MEMORANDUM

DATE: February 1, 2007
TO: John Charlton
FROM: Mike Cadwalader
RE: Revised Assumptions for ICAP Demand Curve Study

During the Jan. 18, 2007 meeting of the Installed Capacity Working Group (ICWG), the consultants that the NYISO has selected to perform the ICAP demand curve study (Sargent & Lundy and NERA) presented a revised set of assumptions upon which they proposed to base that study. At that meeting, you asked for market participants to submit comments and questions regarding those assumptions. Accordingly, I submit these comments and questions on behalf of LIPA, NYPA and the members of the Transmission Owners sector. (Please identify them accordingly.)

COST AND OPERATING ASSUMPTIONS

We will be more specific regarding some of the cost assumptions we had asked about earlier:

- How did the consultants arrive at the range of property tax rates included on page 7 of the table provided by Sargent & Lundy? Why did the likely value increase from 1.7% (in the table distributed in December) to 2.0%? Why did the maximum value increase from 2.5% to 5.4%?[1]

- How did the consultants arrive at the range of insurance rates included on page 7 of that table? Why did the maximum value increase from 0.5% (in the table distributed in December) to 0.7%?

- How did the consultants arrive at the range of indirect capital costs included on page 8 of that table?

- How did the consultants arrive at the range of costs associated with working capital and inventories included on page 8 of that table?

- Why was the elevation for a NYC unit (provided on p. 3 of the Sargent & Lundy table) considered to be 131 feet? We would expect it to be closer to the elevation of a Long Island unit (16 feet).

- If the cost for environmental allowances is included in the analysis, the calculation of market-clearing prices should also reflect the inclusion of these costs in generators' bids.

[1] In addition, property taxes for New York City should reflect the Industrial and Commercial Incentive Program exemption, as Scott Butler described in materials sent to Sargent & Lundy earlier.

DEBT/EQUITY RATIO

As noted in our previous comments, we also believe that the debt/equity ratio needs additional justification. In those comments, we had noted that information that some of the TOs have received indicates that the debt fraction for new development generally exceeds 50 percent. In light of that, we would like for the consultants to explain why they eliminated the range of debt fractions (from 45-60 percent) that were included in the table that Sargent & Lundy distributed in December, instead setting the debt and equity fraction at 50 percent in all scenarios in the table distributed at the last meeting.

GENERATOR SITE DEVELOPMENT REQUIREMENTS

During the discussion at the last ICAP WG meeting, there was a good deal of discussion of the costs that would be incurred to develop generation at various sites (e.g., compressor needs, switchyards, etc.). While it would be necessary to incur some of these costs at some sites, that does not mean it will be necessary to incur most of these costs at most sites. Therefore, we think the consultants need to be very careful when deciding which of these costs to include, to ensure that the resulting costs represent a reasonable estimate of the cost of entry. At the last meeting, it was suggested that the consultants should look at projects under development to assess the likelihood that these costs would be incurred, and the extent of these costs when incurred. In addition, we think it would be reasonable for the consultants to review the costs that would be associated with sites of projects that are not actually under development but which could go into development as soon as the necessary power purchase contracts are in place, such as the Wayawanda site.[2]

GENERATOR TECHNOLOGY AND FUEL TYPE

Page 5 of the Sargent & Lundy table only includes data for an LM6000 unit in New York City and Long Island. We believe the consultants should also evaluate development of a 7EA unit in those locations to see if the net cost of developing such a unit might be lower than the net cost of developing an LM6000, instead of assuming that they would not be economic there. Also, in addition to reiterating our previous comments regarding dual fuel capability, we note that generators with dual fuel capability in New York City will also qualify for interruptible gas rates. This reduction in gas charges should be included when evaluating the economics of a dual fuel unit.

FINANCIAL MODELING

The determination of the investment that must be recovered during the first three years of a generator's life, as described in the NERA presentation, depends heavily on the present value that is calculated for total revenue for the remainder of the generator's assumed operating life. The last slide states that these revenues will reflect equilibrium conditions, which should include whatever future adjustments to the ICAP demand curve are necessary to ensure that ICAP revenues reflect the net cost of entry at the long-run equilibrium amount of capacity.

[2] See http://phx.corporate-ir.net/phoenix.zhtml?c=103361&p=irol-newsArticle&ID=91099&highlight.

LIKELIHOOD OF SHORTFALL RELATIVE TO MINIMUM ICAP REQUIREMENTS

During the last ICAP WG meeting, some market participants voiced the opinion that there was virtually no chance there would ever be a shortfall relative to the NYCA Minimum ICAP Requirement or a Locational Minimum ICAP Requirement. This is mistaken, as it is entirely possible that there will be a shortfall. In fact, there as a deficiency in the May 2001 deficiency auction. The CRPP simply ensures that if a shortfall is forecasted, the resources necessary to eliminate the shortfall will be developed. It does not eliminate unanticipated shortfalls. These could occur for a number of reasons:

- Minimum ICAP requirements are determined based on the load forecast for the next year. If load grows more quickly than anticipated, there may be a shortfall, even if enough generation was under development to meet previous expectations of load.

- Generators can take longer to develop than was anticipated. As a result, there can be shortfalls, even if enough generation was under development to meet forecasted minimum ICAP requirements if all generation had been placed in service on schedule.

- Generators can retire unexpectedly—due to environmental restrictions, for example, or due to unexpectedly adverse market conditions. If these restrictions are imposed without sufficient lead time, shortfalls can result, even though enough generation was expected to be in service to meet minimum ICAP requirements before these retirements occurred.

- The minimum ICAP requirement, stated as a percentage of peak load, can increase (as it has in Long Island). Again, these percentages are determined just a few months before each Capability Year begins, so increases in these percentages can cause a shortfall, even if there was enough generation in development to meet the ICAP requirements that would have been calculated using the previously effective percentages.

USING LONG-RUN EQUILIBRIUM MEASURES OF COSTS

In our first set of comments, we stated that the intent of the study was to estimate the net cost of developing new peaking generation in the long-run equilibrium, so temporary fluctuations in costs or financing assumptions should be ignored. In the NERA presentation, NERA indicated that it believed that it *should* take these transient factors into account, stating, "It is necessary to recognize these [non-equilibrium transitory] conditions to avoid results that attract too much or too little capacity."[3] With this in mind, we have re-examined our previous recommendation. The vast majority of the payments made to new generation will be based on future demand curves that will not reflect current deviations from long-term equilibrium conditions, so investments made in new generation will primarily reflect expectations regarding these future demand curves, not the 2008-11 demand curves; as a result, we doubt that taking these transitory

[3] "Demand Curve Reset Update Financial Assumptions," Jan. 18, 2007, p. 18.

conditions into account in the development of the 2008-11 demand curves will actually ”avoid results that attract too much or too little capacity.” Nevertheless, our conclusion is that the approach that NERA has proposed is acceptable, *as long as future demand curve studies also use this approach.*

To illustrate the logic leading to this conclusion, consider a simple example. Ignore inflation, and suppose that all relevant factors are set at their long-run equilibrium levels at all points in time with one exception: the cost of generating equipment. Over the time frame to which the reset demand curves will apply (May 2008 through April 2011), suppose that a glut of generating equipment is anticipated, which causes the cost of generation development, including all fixed operating costs, to be $70/kW-yr. Also assume that the margins on energy and ancillary services sales that would be expected at the targeted ICAP level are $20/kW-yr. In that case, the net cost of entry, evaluated at the targeted ICAP level, is currently $50/kW-yr. (Since margins depend on the amount of capacity developed, the net cost of entry will be higher at higher quantities of ICAP, and lower at lower quantities of ICAP.) In each succeeding three-year period, assume that three different scenarios are possible:

1. There will be a glut of generating equipment, so the cost of generation development will be $70/kW-yr. Then the net cost of entry in that three-year period, evaluated at the targeted ICAP level, will be $70 – $20 = $50/kW-yr.

2. There will be a shortage of generating equipment, so the cost of generation development will be $90/kW-yr. Then the net cost of entry in that three-year period, evaluated at the targeted ICAP level, will be $90 – $20 = $70/kW-yr.

3. There will be neither a glut nor a shortage of generating equipment, so the cost of generation development will be $80/kW-yr. Then the net cost of entry in that three-year period, evaluated at the targeted ICAP level, will be $80 – $20 = $60/kW-yr.

Also assume that the first two scenarios are equally likely. In that case, the long-run expected cost of generation development is $80/kW-yr., and the long-run equilibrium net cost of entry is $60/kW-yr. Finally, assume that generators that begin development now will not be ready to go into service until May 2011. (We will relax this assumption later.)

Initially, let us set the demand curves using long-run expectations. Then the price of ICAP, evaluated at the target ICAP level, is $60/kW-yr. How much generation will be developed?

- The current net cost of entry evaluated at the target ICAP level is only $50/MWh.

- The revenues that ICAP providers will receive if ICAP is at the target level will be $60/kW-yr.

- Therefore, the target ICAP level cannot be an equilibrium in the short term, since the ICAP revenues that entrants would expect at that level of ICAP exceeds the current net cost of entry at that level of ICAP. Additional entry will occur, which will drive up the net cost of entry (because it depresses margins) and which will drive down the ICAP revenues that generators expect to earn over their lives. At some quantity that exceeds the target ICAP level, the net cost of entry will equal the price of ICAP. That will be the short-run equilibrium quantity of ICAP.

Next, assume that each demand curve is set using short-run expectations, so that the price of ICAP, evaluated at the target ICAP level, is $50/kW-yr. How much generation will be developed?

- The current net cost of entry evaluated at the target ICAP level is again only $50/MWh.

- The price of ICAP at the target ICAP level will be $50/kW-yr. from 2008-11, but newly built generators will not be available then, so this does not affect the revenues they receive.

- In future years, the price of ICAP at the target ICAP level might be $50/kW-yr. (if scenario 1 applies), might be $70/kW-yr. (if scenario 2 applies), and might be $60/kW-yr. (if scenario 3 applies). On average, the price of ICAP at the target ICAP level will be $60/kW-yr., because scenarios 1 and 2 are equally likely, so they offset each other. Therefore, the revenues that ICAP providers will receive if ICAP is at the target level will average $60/kW-yr.

- Therefore, the target ICAP level once again cannot be an equilibrium in the short term, as the ICAP revenues that entrants would expect at that level of ICAP exceeds the current net cost of entry at that level of ICAP. Additional entry will occur, which will drive up the net cost of entry (because it depresses margins) and which will drive down the ICAP revenues that generators expect to earn over their lives. At some quantity that exceeds the target ICAP level, the net cost of entry will equal the price of ICAP. That will be the short-run equilibrium quantity of ICAP (which exceeds the target ICAP level, so this approach does not avoid attracting too much capacity).

In fact, the short-run equilibrium quantity of ICAP is the same under either approach. This is due to the assumption that new generation will not be ready to go into service until May 2011, so that the payments it receives are unaffected by the results of the demand curve reset process for 2008-11. In fact, the results of this demand curve reset process are scheduled to be filed with FERC by the end of this year. The minimum construction duration included in Sargent & Lundy's table is 20 months, so if construction began immediately upon FERC acceptance of the reset demand curve, a new generator might be ready by late 2008, so that it might receive as much as 1½ years of revenue under the 2008-11 demand curves. This would decrease the amount of capacity developed under the second approach slightly, as the price of ICAP at the target ICAP level would be $50/kW-yr. for the first 1½ years of the new generator's life, instead of averaging $60/kW-yr. throughout that generator's life. A small reduction in the amount of capacity developed would cause an increase in margins which would offset this reduction in capacity revenue. But this would not have a large impact, as the vast majority of the new generator's revenue would be based on future demand curves.

On the other hand, adopting an approach that shifts back and forth between using short-term assumptions and using long-term assumptions could substantially affect the amount of capacity that is developed. If, for example, demand curves were set using short-term expectations when there is a equipment glut (i.e., when scenario 1 occurs), and long-term expectations otherwise, then the price that corresponds to the target ICAP level would, over the long term, average less than $60/kW-yr. As a result, over the long term, less than the target level of ICAP would be developed, since the net cost of entry averages $60/kW-yr. when evaluated at the target level of ICAP, and that would exceed expected revenues. Similarly, if demand curves were set using short-term expectations when there is a equipment shortage (i.e., when scenario 2 occurs), and long-term expectations otherwise, then the price that corresponds to the target ICAP level would, over the long term, be more than $60/kW-yr., and over the long term, more than the target level of ICAP would be developed since the net cost of entry averages $60/kW-yr. when evaluated at the target level of ICAP, and that would be less than expected revenues.