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October 25, 2004

VIA HAND DELIVERY

Mr. John W. Boston
Chair of the Board of Directors of the
New York Independent System Operator
c/o Robert E. Fernandez
General Counsel
New York Independent System Operator
290 Washington Avenue Extension
Albany, NY 12065

Dear Mr. Boston,

Attached is a submission of responsive supplemental information in the matter of the NYISO Staff's proposed demand curves for installed capacity for the 2005-06, 2006-07 and 2007-08 capability years, which is filed on behalf of Central Hudson Gas & Electric, LIPA, New York State Electric & Gas, Niagara Mohawk Power Corporation and Rochester Gas & Electric.

Sincerely,

Paul L. Gioia

PLG:jt (88369)

Responsive Supplemental Information Regarding Installed Capacity Demand Curves

Submitted by Central Hudson Gas & Electric, LIPA, New York State Electric & Gas, Niagara Mohawk Power Corporation and Rochester Gas & Electric

October 25, 2004

EXECUTIVE SUMMARY

This submission responds to the initial submissions of supplemental information by the Independent Power Producers of New York (IPPNY); the staff of the Department of Public Service (DPS); Entergy, Mirant and Sithe (EM&S); and KeySpan-Ravenswood (KSR).

NYISO Staff based its proposed demand curves for the New York Control Area (NYCA) for the 2005-06, 2006-07 and 2007-08 capability years, in part, on estimates of margins above variable costs that new generators could reasonably expect to earn from the sale of energy and ancillary services that IPPNY claims are overstated in its initial submission. IPPNY asserts that estimates produced by a model operated by the NYISO's consultant yield more realistic estimates of these margins. However, IPPNY ignores the fact that the price forecasts produced by this model are considerably below forward prices actually observed in the market, as we demonstrated in our initial submission. Correction for this difference leads to the conclusion that NYISO Staff's estimates of these margins are not overstated, but rather are understated.

DPS Staff reduced its estimate of margins on energy and ancillary services sales to a level that is near the midpoint of the range we proposed in our initial submission. However, DPS Staff then recommended that this margin be halved when setting the level of the demand curves. DPS Staff has provided no basis for this assumption, and the resulting estimate of energy and ancillary services margins falls outside the range of reasonableness. The estimate of these margins that appeared in our initial submission is more appropriate.

EM&S contend that the NYISO should not include a winter revenue benefit, which is intended to correct for errors in assumptions regarding the amount of ICAP that is supplied during the winter as compared to the amount supplied during the summer, in its demand curve. To support this, EM&S selectively cite data on ICAP imports to suggest that substantial amounts of additional ICAP will be supplied this winter, and as a result, the errors in these assumptions observed last year will not recur this year. However, a broader view of ICAP imports actually confirms the NYISO Staff estimate of the winter revenue benefit, as the change in ICAP imports is relatively small. Therefore, the NYISO Staff estimate of the winter revenue benefit should be approved.

KSR alleges that a 15-year lifespan should be used to determine the period of time in which a new generator would need to produce sufficient revenue to justify the initial investment. However, KSR provides no credible support for the claim that investors would require payback within 15 years for a facility with a useful life well in excess of that.

Responsive Supplemental Information Regarding Installed Capacity Demand Curves

Submitted by Central Hudson Gas & Electric, LIPA, New York State Electric & Gas, Niagara Mohawk Power Corporation and Rochester Gas & Electric

October 25, 2004

The parties above hereby submit the following responsive supplemental information for consideration by the Board of Directors of the NYISO (Board) as it reviews the initial supplemental information it has received regarding the proposal prepared by NYISO Staff for installed capacity (ICAP) demand curves to apply to the 2005-06, 2006-07 and 2007-08 capability years for the NYCA. We have broken our responses down into three principal areas: energy and ancillary services margins, the winter revenue benefit, and development costs. We have also included a clarification of the recommendation included in our initial submission regarding the zero-crossing point and the adjustments to the demand curves needed to accommodate our recommendation regarding the zero-crossing point.

In reviewing the initial and responsive submissions of supplemental information, we urge the Board not to lose sight of our basic objective in establishing ICAP demand curves: to provide sufficient economic incentives to encourage the development of adequate resources in the NYCA to meet the installed capacity requirement (currently 118% of peak load). While we recognize and support the need for some conservatism in the development of ICAP demand curves, establishing demand curves above what is reasonably necessary will have serious economic consequences for New York consumers and the New York economy. It is not possible to accurately quantify the cost to New York of unnecessarily high ICAP demand curves. However, it is quite possible that, over a ten-year period, the difference between the ICAP demand curves we are recommending and those proposed by NYISO staff could cost New York consumers and the New York economy hundreds of millions of dollars. The parties submitting these comments have statutory responsibilities to maintain reliability in the New York control area, and do not take those responsibilities lightly. However, we also are very concerned with the imposition of unnecessary costs on New York consumers, as should the NYISO and FERC. When the NYISO submits its demand curve to FERC, it will be seeking a FERC finding that the resulting costs imposed on consumers are just and reasonable. The Board should give that issue its most careful consideration.

I. Energy and Ancillary Services Margins

As noted in the initial supplemental information we submitted, the net cost of entry for new generation must take into account the margins above variable cost that new generators will expect to earn. The greater these margins, the smaller the amount that must be paid to induce entry, and hence the lower the level at which the ICAP demand curves should be set. NYISO Staff, in its proposal, estimated that developers of new Frame 7 generators in the rest-of-state (ROS) region could expect to earn $15/kW-yr. during supply conditions that correspond to the minimum ICAP requirement for the New York Control Area (NYCA). This $15/kW-yr. consists of $5/kW-yr. that investors would expect to earn during non-shortage conditions and $10/kW-yr. that could be expected during shortage conditions.

A. IPPNY Submission

IPPNY, in its initial submission of supplemental information, objects to this estimate, claiming that it overstates the energy and ancillary services margins that a developer of such a generator could reasonably anticipate. IPPNY's arguments supporting this contention include the following:

- Entities such as public power authorities will not permit the ICAP supply to fall to 118 percent. Instead, they will take action to develop additional capacity before we reach that point. Therefore, the *de facto* minimum level of ICAP exceeds 118 percent of NYCA peak load (the official level of the minimum NYCA ICAP requirement), and the estimates of energy and ancillary services margins be consistent with this *de facto* minimum requirement.

- New generation cannot be added in extremely small increments, but must rather be added in discrete "lumps." As a result, if we were to begin at equilibrium, with the amount of capacity supplied equal to the minimum NYCA ICAP requirement, addition of a lump of capacity would cause the price of ICAP to fall below the net cost of entry, ensuring that such an investor could not expect to recover the cost of its investment (if the net cost of entry has been estimated accurately).

- Energy and ancillary services margins are best estimated using models, such as the model that LAI used, which can account for factors such as start-up times and costs and minimum generation costs. These factors cause the estimates of these margins prepared by Dr. David Patton, the NYISO's independent market advisor (and estimates calculated by the staff of the Department of Public Service (DPS), which were based on Dr. Patton's analysis) to be overstated.

Each of these arguments is incorrect. The first argument states that the Board should promulgate ICAP demand curves that reflect the energy and ancillary services margins that are consistent with what IPPNY claims is a *de facto* minimum ICAP requirement for the NYCA that exceeds the ICAP requirement that has been set by the NYISO. However, the NYISO ICAP Manual clearly states, "Each ICAP Demand Curve is set based upon the localized, levelized cost of a gas turbine at the NYCA Minimum Installed Capacity Requirement…." In other words, IPPNY recommends that the Board design the ICAP demand curves in a manner that is inconsistent with the procedure required under the ICAP Manual. Moreover, if the Board were to do so, the anticipated result would be that more capacity would be developed than is required to meet the NYCA minimum ICAP requirement. If IPPNY believes that the NYCA minimum ICAP requirement should be increased, IPPNY should propose tariff modifications implementing such an increase to the appropriate NYISO committees. IPPNY has not done so, and it certainly has not presented any evidence in support of such a proposal. The Board should summarily reject IPPNY's attempt to perform an end-run around the procedures that are spelled out in the NYISO's Services Tariff and the NYISO ICAP Manual for determining the minimum NYCA ICAP requirement.

IPPNY's second argument states that if the ICAP demand curve is drawn with the intent of ensuring that new entrants into the market just recover the net cost of entry when the NYCA is at its minimum ICAP requirement, developers will lose money unless New York goes slightly short on capacity due to the lumpiness of new generation. In particular, IPPNY asserts that since a new twin Frame 7 installation will have generating capacity of 293 MW,[1] approximately one percent of the NYISO's ICAP requirement, the addition of a new twin Frame 7 installation when the NYISO was at the minimum ICAP requirement would cause the supply of ICAP to exceed the minimum requirement by approximately one percent, forcing prices below the net cost of entry. This suggests such a generator would not be added until the supply of ICAP in the NYCA is less than the minimum requirement, because under only those conditions could a new generator recover the cost of entry. This would be contrary to the objective of the ICAP market, which is to ensure that the minimum ICAP requirement is met.

However, this argument implicitly ignores the ability of such a unit to sell ICAP into other markets. If selling all of its ICAP into the New York market would depress prices below the net cost of entry, it can sell some of that ICAP elsewhere.[2] Therefore, to assess the effect of additional capacity on ICAP prices,

[1] IPPNY actually cites generating capacity of 326 MW, but if a single figure is to be used, the summer capacity of 293 MW is more reasonable, since the NYCA ICAP demand curve is drawn to ensure that the NYISO will be able to meet the minimum NYCA ICAP requirement during the summer.

[2] In the past, this option may not have been very palatable for two reasons. First, differences between the structures of the New York ICAP market and adjoining markets have caused prices in the New York ICAP market to be significantly above ICAP prices elsewhere. However, both PJM and ISO New England are deeply

the proper comparison is not between the amount of ICAP the new generator would supply and the demand for ICAP in New York. Instead, it is between the amount of ICAP the new generator would supply and the demand for ICAP in New York, New England and PJM. The total demand for ICAP in that region is well over 100,000 MW, and so the effect on regional ICAP prices resulting from the entry of a single new generator will be *de minimis*.[3]

Finally, IPPNY claims that the estimates of energy and ancillary services margins that Dr. Patton prepared are flawed, because they did not properly account for the presence of start-up times and start-up and minimum generation costs.[4] Dr. Patton has acknowledged that his analysis contains some simplifying assumptions that could cause his estimate of these margins to be overstated. However, they could also cause his estimates to be understated in some cases. More important, even if one were to accept IPPNY's criticisms, it does not follow that the NYISO therefore should use an estimate of energy and ancillary services margins produced by the model that LAI used. The problem with the use of such models, as we discussed in our initial submission, is that they do not properly estimate the energy and ancillary services that peaking units—such as a Frame 7—would earn because they fail to dispatch such units with anything approaching the frequency with which such units are dispatched in actual operations. Consequently, the models produce results that are inconsistent with market participants' expectations regarding future prices, so those results must be adjusted to reflect the differences between the prices produced by the model and the prices that market participants actually expect to observe. Our initial submission contained such an adjustment, and nothing in IPPNY's submission indicates that such an adjustment is not needed.

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involved in the process of revamping their ICAP markets, and while the final outcome of those procedures are unknown, the very likely result is an increase in payments to ICAP providers that better reflects the net cost of entry in each of those regions. Consequently, this option will become more practical. Second, prices in adjoining ICAP markets have been very low recently due to a glut of capacity in those markets. But this glut will dissolve over time. Since the ICAP demand curve is supposed to be based on the long-term net cost of entry, it should not reflect short-term phenomena such as the glut of capacity in adjoining markets.

[3] In situations in which the amount of capacity likely to be provided by a new generator was a large portion of the minimum ICAP requirement, some adjustment likely would be necessary to guard against the problem IPPNY describes. However, even in those cases, we would oppose deliberately understating energy and ancillary services margins, which effectively seems to be the approach IPPNY advocates for dealing with this problem. Instead, energy and ancillary services margins, along with all other components feeding into the ICAP demand curve, should be estimated as accurately as possible, and then, at the end of the process, some adjustment ought to be made to account for lumpiness. Therefore, IPPNY's argument that the energy and ancillary services margins ought to be estimated "conservatively" (i.e., ought to be deliberately underestimated) to account for lumpiness fails even in cases in which lumpiness is a significant concern.

[4] IPPNY also improperly asserts that Dr. Patton calculated an upper bound of $18.52/kW-yr. on energy and ancillary services margins in the Capital zone. Actually, Dr. Patton calculated an upper bound on energy and ancillary services margins *during non-scarcity conditions* of $8.52/kW-yr. He then added an estimate of margins during scarcity conditions of $10/kW-yr. to arrive at an estimate of $18.52/kW of energy and ancillary services margins over the course of the year, but that is not an upper bound on total energy and ancillary services margins, since he did not characterize the $10/kW-yr. estimate as an upper bound. Indeed, he has clearly indicated in ICAP Working Group meetings that it is not an upper bound, and that one could reasonably use higher estimates of margins during scarcity conditions. Since his $10/kW-yr. estimate was based on the assumption that there would only be 20 hours per year in which there was scarcity pricing, and Dr. Patton indicated that there would likely be more than 20 hours per year of scarcity pricing when the ICAP supply was equal to the minimum NYCA ICAP requirement, the $10/kW-yr. estimate of margins during scarcity conditions is probably closer to a *lower* bound for energy and ancillary services margins during scarcity conditions—which renders problematic IPPNY's recommendation of $10/kW-yr. in margins for these units for *all* hours, including both scarcity and non-scarcity conditions.

B. DPS Staff Submission

In a brief initial submission, DPS Staff revised its estimate of the energy and ancillary services margins that a Frame 7 generator in the Capital zone (which is part of ROS) could reasonably expect to earn to $25/kW-yr., reflecting modifications in the analysis performed by Dr. Patton upon which the DPS Staff analysis was based. DPS Staff then recommended that only half of these projected margins be used for the purposes of estimating a demand curve. IPPNY cited the $12.50/kW-yr. margin that results after DPS Staff's estimate is halved in its initial submission as support for its proposal to assume margins of $10/kW-yr. for such a generator when calculating the net cost of entry in ROS.

In our initial submission, we had suggested that reasonable estimates for these margins could range from $17/kW-yr. to $37/kW-yr., depending on assumptions regarding the number of hours in which scarcity pricing applied. DPS Staff's assessment of margins this generator could expect to earn is fully consistent with ours, as its $25/kW-yr. estimate is very close to the midpoint of our range of reasonable estimates, so we have no disagreement with DPS Staff regarding the likely level of energy and ancillary services margins.

However, we differ with DPS Staff regarding its proposal to reduce its best estimate of the margins that new generators can reasonably anticipate by one-half. By cutting this estimate in half, reducing it from $25/kW-yr. in margins to $12.50/kW-yr., DPS Staff effectively proposes to calculate the net cost of entry in ROS under the assumption that energy and ancillary services margins that falls outside what we believe to be the range of reasonableness, which therefore will lead to the overcompensation of ICAP providers. DPS Staff has not provided any rationale for halving these margins, as compared to multiplying these margins by some factor other than one-half or using some other approach to ensure conservatism in the net cost of entry.

We acknowledge that estimates of the net cost of entry are subject to error, and there is justification for some conservatism in the development of the ICAP demand curves. However, the need for conservatism does not eliminate the Board's responsibility to ensure that the estimates are reasonable. Therefore, we have recommended that the ICAP demand curve be drawn while estimating margins of $22/kW-yr., which is conservative, but which remains within the range of reasonableness.

II. Winter Revenue Benefit

The amount of ICAP that a generator can provide during the summer capability period is based upon its demonstrated maximum net capability (DMNC) for the summer, while the amount of ICAP a generator can provide during the winter is based on its winter DMNC. Since winter DMNCs typically exceed summer DMNCs, if the same generators sell into the ICAP market in both the summer and the winter, the winter price will typically be lower than the summer price, which reduces ICAP revenue. This effect on ICAP revenue is partially (but not completely) offset by the ability of a new generator to sell more ICAP in the winter than in the summer. NYISO Staff performed an adjustment to its proposed ICAP demand curves to account for this disparity between summer and winter ICAP revenues. This adjustment, which we will call the "seasonality adjustment," is intended to ensure that, when the amount of ICAP supplied in the NYCA is equal to the minimum NYCA ICAP requirement, a developer of new generation in ROS can expect sufficient revenue over the course of the year to recoup the net cost of entry that has been calculated for ROS.

However, the procedure described above for performing the seasonality adjustment rests on one critical assumption: that the same set of generators sells into the NYISO's ICAP market in both the summer and the winter. If some entities sell ICAP in New York in the summer (when ICAP prices are relatively high), but not in the winter (when ICAP prices are relatively low), the methodology proposed above will over-correct for the difference between summer and winter ICAP revenues. This is because the absence of some summer suppliers from the winter ICAP market will cause winter ICAP prices to be higher than they would have been if those suppliers had continued to sell ICAP into New York in the winter, which lessens the amount by which the ICAP demand curve must be raised to account for differences between winter and summer revenues. If the procedure used to develop the demand curve does not take the potential absence of some summer ICAP suppliers from the winter ICAP market into account, and some summer ICAP suppliers are nevertheless absent from the winter market, ICAP suppliers in ROS would receive more revenue over the course of the year than is necessary to induce entry. Consequently, New York end-use consumers would pay too much for ICAP.

NYISO Staff, recognizing these concerns, included a "winter revenue benefit" in its estimate of the net cost of entry in ROS. The winter revenue benefit adjusts the seasonality adjustment to account for the difference between (1) the amount by which the actual supply of ICAP to New York during the winter exceeds the actual supply of ICAP to New York during the summer, and (2) the value the NYISO assumed for this difference when performing the seasonality adjustment. In this case, when it performed the seasonality adjustment included in its ICAP demand curve proposal, NYISO Staff assumed the difference between winter ICAP supply and summer ICAP supply would be 1400 MW, but this difference (during the first year of operation under the NYISO's new ICAP demand curves) was only 600 MW, an 800 MW difference. The winter revenue benefit corrects the seasonality adjustment to account for this difference.

Dr. Patton has issued an opinion recognizing the need for such an adjustment, if such differences can be expected to persist in the long term. Nevertheless, EM&S argue in their initial submission that the winter revenue benefit is groundless and should be discarded.[5] If the winter ICAP price in the New York market is systematically below the summer ICAP price, it is reasonable to expect some entities that decided to supply ICAP to New York during the summer either to supply ICAP into other markets or not to supply ICAP at all during the winter. As established above, ignoring this possibility will lead to an excessively high ICAP demand curve. Consequently, common sense indicates a need for some sort of winter revenue benefit.

While the need to consider the winter revenue benefit when calculating the net cost of entry is clear, the NYISO must also establish the appropriate level for this adjustment. NYISO Staff has calculated that, for every 110 MW by which the NYISO had overestimated the amount of ICAP that would be supplied during the winter when performing the seasonality adjustment, generators receive an additional $1/kW-yr. in revenue, indicating that the ICAP demand curve should be decreased by $1/kW-yr. to counterbalance this effect. Consequently, based on the information presented above for the first year of ICAP market operation under the new demand curves, the appropriate winter revenue benefit of $1/kW-yr. x (800 MW / 110 MW) = $7.27/kW-yr. NYISO Staff conservatively proposed a winter revenue benefit of $5/kW-yr. in its estimate of the net cost of entry in light of these observations from last winter.

In their initial submission, EM&S argue that data from last winter do not reflect what can be expected in the future. In particular, they assert that the difference between the assumptions that NYISO Staff made when performing the seasonality adjustment and the actual supply of ICAP in the summer and the winter that was observed last year will not even persist for the current year. They claim that this is apparent from the amount of ICAP that has already been sold in the ISO's markets for the upcoming winter. To support this claim, they selectively cite comparisons between the amount of ICAP suppliers in certain external control areas provided last winter and the amount of ICAP those suppliers are committed to provide this winter. However, these increases are partially offset by decreases in supply from other control areas. In fact, the winter ICAP supply during the 2003-04 capability year exceeded summer ICAP supply by 555 MW, while winter ICAP supply committed (as of October 17) during the 2004-05 capability year exceeds summer ICAP supply by 361 MW.[6] This is a difference of only about 200 MW, leaving 600 MW of the

[5] IPPNY also objects to the winter revenue benefit, although they defer to EM&S to make the argument.

[6] ICAP imports averaged 2750 MW during the summer of 2003 (excluding May, since the new ICAP demand curves were not effective then) and 2195 MW during the winter of 2003-04, for a difference of 555 MW. ICAP

difference observed by NYISO Staff last winter intact. A 600 MW difference would lead to a winter revenue benefit of $1/kW-yr. x (600 MW / 110 MW) = $5.45/kW-yr., very close to the figure that the NYISO actually plans to use. Instead of supporting EM&S's conclusion that "NYISO Staff's purported winter revenue benefit does not even exist now…," analysis of ICAP sales by *all* external suppliers for the upcoming winter and consideration of their impact on winter ICAP prices yields a result that is fully consistent with NYISO Staff's estimate of winter revenue benefits.[7]

EM&S also argue that, as the amount of ICAP supplied in New York approaches the minimum NYCA ICAP requirement and ICAP prices rise, entities that currently do not sell into the ICAP market in the winter will find it in their interest to do so. This would cause the difference between winter and summer prices to increase over time, decreasing the winter revenue benefit. While this may have some validity, other factors must be considered as well. For example, as previously noted, adjoining control areas are currently deeply involved in considering revisions to their ICAP markets. The likely effect of these revisions will be to increase average annual ICAP prices in those regions to levels that are roughly comparable to prices realized in New York. However, those regions currently do not differentiate between winter and summer DMNCs in determining each seller's ability to sell ICAP, which causes winter and summer prices in those markets to be very similar. If that feature of those markets persists, market participants may have incentives to sell into those markets in the winter, as prices in those markets during the winter would be higher than winter prices in New York, because New York's ICAP prices during the winter have been depressed by the use of winter DMNCs while the prices of ICAP in neighboring regions have not been depressed. In addition, market participants would have an incentive to sell into New York during the summer, because New York's ICAP prices will be relatively high then (due to the need to increase summer prices to make up for the relatively low winter prices). Consequently, additional entities could decide to supply ICAP during the summer only, causing the amount by which the supply of ICAP during the winter exceeds the supply of ICAP during the summer to *decrease* substantially in future years, which would increase the need for a winter revenue benefit.

In the end, despite EM&S's assurance that the difference between the amount of ICAP that will be supplied in the summer in the future and the amount of ICAP that will be supplied in the winter in the future can be accurately forecasted using data in the NYISO's Gold Book, it is very difficult to predict the future difference between winter and summer ICAP supplies. It depends not only on the behavior of participants in the New York markets, but also on the evolution of neighboring markets and the behavior of participants in those markets. Nevertheless, the need for some adjustment to account for this difference is apparent. There is no particular reason to believe that an adjustment based on the past winter's experience would be biased in one direction or the other. NYISO Staff's proposal to set the winter revenue benefit at $5/kW-yr. is reasonable and consistent with all data available to date, and it should be accepted by the Board.

III. Development Costs

KeySpan-Ravenswood's initial submission of supplemental information suggested that the development costs assumed by NYISO Staff for new generators was too low. Even though the KeySpan-Ravenswood (KSR) submission focuses on the ICAP demand curve for New York City and we focus on the ICAP

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imports averaged 2750 MW during the summer of 2004 and 2394 MW during the winter of 2003-04, for a difference of 555 MW. Data source: http://www.nyiso.com/markets/icapinfo.html .

[7] EM&S also assert, "the $5 offset proposed by NYISO Staff assumes that there will be 550 MW of unutilized import capability." It makes no such assumption—a $5 offset merely indicates that at least 550 MW less will be supplied in the winter than the NYISO assumed when it performed its seasonality adjustment. Some of this difference may result from decreases in imports between the winter and the summer, but some of it may result from internal suppliers that sell into the New York ICAP markets in the summer but not the winter, and some may result simply from differences between the database the NYISO used to determine the likely difference in summer and winter ICAP and the actual set of sellers of ICAP to New York.

demand curve for the NYCA, KSR's proposal to assume a 15-year lifespan to determine the ICAP revenue that a new generator would require could also be applied to the calculation of the NYCA ICAP demand curve, so we respond to it here.

KSR suggests that a 15-year lifespan should be used to determine the ICAP revenue that a new generator would require, instead of the 20-year lifespan that the NYISO's consultant, Levitan & Associates (LAI), used when calculating the ICAP payment stream that would be required to induce development of new generation.[8] If investors require their initial capital outlay to be recovered in 15 years instead of 20 years, the ICAP payment they would require each year would increase, and the ICAP demand curve would need to be raised commensurately.

In support of its assertion, KSR points to a report it commissioned from PA Consulting, which concluded that "a 15-year life is a more reasonable methodology for three primary reasons:

- "First, the IRS uses a 15-year life for peaking plants.
- "Second, the investment community has widely accepted a 15-year life for financing peaking plants.
- "Third, the majority of a peaking plant's revenue comes from the ICAP market, thus there is an investment risk associated with fluctuations in market reserve margins, which applies to peaking units more than baseload generation. There is a disincentive to invest in new peaking plant capacity if entities cannot gain full returns on their investments in 15 years."

These assertions are not valid. The first argument is particularly specious. To illustrate, suppose that the tax law were modified to permit investment in new generation to be fully depreciated in one year. Would it then follow that investors in new generation would require payback on new investments within one year? Similarly, if the tax law required investments in these generators to be depreciated over 100 years, investors would not suddenly be willing to wait a century to recover their investment. The depreciable life of an investment for tax purposes is not relevant to the determination of the lifespan over which investors will require recovery of their invested funds.

KSR has not submitted any evidence to support its second argument, so it should be dismissed summarily. Additionally, we note that using a 15-year lifespan contradicts not only the assumptions made by LAI, but also by PJM and ISO New England in their recent studies of the net cost of entry in their regions. Finally, one must consider that the ICAP demand curves must be developed with the intention of providing proper long-run incentives for the development of additional capacity. Consequently, NYISO Staff estimated costs and revenues that would prevail in the long run. They tried to avoid using cost or revenue estimates that may be temporarily distorted due to short-run phenomena. Similarly, financing assumptions should reflect long-run expectations, not short-run phenomena. Even if it had been demonstrated that, given the current regional capacity glut, investors require payback within 15 years, there is no reason to believe that in the long run, when the capacity glut has been exhausted, investors in these plants would ignore all margins they earn in the last five years of a 20-year lifespan when determining whether to invest in those plants. But that is just what using a 15-year lifespan would do, if one expects these generators to be able to operate for 20 years.[9]

Finally, KSR's third argument consists of two seemingly unrelated statements. The first notes that peakers are more subject to ICAP price volatility since ICAP payments constitute a larger part of their revenue. This is true; of course, they are less subject to energy market volatility since energy payments constitute a

[8] IPPNY also briefly makes this assertion in its submission, suggesting that development costs have been understated as a result of the 20-year assumption.

[9] EM&S also suggest that a 15-year lifespan should be assumed to reflect current financing conditions.

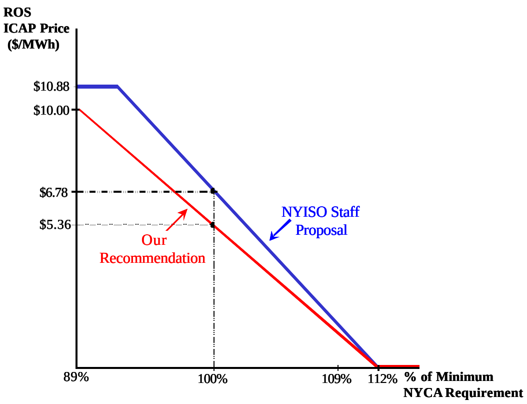
smaller part of their revenue, so it is unclear whether their aggregate revenues are more or less volatile that the aggregate revenues of the average generator. In any case, it is hard to see what this has to do with the lifespan that should be assumed; it might have something to do with the debt rate or return on equity that should be assumed, but KSR makes no such argument. The second statement notes that using a 15-year life would encourage investment. It would, and using a 10- or a 5-year life would encourage it even more. It does not follow that the NYISO should assume a 10- or a 5-year life when calculating the ICAP payment required to induce new investment. Instead, the NYISO should use a reasonable expectation of the lifespan that investors are most likely to consider in the long run when making investment decisions. Anything else would constitute a subsidy, at the expense of New York end-use customers. KSR has presented no evidence to demonstrate that the NYISO should not use LAI's assumption of a 20-year lifespan.

IV. Zero-Crossing Point

The minimum ICAP requirement for the NYCA is currently set at 118 percent of peak load. Under the design of the New York ICAP market, the NYISO may purchase ICAP above that level, although the price decreases as the quantity purchased increases. The zero-crossing point is the maximum quantity of ICAP that the NYISO will purchase at a positive price. The NYISO Staff proposal would set this at 112 percent of the minimum NYCA ICAP requirement, or 118% x 112% = 132.16% of peak load in the NYCA. In our initial submission, we recommended a change to the zero-crossing point that NYISO Staff had proposed, from 112% of the minimum NYCA ICAP requirement (i.e., requiring the purchase of ICAP representing as much as 132.16% of peak load) to 108-110% of the minimum NYCA ICAP requirement (i.e., 127.44-129.8% of peak load). This change could save New York consumers substantial amounts that they would otherwise expend to purchase ICAP in excess of what is reasonably necessary to maintain reliability.

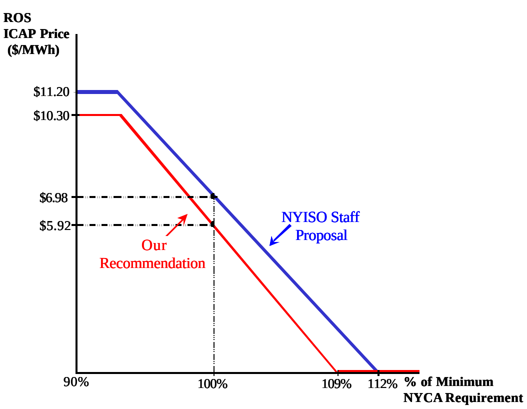
The zero-crossing point is fixed, according to the Services Tariff, for the 2005-06 capability year. Consequently, our recommended change in the zero-crossing point only applies to the NYCA ICAP demand curves for the 2006-07 and 2007-08 capability years. When the zero-crossing point changes, other changes to the ICAP demand curve are also required. In particular, the decrease in the zero-crossing point that we recommended in our initial submission would cause winter ICAP revenues to be lower than they would have been using NYISO Staff's proposed zero-crossing point. The seasonality adjustment (which we discussed in § II above) then must increase, since the difference between summer and winter ICAP revenues is higher, given our proposed zero-crossing point, than it would be for NYISO Staff's proposed zero-crossing point. Our recommended NYCA demand curve reflected this. However, since our recommended zero-crossing point only applied to the 2006-07 and 2007-08 capability years, these changes are only needed for the 2006-07 and 2007-08 capability years. This may have caused some confusion, since we only included an illustration of our proposed NYCA ICAP demand curve for a single year. To eliminate any potential confusion, we include three separate graphs and tables here to illustrate our proposal for each of the three capability years and compare them to NYISO Staff's proposed ICAP demand curves for the NYCA for each of those years. (For the purposes of these graphs, we have assumed a 109% zero-crossing point, the midpoint of our recommended range of zero-crossing points.)

For the 2005-06 capability year, the net cost of entry in ROS should be $53/kW-yr., for the reasons described in our initial submission. With a zero-crossing point of 112% of the minimum NYCA ICAP requirement, a demand curve price of $5.36/kW-mo. at the minimum NYCA ICAP requirement will permit recovery of the net cost in ROS over the course of the year, as the table below illustrates. Finally, per the Services Tariff, the price ceiling is 150% of the revenue requirement ignoring energy and ancillary services margins, or 1.5 x $80/kW-yr. / 12 = $10/kW-mo.



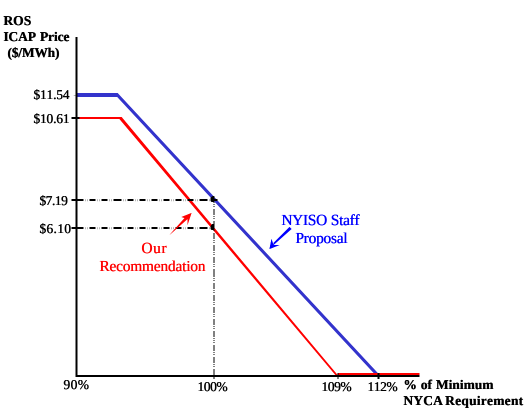
	NYISO Staff Estimate	Adjustment	Our Recommend-ation
Rev. Reqt. Ignoring Energy & A/S Margins ($/kW-yr.)	87.00	(7.00)	80.00
Energy and A/S Margins ($/kW-yr.)	15.00	7.00	22.00
Winter Revenue Benefit ($/kW-yr.)	5.00	-	5.00
Net Cost of Entry for ROS ($/kW-yr.)	67.00	(14.00)	53.00
Net Cost of Entry for ROS ($000/yr.)	21,869	(4,570)	17,299
Evaluated at NYCA Minimum ICAP Requirement in Summer:			
Summer ICAP Price ($/kW-mo.)	6.78	(1.42)	5.36
Winter ICAP Price ($/kW-mo.)	4.72	(0.99)	3.73
Monthly ICAP Revenues in Summer ($000)	1,986.81	(415.15)	1,571.66
Monthly ICAP Revenues in Winter ($000)	1,657.99	(346.45)	1,311.54
Annual ICAP Revenues ($000)	21,868.80	(4,569.60)	17,299.20
Assumptions:			
Summer DMNC for Twin Frame 7's (MW)	293.0		293.0
Winter DMNC for Twin Frame 7's (MW)	351.6		351.6
Capacity of Twin Frame 7's @ 59 degrees (MW)	326.4		326.4
Aggregate Winter DMNC/Summer DMNC Ratio	1.0366		1.0366
Zero-Crossing Point as % of Min. NYCA Reqt.	112%	0%	112%

For the 2006-07 capability year, the net cost of entry in ROS should be $54.59/kW-yr., a three percent increase over the net cost of entry for 2005-06. If the zero-crossing point is set at 109% of the minimum NYCA ICAP requirement, a demand curve price of $5.92/kW-mo. at the minimum NYCA ICAP requirement will permit recovery of the net cost in ROS over the course of the year, as the table below illustrates. The price ceiling is 150% of the revenue requirement ignoring energy and ancillary services margins, or 1.5 x $82.40/kW-yr. / 12 = $10.30/kW-mo.



	NYISO Staff Estimate	Adjustment	Our Recommend-ation
Rev. Reqt. Ignoring Energy & A/S Margins ($/kW-yr.)	89.61	(7.21)	82.40
Energy and A/S Margins ($/kW-yr.)	15.45	7.21	22.66
Winter Revenue Benefit ($/kW-yr.)	5.15	-	5.15
Net Cost of Entry for ROS ($/kW-yr.)	69.01	(14.42)	54.59
Net Cost of Entry for ROS ($000/yr.)	22,525	(4,707)	17,818
Evaluated at NYCA Minimum ICAP Requirement in Summer:			
Summer ICAP Price ($/kW-mo.)	6.98	(1.07)	5.92
Winter ICAP Price ($/kW-mo.)	4.86	(1.34)	3.51
Monthly ICAP Revenues in Summer ($000)	2,046.41	(312.45)	1,733.96
Monthly ICAP Revenues in Winter ($000)	1,707.73	(472.00)	1,235.73
Annual ICAP Revenues ($000)	22,524.86	(4,706.69)	17,818.18
Assumptions:			
Summer DMNC for Twin Frame 7's (MW)	293.0		293.0
Winter DMNC for Twin Frame 7's (MW)	351.6		351.6
Capacity of Twin Frame 7's @ 59 degrees (MW)	326.4		326.4
Aggregate Winter DMNC/Summer DMNC Ratio	1.0366		1.0366
Zero-Crossing Point as % of Min. NYCA Reqt.	112%	-3%	109%

Finally, for the 2007-08 capability year, the net cost of entry in ROS should be $56.23/kW-yr., a three percent increase over the net cost of entry for 2006-07. If the zero-crossing point is set at 109% of the minimum NYCA ICAP requirement, a demand curve price of $6.10/kW-mo. at the minimum NYCA ICAP requirement will permit recovery of the net cost in ROS over the course of the year, as the table below illustrates. The price ceiling is 150% of the revenue requirement ignoring energy and ancillary services margins, or 1.5 x $84.87/kW-yr. / 12 = $10.61/kW-mo.



	NYISO Staff Estimate	Adjustment	Our Recommend-ation
Rev. Reqt. Ignoring Energy & A/S Margins ($/kW-yr.)	92.30	(7.43)	84.87
Energy and A/S Margins ($/kW-yr.)	15.91	7.43	23.34
Winter Revenue Benefit ($/kW-yr.)	5.30	-	5.30
Net Cost of Entry for ROS ($/kW-yr.)	71.08	(14.85)	56.23
Net Cost of Entry for ROS ($000/yr.)	23,201	(4,848)	18,353
Evaluated at NYCA Minimum ICAP Requirement in Summer:			
Summer ICAP Price ($/kW-mo.)	7.19	(1.10)	6.10
Winter ICAP Price ($/kW-mo.)	5.00	(1.38)	3.62
Monthly ICAP Revenues in Summer ($000)	2,107.81	(321.83)	1,785.98
Monthly ICAP Revenues in Winter ($000)	1,758.96	(486.16)	1,272.81
Annual ICAP Revenues ($000)	23,200.61	(4,847.89)	18,352.72
Assumptions:			
Summer DMNC for Twin Frame 7's (MW)	293.0		293.0
Winter DMNC for Twin Frame 7's (MW)	351.6		351.6
Capacity of Twin Frame 7's @ 59 degrees (MW)	326.4		326.4
Aggregate Winter DMNC/Summer DMNC Ratio	1.0366		1.0366
Zero-Crossing Point as % of Min. NYCA Reqt.	112%	-3%	109%