Comments of the Transmission Owners, New York Power Authority and Long Island Power Authority on the NYISO Staff's Installed Capacity Demand Curves Proposal

October 8, 2010

Executive Summary

The Transmission Owners, New York Power Authority and Long Island Power Authority offer the following comments on the ICAP demand curves proposed by ISO Staff for the 2011-12 through 2013-14 capability years:

1. ISO Staff's proposal to base the ICAP demand curves for New York City and Long Island on the net cost of developing, constructing and operating an LMS 100 generator in those zones is appropriate, but its proposal to base the ICAP demand curve for the NYCA on the net cost of developing, constructing and operating a Frame 7FA generator in the Capital zone is inappropriate. ISO Staff made no attempt to establish that a Frame 7FA generator in the Capital zone is economically viable; the large difference between the net cost of developing the Frame 7FA generator and the net cost of developing an LMS 100 generator on Long Island suggests that the Frame 7FA generator is not economically viable. By tariff, the ICAP demand curve for the NYCA (which includes Long Island) must be based on the net cost of developing a unit that is economically viable, so it should be based on the net cost of developing an LMS 100 generator on Long Island.

2. ISO Staff's proposal for the ICAP demand curve for the NYCA correctly excludes the costs of deliverability upgrades for a proxy generator in the Capital zone. Whether such a resource would need to incur those costs is entirely speculative. The analysis presented by suppliers that purport to demonstrate that new generators in the Capital zone would incur such costs is based upon flawed calculations and unrealistic assumptions.

3. ISO Staff's proposal for the ICAP demand curve for New York City correctly assumes that a new peaking unit would be able to take advantage of available tax abatements,as the New York City Industrial Development Agency would have strong incentives to grant those abatements.

4. With regard to the amount of surplus capacity that is assumed to exist for purposes of determining the energy and capacity revenues that a new resource would receive, the ISO Staff's proposal is much better supported and justified than the assumptions that were used in the last demand curve review. Nevertheless, the ICAP demand curves should be set under the assumption that the

amount of capacity provided is equal to the minimum ICAP requirement. If the Board nevertheless elects to assume a surplus, ISO Staff's proposal for estimating those surpluses is generally reasonable, although the Board should eliminate ISO Staff's assumption that the surplus for the NYCA must be at least one percent of the ICAP requirement, even if the calculations used by ISO Staff result in a surplus of less than one percent.

5. ISO Staff's proposal correctly escalates the ICAP demand curves for future years using forecasted general inflation rates. Historic inflation rates are inappropriate for this purpose since they do not reflect expectations of the rate at which costs will increase.

6. ISO Staff's proposal includes an adjustment to account for differences in the amount of ICAP available in the market in the winter as compared to the summer, and the associated seasonal differences in ICAP prices. The adjustment unrealistically assumes that the same resources will sell capacity in both seasons. As historical experience has repeatedly demonstrated, this approach leads to too large an adjustment and unnecessarily high capacity prices. Instead, this seasonality adjustment should be performed using an approach that is consistent with the procedure that ISO Staff and its consultants used to estimate energy revenues. This would lead to a smaller and more realistic adjustment that is more consistent with historical experience.

7. ISO Staff's proposal would maintain the same ICAP demand curve shapes, slopes and zero crossing points that have been used since the ICAP demand curves were first implemented. The ICAP demand curve for the NYCA is too flat and requires end-use consumers to pay for significant amounts of capacity that provides little or no reliability benefit. To address this, the point at which the price of capacity reaches zero on the NYCA demand curve ought to be reduced from 112 percent of the ICAP requirement for the NYCA to 110 percent.

8. Within the next 12 months, the ISO should begin a comprehensive review of its capacity markets, including reconsideration of a forward ICAP market, consideration of setting the demand curve using alternative resources (e.g., combined cycle units, demand response providers), analysis of different demand curve shapes and zero-crossing points, and assessment of different approaches to adjusting for seasonal price differences. These topics have received insufficient attention in past demand curve reviews due to the need to meet tariff-established deadlines for filing the new demand curve proposal with FERC.

Appendix B provides a summary of the impact on end-use consumers of the various issues addressed in these comments.

COMMENTS OF THE TRANSMISSION OWNERS, NEW YORK POWER AUTHORITY AND LONG ISLAND POWER AUTHORITY ON THE NYISO STAFF'S INSTALLED CAPACITY DEMAND CURVES PROPOSAL

OCTOBER 8, 2010

The Transmission Owners,[1] New York Power Authority and Long Island Power Authority (collectively, "TOs") submit the following comments on the ISO Staff's ICAP demand curves proposal for the 2011-12 through 2013-14 capability years.[2] The TOs have commented on many aspects of the ISO Staff's proposal at various points in the development process, but in the interest of brevity, we are focusing these comments on the most significant elements of the ISO Staff Proposal.

I. CHOICE OF PEAKING UNIT

Under the ISO Staff's ICAP demand curves proposal, the ICAP demand curves for the New York City and Long Island localities would be based on the net cost of developing, constructing and operating an LMS 100 generator in those zones, and we concur with those recommendations. However, ISO Staff is also proposing that the ICAP demand curve for the New York Control Area ("NYCA") be based on the cost of a Frame 7FA generator in the Capital zone. We do not concur with that recommendation. Instead, we believe that the ICAP demand curve for the NYCA should be based on the net cost of developing, constructing and operating an LMS 100 generator on Long Island.

It is important to recognize that the ICAP demand curve in question applies to the entire NYCA, not simply the Rest of State ("ROS") region (which is the portion of the NYCA that excludes New York City and Long Island). The ICAP demand curve for the NYCA is intended to ensure that the total revenues that new generators receive will be sufficient to permit the development of additional capacity *in the NYCA* as is needed to meet reliability requirements. Consistent with this intent, in the ICAP spot market auction conducted by the ISO each month, a capacity price is determined at the point where the supply curve for the NYCA—which includes capacity provided by resources in New York City and Long Island, as well as capacity provided by resources located in the ROS region and resources outside the NYCA—intersects the demand curve for the NYCA. The resulting price is paid to all resources selling capacity in that auction, with the exception of resources in the Localities of New York City and Long Island, which receive the price determined by the intersection of the supply and demand curves for those Localities *if and only if* that price exceeds the price that was determined by the intersection of the supply and demand curves for the NYCA.

[1] The members of the Transmission Owners sector include Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric and Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; Orange and Rockland Utilities, Inc.; and Rochester Gas & Electric Corporation.

[2] "New York Independent System Operator, Inc. Proposed NYISO Installed Capacity Demand Curves For Capability Years 2011/2012, 2012/2013 and 2013/2014," Sept. 3, 2010 (revised Sept. 7, 2010) (henceforth, "ISO Staff Proposal").

The Market Administration and Control Area Services Tariff ("Services Tariff") states that the ICAP demand curve for the NYCA will be based on the net cost of developing, constructing and operating a peaking unit, with "peaking unit" 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."[3] Many different generating technologies may be economically viable at various locations within the NYCA at any given point in time; the quoted language instructs the ISO to base the ICAP demand curve for the NYCA on the economically viable generator in the NYCA whose variable costs are highest and fixed costs are lowest. But any proposed demand curve that is based on the cost of a generating unit that is not economically viable cannot be consistent with the tariff. And neither the ISO Staff Proposal, nor the independent consultants' report that was prepared in conjunction with the current demand curve review,[4] provides any evidence that a Frame 7FA generator in the Capital zone would be economically viable. In fact, neither report even addresses the question of whether a Frame 7FA generator in the Capital zone is economically viable, a condition that must be met if the ICAP demand curve for the NYCA is to be based upon that generator. Instead, the ISO Staff Proposal and the NERA/S&L Report simply compare the net cost of developing generators using various technologies in the ROS region, which amounts to the implicit assumption that a generator using at least one of those technologies must be economically viable somewhere within the ROS region.

While the NERA/S&L Report demonstrates that the Frame 7FA generator can be developed in the Capital zone at a lower net cost than generators using other technologies that were evaluated for the ROS region, that does not lead to the conclusion that the Frame 7FA in that location is economically viable for the NYCA. If development in the ROS region is not economically viable, but development in a Locality is economically viable, the ICAP demand curve for the NYCA should be based on the net cost of developing, constructing and operating a generator in a Locality, because that is the place in the NYCA where profit-maximizing developers would be most likely to develop additional resources when those resources are needed to meet reliability requirements. If the net cost is lower than the net cost of developing capacity in the ROS region, that is the correct outcome. There is no requirement that the ICAP demand curve for the NYCA be high enough to support development in the ROS region. The minimum capacity requirement applies to the NYCA. There is no minimum capacity requirement for the ROS region.

The results that ISO Staff and its consultants have produced strongly suggest that a Frame 7FA generator in the Capital zone is not economically viable as the proxy unit for the NYCA. Under ISO Staff's proposal, the annual reference point for the NYCA, which is based on the net cost of adding a Frame 7FA generator in the Capital zone, is $89.79/kW-yr., while the annual reference point for Long Island, which is based on the net cost of adding an LMS 100 generator on Long Island, is only $62.92/kW-yr.,[5] which is

[3] Services Tariff, § 5.14.1.2.

[4] "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator," NERA Economic Consulting, Sept. 3, 2010 (henceforth, "NERA/S&L Report").

[5] ISO Staff Proposal at 18.

30 percent below the NYCA reference point. This illustrates how the net cost of developing an LMS 100 generator on Long Island is far lower than the net cost of developing a Frame 7FA generator in the Capital zone.[6] It is therefore highly unlikely that a Frame 7FA generator in the Capital zone is economically viable, since an LMS100 generator on Long Island can be developed at much lower cost.

The NERA/S&L Report states, "the peaking unit … will not necessarily be the lowest 'net cost' unit under current conditions…."[7] It is true that transient differences in system conditions can affect some factors such as net energy revenues that are taken into account when calculating net costs. A hot summer, which increases these revenues, may benefit some generators more than others, correspondingly causing a temporary decrease in their net costs. But this does not relieve the ISO, or its consultants, of the responsibility to perform an assessment of whether a generator is economically viable, instead of simply assuming viability. The larger the difference between two different generators' net costs, the more likely it is that the difference is not the result of transient differences in system conditions, and that the difference instead results from the fact that one of the generators is simply not economically viable. Given that there is a large difference in the net costs calculated for a Frame 7FA generator in the Capital zone and for an LMS 100 generator on Long Island, and given that no one has produced an analysis purporting to illustrate that this difference is due to transient conditions, we believe it is reasonable to conclude that a Frame 7FA unit in the Capital zone is not economically viable.

Although it is not stated in the ISO Staff Proposal, it has been suggested that the Services Tariff precludes it from basing the ICAP demand curve for the NYCA on the Long Island LMS 100 generator. This may be due to the language in the Services Tariff stating that the ISO is required to "assess … the current localized levelized embedded cost of a peaking unit in each NYCA Locality and the Rest of State…."[8] However, while the ISO is required to *assess* the net cost of developing a peaking unit in the ROS region, nothing in the Services Tariff requires the ICAP demand curve for the NYCA to be based on the net cost of developing a generator in the ROS region. And, as noted above, the Services Tariff specifically prohibits basing an ICAP demand curve on the net cost of developing a generator that is not economically viable.

Therefore, the ICAP demand curve for the NYCA should be based on the net cost of developing an LMS 100 generator on Long Island, an economically viable generator whose capacity is deliverable throughout the NYCA. Basing the ICAP demand curve for the NYCA on the cost of developing a Frame 7FA

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[6] Given ISO Staff's proposal to set the monthly reference point for the NYCA at $8.86/kW-mo., a Frame 7FA generator in the Capital zone would receive an average of $77.14/kW-year in ICAP revenue, if the amount of ICAP provided in the NYCA averages 101 percent of the NYCA requirement (as assumed by ISO Staff) and all of the ISO Staff's other assumptions are accepted. In contrast, given ISO Staff's proposal to set the monthly reference point for Long Island at $5.96/kW-mo., an LMS 100 generator on Long Island would receive an average of $50.78/kW-year in ICAP revenue, if the amount of ICAP provided on Long Island averages 102.1 percent of the Long Island requirement (as assumed by ISO Staff), all of the ISO Staff's other proposals are accepted, and the Long Island demand curve sets the price on Long Island. This is 34.2 percent below the Frame 7FA's revenue requirement.

[7] NERA/S&L Report at 7.

[8] Services Tariff, § 5.14.1.2.

generator in the Capital zone, instead of the cost of developing an LMS 100 generator on Long Island, could unnecessarily increase capacity costs by roughly $70 million per year.[9]

II. DELIVERABILITY COSTS

In its proposal for the ICAP demand curve for the NYCA, ISO Staff does not include the cost of deliverability upgrades that a generator in the Capital zone may need to incur at some point in time in the future. We agree with ISO Staff's conclusion. In addition to the important arguments supporting ISO Staff's conclusion made in the ISO Staff Proposal, we do not think deliverability costs should be included because the inclusion of these costs would be speculative, as it cannot reasonably be assumed that those costs would be incurred by the developer of new generating capacity in the Capital zone if we were at the minimum ICAP requirement for the NYCA, nor can it reasonably be assumed that those costs would actually be incurred in the future by developers in that zone.

Currently, there is a large surplus of capacity in the NYCA. However, whether the developer of new generating capacity under current surplus conditions would need to incur deliverability costs in order to make the capacity deliverable is not relevant. Instead, the relevant question is whether the developer of new generating capacity would need to incur deliverability costs if the NYCA were at its minimum ICAP requirement—i.e., if there were considerably less capacity (relative to load) in the NYCA than is actually there now.[10] The reduction in generating capacity that would be necessary to eliminate the current surplus would create substantial headroom for making new capacity available without the need to upgrade the transmission system.

Mark Younger, a consultant for several suppliers, presented an analysis to the ICAP Working Group which purports to demonstrate that "[a]s the system approaches minimum requirements it will continue to be incapable of delivering all resources above UPNY-SENY."[11] He claimed to show that if the NYCA

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[9] Modifying the NERA model, which was used to determine the ICAP demand curve proposal, to reflect assumptions made by ISO Staff regarding the ICAP market for the NYCA (namely, the assumed surplus in the NYCA and the zero-crossing point for the NYCA), while retaining all energy market-related assumptions made by NERA for an LMS 100 generator on Long Island, yields a monthly reference point for the NYCA ICAP demand curve of $6.48/kW-mo., instead of ISO Staff's proposed monthly reference point for the NYCA of $8.86/kW-mo. Such a reduction in the monthly reference point would lead to annual savings to end-use consumers of approximately $73 million in reduced costs of purchasing ROS ICAP in the spot market, given certain assumptions that are described in Appendix B, which generally assume that conditions observed in the ICAP markets recently will continue to prevail after the new ICAP demand curves take effect. A detailed description of the calculation of this estimate can also be found in Appendix B. In addition to these savings, reductions in the monthly reference point could also reduce costs incurred to purchase Long Island ICAP in the spot market, if the Long Island ICAP price is set by the ICAP demand curve for the NYCA, although we will not estimate these savings in these comments.

[10] "The periodic review shall assess… the current localized levelized embedded cost of a peaking unit in each NYCA Locality and the Rest of State *to meet minimum capacity requirements*…." Services Tariff, § 5.14.1.2 (emphasis added).

[11] Mark Younger, "Deliverability Costs Related to Upgrading UPNY/SENY Interface," presented to Installed Capacity Working Group on July 27, 2010 (henceforth, "Younger Presentation").

was near its minimum capacity requirements, the overload on the UPNY-SENY interface would exceed the amount of capacity located upstream of that interface that could be retired, meaning that new generating resources in the Capital zone (which is upstream of that interface) would need to incur deliverability costs if they were needed to provide ICAP. However, this analysis is speculative because it was based on the assumptions that New York City and Long Island would be at their minimum ICAP requirements at the same time that the NYCA is at its minimum requirement, and that the New York City and Long Island minimum ICAP requirements do not change. It is not likely that these assumptions would occur, and it is very unlikely that all of these assumptions will occur simultaneously. Furthermore, the analysis is based on the 2008 Deliverability Study, which is a snapshot of the system at the time of the study, the results of which cannot be used to project the dynamic system behavior at another state.

In addition, Mr. Younger's analysis is flawed. Even if we were to accept the assumptions upon which Mr. Younger's analysis is based, its conclusions are incorrect. In fact, a correct analysis would show that if the entire amount of surplus CRIS capacity in Zones A – F and Zones J and K were retired, so that NYCA and the Localities were at their respective minimum resource adequacy requirements simultaneously, there would be substantial headroom on the UPNY–SENY interface. When the ability to import capacity into the NYCA is fully considered, the amount of capacity that would have to be retired in zones A – F to reach equilibrium would create over 1000 MW of headroom on the UPNY – CENY interface. As a result, deliverability investments would not be needed for the NYCA to meet minimum capacity requirements, even under Mr. Younger's assumptions. Appendix A contains a more detailed explanation of this analysis.

Moreover, it is likely that more economic alternatives that address deliverability concerns would be implemented before the need to incur deliverability costs in the capacity market arises. If such alternatives are implemented, there would be no need to include deliverability costs in the ICAP demand curve for the NYCA, as those costs would never be incurred by new generation located above the UPNY-SENY interface.

Finally, it is not reasonable to assume that a generator in the Capital zone that must incur deliverability costs would be the most efficient resource of new capacity should the NYCA be at its minimum capacity requirement. For the reasons stated above, it is unlikely that such a generator would be economically viable even if it did not need to incur deliverability costs. Increasing its costs by approximately 30 percent to cover the costs of deliverability upgrades would only make this conclusion even more compelling.[12]

For all of the above reasons, the assertion that a generator in the Capital zone would need to incur deliverability costs in the future when needed to meet the minimum installed capacity requirement for the

[12] Modifying the NERA model to incorporate deliverability costs, while using all of ISO Staff's other assumptions regarding the ICAP demand curve for the NYCA, causes the monthly reference point for that demand curve to rise to $11.40/kW-mo. from ISO Staff's proposed monthly reference point of $8.86/kW-mo., an increase of almost 30 percent.

NYCA is totally speculative. Adding deliverability costs to the net costs of developing a generator in that zone upon which ISO Staff's ICAP demand curve proposal for the NYCA is based would impose roughly $70 million per year in additional capacity costs on New York consumers at a time of significant excess capacity, while providing a windfall for existing capacity suppliers who were exempted from paying deliverability costs.[13]

III. NEW YORK CITY TAX ABATEMENT

The ISO Staff Proposal assumes that new generating facilities in New York City would receive tax abatements that would be available to PlaNYC Energy Program Projects.[14] Supplier representatives have argued that there is no guarantee that developers would be granted such abatements. However, there is every reason to believe that the New York City Industrial Development Agency (NYCIDA) would grant these abatements. The,NYCIDA would have a strong incentive to grant abatements if failure to grant such abatements would be likely to increase the cost of NYC ICAP in the future, as it would under the ISO Staff Proposal (which states that "the NYISO will review the outcome of applications to the PlaNYC Energy Program and will recommend that the percentage of tax abatement applied in establishing the next NYC Demand Curve reflect the actual awards made"[15]).

It is also important to recognize that the ISO Staff has not assumed granting 100 percent of the tax abatements made available in NYCIDA's *Third Amended and Restated Uniform Tax Exemption Policy of the New York City Industrial Development Agency*. Rather, the ISO is assuming only a tax abatement value equal to that given by the former Industrial & Commercial Incentive Program (ICIP) which is less than the total potential value of the four tax abatements that are currently available through NYCIDA. NYCIDA's Executive Director has stated, "a reduction of real estate taxes through the provision of a Payment in Lieu of Real Property Taxes ("PILOT") … if deemed appropriate and financially necessary by the Board of Directors … may be set at levels more or less generous than the former ICIP schedule, or they may match that schedule."[16] Accordingly, if NYCIDA can grant exemption from real property taxes at a value equal to or greater than the value of the former ICIP, *in addition to* exemptions from recording fees, mortgage recording taxes, and sales and use taxes, then it is clear that ISO Staff is not assuming 100 percent of all available abatements are being granted by NYCIDA.

In sum, assuming that such abatements would not be granted would ignore the strong incentive that NYCIDA would have to grant such abatements if the NYC ICAP demand curve is developed on the

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[13] The increase in the monthly reference point resulting from the inclusion of deliverability costs (*see* fn. 12 *supra*) would cause an increase in estimated end-use consumer costs of about $73 million annually, given certain assumptions described in Appendix B.

[14] ISO Staff based this assumption on the *Third Amended and Restated Uniform Tax Exemption Policy of the New York City Industrial Development* Agency, approved August 3, 2010.

[15] ISO Staff Proposal at 10.

[16] "Motion to Intervene and Protest of the City of New York," *New York Indep. Sys. Operator, Inc.*, Docket No. EL09-4-000 (Oct. 31, 2008), Exh. A (Affidavit of Maureen Babis) at ¶ 7.

assumption that such abatements would be granted. It would increase the price of ICAP to cover taxes that developers of new NYC peaking units would not have to bear if they receive tax abatements, and it would needlessly increase ICAP prices to provide revenues to existing generators to cover taxes from which existing generators were exempted under the former ICIP program. We estimate that ignoring these tax abatements would increase costs for purchasers of New York City ICAP by as much as $260 million annually.[17]

IV. ASSUMED CAPACITY SURPLUS

A. ISO Staff's Proposal is Generally Reasonable if the Board Believes the ICAP Demand Curves Should Assume Surplus Capacity

ISO Staff has proposed to calculate the ICAP demand curves under the assumption that, over the fourth through 30th years of a new peaking unit's lifespan, the amount of surplus capacity provided in the NYCA and in each Locality will be equal to one half of the amount of capacity that would be provided by a peaking unit in each of those regions (with a minimum level of one percent of the relevant requirement).

If the ISO Board concludes that the ICAP demand curves should be developed under the assumption that there will be surplus capacity, we believe ISO Staff's approach is generally reasonable, considerably better than the surplus capacity assumptions that were made during the last ICAP demand curve review in 2007, as well as proposals made earlier in the current ICAP demand curve review. If a new peaking unit enters the market at the time that the surplus falls to zero, then the amount of surplus capacity immediately following the addition of that unit would be equal to the amount of capacity provided by that unit, but that surplus would then decrease over time as load grows. Assuming that load grows at a constant rate, the average surplus that results from the assumptions made by ISO Staff is not actually the amount of capacity provided by the new peaking unit, but half of that amount. Consequently, ISO Staff's approach reflects the surplus that would exist if new capacity is added when it is needed, and not before.

However, we do not believe there is any justification for assuming the surplus will average at least one percent of the relevant ICAP requirement, even if Staff's approach would result in a lower surplus. We recommend that the Board strike that element of ISO Staff's proposal. In addition, we believe that one other minor modification to the Long Island requirement is necessary.[18]

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[17] Modifying the NERA model to exclude tax abatements, while accepting all of ISO Staff's other assumptions regarding the New York City ICAP demand curve, would cause ISO Staff's proposed monthly reference point for that demand curve to rise from $16.51/kW-mo. to $23.81/kW-mo. This increase would cause an increase in estimated end-use consumer costs of about $266 million annually, given certain assumptions described in Appendix B.

[18] The modification pertains to the calculation of the Long Island surplus. ISO Staff proposed a 2.1 percent surplus, which was calculated as 0.5 times the 195 MW capacity provided by an LMS 100 generator, divided by Long Island's Winter 2009-10 capacity requirement, which was approximately 4700 MW. (ISO Staff Proposal at 13, referencing NERA/S&L Report at 70.) However, that is the UCAP requirement for Long Island—not the ICAP requirement, which is 5337.2 MW. Since the amount of capacity provided by the LMS 100 is not measured in terms

B. Nevertheless, the ICAP Demand Curves Should Be Developed Under the Assumption that the Amount of ICAP Provided is Equal to the Minimum ICAP Requirement

While the ISO Staff's assumptions with regard to surplus capacity levels are more reasonable and better supported than surplus capacity assumptions made in the past, we continue to maintain that the ICAP demand curves should be developed under the assumption that there is no surplus capacity, consistent with our understanding of the basic intent of the demand curves, which is to ensure that revenues provided by the ICAP market are sufficient to induce entry when the NYCA or a Locality is at its minimum capacity requirement. No excess supply is assumed, or needed, to meet Reliability Rule A-R1 of the New York State Reliability Council ("NYSRC"). Furthermore, under the ISO's Reliability Planning Process, capacity is to be added only when needed to avoid a reliability criteria violation, not during periods of surplus capacity.

The assumption of surplus capacity becomes a self-fulfilling prophecy. By assuming that surplus capacity will be supplied, the ISO is effectively increasing the minimum ICAP requirements. Demand curves based on the assumption that there is surplus capacity would permit a new generator considering entry to earn enough money over its lifespan to support its decision to enter even if new capacity is not needed in order to meet capacity requirements. This result is contrary to the basic objective of the demand curves which is to set a price for capacity that supports new entry when the NYCA is at its minimum installed capacity requirement. Moreover, nothing in the Services Tariff requires the ISO to set the ICAP demand curves so that they will support new entry during periods of surplus capacity.

We estimate the cost of this excess capacity required to be purchased as a result of the *de facto* increases in minimum ICAP requirements to end-use consumers to be about $85 million per year,[19] which greatly exceeds any plausible estimate of the value to end-use consumers of the reliability provided by that additional capacity.

C. The Arguments of the ISO's Consultants and the Market Monitor Recommending that the Demand Curves Assume Larger Surpluses Are Incorrect

The ISO's consultants recommended setting the demand curves under the assumption that the amount of surplus capacity provided in the NYCA and each Locality would be equal to 1.5 times the peaking unit's capacity, instead of one-half of the peaking unit's capacity. This amounts to the assumption that, on average, a peaking unit would come on-line whenever the NYCA (or a Locality) is already one peaking

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of UCAP, it is inconsistent to measure the Long Island requirement in terms of UCAP. Using the Long Island ICAP requirement, instead of the UCAP requirement, reduces the assumed surplus for Long Island to 1.8 percent.

[19] Modifying the NERA model to eliminate the assumed surplus, while accepting all of ISO Staff's other assumptions regarding the NYCA and New York City ICAP demand curves, would cause ISO Staff's proposed monthly reference point for the NYCA demand curve to fall from $8.86/kW-mo. to $7.95/kW-mo., and would cause ISO Staff's proposed monthly reference point for the New York City ICAP demand curve to fall from $16.51/kW-mo. to $14.90/kW-mo. These decreases would cause a reduction in estimated end-use consumer costs of about $26 million annually in ROS and $59 million in New York City, for a total of $85 million, given certain assumptions described in Appendix B. We have not estimated reductions in Long Island capacity costs because Long Island capacity prices are frequently set by the ICAP demand curve for the NYCA.

unit's capacity above the minimum capacity requirement, causing the NYCA (or Locality) to go two peaking units' capacity above the minimum capacity requirement. The consultants offer no support for this assumption, other than to state their belief that it is reasonable.[20] However, as noted above, it is not necessary to make such an assumption to comply with the NYSRC's Reliability Rules, and there is no justification for the ISO to set ICAP demand curves that support permanent capacity surpluses and prevent the market from moving towards equilibrium.

The ISO Staff Proposal states, "The NYISO has consulted with the Market Monitor, Dr. David Patton, regarding the conclusions in this report…. Dr. Patton generally concurred with most of the conclusions in this report. However, he expressed concern that the NYISO [Staff]'s proposed level of expected excess capacity in New York City of 1.1 percent. He indicated that it is not reasonable to expect this low a level of excess capacity over the long-term."[21] We disagree. As noted above, the ICAP demand curves should not assume any surplus. In addition, under the New York City ICAP demand curve that is in effect for the 2010-11 capability year, the monthly reference point is $15.99/kW-mo. ISO Staff's proposal for the 2011-12 capability year would set the monthly reference point for the New York City ICAP demand curve at $16.51/kW-mo., an increase. Increasing the assumed surplus above 1.1 percent of the New York City ICAP requirement—which is the amount of surplus capacity assumed by ISO Staff when developing its proposed New York City ICAP demand curve—would cause the monthly reference point, and hence the New York City ICAP demand curve, to be set even higher than $16.51/kW-mo. Yet developers are willing to build generation in New York City,[22] even under the current conditions in the New York City ICAP market, in which ICAP prices are well below the $15.99/kW-mo. monthly reference point for the current demand curve. Their willingness to do so demonstrates that there is no need to assume large surpluses to force the demand curve even higher. Under ISO Staff's proposal, it is already more than high enough to induce development in New York City.

V. ESCALATION RATE

ISO Staff has proposed an escalation rate of 1.7 percent per year for use when translating the ICAP demand curve it has developed for the 2011-12 capability year into demand curves for the 2012-13 and 2013-14 capability years. We recommend that the Board adopt ISO Staff's recommendation. The Handy-Whitman Index, which was used to set the currently effective demand curves, was a retrospective analysis of past changes in power plant development costs, and was never intended to be a forecast of the rates at which costs would change in the future. Instead, it is important to use a forecast to estimate the rate at which costs are likely to increase in the future. In the absence of any evidence indicating that the real costs of constructing power plants are likely to increase or decrease over the 2011-14 time period, the most reasonable procedure is to construct the ICAP demand curves for the 2012-13 and 2013-14

[20] NERA/S&L Report at 71.

[21] ISO Staff Proposal at 19.

[22] The ISO recently adopted a reliability needs assessment that includes new merchant generation (the Hess Bayonne plant) in Zone J.

capability years under the assumption that these construction costs will increase at the forecasted general rate of inflation for that time period, which is what ISO Staff has done.

VI. SEASONALITY ADJUSTMENT

Each generator that provides ICAP must undergo a Dependable Maximum Net Capability ("DMNC") test in the summer and in the winter. Because the amount of UCAP that a generator can provide depends on its DMNC, and many generators have significantly higher winter DMNCs than summer DMNCs, the supply of UCAP is generally higher in the winter than in the summer. This causes capacity prices to be lower in the winter than in the summer. As a result, even if summer prices were sufficient to support the development of capacity when it is needed, development would not occur because ICAP revenue over the course of the year would be insufficient to support development, due to the lower winter prices. To ensure that the ICAP demand curve provides sufficient revenue to induce the development of capacity when it is need, the ISO incorporates an upward adjustment in the ICAP demand curves. This adjustment causes ICAP prices to be higher in both the summer and the winter than they would have been without the adjustment. The intent of the adjustment is to offset the impact of seasonal price differences, so that the average revenue received over the course of the year is equal to the revenue generators would have received if there were no systematic differences between winter prices and summer prices.

The controversy pertains to the assumption that is made regarding how much capacity will be sold in the winter compared to the summer. The higher this assumed winter-to-summer capacity sales ratio, the larger the assumed difference between summer and winter ICAP prices. This, in turn, will lead to a larger adjustment to the demand curves to counteract this assumed seasonal price difference. However, if the ISO sets the ICAP demand curves under the assumption that more ICAP will be sold into the New York market in winter months than would actually be sold in those months, winter ICAP prices will be suppressed by less than the amount anticipated by the ISO when it calculated the adjustment. As a result, the adjustment will be larger than it would have been if the ISO had properly anticipated the amount of ICAP that would be sold in the winter. The ICAP demand curve will be set too high, ICAP providers will earn more than the anticipated amount of ICAP revenue over the course of the year, and consumers will pay more for ICAP than they should.

In its proposal, ISO Staff assumed that the winter-to-summer capacity sales ratio will be 1.052 for the NYCA as a whole, 1.098 for New York City, and 1.062 for Long Island.[23] These ratios are simply a forecast of the amount of capacity expected to be *available* in the NYCA and each Locality in the winter as compared to the summer, not a forecast of the amount of capacity expected to be *sold* in the winter as compared to the summer. In fact, since the implementation of the ICAP demand curves in June 2003, actual winter-to-summer capacity sales ratios have almost always been lower than the ratios that ISO Staff is using. That is because some resources that sell capacity into New York markets in the summer do not sell it into New York markets in the winter, likely because prices are lower in the winter than in the

[23] ISO Staff Proposal at 23.

summer. The ratio used by ISO Staff therefore overstates the winter-to-summer capacity sales ratio that is likely to prevail; consequently, ISO Staff's approach leads to an unrealistically large seasonality adjustment and higher capacity prices than are warranted.

There is a reasonable alternative to ISO Staff's assumption that all available capacity will actually be sold in the winter. To estimate energy revenues, the ISO's consultants calculated energy revenues over the last three years, and then adjusted those estimates of energy revenues to account for the difference between the actual capacity surplus over that time period, and the capacity surplus level assumed by the ISO for the purpose of developing the demand curves. There is no reason why the ISO should not use a similar procedure for the seasonal adjustment. The ISO should calculate the ICAP demand curves under the assumption that the winter-to-summer capacity sales ratio will be equal to the average ratios calculated over the 2007-08 through 2009-10 capability years, which are 1.020 for the NYCA, 1.072 for New York City and 1.044 for Long Island,[24] adjusted as necessary to reflect any differences between winter-to-summer capacity sales ratios given the actual capacity surpluses observed over this period and the winter-to-summer capacity sales ratio one would expect to observe if the capacity surplus had been at the level assumed by the ISO for the purpose of developing the demand curves.

ISO Staff has not shown that the winter-to-summer capacity sales ratios that it is using are consistent with the system at equilibrium or with the levels of surplus capacity assumed when developing its recommendations. Its proposal is unsupportable. The approach we recommend, on the other hand, is fully consistent with the approach used by the ISO's consultants to estimate energy revenues under equilibrium conditions, and is the most reasonable estimate of the winter-to-summer ratio under those conditions. It also is consistent with the fact that some resources sell capacity in the summer but not the winter. We estimate that using these alternative winter-to-summer capacity sales ratios would reduce ICAP costs for end-use consumers by about $102 million per year.[25]

VII. ZERO-CROSSING POINT

The zero-crossing point is the quantity at which the price of capacity becomes zero. ISO Staff has recommended that the zero-crossing point for the NYCA ICAP demand curve remain at 112 percent of the NYCA ICAP requirement and that the zero-crossing points for the New York City and Long Island

[24] Additional details of these calculations are available from the TOs upon request.

[25] Modifying the NERA model to use a winter-to-summer capacity sales ratio of 1.020 for the NYCA and 1.072 for New York City, while accepting all of ISO Staff's other assumptions regarding the NYCA and New York City ICAP demand curves, would cause ISO Staff's proposed monthly reference point for the NYCA demand curve to fall from $8.86/kW-mo. to $7.38/kW-mo., and would cause ISO Staff's proposed monthly reference point for the New York City ICAP demand curve to fall from $16.51/kW-mo. to $14.88/kW-mo. These decreases would cause a reduction in estimated end-use consumer costs of about $43 million annually in ROS and $59 million in New York City, for a total of $102 million, given certain assumptions described in Appendix B. We have not estimated reductions in Long Island capacity costs because Long Island capacity prices are frequently set by the ICAP demand curve for the NYCA.

demand curves remain at 118 percent of their respective locational capacity requirements, which are the same zero-crossing points that have been used since the inception of the ICAP demand curves.

In comments submitted to ISO Staff, the TOs have emphasized the importance of analyzing changes in the zero-crossing point. The Services Tariff states that the periodic review of the demand curves must include an assessment of "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."[26] Despite this tariff requirement, the ISO Staff Proposal does not include a meaningful assessment of the shape and slope of the curve and the zero-crossing point. Instead, it warns that, "The likelihood of unintended consequences [associated with a change in the zero-crossing point] is great…. In addition, market power issues associated with withholding capacity would likely need to be addressed,"[27] before concluding, "[T]here is no compelling evidence to adjust the zero-crossing points on any of the demand curves."[28] The concerns expressed by ISO staff are unsupported. We have yet to see any analysis of the market power implications of alternative zero-crossing points.

The ISO's consultants simply failed to conduct the analysis that should have been conducted as part of this review. In their report, the consultants asserted:

> Steeper slopes can … be counterproductive if … [they] lead[] to clearing at prices well below the reference point. At such prices, retaining existing plants may be difficult as the economics of mothballing and retirement could become attractive for older plants. To the extent that such scenarios occur, any decrease in payments that would arise from a steeper slope may well be offset by retirements or mothballing.[29]

In our view, this statement illustrates one of the benefits of making the demand curves steeper. If an older, inefficient unit is not needed for reliability, there is no need to set capacity payments at a level that is high enough to prevent it from retiring. Retirement of such generators would generally make the market more efficient. Furthermore, the consultants gave no consideration to the concern that demand curves with the current shape and zero-crossing points require consumers to support surplus generation and pay more for capacity than is needed for reliability.

The consultants also argued:

> Adjusting the curve to steepen the slope when it is almost certain to depress revenues would appear opportunistic and would likely undermine confidence in the objectivity of the capacity market. Any significant adjustment to the slope is best done at a time when

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[26] Services Tariff, § 5.14.1.2.

[27] ISO Staff Proposal at 15.

[28] *Id.*

[29] NERA/S&L Report at 76.

> the immediate impact will be relatively neutral so that it is clear that the adjustment is being made to improve the market not to reach a desired outcome.[[30]]

This argument suggests that there should be no change in the shape of the curves or the zero-crossing point, despite the tariff requirement, if that change would reduce revenues for existing generators—even if such changes would provide a better price signal for capacity and would reduce consumer payments for excess capacity. It also assumes that the ICAP market will eventually reach a point where the amount of capacity provided is close to the amount the ISO assumed when it developed the demand curves. But it is possible, and perhaps even likely, that the ICAP market will never reach such a point. The amount of UCAP provided in recent years has been far above the ISO's expectations. If that is because the demand curves have systematically overestimated the net cost of developing additional capacity, and if they continue to systematically overstate that cost, surpluses will continue. Adopting the consultants' rationale would never permit the ISO to adjust the demand curves, because the surplus would never be eliminated.

Throughout the demand curve reset process, the TOs have requested that the ISO or its consultants conduct an analysis to examine the feasibility of alternative zero-crossing points. Yet each time this request has been made, it has been ignored. Based on our own investigation, including analysis of the potential impact of steeper ICAP demand curves on incentives for suppliers to withhold capacity, the TOs recommend that the zero-crossing point for the NYCA demand curve be reduced from 112 percent to 110 percent of the ICAP requirement. A lower zero-crossing point would reduce capacity prices to consumers during periods of excess capacity and increase capacity prices as the NYCA gets closer to its minimum reserve requirement, which are precisely the price signals the ICAP demand curves should be sending. Neither ISO Staff nor its consultants have provided any analysis to support the contention that a revised zero-crossing point would increase the incentive or ability of suppliers to exercise market power. Furthermore, the ISO is responsible for monitoring its markets effectively, and has improved its procedures for deterring the exercise of market power. The ISO's consultants note these factors in their report in expressing their reduced concern with respect to the exercise of market power.[31] A reduction in the zero-crossing point for the ICAP demand curve for the NYCA, as we recommend, could reduce the amount that LSEs must pay for capacity in the ROS region by as much as $200 million per year.[32]

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[30] *Id.* at 77.

[31] NERA/S&L Report at 75.

[32] Modifying the NERA model to set the zero-crossing point at 110 percent of the NYCA ICAP requirement, while using all of ISO Staff's other assumptions regarding the ICAP demand curve for the NYCA, would cause the monthly reference price to increase from $8.86/kW-mo. to $9.68/kW-mo. This change in the monthly reference price, coupled with the decrease in the zero-crossing point, would cause an annual reduction of about $202 million in end-use customer costs, given certain assumptions described in Appendix B. Because this estimate assumes that ICAP sales do not change, this estimate may overstate the savings resulting from the reduction in the zero-crossing point.

VIII. NEXT STEPS

To date, the demand curve reset process has been contentious and time-consuming. Furthermore, we do not believe that the ISO capacity market has effectively balanced the interests of customers and investors, nor has it succeeded in achieving its goal of providing efficient incentives for the development of new capacity and the retirement of unnecessary and inefficient capacity. The TOs accordingly request that the ISO undertake a comprehensive review of its capacity markets before the next demand curve reset cycle (starting within the next 12 months). We believe that such a review should encompass the following elements:

- A comprehensive review of the ISO's capacity market, including reconsideration of a forward ICAP market, which may or may not use a demand curve;
- An analysis of whether the demand curve should be based on the cost of resources such as combined cycle units and demand response providers;[33]
- A full analysis of different demand curve shapes, including truncated and kinked demand curves, and different zero-crossing points, for the NYCA and for each of the Localities; and
- Assessment of alternative approaches to the methodology used by ISO Staff to adjust for seasonal differences in ICAP prices.

In the past, these topics have not received sufficient attention due to the need to complete the demand curve review in time to meet tariff-established deadlines for filing the new demand curve proposal with FERC. Performing these analyses well before the next demand curve review begins would permit a full review of these topics, and would permit the ISO to file any tariff changes that would be necessary in order to implement the conclusions of the review.

[33] In 2005, FERC rejected an ISO proposal to base the ICAP demand curves on the net costs of developing gas turbines, stating, "It is entirely possible, due to future advancements in technology, that gas turbines may not be the preferred type of unit to use in the future resets of the NYISO ICAP Demand Curves." *New York Indep. Sys, Operator, Inc.*, 113 FERC ¶ 61,271 (2005) at P 11. For that reason, FERC directed the ISO to base the ICAP demand curves on the net cost of developing peaking units (with peaking units defined as in § 5.14.1.2 of the Services Tariff). To comply with this order, the ISO must consider a broader set of resources in future ICAP demand curve reviews.

APPENDIX A: ANALYSIS OF THE AMOUNT OF ICAP THAT COULD BE DELIVERED FROM ZONES A THROUGH F AT MINIMUM CAPACITY REQUIREMENTS

At the ICAP Working Group meeting on July 27, 2010, Mark Younger made a presentation on behalf of a number of suppliers in support of including deliverability costs in the current demand curve reset process.

Mr. Younger concluded, "As the system approaches *minimum requirements* it will continue to be incapable of delivering all resources above UPNY- SENY; [t]hus, the proxy unit for Rest of State must include deliverability upgrade costs" (emphasis added). However, Mr. Younger's justification for adding deliverability cost to the proxy unit in the ROS region is based on the flawed conclusion that the "UPNY-SENY overload is greater than the amount of capacity that could be retired in Zones A – F."

Mr. Younger's presentation was based on the assumption that the existing capacity surplus no longer exists and that the NYCA, as well as New York City and Long Island, are at their minimum capacity requirements simultaneously. While this assumption is speculative, even if it is accepted, the conclusion reached by Mr. Younger is incorrect.

The following assessment provides an accurate accounting of resources with existing deliverability rights (CRIS rights) and the associated impact they have on existing transmission capability. In order to thoroughly assess the need for deliverability upgrades when the NYCA is at equilibrium conditions we address the following threshold questions in our analysis:

1. How much capacity currently has CRIS rights and is thereby qualified to provide ICAP in the New York ICAP markets?
2. How much surplus capacity (i.e., capacity not needed to maintain reliability) is upstream of the UPNY –SENY deliverability constraint?
3. If the existing surplus capacity exits the market, is there any unutilized transmission capability ("headroom") available for new capacity?

Based on existing CRIS rights that were "grandfathered" in the 2008 Class Year Deliverability Study (CY08 Study), we conclude that if all surplus CRIS capacity in Zones A-F and Zones J and K retired, such that the NYCA and its Localities were at their minimum resource adequacy requirements, there would be more than 1000 MW of headroom on the UPNY-SENY interface.

The Existing Supply: How Much Capacity Currently Has CRIS Rights and is Thereby Qualified to Provide ICAP in the New York ICAP Markets?

As Mr. Younger correctly states, the CY08 Study concludes "UPNY-SENY [is] overloaded by 1,542.3 MW before the additional of any 2008 Class Year projects".[34] This result was largely based on all the existing capacity that currently has deliverability rights (Grandfathered CRIS rights) being modeled in CY08 Study and Grandfathered CRIS Rights being awarded to 2220 MW of imports from external areas to zones above the UPNY-SENY interface. These two factors, grandfathered unit capacity and grandfathered import capacity, are the fundamental drivers that produced the 1543 MW overload.

The level of Grandfathered CRIS Rights and the associated points of injection serve as a basis for determining the amount of capacity qualified to participate in the New York ICAP market. Per Section 3, *CY2008 ATBA-Deliverability Base Case Conditioning Steps* of the CY08 Study:

[34] Note CY08 projects were modeled under an assumed 2013 topology and load.

[B]ase case power flow models and transfer assessments includes the following considerations to determine the initial generation and interchange schedules for the NYCA and the three NY Capacity Regions.

a. Inter-Area external interchange schedules shall include all grandfathered long-term firm power transactions that are expected to be in place for the CY2008 case year (2013) by Tariff.

1. Hydro Quebec to NY 1090 MW
2. PJM to NYSEG 1043 MW

b. Grandfathered external firm capacity imports represented are consistent with Attachment E of the NYISO Installed Capacity Manual:

1. FirstEnergy/Penelec to NYSEG 37 MW
2. ISO-NE to NY 50 MW

Thus, the grandfathered import rights sum to 2220 MW.[35] In addition, generation UCAP values assumed in the CY08 base case are summarized in Table A-1 below.

Table A-1

Existing CRIS Rights (ATBA)	Zones A – I ICAP	Zones A – F UCAP (Pmax)	Zones G – I UCAP (Pmax)
Grandfathered Units	**26,381**	**18,015**	**4,902**
Grandfathered Imports	**2,220**	**2,220**	**0**
Total	**28,601**	**20,235**	**4,902**

The Reliability Requirement: How Much Capacity is Needed for Reliability?

Following Mr. Younger's presentation, Table A-2 assumes the peak load forecasts for 2015, as reported in the 2010 Gold Book. However, in order to identify the surplus and measure its impact on the UPNY-SENY transfer; we need to convert ICAP requirements into UCAP requirements.

Table A-2

Region	2015 Peak Load	2010 Resource Adequacy Req'ts	2015 ICAP Requirement	2015 UCAP Requirement[36]	Assumed Surplus Capacity[37]	2015 Expected Capacity Level (UCAP)
NYCA	**34,021**	**118%**	**40,145**	**36,103**	**1.5%**	**36,644**
Zone J	**12,065**	**80%**	**9,652**	**8,578**	**3.0%**	**8,835**
Zone K	**5,417**	**104.5%**	**5,661**	**5,068**	**7.0%**	**5,422**
ROS[38]	**-------**	**-------**	**24,832**	**22,457**		**22,386**

[35] It appears that one of the flaws in Mr. Younger's presentation is a substantial underrepresentation of import rights when calculating the available capacity in Zones A – F.

[36] Factors for translating ICAP requirements into UCAP requirements were obtained from the ISO website. *See* source for data in Table B-2, row 2 *infra.*

[37] These assumptions were taken from the Younger Presentation. ISO Staff has subsequently modified these assumptions. Using the surplus capacity levels assumed by ISO Staff in its proposal would not significantly affect the results of this analysis.

After considering the existing capacity in Zones G–I from Table A-1, Table A-3 calculates the minimum amount of capacity needed in Zones A–F in order to satisfy the 2015 resource adequacy requirement for the NYCA that was calculated in Table A-2.

Table A-3

	2015 ICAP Requirement	2015 UCAP Requirement	2015 Expected UCAP
ROS "Needs"	**24,832**	**22,457**	**22,386**
Grandfathered CRIS in Zones G–I	**5,245**	**4,902**	**4,902**
Zones A–F "Needs"	**19,587**	**17,555**	**17,484**

Quantifying the Impact of Existing Capacity on Transmission: Is There Sufficient Transmission Capability to Accommodate the Deliverability of "New Entry" at Market Equilibrium?

A detailed examination of the capacity assumptions in the CY08 Study was necessary prior to evaluating the headroom available at market equilibrium. We shall now apply the information above in order to consider the impact the loss of the existing supply surplus would have on the UPNY-SENY constraint. In Table A-4, we subtract the amount of capacity in Zones A–F that is needed to maintain reliability, as was calculated in Table A-3, from the amount of capacity that is currently qualified to sell ICAP in the New York ICAP markets, as was calculated in Table A-1. This shows that there would be a significant amount of surplus capacity in Zones A–F at minimum capacity requirements.

Table A-4

	ICAP-Based Requirement	UCAP-Based Requirement	Based on Expected UCAP
Grandfathered CRIS in Zones A–F	**23,356**	**20,235**	**20,235**
Zones A–F "Needs"	**19,587**	**17,555**	**17,484**
Zones A–F Surplus	**3,769**[39]	**2,680**	**2,751**

Because the level of surplus capacity in Zones A–F would exceed the 1542 MW overload on the UPNY-SENY interface by more than 1000 MW, it is reasonable to conclude that the loss of surplus capacity in Zones A–F would create at least 1000 MW of headroom on the UPNY-SENY interface. Therefore, it is not necessary to add deliverability costs to the ROS proxy unit when the system is at the assumed equilibrium point (i.e. meeting reliability needs of the NYCA with a minimal amount of capacity).

[38] Calculations for ROS are not minimums, since there is no minimum ROS requirement. Instead, they are ROS residuals representing the minimum required for reliability if Zones J and K are at their minimum requirements. The expected amount of capacity in the ROS is below this ROS residual because excess supply held in Zones J and K would require less capacity in Zones A–I to meet the minimum requirement for the NYCA.

[39] It would not be appropriate to compare ICAP values to the overload because the deliverability test adjusts unit ICAP values to a UCAP value prior to testing their deliverability.

APPENDIX B: IMPACT ON END-USE CONSUMER COSTS OF VARIOUS ASSUMPTIONS REGARDING ICAP DEMAND CURVES

Table B-1

		2011-12 Demand Curve for the NYCA (Costs of ROS UCAP Purchases Only)						2011-12 Demand Curve for NYC			
		ISO Staff Proposal	If Based on Long Island LMS 100	If Deliverability Costs Are Included	If No Surplus Is Assumed	If Alternate Seasonality Adj. Is Used	If Zero-Crossing Point is 110%	ISO Staff Proposal	If Tax Abatement is Excluded	If No Surplus Is Assumed	If Alternate Seasonality Adj. Is Used
[1]	ISO Staff Proposed Monthly Reference Price ($/kW-mo.)	8.86	6.48	11.40	7.95	7.38	9.68	16.51	23.81	14.90	14.88
[2]	EFORd Used for UCAP DC Translation	10.07%	10.07%	10.07%	10.07%	10.07%	10.07%	11.13%	11.13%	11.13%	11.13%
[3]	ISO Staff Proposed Mo. Ref Price (Adj. for UCAP) ($/kW-mo.)	9.85	7.21	12.67	8.84	8.20	10.76	18.58	26.79	16.77	16.74
[4]	Zero-Crossing Point, as a Pct. of Minimum Requirement	112%	112%	112%	112%	112%	110%	118%	118%	118%	118%
[5]	Ratio of Summer UCAP Sales to Minimum Requirement	1.093	1.093	1.093	1.093	1.093	1.093	1.048	1.048	1.048	1.048
[6]	Summer UCAP Price ($/kW-mo.)	2.20	1.61	2.84	1.98	1.84	0.74	13.61	19.62	12.28	12.26
[7]	Summer UCAP Purchases (MW)	24,087.8	24,087.8	24,087.8	24,087.8	24,087.8	24,087.8	8,737.6	8,737.6	8,737.6	8,737.6
[8]	Summer UCAP Costs ($)	318,562,000	233,082,000	409,773,000	285,996,000	265,279,000	106,500,000	713,286,000	1,028,629,000	643,697,000	642,777,000
[9]	Ratio of Winter UCAP Sales to Minimum Requirement	1.104	1.104	1.104	1.104	1.104	1.104	1.095	1.095	1.095	1.095
[10]	Winter Price ($/kW-mo.)	1.31	0.96	1.69	1.18	1.09	-	8.72	12.58	7.87	7.86
[11]	Winter UCAP Purchases (MW)	24,287.7	24,287.7	24,287.7	24,287.7	24,287.7	24,287.7	9,368.1	9,368.1	9,368.1	9,368.1
[12]	Winter UCAP Costs ($)	191,502,000	140,116,000	246,333,000	171,925,000	159,471,000	-	490,348,000	707,129,000	442,509,000	441,876,000
[13]	Annual UCAP Costs ($)	510,064,000	373,198,000	656,106,000	457,921,000	424,750,000	106,500,000	1,203,634,000	1,735,758,000	1,086,206,000	1,084,653,000
[14]	Percentage of ICAP Requirements Hedged	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
[15]	Unhedged Annual UCAP Costs ($)	255,032,000	186,599,000	328,053,000	228,961,000	212,375,000	53,250,000	601,817,000	867,879,000	543,103,000	542,327,000
[16]	**Annual Impact of Change on Unhedged Costs ($)**		(68,433,000)	73,021,000	(26,071,000)	(42,657,000)	(201,782,000)		266,062,000	(58,714,000)	(59,490,000)

Sources:

[1]: NERA model, with modifications to inputs as described in text.
[2]: ISO website, at http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_detail.do (select "Summer 2010").
[3]: [1] / (1 - [2])
[4]: ISO Staff Proposal at 18 (with modifications as described in text).
[5]: Summer months average from Table B-2. Averages from 9/09 through 8/10 used for NYCA and from 2/10 through 8/10 used for New York City.
[6]: max(0, [3] x ([4] - [5]) / ([4] - 1))
[7]: Summer months average from Table B-2. Averages from 9/09 through 8/10 used for ROS and from 2/10 through 8/10 used for New York City.
[8]: [6] x [7] x 6 x 1000
[9]: Winter months average from Table B-2. Averages from 9/09 through 8/10 used for NYCA and from 2/10 through 8/10 used for New York City.
[10]: max(0, [3] x ([4] - [9]) / ([4] - 1))
[11]: Winter months average from Table B-2. Averages from 9/09 through 8/10 used for ROS and from 2/10 through 8/10 used for New York City.
[12]: [10] x [11] x 6 x 1000
[13]: [8] + [12]
[14]: Same assumption used when calculating variant 2 of the ICAP metric for regulated economic projects, as described in the NYISO Open Access Transmission Tariff, Sec. 31.3.1.3.5.6.2.
[15]: (1 - [14]) x [13]
[16]: [15] - ([15] for ISO Staff Proposal).

Table B-2 (Used as an Input in Table B-1, Rows 5, 7, 9 and 11)

	NYCA			New York City			Long Island		ROS
Month	UCAP Requirement (MW)	UCAP Sales (MW)	Ratio of Sales to Requirement	UCAP Requirement (MW)	UCAP Sales (MW)	Ratio of Sales to Requirement	UCAP Requirement (MW)	UCAP Sales (MW)	UCAP Sales (MW)
Sep-09	36,362.4	39,510.1	1.087	8,855.3	9,671.7	1.092	4,748.5	5,487.4	24,351.0
Oct-09	36,362.4	39,742.9	1.093	8,855.3	9,666.4	1.092	4,748.5	5,491.6	24,584.9
Nov-09	35,785.3	39,866.7	1.114	8,551.6	9,973.9	1.166	4,685.0	5,528.3	24,364.5
Dec-09	35,785.3	39,762.0	1.111	8,551.6	10,019.0	1.172	4,685.0	5,527.3	24,215.7
Jan-10	35,785.3	39,290.7	1.098	8,551.6	10,048.7	1.175	4,685.0	5,528.3	23,713.7
Feb-10	35,785.3	38,595.3	1.079	8,551.6	9,333.6	1.091	4,685.0	5,528.3	23,733.4
Mar-10	35,785.3	39,718.7	1.110	8,551.6	9,358.9	1.094	4,685.0	5,528.3	24,831.5
Apr-10	35,785.3	39,807.1	1.112	8,551.6	9,411.7	1.101	4,685.0	5,528.3	24,867.1
May-10	35,045.3	37,905.5	1.082	8,336.0	8,708.0	1.045	5,021.1	5,375.1	23,822.4
Jun-10	35,045.3	38,441.8	1.097	8,336.0	8,739.6	1.048	5,021.1	5,850.1	23,852.1
Jul-10	35,045.3	38,520.6	1.099	8,336.0	8,748.0	1.049	5,021.1	5,838.0	23,934.6
Aug-10	35,045.3	38,609.0	1.102	8,336.0	8,754.7	1.050	5,021.1	5,872.3	23,982.0
Averages Calculated from Sept. 2009 through Aug. 2010									
Summer Months		38,788.3	1.093		9,048.1	1.063		5,652.4	24,087.8
Winter Months		39,506.8	1.104		9,691.0	1.133		5,528.1	24,287.7
Averages Calculated from Feb. 2010 through Aug. 2010									
Summer Months		38,369.2	1.095		8,737.6	1.048		5,733.9	23,897.8
Winter Months		39,373.7	1.100		9,368.1	1.095		5,528.3	24,477.3