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**To:** John Charlton, NYISO

**From:** Glenn D. Haake

**Date:** August 6, 2004

**Re:** IPPNY Comments on LAI Draft Demand Curve Report

### A. Introduction

On behalf of its members, IPPNY offers the following comments on the draft "Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator" ("Draft Report") prepared and distributed by Levitan & Associates, Inc. ("LAI").

### B. General Policy Issues

1. Financing Assumptions

IPPNY's greatest concern with the Draft Report centers around its utilization of a confluence of extremely optimistic assumptions that, if maintained by LAI and adopted by the NYISO, will result in artificially depressed simple-cycle gas turbine ("GT") carrying cost estimates for the three regions and in demand curves ("DCs") that will not achieve the purposes for which the demand curve concept was implemented. Viewed in isolation, each of these assumptions alone arguably may be viewed as reasonable, given a proper context. However, taken together as LAI has proposed them these assumptions are unrealistic and unworkable in our view.

Specifically, LAI assumes a financing structure that is quite aggressive. Notwithstanding the state of financial markets generally, and specifically in the electric industry, LAI contemplates a 50% debt/50% equity, on-balance sheet financing structure with debt at 7.5% and equity at 12.5% (which equates to a weighted average cost of capital of 8.5%) for a 20 year term. Indeed, contrary to the direction that markets have taken and the marked reduction in the availability of funding, the LAI assumptions represent a 5 year increase in term over the 15 year term that was used to set the GT costs that formed the basis of the 2003 and 2004 demand curves. IPPNY believes that these assumptions are unreasonable.

Moreover, the impact of these "idealized" assumptions is exacerbated if the resulting cost of capital is combined with (1) an offset based on imputation of substantial net revenues for energy and ancillary services ("Net EA Revenues"), and (2) placement of the resultant localized, levelized GT carrying cost (the "Reference Price") at a point on the demand curve equal to the applicable statewide or locational minimum ICAP requirement (the "Minimum Requirement").

As discussed below (Section B.3), forecasting the level of Net EA Revenues that will be received by a new GT over a twenty year term is an extremely speculative undertaking, because of the very real risks and uncertainty associated with these Net EA Revenues. Not the least of these risks is represented by the fact that the NYISO currently is embarked on a Comprehensive Planning Process and recently has issued documentation proposing a process for the selection and development of "economic upgrades." It goes without saying that the potential for a GT investment to become uneconomic is greatly increased if the NYISO intends to assume the role of intervening in the market to affect economic outcomes.

IPPNY submits that, were this a non-recourse, project financing, a rational lender would be unwilling to finance a GT if its financial pro forma relied significantly upon substantial Net EA Revenues over a 20 year term to meet minimum debt coverage ratio requirements. Likewise, a rational creditworthy corporate entity is unlikely to assume high levels of Net EA Revenues when it contemplates committing its balance sheet, at the relatively low returns assumed by LAI, to the financing of a GT over a 20 year term. Conversely, if a rational corporate entity were to predicate its investment in the GT in significant part on assumed Net EA Revenues, it would require a risk-adjusted return substantially higher than the 12.5% assumed by LAI and would expect a payback period substantially shorter than the 20 years contemplated in the Draft Report. Indeed, at the August 2, 2004 meeting of the ICAP Working Group ("ICAPWG"), LAI's Seth Parker acknowledged that LAI had considered using a 15 year term and agreed that such a term would be reasonable. IPPNY would request that LAI assume a 15 year financing term when it prepares its final report.

As mentioned, LAI's assumed weighted average cost of capital is 8.5% (See, Draft Report, Appendix F, page 5). This is too low to reflect the cost of capital for a merchant project and is closer to the cost of capital of generators with power purchase agreements (LAI expressly predicates its capital assumptions on the principle that power purchase agreements should not be necessary).[1] IPPNY's members' experience with the financial markets suggests a more appropriate cost of capital for merchant projects would be in the range of 10.2% to 11.3%. The derivation of and support for IPPNY's proposed cost of capital is provided in Attachment A. IPPNY would request that LAI employ this cost of capital in preparing its final report.

2. Reference Price Placement

As argued below, IPPNY believes no Net EA Revenue offset should be made to the GT capital cost. However, if a Net EA Revenue offset is to be adopted, then the associated Reference Price must not be located at the Minimum Requirement on the demand curve. To do so effectively means that in order for an investor to recover the cost of its GT investment, it must receive the full Net EA Revenue (and its full capacity revenue) in each of the 20 years contemplated in the Draft Report and any periods of capacity surplus must be offset by equal periods of capacity deficiency.

Yet, a rational investor cannot expect that deficient Net EA Revenues and capacity revenues received during periods of surplus will be compensated by excess Net EA Revenues and capacity revenues available during periods of shortage. History has shown that policy makers will not allow the State to fall into a capacity deficient condition. In addition to the 11 NYPA gas turbines that were hurriedly sited to avoid a capacity deficiency in the summer of 2000, in more recent months we have seen LIPA secure expedited System Reliability Impact Studies to support its installation this Summer of emergency generators on Long Island that are expected to be in place for each of the next three summers.

As a result, if Net EA Revenues are assumed to offset GT carrying costs, then the associated Reference Price must be located at a position on the demand curve in excess (to the right) of the

[1] Indeed, the rate of return assumed by LAI is no higher than the rates of return approved by the FERC in recent times for regulated transmission investments. It is apparent that riskier merchant investments should command a substantially higher return than is afforded regulated, ratebased investments.

Minimum Requirement. Otherwise, the GT owner will be unable to fully recover the cost of its investment. Alternatively, this problem could be addressed by crediting only a very conservative level of Net EA Revenues against the GT carrying costs. In this case, the potential for upside on Net EA Revenues could be relied upon to maintain the minimum installed reserve margin.

In summary, IPPNY believes that it is unreasonable to calculate the GT cost on the basis of a set of assumptions that, when taken together, are not rationally consistent. That is, the term, debt/equity ratio, and interest and return on equity rates must reflect the risks associated with the level of Net EA Revenues assumed and the location on the demand curve of the Reference Price.

3. <u>Net EA Revenue Considerations</u>

It is noteworthy that during the ICAPWG's discussions involving the original development of the DCs, the NYISO's Independent Market Advisor, Dr. David Patton, recommended that no Net EA Revenues should be imputed to offset the carrying cost of the GT and that if an offset is assumed it should be calculated in a conservative manner, due to the uncertainty inherent in forecasts of these revenues. IPPNY supports Dr. Patton's position and would urge LAI to adopt conservative assumptions in forecasting Net EA Revenues.[2]

LAI's analysis includes two forecasts of Net EA Revenues: the Deterministic Case, based on average loads and dispatch, and the Stochastic Case, which is intended by LAI to better capture volatility experienced, largely, in the real-time market ("RTM"). IPPNY believes the LAI models include a number of inaccurate assumptions which are discussed below.

First, we understand that a substantial portion of the Net EA Revenue's predicted by the Stochastic Model are expected in connection with high prices that result from the commitment of special case resources ("SCRs"). However, it is unlikely that the GT that is the subject of this exercise will receive these payments. This is because during periods of expected peak loads, new units like the GT are likely to be committed in the day-ahead market ("DAM"). SCRs are committed and dispatched exclusively in the RTM. While less-efficient, older units may benefit from higher prices associated with SCR commitment, it is likely that the GT will be running against a DAM commitment and the DAM is unlikely to have prices at the scarcity level of the SCRs. In addition, the revenues associated with SCR commitment appear to have been overstated, because LAI assumed that in each hour an SCR was dispatched it was paid a minimum of $500/MWh. The rules pertaining to SCRs now permit them to bid at strike prices below $500/MWh. Accordingly, it would be necessary for LAI to evaluate the proportion of hours in which SCRs have bid lower amounts in order to determine a more accurate representation of clearing prices based on SCR bids. Thus, IPPNY would request LAI to adjust its Net EA Revenues downward to the extent that its model shows the GT would have been committed in the DAM and to the extent that SCRs are expected to bid at prices below $500/MWh.

Moreover, this condition highlights a risk that must be considered when calculating Net EA Revenues. During the August 2, 2004 ICAPWG meeting, KeySpan's James D'Andrea reported that his client has been advised to expect future curtailment of natural gas during peak summer days when operational flow orders ("OFOs") are likely to be issued. If the GT receives an OFO after it has been given a DAM commitment and is, as a result, wholly or partially unable to meet its DAM schedule, it will incur potentially severe losses associated with buying out its DAM commitment in the RTM at prices that can be expected to be well in excess of those in the DAM.[3]

[2] IPPNY recognizes that the Draft Report does not make any recommendation as to whether, and if so in what amount, Net EA Revenues should offset GT carrying costs. Instead, LAI has provided two models of Net EA Revenues for Market Participant and NYISO consideration.

[3] Nor can the GT avoid this loss by burning alternate fuel, because the GT contemplated in the Draft Report does not have dual fuel capability. Having such capability would obviously greatly increase fixed and variable costs beyond those in the Draft Report.

Such an occurrence can greatly reduce any expected profits from Net EA Revenues that the GT might otherwise receive. It is unclear whether the LAI models adequately capture this risk and impact on Net EA Revenues.

It appears that significant portions of the Net EA Revenues are assumed to come from payments for reserves, and in particular 10-minute non-synchronized reserves ("TMNSR"). We assume the models calculate these revenues based on historic average prices. However, recent experience and market changes that will be made in connection with the NYISO's implementation of SMD2 suggest that TMNSR revenues, which have been trending downward, will be minimal during the study period.

In the NYISO's July 8, 2004 "Review of the 10 Minute Non-Sync Reserve Market" filed at the Federal Energy Regulatory Commission in Docket No. ER03-836-005, the NYISO stated that "10 Minute NSR prices have continued to decrease to their lowest levels since the introduction of the NYISO markets in November 1999." Moreover, as reported at the NYISO's August 3, 2004 Management Committee meeting, this trend has continued. Prices for TMNSR in July 2004 have reached historic lows of between 33% and 77% below last years' prices. In addition, under SMD2, all units that submit energy bids and are capable of providing TMNSR will be deemed to have bid TMNSR into the market at a price of $0. This can be expected to exacerbate the trend toward diminished TMNSR revenues. Accordingly, IPPNY would propose that the LAI models be revised to greatly reduce predicted TMNSR revenues.

One additional factor that calls into question LAI's estimate of Net EA Revenues is the fact that its MarketSYM model does not correctly model the presence and impacts of the many significant transmission constraints which are present on the NYISO system. MarketSYM uses what is termed a "transportation" model which, among other drawbacks, does not reflect the fact that transmission constraints are a function of the generation capacity present at specific locations and the output level at which each generator is committed and dispatched. This is in contrast to other acceptably accurate models such as MAPS, which is used for such studies not only by the NYISO but also the NYPSC. The use of the transportation model in MarketSYM can have at least two potential impacts: (1) it can result in incorrect MW needs in the commitment and dispatch modeling, and (2) it can cause an overstatement of projected Net EA Revenues.

The reason that a transportation model overstates Net EA Revenues is that such a model uses worst case assumptions about transfer limits in all hours, whereas MAPS is able to calculate on an hourly basis what those limits actually are. Since (as we know from actual NYISO real-time experience) the limits are oftentimes much less than the maximum assumed by a transportation model, the net result is that LAI's model overstates the number of hours combustion turbines will run in the constrained areas and thus also will overstate the Net EA Revenues. Accordingly, it may be appropriate for the NYISO to audit the LAI results using a MAPS simulation for comparison, assuming this can be accomplished given the resources and time available. Moreover, this is yet another reason why the Net EA Revenues calculated by LAI should be treated conservatively.

**C. Gas Turbine Assumptions**

1. <u>Capital Costs – Interconnection</u>

The Draft Report reflects interconnection costs of $3 million on Long Island and $3.5 million in NYC. IPPNY believes that the premium associated with constructing an underground interconnection in NYC is much greater than that assumed by LAI. We understand that constructing an underground line within NYC costs approximately $3 million per mile. Assuming a one-half mile long interconnection line, this equates to $1.5 million. Thus, rather than the $500 thousand premium assumed by LAI, IPPNY believes the premium should be $1.5 million. Accordingly, IPPNY requests that LAI increase the NYC interconnection cost by $1 million over that contained in the Draft Report.

2. DMNC Calculation

As LAI's Seth Parker acknowledged during the August 2, 2004 ICAPWG meeting, the unitized GT costs contained in the Draft Report were calculated based on ISO conditions (59 degrees F), and they should have been calculated based on the GT's expected dependable maximum net capability ("DMNC") during the Summer Capability Period to reflect the rules that are applied to suppliers in New York for the sale of capacity. In addition, the Draft Report indicates that LAI assumes 90 degrees Fahrenheit is the appropriate temperature to reflect Summer DMNC testing conditions. IPPNY believes that the correct Summer DMNC temperature is several degrees higher and would request that LAI verify with the NYISO what temperatures should be applied in each of the three regions for the purpose of calculating Summer DMNC. As with the current demand curve numbers, the NYISO will adjust the Summer DMNC in calculating the demand curves to incorporate the Summer/Winter DMNC adjustment and the conversion from ICAP to UCAP values.

3. Variable Operating Costs

a. Gas Transportation, Imbalance Charges and Intraday Gas costs premiums

Pages 26 and 27 of the Draft Report provide LAI's assumptions regarding gas transportation rates, imbalance charges and intraday gas premiums. IPPNY has concerns regarding the application of the following assumptions for NYC GTs:

Local gas transportation - .19/mmbtu on year-round basis;
Imbalance Charges - .15/mmbtu for generators serviced by New York Facilities System (Con Ed and KeySpan/Brooklyn Union and KeySpan/Long Island);
Intraday Premiums - no allowance for intraday gas pricing

IPPNY requests that LAI reflect in its analysis the provisions of Con Edison's S.C. 9 gas transportation service for power generators. This is a public document on the NYPSC website and provides price, terms and conditions followed by Con Edison when developing transportation and balancing services for power generators. The KeySpan tariff is similar. The tariffs apply to NYC GTs. These facilities do not have viable bypass alternatives in most cases.

During the August 2, 2004 ICAPWG meeting, LAI suggested that these costs can be avoided by the GT by bypassing the Con Edison system. However, IPPNY strongly believes that such bypass should not be deemed a viable alternative for the GT at issue here.

This is especially true because GT load factors are likely to be relatively low and unpredictable. Therefore, it is unlikely that they can support the upfront investment needed to build a line to bypass the Con Edison system. At the very least, it appears that the GT capital costs assumed by LAI do not include adequate funds for the associated bypass facilities. In addition, it is our understanding that the only tunnel in the vicinity of the Hunts Point gate station referenced by LAI in which bypass facilities could be constructed is owned by Con Edison. It is not reasonable to assume it will grant access to that tunnel at a cost substantially lower than it would receive if service were taken pursuant to its tariff.

Applicable transportation rates, minimum bill provisions, balancing and unauthorized use charges are indicated in each company's tariff. The Draft Report does not reference these tariffs, which should be the basis for LAI's rate assumptions. The key elements of the Con Edison tariff, which would apply to a GT located in the Bronx, Queens or Manhattan, are as follows:

Minimum Bill = Max annual qty * .50 load factor times rate. For a 96 MW GT, this would be 960 per hour *8760*.5*.192 = $ 807k per year. At a 15% load factor, that equates to 64 cents/mmbtu.

Balancing – the tariff calls for imbalances to be billed at 167%/60% of gas costs for imbalances exceeding 10%. For a GT, an extra hour of run time could cause this degree of exceedance. 167% of 6.00/mmbtu gas is $10.00/dth. This treatment of imbalance applies equally to summer or winter. Since peaker operation in the RTM is likely to vary significantly from DAM schedules, imbalances are likely. The Draft Report shows $0.15/mmbtu for balancing costs, a much lower assumption than the multi dollar/mmbtu penalty that generators face.

Unauthorized Use Charge: The Con Edison tariff includes a provision of $45/dth for unauthorized use charges. Con Edison has the discretion on when to apply these charges. There are circumstances when a single-fuel GT might not be able to avoid this charge. For example, when required to run due to reliability reasons, the electric operator may require start-up or continued operation. It should be noted that the power generation tariff available to GTs in NYC is interruptible and the customer must abide by curtailment provisions. Given that a mere one hour of unauthorized use gas equates to $45,000, some allowance should be made within imbalance charges for this circumstance. We suggest 5 hours per year or 5000 dth per year * $45 per mmbtu = $225,000 to be imputed into the variable charge.

Intraday Premium – it is generally agreed that intraday gas prices carry with them a risk premium. Though difficult to quantify due to lack of market liquidity and historical pricing, some percentage over the day-ahead pricing is warranted. IPPNY supports a 2% to 4% premium over day-ahead pricing assumptions, based on members' experience with buying gas late in the afternoon to support peaker real-time dispatch. It should be noted that sellers of intraday gas are aware of in-city generators alternatives, included aforementioned balancing penalties and therefore factor this into their determination of sales price.

b. <u>TMNSR Expenses</u>

As mentioned above, it appears that significant portions of the Net EA Revenues are assumed to come from payments for TMNSR. However, the GT O&M and staffing assumptions in the Draft Report are inconsistent with the ability of the GT to participate in the TMNSR market. We understand that in order for the paired LM6000 unit assumed for the NYC and Long Island regions to supply TMNSR, that unit must continually pre-heat the ammonia consumed by the selective catalytic reduction technology ("SCRT"). Otherwise, the GT cannot achieve a 10-minute start-up. However, it appears that the model does not reflect these ammonia pre-heat expenses. In addition, it is IPPNY's understanding that higher staffing levels than assumed in the Draft Report are required in order to achieve 10-minute start-up and perform associated operation and maintenance procedures. Accordingly, IPPNY requests that LAI increase its variable O&M expenses to reflect the cost that will be incurred by the GT owner in order to participate in the TMNSR market.

c. <u>Variable O&M Expenses</u>

It should be noted that a number of IPPNY's members are active in the development of generation facilities and, thus, are intimately familiar with market prices for both fixed and variable operation and maintenance service expenses. The following information is based upon that experience.

1. <u>GT Staffing Levels</u>

LAI assumes that the paired LM6000 GT assumed for NYC and Long Island can be operated and maintained by the equivalent of a single full time employee. IPPNY believes that this assumption is understated by a factor of at least three. As we know, NYPA has 10 GTs at six sites within NYC. It is our understanding that NYPA has retained a nationally recognized third party O&M vendor to operate and maintain these units. We understand that this entity has dedicated 20 full time personnel to operate and maintain these 10 GTs at six sites. This equates to 3.3 full time employees per site. It is noteworthy that NYPA's units are not capable of participating in the TMNSR market. Achieving such capability would, IPPNY believes, require NYPA to commit additional staffing for the units. Moreover, we understand that NYPA realizes economies of scope by virtue of having a central office responsible for bidding all 10 units into the market. It would not be reasonable to assume that the developer of a new GT would realize similar economies of scope. Accordingly, IPPNY would request that LAI increase, to at least 3.3 personnel per paired LM6000 GT, the personnel required to operate and maintain the GT.

2. Variable O&M Categories and Costs

LAI estimates a $3.0/MWh variable O&M expense. IPPNY believes such estimate is insufficient to cover all variable costs related to the GT. The variable costs should include: (1) combustion turbine hot gas path overhaul, (2) combustion turbine major overhaul, (3) SCRT catalyst replacement, (4) borescope inspections, (5) water, (6) chemicals, (7) consumables, (8) spare parts (combustion turbines and other equipment), and (9) balance of plant maintenance. When including all costs referenced above, the variable O&M can be more than double LAI's estimate. IPPNY would therefore propose a variable O&M expense of $7/MWh for the above items. Indeed, IPPNY understands that one of its members has provided the NYISO with publicly filed information documenting variable O&M costs in excess of $7/MWh.

4. Fixed Operating Costs

a. Fixed O&M Expense

LAI estimates fixed O&M costs to be $10.5/kW-year plus property taxes. IPPNY believes this estimate is insufficient to cover for all fixed costs related to the GT. The fixed costs should include Operation and G&A costs such as: operation supervision, operating labor, routine maintenance labor, turbine lease program, electricity back-up, external services (security, etc.), asset management, fuel/power management, dispatching services, risk management, credit support for hedging, accounting and administration allocations, insurance, and other miscellaneous costs. When including all costs identified above, the fixed costs can be expected to be more than double LAI's estimate. IPPNY therefore requests that LAI increase its fixed O&M expenses when it prepares its final report.

b. Taxes

IPPNY is advised that the percentage figures assumed by LAI for property taxes are greatly understated. IPPNY's in-City members are expected to address this issue in their comments, and IPPNY would encourage LAI to give careful consideration to revising upward this expense.

c. NYC Lease Expense

LAI assumed three acres of land would be required for the GT in Long Island and upstate, but only two acres in NYC. IPPNY believes that it is unreasonable to believe that two acres will be sufficient in NYC. First, it is likely that additional land will be required as buffer area in NYC. Second, using a smaller site would likely impose additional costs for construction laydown area and engineering costs, which it is not clear are included in the Draft Report. Accordingly, IPPNY would suggest that LAI revise the model to reflect at least three acres in NYC, as in the other regions.

## Attachment A

## Cost of Capital for Merchant Projects

**Summary**

The cost of capital for merchant projects is estimated to be 10.2% to 11.3% un-levered after tax. Such cost might be even higher today due to the current credit difficulties of market players but could possibly go lower over time with improved stability and predictability of energy markets.

The above cost of capital is significantly higher than the 8.5% estimated by LAI in the Draft Report. [50% Debt x 7.5% x (1 – 40%) + 50% equity x 12.5%]

A higher return is also required for peaking projects due to their higher sensitivity to market price volatility.

This cost of capital for merchant projects of 10.2% to 11.3% is based on an estimated weighted average cost of capital of 9.2% to 9.8% for merchant companies and a minimum project premium of 1 to 1.5% to cover corporate overhead including administration and development costs of un-successful projects. The two components of the cost of capital are discussed below.

**Project Costs vs. Corporate Costs**

Return on Projects should be higher than Return on Corporate Capital because successful projects have to fund costs of corporate administration and the development costs of un-successful projects.

Such project premium is estimated to be 1% to 1.5% of total capital and could vary depending on project size (economies of scale) and marketing aggressiveness.

Today's markets do not favor merchant projects and as such premiums may be even higher.

**Corporate Cost of Capital of Merchant Business.**

Using a CAPM (Capital Asset Pricing Model) approach, Cost of Capital of Corporations will reflect overall business risks according to the following formula:

Cost of Capital (CC) = Rf + Beta x Rp

Rf is a Risk Free rate (20 Year Treasury for long term investment = 5% today)
Beta is a risk ratio based on earning volatility
Rp is an equity risk premium (assumed to be 6%)

Comparable market analysis suggests Beta for merchant being 0.7 to 0.8 un-levered (before effect of financing). This should be compared to a Beta of 0.4 to 0.5 for contracted generation assets.

The differences reflect higher risks from energy price volatility, commodity market liquidity, regulatory uncertainty, and recent failures (Enron, NRG, Mirant, etc.).

Corporate Cost of Capital = 5% + (0.7 to 0.8) x 6% = 9.2% to 9.8%