which would seem to require a start-up. Second, we assume that all runtimes are measured (including start-up time). Third, we assume that the pattern of prices over the hour is such that given hourly net revenue is evenly divisible over the hour.

We should note that we have not adjusted real time net revenues for reserve margin. There are several reasons for this assumption. First, the major source of net revenues in the real-time market is spikes relating to thunderstorm activity and losses of operating reserves. The former is clearly unrelated to reserve margin. Second, we know that real-time prices will always follow day-ahead prices. This causes, if anything, a negative correlation between real-time net revenues and day-ahead net revenues, as the probability that a unit will not otherwise be running during periods of price spikes rises. The absence of arbitrage opportunities in a competitive market requires that the expected value of the real-time market be no higher than the day-ahead market. Thus, the possibility of a profitable opportunity should be about the same regardless of the level of prices within a reasonable range. Against this, we might expect some additional opportunities for very high price as the supply demand balance tightens. On the other hand, since the number of hours the unit already runs rises as the day-ahead prices rise, the opportunity to take advantage of a higher number of scarcity hours falls. Consequently, we have made no adjustment.

Finally, we have added adjustment for ancillary service revenues for reserves and voltage support. The NYISO has supplied us with average ancillary service revenues over the last several years. We have added these values in. They total about $1.68/kW-yr. downstate and about half that upstate.

F. Results

The results are summarized in the excel model, on the tab labelled “Energy Curve Raw”. Presented are the unit type and region, the margin above or below the capacity requirement, and aggregate net revenues, which can be broken down into real time and net day-ahead revenues, where start-up costs are netted out of gross net revenues.

G. Other Considerations: Adjustments to NYC Prices

Several market participants have argued that the addition of 1,000 MW of new combined cycle capacity in 2006 should be expected to lower energy prices in 2007 and forward by more than would be implied by the additions this capacity adds to the reserve margin. While this effect makes sense as a potential matter, the quantitative effect will depend on the particular units displaced by these units and the shape of the Demand Curve in that region. Thus, theoretically, there is no real reason for the addition of capacity which is inframarginal to affect prices for peakers at all, beyond their obvious effect on shifting the supply curve out, which is already captured in the reserve margin adjustment. So long as there are enough peakers in NY which are marginal, an addition of baseload capacity will simply move the clearing price down the supply curve to peakers with roughly the same costs.

In fact, when we look at 2006, while it is true that the regression somewhat over predicts New York City in 2006, as is consistent with the possibility that the new capacity reduced prices, the over prediction is also consistent with normal levels of variance around expected prices. Thus, it is impossible to conclude on a valid statistical basis that there was any effect at all. The total impact on prices in New York City in any case would be under 75 cents pet MWh, with most of that change concentrated in mid-merit hours in which it is less likely that peakers will be operating.

We have compared the results with the May 2007 report of the Market Monitor and find the basic results to be broadly consistent with the revenue numbers found there. Obviously, revenues associated with the LMS100 are considerably higher given its lower heat rate. While the market monitor's report attributed some of the 2006 price drop in NYC to the addition of new capacity, it does not separate out the effect of this increase and gas prices, which were 27 percent lower in 2006 than 2007. Since gas is usually on the margin in NYC, this clearly explains most of the NYC drop. In addition, some of the effect of added combined cycle capacity occurs when peaking units, even units as efficient as the LMS100, are not on the margin. Finally, we already take some of this effect into account with changes in observed reserve margin in NYC.

Several market participants have raised the issue that the larger size of the LMS100 vis-à-vis the LM6000 makes it more likely that it will collapse prices in NYC load pockets if such a plant is built in a load pocket, and that these load pockets substantially contribute to the high level of prices in NYC. Thus, to simulate this effect, we have assumed that an LMS100, if built, will be connected at a 345kV bus and earn these rates rather than the average NYC zonal rate. Using Poletti as a 345kV connection (as does the market monitoring report) we find that prices in the 345kV system are, on average $1.54/MWh lower than the NYC zonal price, so we have adjusted LMS100 dispatch to reflect this lower rate. Note that this does not mean that an LMS100 would necessarily be constructed to directly inter-tie with the 345kV system, only that wherever it chooses to locate, such prices would be likely to follow.

Comments have also suggested that as LMS100 or LM6000 units are added in response to load growth, net revenues will decline as the generating mix changes. That may be true, however, the objective is to estimate net revenues over the demand curve reset period, with installed capacity at or slightly above the target capacity level. Penetration and mix change in this period, the next three years, would not be significant enough to have an effect. While the demand curve model does consider net revenue over a longer horizon, it is important to recognize that while energy net revenues may decline for peakers, future resets would account for that and compensate with a higher demand curve reference point. Further, in the long run there are many factors which may affect energy net revenues. Mix change could reduce net revenues for units like the LM6000 and LMS100, which run quite a bit, but the tightening of the demand and supply balance in adjoining markets, which have had surpluses historically, could go in the other direction. We believe it would not be appropriate to account for only one factor.

The NYC LM6000 implied capacity factors from the modelling are about 30%. Single unit LM6000 plants in NYC, in recent year operate at about 20%, but historically have operated as high as 40%. We have reviewed confidential bid data and operating patterns of those plants. We believe that there is no reason to adjust the values we estimate based on that review.

We have assumed that the units in NYC are dual-fuelled. We have ignored that distinction in our modelling. This is an example of the phenomenon cited above in which more detail will not necessarily make the estimate more precise, but instead will likely simply raise the noise level of the estimate. First, we have no idea how often generators will in fact be restricted from using gas; even if we knew, the results may be site-specific. Second, the shift to oil physically necessitates shutdown on conversion back to gas in order to clean the generating unit. Against this, there is a benefit from economic switching to oil should prices of oil fall sufficiently relative to gas prices. While in concept all of these (and other effects) might be measured, we have no confidence that our measurement of them would illuminate the ultimate question: what is the net energy revenue of a peaking unit in NYC? Errors in any part of these calculations are far more likely to introduce error than they are to improve the expected value of the estimate.

Table III-1. Variables in the Regression Model

Dependent Variable:

lbmp	Zonal LBMP in $/MWh

Independent Variables:

_cons	Indicator variable =1
dow	Indicator variable for day of week, 1=Monday, etc.
nameind	Indicator variable for zone, 1=Capital, 2=Central, 3=Dunwood, 4=Genesee, 5=Hudson Valley, 6= Long Island, 7=Mohawk Valley, 8=Millwood, 9=NYC, 10=North, 11=West
tmin	Daily minimum temperature in degrees Fahrenheit
tmax	Daily maximum temperature in degrees Fahrenheit
tmean	Daily mean temperature in degrees Fahrenheit
load	Hourly zonal load for the hour in MW
aggload	Aggregate hourly NYISO load in MW
aggload2	$aggload^2$ divided by 10^8
aggload3	$aggload^3$ divided by 10^{12}
region	Indicator variable for region, 1=Rest of State, 2=NYC, 3=Long Island
h	Indicator variable for hour: 1=Midnight-1 am, 2=1 am-2am, etc.
m	Indicator variable for month: 1= January, etc.
lgasp	Natural logarithm of gasp price plus gas transportation cost in log $/MMBTU
rm	Supplied reserves divided by required reserves, measured monthly

Finally we note that net energy revenues are adjusted for forced outages by multiplying by one minus the forced outage rate. Further, based on reports that LMS100 availability is in the high 80s and trending up, we have used a twelve percent forced outage rate as the immature forced outage rate applicable to the LMS100 for the three years covered by the reset period.

IV. Developing the Demand Curves and Calculating Carrying Charges

A. Approach Overview

The Demand Curve Model is designed to find the annual CONE at the reference point that will provide for the full recovery of capital costs over a twenty-year amortization period, using the financial assumptions of a 50%/50% capital structure and 7%/12% debt/equity cost. The CONE consists of two items. First, an implied annual capital cost that will provide for the full recovery described above, recognizing that there will be a tendency to clear at capacity values above the reference value and at prices below the reference value, as well as a tendency in the long term to earn energy revenues consistent with a degree of excess capacity. And second, an energy offset based on energy revenues over the three-year period, assuming capacity levels at one-half of one percent above the target capacity level.

The model allows for a wide array of scenarios by incorporating about forty variables that can be changed to accommodate different market conditions, target levels of capacity and Demand Curve shapes (intercept and kink). In addition, various regions (e.g., New York City, Capital) and three types of generator units (LMS100, LM6000 or Frame 7) can be simulated. This flexibility allows the user to compare the effect of a variable over multiple scenarios.

The model includes results for the Lower Hudson Valley. The Lower Hudson Valley is not a capacity zone and hence we have not incorporated results for the Lower Hudson Valley in this report. Were the Lower Hudson valley a capacity zone, the demand curve would be higher than the NYCA demand curve and lower than the NYC demand curve. Results for the Lower Hudson Valley are available in the model provided to all market participants.

The model reports the CONE at the reference point, the implied annual capital cost, the carrying charge and the implied amortization period. The zero crossing point affects all these values. A lower zero crossing point (i.e., closer to 100%) produces a shorter amortization period and higher carrying charge, as demand revenues go down faster for a given level of excess capacity.

Many of the inputs to the Demand Curve model requirements are based on judgment. The inputs used will be described below. As a result of the judgmental nature of the inputs, it is important to note that in selecting inputs, we are guided also by the result produced. The results produced show implied amortization periods of 13.5-14.5 years in ROS and NYC, which reflects measurable, but not extreme merchant risks.

B. Model Description

The model works by simulating revenues and expenditures given a set of input parameters, energy functions, the region and the type of unit. The revenues are cash flows that the owner of a new unit would expect to receive over the thirty-year economic life of the unit. Similarly, the expenditures represent expenses and the required return on equity and debt. The model solves for the Demand Curve by finding demand payments that satisfy the zero supernormal profit criteria (revenues equal expenditures). Supernormal net revenues are those above the normal cost of equity capital.

A new generating unit can expect to receive revenues from two main sources. Energy and ancillary service net revenues represent long-term power contracts or sales on the spot energy and ancillary service markets. These net revenues are modeled using a Monte Carlo analysis. The model uses the user-defined expected value and standard deviation of supply to generate 100 possible values for capacity. These capacity values are put through an energy and ancillary service net revenue function. The function is region- and unit-specific and calculates expected energy and ancillary services net revenue given a level of supply. The revenues will be lower when there is surplus capacity and higher when there is not enough capacity. The model is designed to simulate this and to adjust the Demand Curve so that, given an expectation of surplus capacity, the new entrant will be able to fully recover costs.

Demand payments approximate payments the owner of a new unit could expect to make through NYISO ICAP auctions. Like the energy and ancillary service payments, they are determined through a Monte Carlo analysis. User-defined parameters are used to determine possible values for supply in the auction from which an expected capacity value payment is derived. Since these payments are simulated by the Demand Curve, which is also an output of the model, the demand payments are endogenous to the model.

Expenditures are fixed O&M, property tax and insurance, and levelized fixed charges (carrying charge). Fixed O&M and property tax and insurance are defined by input parameters and the cost of new entry. The carrying charge is calculated by Sargent & Lundy assuming a 50% debt share cost of capital.

From these revenues and expenditures, a Demand Curve is derived such that revenues equal expenditures (binding constraint). As the Demand Curve in part determines demand payments, which is one of the sources of revenue, the model solves for both using a goal seek.

Once the model solves for the Demand Curve, it calculates net revenues as percentage of the cost of new entry. The model then looks up the amortization period that matches this percentage in the table of levelized fixed charges. The real levelized carrying charge is determined using this amortization period.

C. Model Inputs

The model's thirty plus variables can be broken down into the following categories:

Demand curve variables determine the x-axis intercept of the curve and can also be used to kink the Demand Curve.

As previously described, we see no compelling reason to change the existing zero crossing point and use 112% for NYCA and 118% for NYC and LI.

Technological progress variables can be used to determine how the cost of new entry increases or decreases over time.

The DOE forecasts roughly a 0.5% real decline in capital costs. We have used a .25% decline to recognize that non-technology factors could offset this decline.

Plant variables determine the location, type and performance of the generating unit and are used to select the appropriate cost of new entry from those provided by Sargent & Lundy.

Residual Value is the value of the unit at the end of the thirty-year life. For aeroderivatives, we use a residual value of 5% of the initial investment

Monte Carlo variables are used to calculate expected values for demand payments and energy and ancillary service payments.

Based on modeling work filed by PJM, we use a 1.4% standard deviation in the capacity level achieved relative to need. Considering the NYISO's Reliability Need Assessment (RNA) process and procedures to prevent inadequate capacity levels, we assume that the typical achieved level of capacity will be two standard deviations above the required level. This applies to both the energy and capacity functions. This allows for a 2.5% probability of a capacity shortage in the spot capacity market. As New York City and Long Island are smaller markets, they could be expected to have larger capacity variability. The standard deviations for those areas are set at 2.0%.

The value of 1.4% standard deviation of capacity values for both the capacity payment and the energy net revenue Monte Carlo simulation were estimated using a model developed by Dr. Benjamin Hobbs. Details regarding use of the model can be found in Appendix 5. The model was developed for PJM and modified to reflect the NYISO NYCA demand curve zero crossing point. The model considers items such as load forecast uncertainty, lead time, unit addition size, generator risk aversion, demand curve shape and market size. When modified just for the NYISO NYCA demand curve shape the model yielded a 1.4% standard deviation. We made no adjustment for the NYCA market despite the fact that the NYCA market is smaller than PJM and a larger standard deviation may be appropriate. We made a modest adjustment for the NYC and LI markets, increasing the standard deviation to 2%. For the entire NYCA market, the 1.4 % standard deviation represents just over 500 MW or a single large combined cycle plant. It seems quite reasonable that without any explicit coordination mechanism for entry, the supply variance would be equal to one plant addition. The possibility for swings from imports would further suggest that this value is reasonable and may be low. For NYC and LI, the standard deviation is only about 200 MW and 100 MW respectively. Arguments may be made that, given plant size, a 2% standard deviation is too low. However, after observing the results at this level, the carrying charge reflected a significant merchant risk and we were hesitant to further increase the standard deviation.

Regulatory Risks – the Demand Curve is an administered value subject to regulatory risk. We assume 20 percent probability that the Demand Curve will yield only 50% of the required revenue. Regulatory risks include items such as rate-supported long-term contracts that may be added even when there are surpluses or to create surpluses.

Energy function variables can be used to change the shape of the energy function and can also be used to change the way energy and ancillary service net revenues in the first three years are calculated.

The energy net revenue functions are described in Section III. In developing the recommendation, we use an energy and ancillary service net revenue offset at 100.5% of the target installed capacity level. Essentially, we assume energy net revenues at this level for the first three years. As discussed above, we have adjusted for ancillary service net revenues for voltage support by adding $0.83 per KW year. For NYC and LI we add a further $0.85 per KW year for 30 minute reserves.

Property taxes for NYC may be used with or without the Industrial and Commercial Incentive Program (ICIP). The effect is very significant. The ICIP renewal for the next three years was passed by the Legislature in late June 2007 and has been signed in to law. Hence the optional feature here is now moot.

D. Analysis of Results

The implied amortization period for ROS is 14.5 years. The implied carrying charge is 15.36% and the premium on WACC[21] is 241 basis points. For the NYC LMS100, the implied amortization period is 15.5 years, the implied carrying charge is 13.57% and the implied premium on WACC is 116 basis points (for the LM6000, the implied amortization period is 13.5 years, the implied carrying charge is 14.17% and the implied WACC premium is 176 basis points). Results for Long Island are somewhat different. For the LMS100, the implied amortization period is 22.5 years, the implied carrying charge is 12.30 percent and the implied equity premium is -65 basis points. In the LM6000, the values are 18.5 years, 13.31% and 36 basis points. The Long Island results show less

[21] Implied WACC premiums are quoted in this section relative to a 20 year amortization period and 50%/50% and 7%/12% capital structure.

risk, as a much higher portion of returns come from energy markets which are much less sensitive to capacity surpluses for the LMS100 and LM6000.

As discussed above, the model inputs require judgment. Hence, we believe that it is important to apply a reasonableness assessment to the results. In general, the results indicate that using an investment grade capital structure the amortization period is about 15 years for ROS and NYC and at a 20 year amortization period, the WACC premium is roughly 200 basis points.

These results appear to reasonably reflect a degree of merchant risk and to represent a considerable move in that direction from the prior update[22]. Using NYCA as an example, a 30-year life would yield a carrying charge of 11.20%. The 2004 update used 20 years which, all else equal, would yield a charge rate of 12.95%. The current study uses 15.36%.

For reference, the ROS carrying charge at 10 years is 18.57%. The function begins to flatten at 15 years, but is sharply sloped prior to that point, much like a mortgage. While some may argue that merchant risk should have an even greater impact on the amortization period and carrying charge than we allow, there are several factors that mitigate against this. First, there is the desire to maintain continuity. We are already moving to reflect considerably more merchant risk than the previous update. Second, risk should be reduced as adjoining markets (PJM and ISO NE) institute forward markets and the NYISO is not flooded with imported capacity. Third, higher merchant risk levels, such as those associated with 10-year amortization, would probably be unsustainable in equilibrium. Such spot price levels would make contracting a much more attractive alternative. We see little value in developing a Demand Curve that is not reasonably sustainable.

E. Demand Curve Recommendations

The Demand Curves that are recommended for each technology and region have been presented in the Executive Summary. We have not recommended changing the Demand Curve zero crossing points or slopes. We use the term slope to refer to the zero crossing point. While we discuss slope impacts in the Sensitivity Analysis Section of the report, we will briefly discuss the slope issue further here.

[22] We do not mean to imply that merchant risk was not reflected in the prior study. The 2004 update used a 20 year amortization period. For reference, carrying charges for ROS are 18.57% at 10 years, 14.85% at 15 years, 12.95% at 20 years and 11.2% at 30 years.

The method that we use to develop the demand curve produces curves that contain a consistent slope and reference point that are expected to yield the same present value of revenue to generators as any other consistent combination. Hence, if we increase the zero crossing point we would reduce the reference point and vice versa. These consistent combinations also yield the same expected value of payments to generators. Hence, alternate zero crossing points would all have the same customer cost impact. As the zero crossing point is moved in towards the origin, the reference price will rise and as the zero crossing point is pushed away from the origin, the reference price will decline. With neither customer nor generator revenue a deciding factor, the basis for slope selection is narrowed.

One criterion for slope selection is market power. Withholding in New York City has been alleged to be a problem even with a relatively long zero crossing point at 118%. Hence, we would not recommend a curve that would exacerbate withholding by moving the zero crossing point towards the origin. In NYCA, all capacity does not clear, but the impact seems acceptable and has been accounted in the price floor we have tested. We see no need to move the zero crossing point further out. In LI, the market has a very small size and moving the zero crossing point in from 118% would potentially make large additions risky.

Another factor to consider is the benefit to be gained from moving the zero crossing points. Moving the zero crossing point towards the origin increases the importance of having accurate information on the standard deviation. We have used available tools and our best judgment, but cannot assert that we have a demonstrated empirical base for the assumption and would not want to adopt a slope that made the demand curve even more sensitive to the assumption. With a steep slope, if there is an understatement of the standard deviation, the demand curve will be under-compensatory and sufficient capacity may not develop. Steeper slopes increase risk and uncertainty and, while not specifically modeled, may require higher returns. Steeper slopes can also be counterproductive if a little excess in additions or a decline in growth leads to clearing at prices well below the reference point. At such prices, retaining existing plants may be difficult as the economics of moth balling and retirement could become attractive for older marginal plants. This complicates any analysis of withholding, as it becomes much more likely that plant economics favor withdrawing from the capacity market. It would be counterproductive to drive existing plants out of the market, when they may be needed in the future. In sum, based on a qualitative analysis, and considering the internal consistency of the reference point and zero crossing point, we see more downside than upside to modifying the zero crossing points.

V. Sensitivity Analyses

Numerous sensitivity analyses were conducted using the Demand Curve and carrying charge model in order to identify variables that would have a significant impact on results. Further, the model is available to the public to conduct sensitivities. Two related variables dominate the assumption sensitivities. Those variables are the standard deviation of capacity relative to the installed capacity level and the average installed capacity level relative to the target or required level. Relatively small changes in those variables have a significant impact on results. For all other variables, impacts are moderate.

For example, the NYCA demand at the reference point is $103.16/kW-year using a 1.4% standard deviation and 102.8% average capacity level and the amortization period is 14.5 years. If we use the same standard deviation and an average capacity level of 104% the price rises to $114.53 and the amortization period changes to 11.5 years. If we use a 101.4% average capacity level, the price drops to $92.03 and the amortization period increases to 17.5 years. Ideally, we would have an empirical basis for this assumption, but there is not sufficient history to develop one. Arguments could be made ranging from 101.4 to 104. While we believe that we have selected variables for these values that both are plausible and consistent with the RNA process and that produce results that introduce a reasonable but not excessive degree of merchant risk, we do not claim that they are the only plausible values for these variables. We are guided in the selection of these variables by the results that they produce. We then use the Demand Curve Model to produce results that are consistent with and responsive to other assumptions – for example, the Demand Curve zero crossing point and technical progress assumption.

We have sensitivity tested all key assumptions. We provide here examples for NYCA. Moving the NYCA zero crossing point to 118% from 112% would decrease the reference value by $7.15/kW-year. Increasing the technical progress rate to 0.5% would increase this reference point by $2.61/kW-year, reducing the 20% regulatory risk probability to zero would reduce the reference point by $7.83/kW-year, reflecting a five percent residual value would reduce the reference point by

$3.35 per kW-year and basing the energy and ancillary service net revenue for the Demand Curve period on a capacity level of 104% of the target would increase price by less than $0.39/kW-year. In sum, most input variables or assumptions have a moderate impact. The primary exception is the average capacity level.

The model also shows that a major change to the Demand Curve shape would have a significant impact. For example a kinked Demand Curve for NYCA with an initial slope toward a 133 percent crossing point and kink at 106% to a zero crossing point at 112% would reduce the reference point by $12.80/kW-year. This would, of course, not reduce the cost of capacity to load as the curve would be flatter between 100% and 106% and the model is set to produce the same expected cost to load for any zero crossing point. This case does illustrate how the model can be used to evaluate such large changes to the Demand Curve shape.

As we have provided the model to the market participants to enable them to conduct their own sensitivities, we do not summarize all the sensitivities herein.

VI. Appendices

A. Appendix 1 – Construction Cost and Unit Operating Cost Details

Appendix 1 provides more detailed information about the cost and performance characteristics of the peaking technologies evaluated in this study.

Table A-1, Figures A-1 through A-6, and Table A-2 provide information on the capacity and heat rates for the LMS100, 7FA, and LM6000PC Sprint as a function of elevation, temperature, and humidity. Figures A-1 through A-6 show capacity and heat rate at 60% relative humidity and mean sea level. Table A-2 shows capacity and heat rate at the relative humidity and elevation conditions in Table A-1.

Table A-3 provides capacity and heat rate information by technology and by location in tabular form. It also shows data for outage rates, availability, start fuel, annual fixed O&M cost, annual site leasing, property taxes and insurance costs, and variable O&M costs.

Tables A-4 through A-6 provide capital cost estimates for each technology by location. Cost breakdown is provided for both EPC and non-EPC costs. The definition of most cost categories is self-evident. Owner's Project Management and Miscellaneous Engineering refers to the cost of preliminary engineering, owner's engineer during construction, and general oversight. Owner's Development Costs refer to the owner's internal costs for all development activities from the initial feasibility studies through start-up. Financing Fees are sometimes built into the interest rate, but here are explicitly broken out separately from Financing cost.

Table A-7 provides a comparison of LM6000 and 7FA cost estimates for this study with the published cost estimates of the previous Demand Curve review in 2004. In many cases the cost categories from this study are the same ones used in the 2004 study report. In other cases, equivalent cost categories are compared as best as can be determined from the 2004 report. Consulting costs from the 2004 report are explicitly broken out as Financial Advisory, Environmental Studies, Market Studies, and Interconnection Studies in this report.

Tables A-8 through A-11 provide an in-depth comparison of four line items from the LM6000 cost estimates in Table A-6 for New York City and upstate (Zone C). The purpose of this comparison is to show how differences in material costs, labor productivity and labor rates were used to estimate the higher cost of construction in New York City. The four line items are equipment, construction labor and materials, electrical connection and substation, and site preparation. The crew wage rates shown in Table A-8 and A-9 include the base craft rate; fringe benefits; FICA and federal and state unemployment insurance; workmen's compensation costs; construction equipment, including fuel, oil and maintenance; markup for small tools and expendables; and markup for site overheads, including construction trailers, indirect craft support, and craft supervision.

Table A-1 — Site Assumptions for Capacity and Heat Rate Calculations

Load Zone	Weather Basis	Elev. (Feet)	Season	Ambient Temp. °F	Relative Humidity
C - Central	Syracuse	421	Summer	79.7	67.7
			Winter	17.3	73.7
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0
F - Capital	Albany	275	Summer	80.7	67.2

			Winter	15.3	70.7
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0
G - Hudson Valley	Poughkeepsie	165	Summer	82.3	77.7
			Winter	19.3	74.0
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0
J - New York City	New York City	20	Summer	83.0	64.3
			Winter	28.0	61.7
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0
K - Long Island	Long Island	16	Summer	80.7	69.3
			Winter	28.0	66.2
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0

Figure A-1 — LMS100: Net kW vs. Ambient Temperature

Average Degradation, 60% Relative Humidity

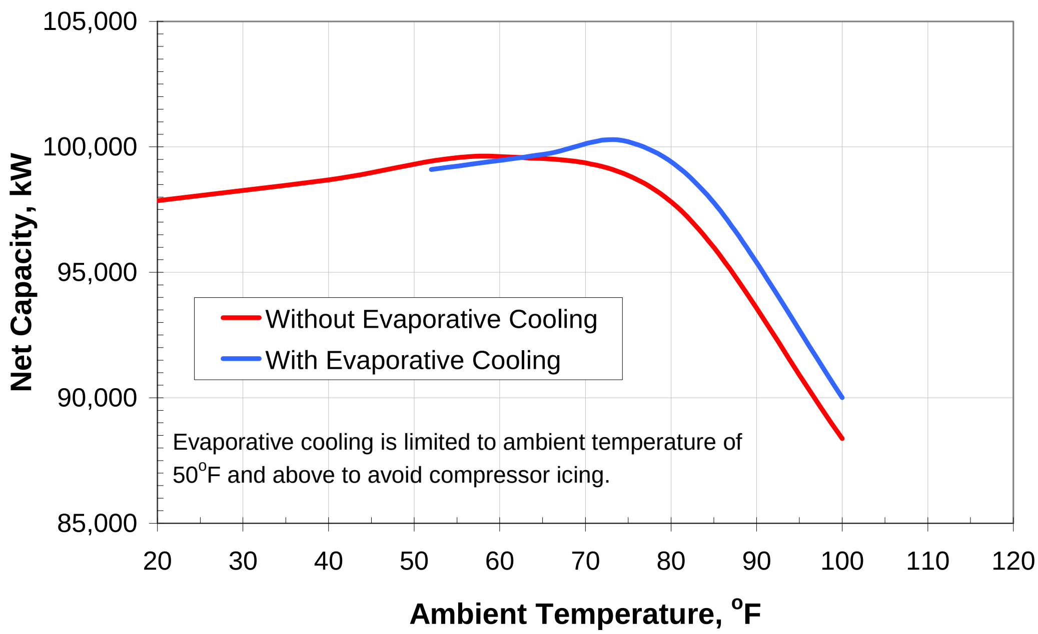

Figure A-2 — LMS100: Net Capacity vs. Net Heat Rate

Average Degradation

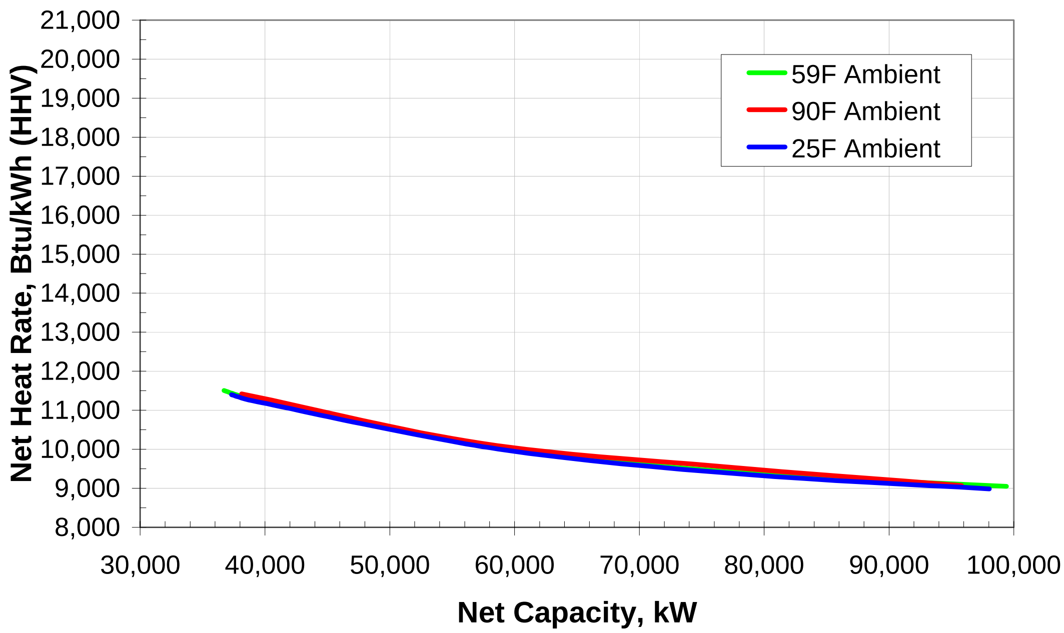

Figure A-3 — 7FA: Net kW vs. Ambient Temperature

Average Degradation, 60% Relative Humidity

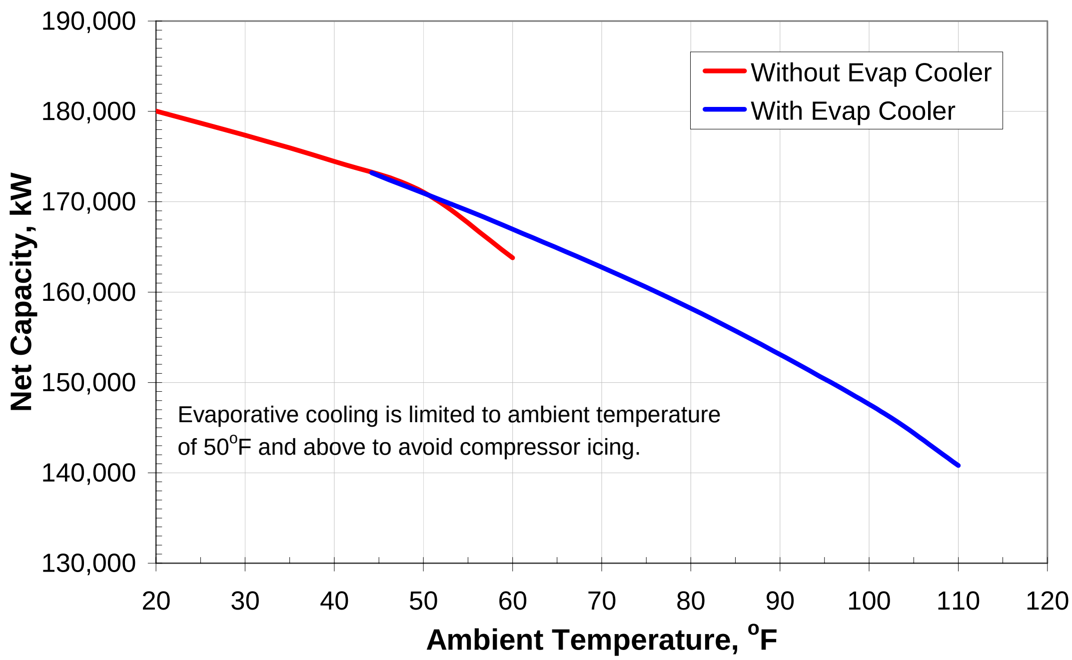

Figure A-4 — 7FA: Net Capacity vs. Net Heat Rate

Average Degradation

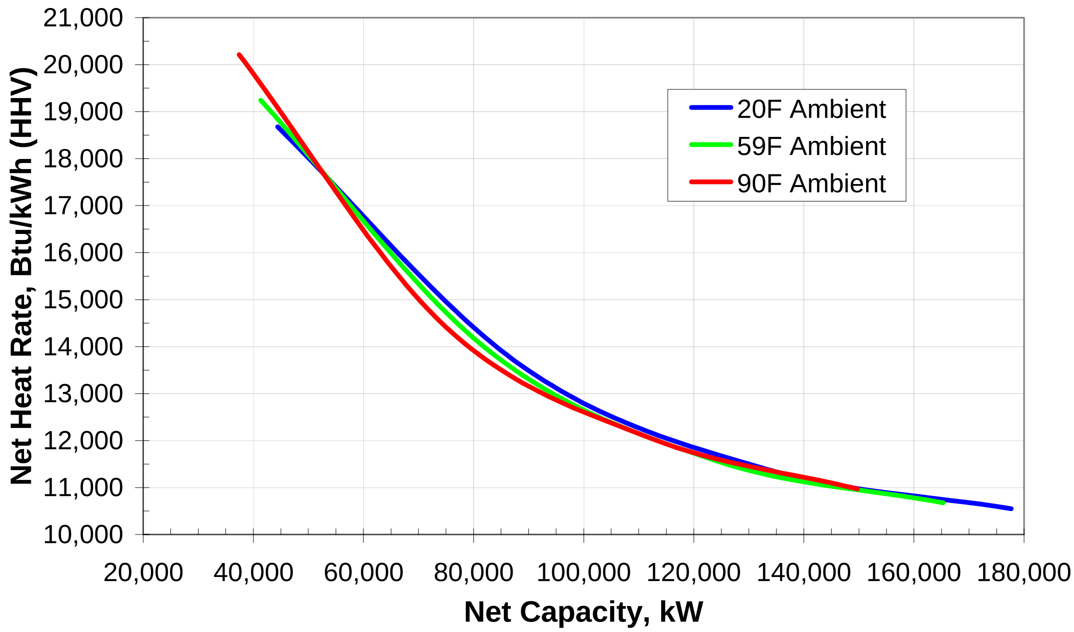

Figure A-5 — LM6000PC – Sprint: Net kW vs. Ambient Temperature

Average Degradation, 60% Relative Humidity

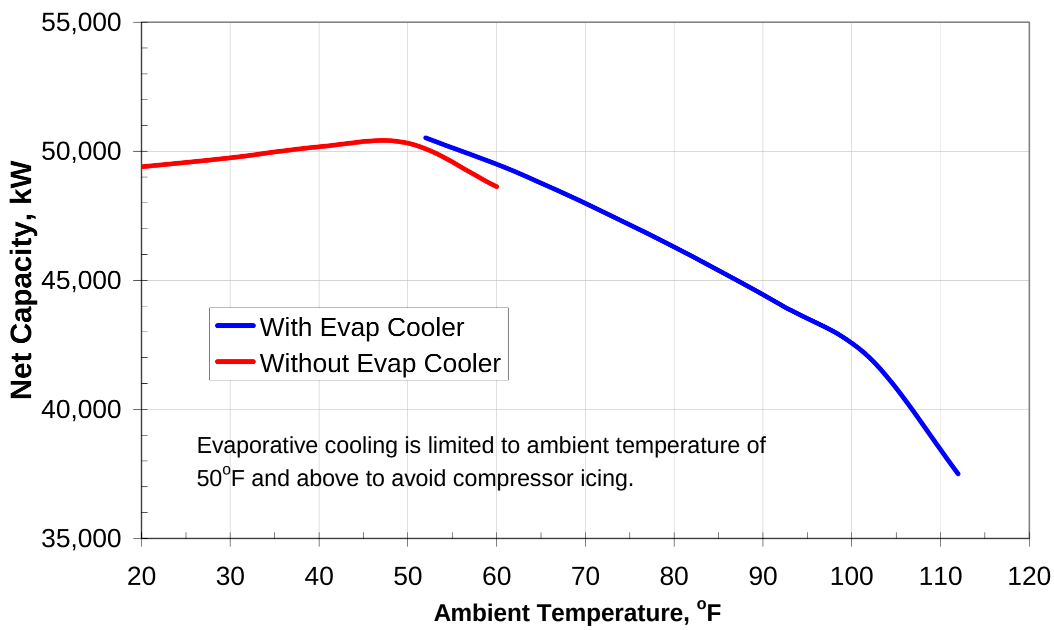

Figure A-6 — LM6000PC – Sprint: Net Capacity vs. Net Heat Rate

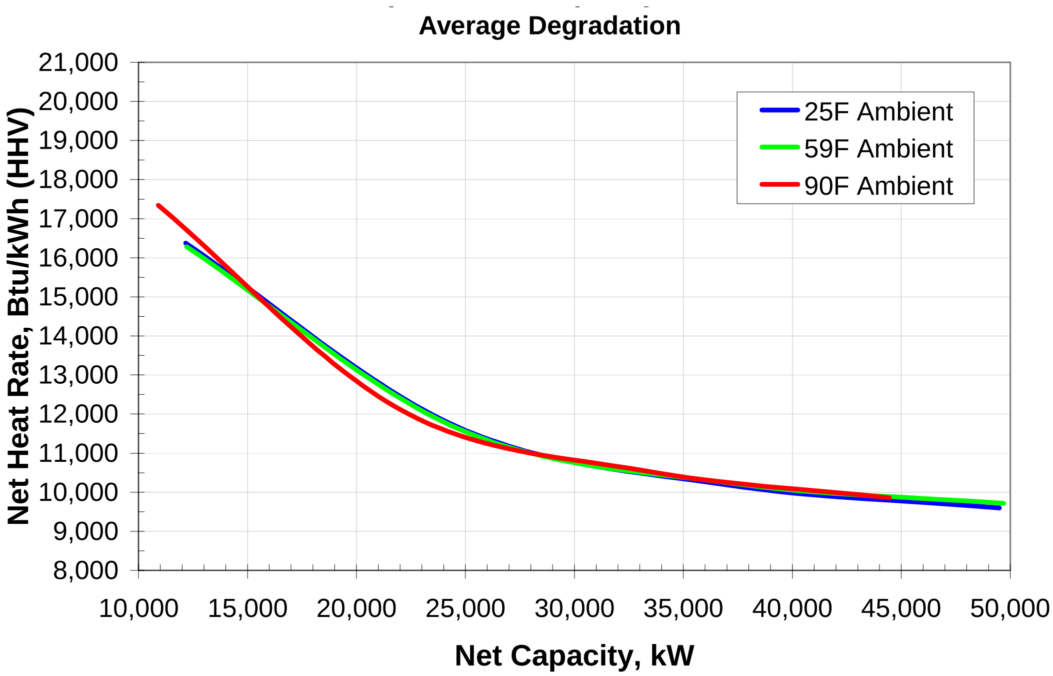

Table A-2 — Calculation of Net Capacity

LM6000 PC Sprint

Load Zone	Gross kW	Auxilary Power, kW	Net kW	Net kW, with degradation	Gross Btu/kWh (HHV)	Net Btu/kWh (HHV)	Net Btu/kWh (HHV), with degradation
C - Central	45,984	768	45,216	**45,216**	9,520	9,682	**9,808**
	49,760	806	48,954	**48,954**	9,280	9,432	**9,555**
	49,707	805	48,902	**48,902**	9,437	9,593	**9,717**
	43,841	746	43,095	**43,095**	9,587	9,753	**9,880**
F - Capital	46,087	769	45,318	**45,318**	9,524	9,685	**9,811**
	50,011	808	49,203	**49,203**	9,272	9,424	**9,547**
	49,986	808	49,178	**49,178**	9,437	9,592	**9,717**
	44,096	749	43,347	**43,347**	9,587	9,753	**9,880**
G - Hudson Valley	45,451	763	44,688	**44,688**	9,546	9,709	**9,835**
	50,239	810	49,429	**49,429**	9,290	9,442	**9,565**
	50,197	810	49,387	**49,387**	9,436	9,591	**9,716**
	44,280	751	43,529	**43,529**	9,587	9,752	**9,879**
J - New York City	46,268	771	45,497	**45,497**	9,530	9,692	**9,818**
	50,511	813	49,698	**49,698**	9,347	9,500	**9,624**
	50,473	813	49,660	**49,660**	9,436	9,591	**9,715**
	44,531	753	43,778	**43,778**	9,586	9,751	**9,878**
K - Long Island	46,443	772	45,671	**45,671**	9,527	9,688	**9,814**
	50,510	813	49,697	**49,697**	9,347	9,500	**9,624**
	50,481	813	49,668	**49,668**	9,436	9,591	**9,715**
	44,538	753	43,785	**43,785**	9,586	9,751	**9,878**

LMS100

Load Zone	Gross kW	Auxilary Power, kW	Net kW	Net kW, with degradation	Gross Btu/kWh (HHV)	Net Btu/kWh (HHV)	Net Btu/kWh (HHV), with degradation
C - Central	100,161	1,402	98,759	**97,278**	8,763	9,023	**9,140**
	101,456	1,415	100,041	**98,541**	8,569	8,823	**8,937**
	103,161	1,432	101,729	**100,203**	8,657	8,912	**9,028**
	95,575	1,356	94,219	**92,806**	8,869	9,134	**9,252**
F - Capital	100,407	1,404	99,003	**97,518**	8,770	9,030	**9,147**
	101,172	1,412	99,760	**98,264**	8,577	8,831	**8,946**
	102,876	1,429	101,447	**99,926**	8,665	8,920	**9,036**
	96,153	1,362	94,791	**93,370**	8,868	9,132	**9,251**
G - Hudson Valley	98,968	1,390	97,578	**96,115**	8,811	9,073	**9,191**
	101,053	1,411	99,642	**98,148**	8,588	8,842	**8,957**
	102,662	1,427	101,235	**99,717**	8,671	8,927	**9,043**
	96,589	1,366	95,223	**93,795**	8,867	9,131	**9,250**
J - New York City	100,854	1,409	99,445	**97,954**	8,781	9,041	**9,159**
	101,128	1,411	99,717	**98,221**	8,622	8,878	**8,993**
	102,383	1,424	100,959	**99,445**	8,679	8,936	**9,052**
	97,169	1,372	95,797	**94,360**	8,866	9,129	**9,248**
K - Long Island	101,216	1,412	99,804	**98,307**	8,773	9,033	**9,151**
	101,129	1,411	99,718	**98,222**	8,622	8,878	**8,993**
	102,374	1,424	100,950	**99,436**	8,679	8,936	**9,052**
	97,185	1,372	95,813	**94,376**	8,866	9,129	**9,248**

7FA Simple Cycle

Load Zone	Gross kW	Auxilary Power, kW	Net kW	Net kW, with degradation	Gross Btu/kWh (HHV)	Net Btu/kWh (HHV)	Net Btu/kWh (HHV), with degradation
C - Central	161,455	1,615	159,840	**155,045**	10,533	10,639	**10,852**
	185,177	1,852	183,325	**177,825**	10,240	10,343	**10,550**
	171,729	1,717	170,012	**164,911**	10,362	10,467	**10,676**
	155,536	1,555	153,981	**149,361**	10,648	10,756	**10,971**
F - Capital	161,872	1,619	160,253	**155,446**	10,541	10,647	**10,860**
	186,722	1,867	184,855	**179,309**	10,238	10,341	**10,548**
	172,628	1,726	170,902	**165,775**	10,362	10,467	**10,676**
	156,355	1,564	154,791	**150,148**	10,648	10,756	**10,971**

Notes:

1 Includes Water Injection NOx Control (25 ppm) and Inlet Evaporative Cooling
2 Evaporative Cooler Off. Evaporative cooling is limited to ambient temperature of 50^{o}F and above to avoid compressor icing
3 No SCR in Zones C and F; SCRs in Zones G, J, and K
4 7FA includes DLN Combustors
5 Gross kW is at generator terminals
6 Net kW = Gross kW - Auxiliary Power kW
7 Capacity degradation: LM6000 0% (increase Sprint water injection for power augmentation); LMS100 1.5%; 7FA 3%
8 Gross Btu/kWh is heat rate at Gross kW
9 Net Btu/kWh is heat rate at Net kW
10 Heat Rate degradation: LM6000 1.3%; LMS100 1.3%; 7FA 2.0%

Table A-3— Calculation of Net Capacity

	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	Hudson Valley	Albany	Syracuse	Albany	Syracuse	Comments
Combustion Turbine Model	LM6000	LM6000	LM6000	LM6000	LM6000	LMS100	LMS100	LMS100	LMS100	LMS100	GE 7FA	GE 7FA	
Plant Performance (per Unit)													
Net Plant Capacity - Summer (MW)	45.671	45.497	44.688	45.318	45.216	98.307	97.954	96.115	97.518	97.278	155.446	155.045	Avg. degraded value; with evaporative cooling.
Net Plant Capacity - Winter (MW)	49.697	49.698	49.429	49.203	48.954	98.222	98.221	98.148	98.264	98.541	179.309	177.825	Avg. degraded value; evaporative cooler off.
Net Plant Capacity - Summer/Winter Avg. (MW)	47.684	47.598	47.059	47.261	47.085	98.265	98.088	97.132	97.891	97.910	167.378	166.435	Avg. degraded value.
Net Plant Capacity - ICAP (MW)	43.785	43.778	43.529	43.347	43.095	94.376	94.360	93.795	93.370	92.806	150.148	149.361	Avg. degraded value; with evaporative cooling.
Net Plant Heat Rate - Summer (MW)	9,814	9,818	9,835	9,811	9,808	9,151	9,159	9,191	9,147	9,140	10,860	10,852	Avg. degraded value; with evaporative cooling.
Net Plant Heat Rate - Winter (MW)	9,624	9,624	9,565	9,547	9,555	8,993	8,993	8,957	8,946	8,937	10,548	10,550	Avg. degraded value; evaporative cooler off.
Net Plant Heat Rate - Summer/Winter Avg. (MW)	9,719	9,721	9,700	9,679	9,682	9,072	9,076	9,074	9,047	9,039	10,704	10,701	Avg. degraded value.
Net Plant Heat Rate - ICAP (MW)	9,878	9,878	9,879	9,880	9,880	9,248	9,248	9,250	9,251	9,252	10,971	10,971	Avg. degraded value; with evaporative cooling.
Equivalent Forced Outage Rate - Demand Based ($EFOR_d$)	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	Long-term average.

	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	Hudson Valley	Albany	Syracuse	Albany	Syracuse	Comments
Combustion Turbine Model	LM6000	LM6000	LM6000	LM6000	LM6000	LMS100	LMS100	LMS100	LMS100	LMS100	GE 7FA	GE 7FA	
Equivalent Availability Factor	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	Long-term average.
Natural Gas Consumed During Start (mmBtu/start)	110.00	110.00	110.00	65.00	65.00	215.00	215.00	215.00	135.00	135.00	360.00	360.00	
Fixed O&M (2 Units, $/year)													
Labor - Routine O&M	902,720	902,720	728,000	728,000	728,000	902,720	902,720	728,000	728,000	728,000	728,000	728,000	
Materials and Contract Services - Routine	237,000	237,000	237,000	237,000	237,000	305,000	305,000	305,000	305,000	305,000	365,000	365,000	
Administrative and General	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	
Subtotal Fixed O&M	1,345,720	1,345,720	1,171,000	1,171,000	1,171,000	1,413,720	1,413,720	1,239,000	1,239,000	1,239,000	1,299,000	1,299,000	
$/kW-year	15.37	15.37	13.45	13.51	13.59	7.49	7.49	6.60	6.63	6.68	4.33	4.35	Based on net degraded ICAP capacity.
Other Fixed Costs (2 Units, $/year)													
Site Leasing Costs	73,500	427,000	59,500	59,500	59,500	73,500	427,000	59,500	59,500	59,500	59,500	59,500	
Subtotal Fixed O&M	1,419,220	1,772,720	1,230,500	1,230,500	1,230,500	1,487,220	1,840,720	1,298,500	1,298,500	1,298,500	1,358,500	1,358,500	
$/kW-year	16.21	20.25	14.13	14.19	14.28	7.88	9.75	6.92	6.95	7.00	4.52	4.55	Based on net degraded ICAP capacity.

	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	Hudson Valley	Albany	Syracuse	Albany	Syracuse	Comments
Combustion Turbine Model	LM6000	LM6000	LM6000	LM6000	LM6000	LMS100	LMS100	LMS100	LMS100	LMS100	GE 7FA	GE 7FA	
Property Taxes	2,531,020	7,016,044	2,192,620	1,832,360	1,811,500	4,493,240	12,392,395	3,980,240	3,454,100	3,418,180	4,026,660	3,985,540	Full amount, not accounting for the NYC phased property tax exemption with the ICIP.
Insurance	379,653	389,553	328,893	274,854	271,725	673,986	688,065	597,036	518,115	512,727	603,999	597,831	
Total Fixed O&M (2 Units)	4,329,893	9,178,317	3,752,013	3,337,714	3,313,725	6,654,446	14,921,180	5,875,776	5,270,715	5,229,407	5,989,159	5,941,871	Alternatively, property taxes and insurance may be included in the fixed charge rate, which would account for the phasing of the NYC property tax exemption with the ICIP.
$/kW-year	49.44	104.83	43.10	38.50	38.45	35.25	79.07	31.32	28.22	28.17	19.94	19.89	Based on net degraded ICAP capacity.
Variable O&M ($/MWh)													
Major Maintenance Parts	2.20	2.21	2.23	2.22	2.23	2.89	2.90	2.92	2.90	2.90	n/a	n/a	
Major Maintenance Labor	0.06	0.07	0.05	0.05	0.05	0.08	0.08	0.07	0.07	0.07	n/a	n/a	Labor rates consistent with capital cost estimates.
Unscheduled Maintenance	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.51	0.51	
SCR Catalyst and Ammonia	0.90	0.90	0.90	0.00	0.00	0.90	0.90	0.90	0.00	0.00	0.00	0.00	
Other Chemicals and Consumables	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.02	0.02	
Water	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.01	0.01	
Total Variable O&M ($/MWh)	4.16	4.16	4.18	3.27	3.28	4.86	4.87	4.88	3.96	3.96	0.54	0.54	Based on net degraded summer/winter avg. capacity.

	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	Hudson Valley	Albany	Syracuse	Albany	Syracuse	Comments
Combustion Turbine Model	LM6000	LM6000	LM6000	LM6000	LM6000	LMS100	LMS100	LMS100	LMS100	LMS100	GE 7FA	GE 7FA	
Variable O&M - Cost per Start:													Excluding natural gas consumed (shown above).
Major Maintenance Parts	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	19,298	19,298	.
Major Maintenance Labor	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	650	650	Labor rates consistent with capital cost estimates.
Total ($/factored start)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	19,948	19,948	Factored starts include representative weighting factors for peaking operation.

Table A-4 — Capital Cost Estimates for LMS100 - Demand Curve Review

	Overnight Capital Cost - 2007$s					Costs as a % of Zone C			
	K - Long Island	J - NYC	G - Hudson Valley	F - Capital	C - Central	K - Long Island	J - NYC	G - Hudson Valley	F - Capital
EPC Cost Components									
Equipment									
Equipment	85,040,000	89,050,000	85,040,000	77,149,000	77,149,000	110%	115%	110%	100%
Spare Parts	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	100%	100%	100%	100%
Subtotal	86,040,000	90,050,000	86,040,000	78,149,000	78,149,000	110%	115%	110%	100%
Construction									
Construction Labor & Materials	64,518,000	68,129,000	47,689,000	37,399,000	36,213,000	178%	188%	132%	103%
Electrical Connection & Substation	3,564,000	3,793,000	2,825,000	2,531,000	2,470,000	144%	154%	114%	102%
Electrical System Upgrades	500,000	500,000	500,000	500,000	500,000	100%	100%	100%	100%
Gas Interconnect & Reinforcement	4,250,000	5,000,000	4,250,000	4,250,000	4,250,000	100%	118%	100%	100%
Site Prep	2,428,000	2,491,000	1,841,000	1,498,000	1,460,000	166%	171%	126%	103%
Engineering & Design	8,420,000	8,562,000	7,437,000	6,418,000	6,349,000	133%	135%	117%	101%
Construction Mgmt. / Field Engr.	2,105,000	2,140,000	1,859,000	1,605,000	1,587,000	133%	135%	117%	101%
Subtotal	85,785,000	90,615,000	66,401,000	54,201,000	52,829,000	162%	172%	126%	103%
Startup & Testing									
Startup & Training	1,403,000	1,427,000	1,239,000	1,070,000	1,058,000	133%	135%	117%	101%
Testing	-	-	-	-	-	N/A	N/A	N/A	N/A
Subtotal	1,403,000	1,427,000	1,239,000	1,070,000	1,058,000	133%	135%	117%	101%
Contingency	16,748,000	17,031,000	14,793,000	12,767,000	12,629,000	133%	135%	117%	101%
Subtotal - EPC Costs	189,976,000	199,123,000	168,473,000	146,187,000	144,665,000	131%	138%	116%	101%
Non-EPC Cost Components									
Owner's Costs									
Permitting	1,900,000	1,991,000	1,685,000	1,462,000	1,447,000	131%	138%	116%	101%
Legal	3,800,000	3,982,000	3,369,000	2,924,000	2,893,000	131%	138%	116%	101%
Owner's Project Mgmt. & Misc. Engr.	3,800,000	3,982,000	3,369,000	2,924,000	2,893,000	131%	138%	116%	101%
Social Justice	375,000	2,000,000	275,000	275,000	275,000	136%	727%	100%	100%
Owner's Development Costs	5,699,000	5,974,000	5,054,000	4,386,000	4,340,000	131%	138%	116%	101%
Financing Fees	3,800,000	3,982,000	3,369,000	2,924,000	2,893,000	131%	138%	116%	101%
Financial Advisory	475,000	498,000	421,000	365,000	362,000	131%	138%	116%	101%
Environmental Studies	475,000	498,000	421,000	365,000	362,000	131%	138%	116%	101%
Market Studies	475,000	498,000	421,000	365,000	362,000	131%	138%	116%	101%
Interconnection Studies	475,000	498,000	421,000	365,000	362,000	131%	138%	116%	101%
Subtotal	21,274,000	23,903,000	18,805,000	16,355,000	16,189,000	131%	148%	116%	101%
Financing (incl. AFUDC, IDC)									
EPC Portion	8,644,000	9,060,000	7,666,000	6,652,000	6,582,000	131%	138%	116%	101%
Non-EPC Portion	968,000	1,088,000	856,000	744,000	737,000	131%	148%	116%	101%
Working Capital and Inventories	3,800,000	3,982,000	3,369,000	2,924,000	2,893,000	131%	138%	116%	101%
Subtotal - Non-EPC Costs	34,686,000	38,033,000	30,696,000	26,675,000	26,401,000	131%	144%	116%	101%
Total Capital Investment	224,662,000	237,156,000	199,169,000	172,862,000	171,066,000	131%	139%	116%	101%

Table A-5 — Capital Cost Estimates for GE 7FA - Demand Curve Review

	Overnight Capital Cost - 2007$s		Costs as a % of Zone C
	F - Capital	C - Central	F - Capital
EPC Cost Components			
Equipment			
Equipment	86,661,000	86,652,000	100%
Spare Parts	1,000,000	1,000,000	100%
Subtotal	87,661,000	87,652,000	100%
Construction			
Construction Labor & Materials	47,454,000	46,036,000	103%
Electrical Connection & Substation	2,470,000	2,470,000	100%
Electrical System Upgrades	500,000	500,000	100%
Gas Interconnect & Reinforcement	5,000,000	5,000,000	100%
Site Prep	1,835,000	1,790,000	103%
Engineering & Design	7,492,000	7,413,000	101%
Construction Mgmt. / Field Engr.	1,873,000	1,853,000	101%
Subtotal	66,624,000	65,062,000	102%
Startup & Testing			
Startup & Training	1,249,000	1,235,000	101%
Testing	-	-	N/A
Subtotal	1,249,000	1,235,000	101%
Contingency	14,903,000	14,745,000	101%
Subtotal - EPC Costs	170,437,000	168,694,000	101%
Non-EPC Cost Components			
Owner's Costs			
Permitting	1,704,000	1,687,000	101%
Legal	3,409,000	3,374,000	101%
Owner's Project Mgmt. & Misc. Engr.	3,409,000	3,374,000	101%
Social Justice	275,000	275,000	100%
Owner's Development Costs	5,113,000	5,061,000	101%
Financing Fees	3,409,000	3,374,000	101%
Financial Advisory	426,000	422,000	101%
Environmental Studies	426,000	422,000	101%
Market Studies	426,000	422,000	101%
Interconnection Studies	426,000	422,000	101%
Subtotal	19,023,000	18,833,000	101%
Financing (incl. AFUDC, IDC)			
EPC Portion	7,755,000	7,676,000	101%
Non-EPC Portion	866,000	857,000	101%
Working Capital and Inventories	3,409,000	3,374,000	101%
Subtotal - Non-EPC Costs	31,053,000	30,740,000	101%
Total Capital Investment	201,490,000	199,434,000	101%

Table A-6 — Capital Cost Estimates for LM6000 - Demand Curve Review

	Overnight Capital Cost - 2007$s					Costs as a % of Zone C			
	K - Long Island	J - NYC	G - Hudson Valley	F - Capital	C - Central	K - Long Island	J - NYC	G - Hudson Valley	F - Capital
EPC Cost Components									
Equipment									
Equipment	41,502,000	44,059,000	41,502,000	36,072,000	36,072,000	115%	122%	115%	100%
Spare Parts	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	100%	100%	100%	100%
Subtotal	42,502,000	45,059,000	42,502,000	37,072,000	37,072,000	115%	122%	115%	100%
Construction									
Construction Labor & Materials	39,786,000	42,524,000	28,954,000	21,997,000	21,335,000	186%	199%	136%	103%
Electrical Connection & Substation	3,323,000	3,549,000	2,602,000	2,316,000	2,257,000	147%	157%	115%	103%
Electrical System Upgrades	500,000	500,000	500,000	500,000	500,000	100%	100%	100%	100%
Gas Interconnect & Reinforcement	3,400,000	4,000,000	3,400,000	3,400,000	3,400,000	100%	118%	100%	100%
Site Prep	1,487,000	1,526,000	1,124,000	912,000	888,000	167%	172%	127%	103%
Engineering & Design	4,660,000	4,755,000	4,015,000	3,318,000	3,278,000	142%	145%	122%	101%
Construction Mgmt. / Field Engr.	1,165,000	1,189,000	1,004,000	829,000	819,000	142%	145%	123%	101%
Subtotal	54,321,000	58,043,000	41,599,000	33,272,000	32,477,000	167%	179%	128%	102%
Startup & Testing									
Startup & Training	777,000	793,000	669,000	553,000	546,000	142%	145%	123%	101%
Testing	-	-	-	-	-	N/A	N/A	N/A	N/A
Subtotal	777,000	793,000	669,000	553,000	546,000	142%	145%	123%	101%
Contingency	9,270,000	9,459,000	7,987,000	6,600,000	6,520,000	142%	145%	123%	101%
Subtotal - EPC Costs	106,870,000	113,354,000	92,757,000	77,497,000	76,615,000	139%	148%	121%	101%
Non-EPC Cost Components									
Owner's Costs									
Permitting	1,069,000	1,134,000	928,000	775,000	766,000	140%	148%	121%	101%
Legal	2,137,000	2,267,000	1,855,000	1,550,000	1,532,000	139%	148%	121%	101%
Owner's Project Mgmt. & Misc. Engr.	2,137,000	2,267,000	1,855,000	1,550,000	1,532,000	139%	148%	121%	101%
Social Justice	375,000	1,000,000	275,000	275,000	275,000	136%	364%	100%	100%
Owner's Development Costs	3,206,000	3,401,000	2,783,000	2,325,000	2,298,000	140%	148%	121%	101%
Financing Fees	2,137,000	2,267,000	1,855,000	1,550,000	1,532,000	139%	148%	121%	101%
Financial Advisory	267,000	283,000	232,000	194,000	192,000	139%	147%	121%	101%
Environmental Studies	267,000	283,000	232,000	194,000	192,000	139%	147%	121%	101%
Market Studies	267,000	283,000	232,000	194,000	192,000	139%	147%	121%	101%
Interconnection Studies	267,000	283,000	232,000	194,000	192,000	139%	147%	121%	101%
Subtotal	12,129,000	13,468,000	10,479,000	8,801,000	8,703,000	139%	155%	120%	101%
Financing (incl. AFUDC, IDC)									
EPC Portion	4,863,000	5,158,000	4,220,000	3,526,000	3,486,000	140%	148%	121%	101%
Non-EPC Portion	552,000	613,000	477,000	400,000	396,000	139%	155%	120%	101%
Working Capital and Inventories	2,137,000	2,267,000	1,855,000	1,550,000	1,532,000	139%	148%	121%	101%
Subtotal - Non-EPC Costs	19,681,000	21,506,000	17,031,000	14,277,000	14,117,000	139%	152%	121%	101%
Total Capital Investment	126,551,000	134,860,000	109,788,000	91,774,000	90,732,000	139%	149%	121%	101%

Table A-7 — Comparison of Capital Cost Estimates - Demand Curve Review

	Capital Cost Comparison 2 x LM6000 New York City				Capital Cost Comparison 2 x LM6000 ROS (Syracuse)				Capital Cost Comparison 2 x 7FA ROS (Syracuse)			
	This DC Review		Last DC Review[1]		This DC Review		Last DC Review[1]		This DC Review		Last DC Review[1,3]	
	Cost (2007$)	Non-EPC as % of EPC	Cost (2004$)	Non-EPC as % of EPC	Cost (2007$)	Non-EPC as % of EPC	Cost (2004$)	Non-EPC as % of EPC	Cost (2007$)	Non-EPC as % of EPC	Cost (2004$)	Non-EPC as % of EPC
EPC Cost Components												
Equipment												
Equipment	41,502,000		40,500,000		36,072,000		40,500,000		86,652,000		118,000,000	
Spare Parts	1,000,000		1,000,000		1,000,000		1,000,000		1,000,000		3,500,000	
Subtotal	42,502,000		41,500,000		37,072,000		41,500,000		87,652,000		121,500,000	
Construction												
Construction Labor & Materials	41,279,000		44,980,000		21,335,000		33,960,000		46,036,000		37,935,900	
Electrical Connection & Substation	3,549,000		3,500,000		2,257,000		2,750,000		2,470,000		6,500,000	
Electrical System Upgrades	500,000		2,500,000		500,000		1,250,000		500,000		1,500,000	
Gas Interconnect & Reinforcement	4,000,000		4,000,000		3,400,000		3,400,000		5,000,000		6,210,709	
Site Prep	1,526,000		2,200,000		888,000		1,300,000		1,790,000		3,000,000	
Engineering & Design	4,755,000		4,000,000		3,278,000		3,000,000		7,413,000		7,125,000	
Construction Mgmt. / Field Engr.	1,189,000		0		819,000		0		1,853,000		0	
Subtotal	56,798,000		61,180,000		32,477,000		45,660,000		65,062,000		62,271,609	
Startup & Testing												
Startup & Training	793,000		750,000		546,000		750,000		1,235,000		1,900,000	
Testing	-		250,000		-		250,000		-		700,000	
Subtotal	793,000		1,000,000		546,000		1,000,000		1,235,000		2,600,000	
Contingency	9,459,000		0		6,520,000		0		14,745,000		0	
Subtotal - EPC Costs	109,552,000		103,680,000	100%	76,615,000		88,160,000	100%	168,694,000		186,371,609	100%
Non-EPC Cost Components												
Owner's Costs												
Permitting	1,096,000	1.00%	4,050,000	3.91%	766,000	1.00%	1,050,000	1.19%	1,687,000	1.00%	1,697,000	0.91%
Legal	2,191,000	2.00%	1,285,714	1.24%	1,532,000	2.00%	1,000,000	1.13%	3,374,000	2.00%	1,414,000	0.76%
Owner's Project Mgmt. & Misc. Engr.	2,191,000	2.00%	1,333,333	1.29%	1,532,000	2.00%	1,000,000	1.13%	3,374,000	2.00%	2,239,000	1.20%
Social Justice	500,000	0.46%	500,000	0.48%	125,000	0.16%	125,000	0.14%	125,000	0.07%	400,000	0.21%
Owner's Development Costs	3,287,000	3.00%	0	0.00%	2,298,000	3.00%	0	0.00%	5,061,000	3.00%	0	0.00%
Financing Fees	2,191,000	2.00%	0	0.00%	1,532,000	2.00%	0	0.00%	3,374,000	2.00%	0	0.00%
Financial Advisory	274,000	0.25%	0	0.00%	192,000	0.25%	0	0.00%	422,000	0.25%	0	0.00%
Environmental Studies	274,000	0.25%	0	0.00%	192,000	0.25%	0	0.00%	422,000	0.25%	0	0.00%
Market Studies	274,000	0.25%	0	0.00%	192,000	0.25%	0	0.00%	422,000	0.25%	0	0.00%
Interconnection Studies	274,000	0.25%	0	0.00%	192,000	0.25%	0	0.00%	422,000	0.25%	0	0.00%
Subtotal	12,552,000	11.46%	7,169,047	6.91%	8,553,000	11.16%	3,175,000	3.60%	18,683,000	11.08%	5,750,000	3.09%
Financing (incl. AFUDC, IDC) [(2)]												
EPC Portion	4,985,000	4.55%	3,169,895	3.06%	3,486,000	4.55%	1,899,500	2.15%	7,676,000	4.55%	8,333,186	4.47%
Non-EPC Portion	571,000	0.52%	0	0.00%	389,000	0.51%	0	0.00%	850,000	0.50%	0	0.00%
Working Capital and Inventories	2,191,000	2.00%	0	0.00%	1,532,000	2.00%	0	0.00%	3,374,000	2.00%	0	0.00%
Subtotal - Non-EPC Costs	20,299,000	18.53%	10,338,942	9.97%	13,960,000	18.22%	5,074,500	5.76%	30,583,000	18.13%	14,083,186	7.56%
Total Capital Investment	129,851,000	118.53%	114,018,942	109.97%	90,575,000	118.22%	93,234,500	105.76%	199,277,000	118.13%	200,454,795	107.56%

Notes:

1. Levitan & Associates, Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator, August 16, 2004, p. 6.
2. Value for this review is estimated from a typical construction period drawdown schedule for a gas turbine peaking plant.
3. Excludes $1,000,000 in Emission Reduction Credits.

Table A-8 — Breakdown of Selected Costs for LM6000 Installation in Zone J (New York City) (costs in 2007 $)

Description	Total Equipment Cost	Total Material Cost	Total Personnel Hours	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
Combustion Turbines w/ Accessories	29,100,000		15,180	126.44	1,919,359	31,019,359
SCR w/ Exhaust Stack	5,500,000		22,080	126.44	2,791,795	8,291,795
Pumps	330,400		1,866	127.57	238,015	568,415
Field Erected Tanks	350,000					350,000
Shop Fabricated Tanks	272,000		1,230	126.46	155,494	427,494
Cranes & Hoists	10,000		69	127.57	8,802	18,802
Fuel Gas Compressors	1,340,000		2,346	126.44	296,628	1,636,628
Fuel Gas Conditioning	370,000		607	126.44	76,774	446,774
Bulk Gas Storage Provisions		8,000	193	126.44	24,428	32,428
Air Compressors & Dryers	114,000		331	126.44	41,877	155,877
Fire Protection	350,000					350,000
B.O.P. Mechanical (Miscellaneous)	92,500		552	126.44	69,795	162,295
BOP Piping		599,830	27,283	129.62	3,536,439	4,136,269
Valves & Specialties	174,500		806	132.57	106,841	281,341
Electrical Major Equipment	2,015,000		6,127	117.89	722,364	2,737,364
Electrical BOP		1,142,950	41,327	121.93	5,038,908	6,181,858
Instrumentation & Controls	945,000		3,809	127.19	484,441	1,429,441
Steel		113,394	1,214	144.70	175,718	289,112
Buildings		542,000	8,432	126.44	1,066,117	1,608,117
Foundations		525,599	17,565	120.56	2,117,653	2,643,253
Heavy Haul Subcontracts					325,000	325,000
Construction and Temporary Utilities					100,000	100,000
Indirect and Startup Craft Support			2,600	126.44	328,744	328,744
Allowances to Attract Labor			17,235		5,139,441	5,139,441
Erection Contractors G&A and Profit					4,547,304	4,547,304
Consumables					227,900	227,900
Freight, Duties, Taxes, Etc.	538,353	207,951				746,304
EPC Contractor's Fee					8,599,000	8,599,000
Total Equipment, Materials, & Labor	41,501,753	3,139,724	170,852		38,138,839	82,780,316
Switchyard	1,258,700		17,946	127.61	2,290,028	3,548,728
Site Preparation, Drainage, & Yard Work		430,660	8,402	130.33	1,094,999	1,525,659

Table A-9 — Breakdown of Selected Costs for LM6000 Installation in Zone C (Syracuse) (costs in 2007 $)

Description	Total Equipment Cost	Total Material Cost	Total Personnel Hours	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
Combustion Turbines w/ Accessories	29,100,000		11,550	72.92	842,226	29,942,226
SCR w/ Exhaust Stack	5,500,000		16,800	72.92	1,225,056	6,725,056
Pumps	330,400		1,420	73.61	104,497	434,897
Field Erected Tanks	350,000					350,000
Shop Fabricated Tanks	272,000		936	73.12	68,411	340,411
Cranes & Hoists	10,000		53	73.61	3,865	13,865
Fuel Gas Compressors	1,340,000		1,785	72.92	130,162	1,470,162
Fuel Gas Conditioning	370,000		462	72.92	33,689	403,689
Bulk Gas Storage Provisions		8,000	147	72.92	10,719	18,719
Air Compressors & Dryers	114,000		252	72.92	18,376	132,376
Fire Protection	350,000					350,000
B.O.P. Mechanical (Miscellaneous)	92,500		420	72.92	30,626	123,126
BOP Piping		599,830	20,759	78.56	1,630,694	2,230,524
Valves & Specialties	174,500		613	81.15	49,761	224,261
Electrical Major Equipment	2,015,000		4,662	64.51	300,760	2,315,760
Electrical BOP		1,139,752	31,445	68.36	2,149,521	3,289,273
Instrumentation & Controls	945,000		2,898	68.17	197,557	1,142,557
Steel		104,187	924	87.63	80,972	185,159
Buildings		542,000	6,416	72.92	467,818	1,009,818
Foundations		484,179	13,365	68.12	910,404	1,394,583
Heavy Haul Subcontracts					325,000	325,000
Construction and Temporary Utilities					100,000	100,000
Indirect and Startup Craft Support			2,600	72.92	189,592	189,592
Allowances to Attract Labor			13,163		2,681,851	2,681,851
Erection Contractors G&A and Profit					2,730,018	2,730,018
Consumables					227,700	227,700
Freight, Duties, Taxes, Etc.	538,353	205,529				743,882
EPC Contractor's Fee					6,759,000	6,759,000
Total Equipment, Materials, and Labor	41,501,753	3,083,477	130,668		21,268,275	65,853,505
Switchyard	1,258,700		13,654	73.10	998,122	2,256,822
Site Preparation, Drainage, & Yard Work		430,660	6,393	79.74	509,757	940,417

Table A-10 — Difference in Selected Costs for LM6000 Installation in Zones J and C (Zone J minus Zone C) (costs in 2007 $)

Description	Total Equipment Cost	Total Material Cost	Total Personnel Hours	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
Combustion Turbines w/ Accessories	0		3,630	53.52	1,077,133	1,077,133
SCR w/ Exhaust Stack	0		5,280	53.52	1,566,739	1,566,739
Pumps	0		446	53.96	133,518	133,518
Field Erected Tanks	0					0
Shop Fabricated Tanks	0		294	53.34	87,084	87,084
Cranes & Hoists	0		17	53.96	4,938	4,938
Fuel Gas Compressors	0		561	53.52	166,466	166,466
Fuel Gas Conditioning	0		145	53.52	43,085	43,085
Bulk Gas Storage Provisions		0	46	53.52	13,709	13,709
Air Compressors & Dryers	0		79	53.52	23,501	23,501
Fire Protection	0					0
B.O.P. Mechanical (Miscellaneous)	0		132	53.52	39,168	39,168
BOP Piping		0	6,524	51.07	1,905,745	1,905,745
Valves & Specialties	0		193	51.42	57,080	57,080
Electrical Major Equipment	0		1,465	53.38	421,604	421,604
Electrical BOP		3,198	9,883	53.57	2,889,387	2,892,585
Instrumentation & Controls	0		911	59.02	286,885	286,885
Steel		9,207	290	57.06	94,746	103,953
Buildings		0	2,016	53.52	598,299	598,299
Foundations		41,420	4,200	52.44	1,207,250	1,248,670
Heavy Haul Subcontracts					0	0
Construction and Temporary Utilities					0	0
Indirect and Startup Craft Support			0	53.52	139,152	139,152
Allowances to Attract Labor			4,072		2,457,590	2,457,590
Erection Contractors G&A and Profit					1,817,286	1,817,286
Consumables					227,900	200
Freight, Duties, Taxes, Etc.	0	2,422				2,422
EPC Contractor's Fee					1,840,000	1,840,000
Total Equipment, Materials, and Labor	0	56,247	40,185		16,870,564	16,926,812
Switchyard	0		4,291	54.51	1,291,906	1,291,906
Site Preparation, Drainage, & Yard Work		0	2,009	50.59	585,242	585,242

Table A-11 — Percentage Difference in Selected Costs for LM6000 Installation in Zones J and C (Zone J minus Zone C)

Description	Total Equipment Cost	Total Material Cost	Total Personnel Hours	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
Combustion Turbines w/ Accessories	0%		31%	73%	128%	3.6%
SCR w/ Exhaust Stack	0%		31%	73%	128%	23%
Pumps	0%		31%	73%	128%	31%
Field Erected Tanks	0%					0%
Shop Fabricated Tanks	0%		31%	73%	127%	26%
Cranes & Hoists	0%		31%	73%	128%	36%
Fuel Gas Compressors	0%		31%	73%	128%	11%
Fuel Gas Conditioning	0%		31%	73%	128%	11%
Bulk Gas Storage Provisions		0%	31%	73%	128%	73%
Air Compressors & Dryers	0%		31%	73%	128%	18%
Fire Protection	0%					0%
B.O.P. Mechanical (Miscellaneous)	0%		31%	73%	128%	32%
BOP Piping		0%	31%	65%	117%	85%
Valves & Specialties	0%		31%	63%	115%	25%
Electrical Major Equipment	0%		31%	83%	140%	18%
Electrical BOP		0.3%	31%	78%	134%	88%
Instrumentation & Controls	0%		31%	87%	145%	25%
Steel		8.8%	31%	65%	117%	56%
Buildings		0%	31%	73%	128%	59%
Foundations		8.6%	31%	77%	133%	90%
Heavy Haul Subcontracts					0%	0%
Construction and Temporary Utilities					0%	0%
Indirect and Startup Craft Support			0%	73%	73%	73%
Allowances to Attract Labor			31%		92%	92%
Erection Contractors G&A and Profit					67%	67%
Consumables					100%	0.1%
Freight, Duties, Taxes, Etc.	0%	1.2%				0.3%
EPC Contractor's Fee					27%	27%
Total Equipment, Materials, and Labor	0%	1.8%	31%		79%	26%
Switchyard	0%		31%	75%	129%	57%
Site Preparation, Drainage, & Yard Work		0%	31%	63%	115%	62%

B. Appendix 2 – Financial Assumptions

Table B-1 — Real Carrying Charges on Capital Investment

Merchant Generator Example

Calendar Year			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Operating Year			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Effective Income Tax Rate		39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%
Total Project Capitalized Cost			1,000,000																			
Tax Depreciation			5.000%	9.500%	8.550%	7.700%	6.930%	6.230%	5.900%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%	2.950%	0.000%	0.000%	0.000%	0.000%
Depreciated Value			1,000,000	950,000	855,000	769,500	692,500	623,200	560,900	501,900	442,900	383,800	324,800	265,700	206,700	147,600	88,600	29,500	0	0	0	0
Financing																						
DEBT SERVICE:			500,000																			
Loan Balance Start of Year			500,000	483,532	466,375	448,499	429,875	410,472	390,255	369,193	347,248	324,385	300,564	275,746	249,889	222,949	194,881	165,638	135,171	103,428	70,356	35,899
Principal			16,468	17,157	17,876	18,624	19,404	20,216	21,063	21,945	22,863	23,821	24,818	25,857	26,940	28,068	29,243	30,467	31,743	33,072	34,457	35,899
Interest			20,935	20,245	19,527	18,778	17,999	17,186	16,340	15,458	14,539	13,582	12,584	11,545	10,463	9,335	8,160	6,935	5,660	4,330	2,946	1,503
Balance at End of Year			483,532	466,375	448,499	429,875	410,472	390,255	369,193	347,248	324,385	300,564	275,746	249,889	222,949	194,881	165,638	135,171	103,428	70,356	35,899	0
EQUITY:			500,000																			
TOTAL FINANCING			1,000,000																			
Income Statement (Check)																						
Carrying Charge Revenues:			129,623	100,237	107,013	113,147	118,771	123,952	126,702	127,287	127,830	128,531	129,126	129,882	130,533	131,348	132,061	152,504	172,914	173,795	174,714	175,671
Capital Related Expenses:																						
Property Taxes			20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Insurance			3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Tax Depreciation			50,000	95,000	85,500	77,000	69,300	62,300	59,000	59,000	59,100	59,000	59,100	59,000	59,100	59,000	59,100	29,500	0	0	0	0
Interest Expenses			20,935	20,245	19,527	18,778	17,999	17,186	16,340	15,458	14,539	13,582	12,584	11,545	10,463	9,335	8,160	6,935	5,660	4,330	2,946	1,503
Taxable Income			35,689	-38,009	-21,013	-5,631	8,472	21,466	28,362	29,829	31,191	32,949	34,442	36,336	37,971	40,013	41,801	93,068	144,254	146,465	148,768	151,167
Income Taxes			14,231	-15,156	-8,379	-2,246	3,378	8,559	11,309	11,894	12,437	13,138	13,734	14,489	15,141	15,955	16,668	37,111	57,521	58,403	59,321	60,278
Principal			16,468	17,157	17,876	18,624	19,404	20,216	21,063	21,945	22,863	23,821	24,818	25,857	26,940	28,068	29,243	30,467	31,743	33,072	34,457	35,899
Cash Flow to Equit Equity IRR =	**9.06%**	-500,000	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990
Derivation of Carrying Charges																						
Target Equity IRR =	**9.06%**																					
Principal		-	16,468	17,157	17,876	18,624	19,404	20,216	21,063	21,945	22,863	23,821	24,818	25,857	26,940	28,068	29,243	30,467	31,743	33,072	34,457	35,899
Interest Expenses		-	20,935	20,245	19,527	18,778	17,999	17,186	16,340	15,458	14,539	13,582	12,584	11,545	10,463	9,335	8,160	6,935	5,660	4,330	2,946	1,503
Target Cash Flow to Equity		-	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990
Income Taxes		-	14,231	-15,156	-8,379	-2,246	3,378	8,559	11,309	11,894	12,437	13,138	13,734	14,489	15,141	15,955	16,668	37,111	57,521	58,403	59,321	60,278
Property Taxes and Insurance			23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000
Total Carrying Charges		-	129,623	100,237	107,013	113,147	118,771	123,952	126,702	127,287	127,830	128,531	129,126	129,882	130,533	131,348	132,061	152,504	172,914	173,795	174,714	175,671
Annual Rate (% of initial capital investment)			12.96%	10.02%	10.70%	11.31%	11.88%	12.40%	12.67%	12.73%	12.78%	12.85%	12.91%	12.99%	13.05%	13.13%	13.21%	15.25%	17.29%	17.38%	17.47%	17.57%
After-Tax Cost of Capital =	5.79%																					
Present Value Factor			0.9453	0.8936	0.8447	0.7985	0.7548	0.7135	0.6745	0.6376	0.6027	0.5698	0.5386	0.5091	0.4813	0.4550	0.4301	0.4066	0.3843	0.3633	0.3434	0.3246
Present Value			122,533	89,571	90,396	90,349	89,652	88,445	85,462	81,160	77,048	73,233	69,548	66,128	62,825	59,759	56,797	62,001	66,454	63,139	60,001	57,029
Cumulative Present Value			122,533	212,104	302,500	392,848	482,500	570,945	656,407	737,567	814,615	887,849	957,396	1,023,525	1,086,349	1,146,108	1,202,905	1,264,906	1,331,360	1,394,499	1,454,499	1,511,528
Levelized Carrying Charges (Real)		129,507																				
Levelized Carrying Charge Rate (Real) =		**12.95%**																				

Table B-2 — Real Levelized Carrying Charge Rates - Results of Sensitivity Analysis

Amortization Years =	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34
With Property Taxes and Insurance:																									
non-NYC:	18.57%	17.57%	16.73%	16.01%	15.39%	14.85%	14.37%	13.95%	13.57%	13.24%	12.95%	12.69%	12.45%	12.24%	12.05%	11.87%	11.71%	11.57%	11.43%	11.31%	11.20%	11.10%	11.00%	10.91%	10.83%
NYC:	17.16%	16.13%	15.33%	14.68%	14.16%	13.75%	13.41%	13.11%	12.85%	12.62%	12.41%	12.22%	12.06%	11.91%	11.77%	11.65%	11.54%	11.44%	11.34%	11.26%	11.18%	11.10%	11.03%	10.97%	10.91%
NYC w/o ICIP:	21.69%	20.66%	19.80%	19.06%	18.42%	17.85%	17.35%	16.91%	16.52%	16.18%	15.87%	15.59%	15.35%	15.12%	14.92%	14.74%	14.57%	14.42%	14.28%	14.15%	14.03%	13.92%	13.82%	13.73%	13.64%
Without Property Taxes and Insurance:																									
non-NYC:	16.27%	15.27%	14.43%	13.71%	13.09%	12.55%	12.07%	11.65%	11.27%	10.94%	10.65%	10.39%	10.15%	9.94%	9.75%	9.57%	9.41%	9.27%	9.13%	9.01%	8.90%	8.80%	8.70%	8.61%	8.53%
NYC:	16.86%	15.83%	14.97%	14.23%	13.59%	13.02%	12.52%	12.08%	11.69%	11.35%	11.04%	10.76%	10.52%	10.29%	10.09%	9.91%	9.74%	9.59%	9.45%	9.32%	9.20%	9.09%	8.99%	8.90%	8.81%
200 bp higher on nominal debt and equity cost:																									
With Property Taxes and Insurance:																									
non-NYC:	20.37%	19.36%	18.51%	17.79%	17.16%	16.61%	16.13%	15.71%	15.34%	15.01%	14.72%	14.46%	14.23%	14.03%	13.84%	13.67%	13.52%	13.38%	13.25%	13.14%	13.03%	12.94%	12.85%	12.76%	12.69%
NYC:	19.09%	18.05%	17.22%	16.56%	16.02%	15.58%	15.22%	14.90%	14.62%	14.37%	14.16%	13.96%	13.79%	13.63%	13.49%	13.36%	13.25%	13.14%	13.05%	12.96%	12.88%	12.80%	12.74%	12.67%	12.61%
NYC w/o ICIP:	23.62%	22.58%	21.70%	20.95%	20.30%	19.73%	19.22%	18.77%	18.38%	18.04%	17.73%	17.46%	17.21%	17.00%	16.80%	16.62%	16.46%	16.31%	16.18%	16.05%	15.94%	15.84%	15.74%	15.66%	15.57%
Without Property Taxes and Insurance:																									
non-NYC:	18.07%	17.06%	16.21%	15.49%	14.86%	14.31%	13.83%	13.41%	13.04%	12.71%	12.42%	12.16%	11.93%	11.73%	11.54%	11.37%	11.22%	11.08%	10.95%	10.84%	10.73%	10.64%	10.55%	10.46%	10.39%
NYC:	18.79%	17.75%	16.87%	16.12%	15.47%	14.90%	14.39%	13.94%	13.55%	13.21%	12.90%	12.63%	12.38%	12.17%	11.97%	11.79%	11.63%	11.48%	11.35%	11.22%	11.11%	11.01%	10.91%	10.83%	10.74%
400 bp higher on nominal debt and equity cost:																									
With Property Taxes and Insurance:																									
non-NYC:	22.22%	21.20%	20.35%	19.63%	19.00%	18.46%	17.98%	17.56%	17.20%	16.88%	16.59%	16.34%	16.12%	15.93%	15.75%	15.59%	15.45%	15.32%	15.20%	15.10%	15.00%	14.91%	14.83%	14.76%	14.69%
NYC:	21.07%	20.02%	19.18%	18.50%	17.95%	17.49%	17.12%	16.79%	16.50%	16.24%	16.02%	15.82%	15.64%	15.49%	15.35%	15.22%	15.10%	15.00%	14.90%	14.82%	14.74%	14.67%	14.60%	14.54%	14.49%
NYC w/o ICIP:	25.60%	24.55%	23.66%	22.91%	22.25%	21.68%	21.17%	20.73%	20.34%	20.00%	19.70%	19.43%	19.20%	18.99%	18.80%	18.63%	18.47%	18.33%	18.21%	18.09%	17.99%	17.90%	17.81%	17.73%	17.66%
Without Property Taxes and Insurance:																									
non-NYC:	19.92%	18.90%	18.05%	17.33%	16.70%	16.16%	15.68%	15.26%	14.90%	14.58%	14.29%	14.04%	13.82%	13.63%	13.45%	13.29%	13.15%	13.02%	12.90%	12.80%	12.70%	12.61%	12.53%	12.46%	12.39%
NYC:	20.77%	19.72%	18.83%	18.08%	17.42%	16.85%	16.34%	15.90%	15.51%	15.17%	14.87%	14.60%	14.37%	14.16%	13.97%	13.80%	13.64%	13.50%	13.38%	13.26%	13.16%	13.07%	12.98%	12.90%	12.83%

C. Appendix 3 – Detailed Description of Econometrics Used to Estimate Energy and Ancillary Revenue

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Statistics/Data Analysis

1 . rtprofit LMS100

name	blockp~f
CAPITL	15238.71
CENTRL	11206.41
DUNWOD	14311.55
GENESE	11311.36
HUD VL	12743.71
LONGIL	6515.362
MHK VL	11873.5
MILLWD	14359.93
N.Y.C.	8784.292
NORTH	12386.83
WEST	9422.077

2 . rtprofit LM6000

name	blockp~f
CAPITL	15099.04
CENTRL	10118.5
DUNWOD	15372.57
GENESE	9737.677
HUD VL	13185.81
LONGIL	7798.757
MHK VL	10543.99
MILLWD	15418.72
N.Y.C.	8120.173
NORTH	10690.1
WEST	8537.961

3 . rtprofit Frame7

name	blockp~f
CAPITL	2555.073
CENTRL	2512.938
DUNWOD	3386.576
GENESE	2497.074
HUD VL	3055.001
LONGIL	3705.971
MHK VL	2759.672
MILLWD	3195.392
N.Y.C.	3559.406
NORTH	2506.062
WEST	2333.318

```
4 . log close
       log:  \\Nera-nycfs\Work\Projects\Energy\NYISO CAP REVIEW (K977)\Data\realtime719.smcl
  log type:  smcl
 closed on:  19 Jul 2007, 16:26:14
```

D. Appendix 4 – Guide to Demand Curve Development Model

The model is a Microsoft Excel workbook that simulates revenues and expenditures given a set of user-defined and built-in input parameters. The workbook can be divided into three parts: (1) input sheets, (2) the “Model” sheet and (3) output sheets. The input sheets supply parameters produced by outside sources. The “Model” sheet is where the actual calculations of revenues and expenditures are performed. The output sheets show the results of simulations that NERA has performed.

Input Sheets: The sheets to the right of the “Model” sheet (e.g. “Reference Tables”, “Energy Curve Raw”) contain functions and parameters produced by outside sources. The energy curve is the result of a simulation performed on STATA. The “Current Curve” sheet contains FERC-approved values for the current NYISO capacity curve. The “Reference Tables” sheet contains levelized fixed charges and overnight capital costs calculated by Sargent & Lundy. The values in these input sheets are not meant to be changed by users.

“Model” Sheet: The “Model” sheet allows users to alter certain parameters and run the simulation. User-defined input parameters can be found in the tan areas of the “Model” sheet. Users can change these values to simulate different market conditions. Values in yellow are dependent on other parameters and should not be altered. Values that are shaded out are not relevant given the other parameters. For example, the “kink” variable that determines where the curve kinks is not relevant if there is no kink specified (i.e., if the x-intercept of the first and second slanted segments are identical).

To run the simulation, users click the “Calculate Demand” Button, which solves for the demand curve that allows for full cost recovery given the inputs and parameters. Values in the areas shaded blue are the results of intermediate calculations, including revenue and expenditure streams. Outputs such as the amortization period and demand curve reference values are shown in the pastel green rectangle. The supernormal net revenue variable should always be zero after clicking “Calculate Demand”.

Output Sheets: The “High Level Summary” and “Results Summary” sheets show the results of certain runs that NERA has performed. Included are composite results which are the average results of two runs. The specific runs considered in this report are displayed on “ROS Chart”, “NYC Chart” and “LI Chart”. The “Demand Chart” shows the current NYISO demand curves.

E. Appendix 5 – Expected Value and Standard Deviation of Capacity Values

This appendix explains the basis for the assumptions used to model the average level and standard deviation of excess capacity. The NYISO capacity model uses a Monte Carlo simulation to estimate capacity levels for demand payment and energy payment calculations. This simulation assumes capacity levels are normally distributed. In each run of the model, the normal distribution is specified by two parameters, the expected value and standard deviation assumptions. For the NYCA, the standard deviation was based on the results of a model of PJM markets created by Dr. Benjamin Hobbs ("Hobbs Model") for FERC Case EL05-1410 in which PJM RPM issues were settled. The Hobbs Model is a dynamic analysis of alternative demand Variable Resource Requirement curves, which are effectively capacity demand curves for PJM. The original Excel spreadsheet is published on the PJM website at www.pjm.com/committees/working-groups/pjmramwg/postings/20060518-dynamic-capacity-jhu.xls.

In essence, the Hobbs Model takes a given demand curve and simulates investment in combustion turbines for a period of 100 years. The model uses a Monte Carlo simulation with 25 iterations, each with 100 years. A variety of parameters, such as market size, turbine cost and economic growth, define the economic environment and influence the level of investment in combustion turbine capacity. Many of these parameters determine forecasts of capacity and revenues one, two, three and four years forward. These forecasts influence investment choices in the current period and capacity in future periods.

Given a set of parameters, the Hobbs Model assesses investment trends and for each of the 100 years in each iteration of the Monte Carlo simulation calculates reliability metrics (e.g. the mean and standard deviation of the forecast unforced reserve margin and the percentage of years in which the reserve is greater than the target). The model then aggregates these reliability metrics, as well as other metrics, across all iterations.

The parameters used to produce the standard deviation used for the NYISO capacity model were based on the set of parameters called "Alternate Curve with New Entry Net Cost at IRM + 1% (Shift to 90% Reliability)." This base set was adjusted to reflect changes in the PJM RPM settlement and was further revised to adapt the model to the NYISO market. The overall structure of the model and most inputs were preserved.

Changes related to the settlement agreement were implemented as follows:

1. Demand Curve ICAP Price Threshold: This determines the maximum level of the demand curve as a multiple of the cost of a combustion turbine. This value was lowered to 1.5 from 2.

2. Expected Gross Margin: This was reduced from $28,000/installed MW/yr to $21,000/installed MW/yr to be consistent with the settlement.

3. Ancillary Services and Other Revenue: This was reduced from 10,000/installed MW/yr to 2,400/installed MW/yr.

4. Shift Demand Right: The base set of parameters shifts the demand curve three percentage points to the right. This shift was eliminated.

5. Auction Timeframe: The spreadsheet was significantly modified to reflect a three-year auction timeframe that was agreed to in the settlement. The original version used a four-year auction.

6. Discrete Addition Size: This parameter reflects a minimum (and maximum) efficient size for new capacity additions.

Changes related to NYISO market:

7. Demand Curve: The demand in the base set of parameters was replaced with a set of parameters approximating a non-NYC demand curve. The x-intercept is 12% above the reserve requirement.

8. Reserve Margin: The Installed Reserve Margin ("IRM") was changed to 18% and the unforced reserve margin was changed to the quantity IRM * (1 – Forced Outage Rate)

Variables not mentioned above were not altered.

Of the dozen or so output variables in the Hobbs Model, only the standard deviation of the forecast unforced reserve margin was used in the NYISO capacity model. The standard deviation of the forecast unforced reserve margin in the Hobbs Model was 1.4%. The NYISO model uses the same standard deviation. The expected capacity value in the NYISO capacity value was set at two standard deviations above the reserve requirement i.e., 102.8%. Given this value, one could expect that capacity levels would be below the reserve requirement 2.5% of the time, or once in forty days. Having set the standard deviation, the New York RNA process and Tariff provisions designed to enable the NYISO to avoid capacity shortages were reviewed. As a result of this review, it was reasonable to select an average reserve level that would allow for a very low probability of capacity shortage. As explained in the body of the report, for NYC and LI, the standard deviation was increased from 1.4 % to 2.0 % to account for smaller market size.

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