COMMENTS OF THE TRANSMISSION OWNERS, NYPA AND LIPA ON THE JULY 1, 2010 DRAFT OF THE NERA REPORT ON INSTALLED CAPACITY DEMAND CURVES

July 21, 2010

The Transmission Owners, NYPA and LIPA (the TOs) submit the following comments on the July 1, 2010 draft of NERA's[1] report on ICAP demand curves for the 2011-12 through 2013-14 capability years.[2]

1. Generator Cost Assumptions

a. Selection of Unit

The Draft Report proposes that the NYCA demand curve be based on the net cost of developing a Frame 7FA unit, while the NYC and LI demand curves would be based on the net cost of developing an LMS100 unit. It supports this by noting that the tariff requires that the demand curves be based on "the unit with … the lowest fixed costs and highest variable costs … that [is] economically viable."[3]

The Draft Report correctly notes, "[t]his unit will not necessarily be the lowest 'net cost' unit under current conditions,"[4] as it is possible that two or more units may be economically viable, even though their net costs differ due to transient differences in system conditions that affect factors such as net energy revenues.

However, the Draft Report fails to address which criteria should be used to determine whether a given unit is economically viable. For example, NERA's selection of a Frame 7FA for the NYCA demand curve was based upon the observation that "[t]he Frame 7FA has lower capital and higher operating costs than the LMS100,"[5] but that only dictates the use of a Frame 7FA if such a unit is economically viable. In the Draft Report, NERA simply did not address the question of whether a Frame 7FA unit would be economically viable in the ROS region.

If a generating unit is not economically viable, then the demand curve cannot be based on the net cost of developing that generating unit. In particular, if the net cost of a particular generator is far higher than the net cost of generators in that region using different technologies, it suggests that such a difference may not be due to transient differences in system conditions, and may instead indicate the generator in question is not, in fact, economically viable. The final report should describe the basis for NERA's conclusion

[1] In these comments, we refer to NERA and Sargent & Lundy jointly as "NERA."

[2] "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator," NERA Economic Consulting, July 1, 2010 Draft (henceforth, "Draft Report").

[3] *Id.* at 7.

[4] *Id.*

[5] *Id.* at 8.

that the generators whose net costs were used to set the various demand curves are economically viable.

b. Other Aspects of Current Generator Costs

Land Requirements in NYC

In the Draft Report, NERA assumes a land requirement of 6.0 acres for a 2 × LMS100 plant in New York City. We question the assumption that a 2 × LMS100 plant would require almost twice as much space as a 1 × LMS100 unit (which requires 3.5–4 acres). This is inconsistent with the assumption made in the 2007 Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, in which NERA assumed that a 2 × LMS100 plant would require 3.5 acres in NYC.[6] Using GE's modular plant layout and some assumptions as suggested in a presentation made last month by Levitan & Associates on behalf of New York City generators,[7] Con Edison has determined that 3.5–4 acres would be sufficient for a 2 × LMS100 plant, which would be consistent with the assumptions made in the last demand curve reset.

The four major components in a LMS100 plant are (a) LMS100 generating unit, (b) fin fan cooling system, (c) fuel oil tank and catch basin, and (d) supporting functions. Based on a GE LMS100 modular plant layout, the estimated footprint for 1 × LMS100 generating unit is 0.6 acres. Levitan indicated that the fin fan cooling system for the South Pier Improvement Project was expected to require 65' × 200', equivalent to 0.3 acres.[8] The supporting functions include items such as fire water tank, demineralized water tank, storage areas, demineralized water trailers and pumps, compressors, etc. In the instance of the South Pier project, Con Edison estimates that this area is expected to require 0.6 acres and an area of 0.9 acres for fuel oil tank and catch basin. Using the above assumptions, Con Edison determined that a 2 × LMS100 plant will require: 2 × LMS100 + 2 × fin fan cooling + 1 fuel tank + 1 supporting function = 2 × 0.6 + 2 × 0.3 + 0.9 + 0.6 = 3.3 acres. According to Con Edison engineers, the fin fan cooling system could also be built on top of the LMS100 to conserve space if necessary, which further reduces the land requirement to 2.7 acres. Based on these calculations, Con Edison concludes that a 2 × LMS100 plant will require no more than 3.5–4 acres to ensure sufficient access to the generators and equipment. Therefore, we believe that the NYC land requirement should be changed.

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[6] "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator," NERA Economic Consulting, Aug. 15, 2007 (henceforth, "2007 Report") at 27, Table II-1.

[7] "Response to Multiple Intervenors' Straw Proposal and Transmission Owners' Comments," Levitan & Associates, June 10, 2010.

[8] *Id.* at 6.

NYC Tax Abatements

In its draft report, NERA asserts that the tax abatements available for Zone J generators should not be assumed to be 100% of Industrial & Commercial Incentive Program (ICIP) unless New York City adopts a program that provides for comparable benefits, stating:

> Our understanding is that the NYC EDC is currently considering an abatement policy that may apply to new generation and that the NYISO Board will review any policy that is developed and determine its applicability to the proxy peaking units. In the event that a policy is not developed, we would anticipate that the option without abatement results would apply. In the event an abatement policy is developed that would provide a different incentive than the ICIP, we anticipate that the Model would be revised to reflect the new abatement policy.[[9]]

As the TOs stated in their February 2010 comments, there are existing tax abatements available in New York City the value of which can exceed the previous ICIP:

> The New York [City] Industrial Development Agency (NYCIDA) has the ability to abate the City's real property taxes (on both the land, building, and equipment components of a project) and both the City and State portions of the sales tax. The NYCIDA can also provide a deferral of both the City and State portion of the mortgage recording tax for the life of the project. The NYCIDA has the authority to match or exceed the tax benefits formerly provided by the City's Industrial and Commercial Incentive Program (ICIP).[[10]]

Given that the City of New York has a strong interest in ensuring a reliable supply of economic and clean electricity, there is no basis to exclude the available tax abatements from the calculation of the Net CONE in New York City. Therefore, we recommend that NERA strike the excerpted language from the final version of its report.

Capital Investment Costs

In a number of instances, NERA's capital investment costs are dramatically higher than those used in the 2007 demand curve study. Using Engineering & Design Costs as a detailed example, Tables A-9 and A-10 in Appendix A present comparisons of the various capital cost estimates in Zone C for two 7FA units and Zone J for two LMS100 units, respectively. For Zone C, the cost for Engineering & Design Services is estimated at $7,125,000 in 2004, $7,413,000 in 2007 and $11,152,000 in 2010. For Zone J, the estimated cost is $8,562,000 in 2007 and $11,633,000 in 2010. From 2004 to 2007, the cost increase was 4% in Zone C; no cost estimates were provided for Zone J in 2004. However, comparing the 2010 cost estimates to 2007, it appears that engineering services have increased in cost by 50% in Zone C and 36% in Zone J. It appears very unlikely that these costs would rise so dramatically over the past three years, especially given the

[9] Draft Report at 67.

[10] NYISO Questions to Stakeholders – Demand Curve Reset Issues, Transmission Owners' Responses, Feb. 2010, at 4.

economic growth seen during the 2004 – 2007 period. The questionable nature of this cost increase is even greater when looking at the minimal cost estimate increase from 2004 to 2007. We recommend that a simple multiplier of 4% be applied to the 2007 cost estimates to derive the 2010 estimated Engineering & Design Costs, which is consistent with the period 2004 to 2007.

Other examples of inflated Capital Investment Costs are an increase of 30% for the cost of the generating unit, 37% for construction materials and labor, 860% for electrical system upgrades, and 61% for site prep. However, a recent news article cites a report recently completed by IHS CERA concluding that "its power capital-costs index for North America rose 1% from the third-quarter of 2009 to the first quarter of this year. A similar index for Europe climbed 3% over the same period. The index, which is released every six months, posted its first gains since early 2008."[11] Given the fact that this IHS CERA index showed almost no growth in capital costs in the last two and a half years, it appears that NERA's Capital Investment Cost estimates should be revised downward significantly.

Net Degraded ICAP MW

The O&M cost allows for major overhauls. NERA's assumptions regarding degradation of the proxy peaker's rating should reflect these overhauls.

NYC Site Leasing Costs

NERA assumes that site leasing costs are the same as 2007, adjusted for inflation. However, since 2007, the value of real estate in the New York City has fallen. This should be reflected in NERA's calculations.

Financing Fees

In its Capital Cost estimates in Appendix A, NERA assumes a 2% financing fee and applies this to the total EPC costs. This financing fee is incorrectly calculated in that it should be based on the portion of the EPC costs that are financed using bank debt, which is 50% in this instance. Therefore, the Financing Fees line items for all generator technologies in all zones should be reduced by 50% to reflect this.

c. Technological Progress

NERA's ICAP Demand Curve model assumed that, over the fourth through 30th years of the hypothetical entrant generator's lifespan, the net cost of developing generating capacity will decrease from year to year due to "technological progress". However, this assumption is inconsistent with the trend of higher construction costs that have been

[11] "Power-Plant Building Costs In N America, Europe Inch Up – CERA," available at http://www.advfn.com/news_Power-Plant-Building-Costs-In-N-America-Europe-Inch-Up-CERA_43614989.html. See also "Power Plant Construction Costs Rise for First Time Since Q1 2008, But Gain is Limited," July 15, 2010, available at http://press.ihs.com/article_display.cfm?article_id=4280, which illustrates that power plant construction costs in the U.S. are similar to costs in 2007-2008.

included in the cost estimates for the proxy peakers. The observed reality is that the actual net cost of developing the proxy peaking unit has not been decreasing in real terms. Therefore, we recommend setting this parameter to no less than zero. Furthermore, the slope changes for years 1 – 3 should be consistent with what NERA is recommending as the Net CONE for the upcoming demand curve cycle.

d. Lifespan of New Generator

For the demand curve reset process, NERA has assumed the proxy units have a thirty-year life and for aero-derivatives, NERA has assumed a residual value of 5% of the initial investment. Based on an actual historical age analysis of GTs in New York State, over 75% of GTs are older than 30 years, with 40% of units over 40 years. This demonstrates that the residual values of the proxy peakers at 30 years of age should be much higher than what is being used by NERA. Either the model should assume a 40-year life for entrant generators, or it should assume a residual value of 25% for Frame 7FA units, and $5\% + (95\% \times (10/40)) = 28.75\%$ for aeroderivatives at year 30 of the generator lifetime.

2. Energy and Ancillary Services Revenues

a. Model Output

An email that was sent to Dave Lawrence on our behalf on June 2 stated:

> The TOs are concerned that the underlying statistical relationships during on-peak hours may differ significantly from the underlying statistical relationships during off-peak hours, in which case the regression model that NERA has been using may not have sufficient flexibility to estimate the correct regression parameters. The sample period that is being used to develop the model (all hours between 11/1/06 and 10/31/09) should be split into on-peak and off-peak hours, and the regression parameters should be estimated using the on-peak hours only. These parameter estimates should then be compared to the parameters that have been estimated using all hours. If there are significant differences, this may indicate the need to use parameters estimated using on-peak hours only.

We reiterate the need for such an analysis, for the reasons given above.

b. Special Case Resource Adjustment

NERA included an adjustment to the results generated by its model to account for hours when prices are adjusted to account for the use of Special Case Resources. More detail on this adjustment would be desirable, as the brief description on p. 46 of the draft report does not contain enough detail to permit an informed review of this adjustment, and all we have seen outside the report was a presentation made at the May 21 ICAP Working Group meeting that was based on hypothetical energy prices.

c. Gas Costs

At the July 16th ICAP Working Group meeting, Levitan & Associates gave a presentation in response to the Draft Report. In its presentation, Levitan argued that NERA should increase its New York City day-ahead/real-time gas adder from approximately 20 cents/MMBtu to 50 cents/MMBtu, and add an intraday premium gas adder of 45 cents/MMBtu. The TOs strongly dispute increasing the DA/RT gas adder. For July 2010, Con Edison has calculated that the average DA/RT gas adder for the oldest gas turbines in New York City have been substantially lower than Levitan's recommendation of 50 cents. Also, given that the LMS100 has such a low heat rate relative to other peakers and can be easily redispatched, it is highly likely that it will be scheduled on a day-ahead basis. This ensures that the generator operator will make arrangements to procure gas outside of the intraday market.

Levitan's assumption that there should be an intraday premium component to NERA's assumed fuel cost ignores the reality that the owner of a brand new peaking unit in New York City will be sufficiently sophisticated to manage its fuel supply activities to minimize the impact of the intraday market, and mitigate its fuel cost and supply risk. Therefore, NERA should not include an intraday premium gas adder in its fuel cost assumptions.

3. Carrying Costs

a. Cost of Equity

NERA's analysis indicates that the asset betas of comparable merchant generator companies average 0.48, or 0.52 if AES is excluded, which corresponds to equity betas of 0.96 to 1.04, given the 50/50 capital structure assumed. However, NERA nevertheless chose to use an asset beta of 0.60 for a new generator, which translates to an equity beta of 1.2, because "it is reasonable to assume that the demand curve project would have a riskier business profile than the average of the merchant generator companies [used to calculate the average asset beta]."[12] NERA's carrying costs are based on this equity beta of 1.2.

The asset beta measures the degree to which the net revenues that a project yields vary with returns in the market as a whole.[13] NERA has not shown that the asset beta derived from its analysis of comparables is understated. In fact, NERA has not even asserted that it is understated. Instead, NERA simply decided to add something to the asset beta to offset this perceived additional risk, even though the factor that they added has nothing to

[12] Draft Report at 60.

[13] The leading finance textbook defines equity betas as follows: "A stock's sensitivity to changes in the value of the *market* portfolio is known as *beta*. Beta, therefore, measures the marginal contribution of a stock to the risk of a market portfolio." (R.A. Brealey, S.C. Myers and F. Allen, *Principles of Corporate Finance*, 9th Ed. ("BMA"), at 216, emphasis in original.) Asset betas, in turn, are defined as weighted averages of equity betas and debt betas. (BMA at 543.)

do with asset beta. This arbitrary factor ought to be removed from the calculation of the asset beta, and the cost of equity ought to be recalculated accordingly.

b. New York City Issues

To reiterate the arguments Con Edison made in its July 2, 2010 memo to the NYISO, buyer-side mitigation of the New York City capacity market serves to reduce the merchant risk associated with building new capacity in the city by creating a floor on capacity prices. This eliminates the risk associated with capacity prices falling below the offer floor over a long period of time and has the following specific effects on the cost of capital and amortization period:

Based on the assumption that the proxy peaker will be subject to 100% merchant risks, NERA has proposed a credit rating of BB.[14] In many cases, in-city buyer-side mitigation will prevent new entrants from offering their capacity for less than 75% of net cost of developing new capacity. This will significantly reduce the chances that prices would fall below this level, which would ensure recovery of approximately 50% of capital investment.[15] Consequently, Con Edison proposes that a credit rating of BBB for the NYC generator is more appropriate given the reduction in the investment risk. This is also another reason why the business risk assumptions underlying the assumed asset beta of 0.6 for NYC generation is inappropriate, because even if it were appropriate to make the business risk adjustment to the assumed asset beta, the business risk giving rise to the purported need for this adjustment would be limited by the price protection provided by in-city buyer-side mitigation. This also eliminates the need for a shortened amortization period for Zone J.

4. Surplus Capacity Assumption

NERA has assumed that the average amount of ICAP provided will be 101.5% of the NYCA requirement, 103% of the NYC requirement and 107% of the Long Island requirement. These calculations are based on 1.5 times the amount of capacity provided by a peaking unit, as a percentage of the relevant ICAP requirement, rounded to the nearest 0.5%.

Arguments that we previously made as to why the ISO should not assume any surplus capacity continue to apply. Our May 20, 2010 comments stated:

> The 2008-11 NYCA ICAP demand curve was set under the assumption that 101.5 percent of the Minimum ICAP Requirement for the New York Control Area (NYCA) would be provided on average over the lifespan of a new generator, while the ICAP demand curves for the New York City and Long Island Localities

[14] Draft Report at 58.

[15] Merchant risk for a new generator can typically be divided into 30% energy & ancillary services and 70% capacity revenue risk. If the NYC ICAP price does not drop below 75% of the net cost of developing new capacity, we can conclude that 75% × 70% = approx. 50% of total revenue risk is mitigated by in-city buyer-side capacity mitigation.

for 2008-11 were set under the assumption that 104 percent of their Locational Minimum ICAP Requirements would be provided.

When the NYSRC considers the installed reserve margin (IRM) under its Reliability Rule A-R1, it evaluates the IRM on a probabilistic basis and establishes the installed reserve margin so that the probability of disconnecting any firm load due to resource deficiencies shall be, *on average* not more than once in ten years (i.e., a 50% probability of meeting the one day in ten years LOLE). Excess capacity is not required by the NYSRC Reliability Rules. No excess supply is assumed, or needed, to meet the NYSRC criterion. The net CONE should be based on the IRM, not an adjusted IRM.

Moreover, the assumption of excess capacity becomes a self-fulfilling prophecy. By assuming that excess capacity will be supplied, the NYISO is effectively increasing Minimum ICAP Requirements. For example, if the NYISO were to calculate the ICAP demand curve for the NYCA under the assumption that it should provide sufficient revenue for the development of new capacity even if the amount of capacity provided over such a generator's lifespan averages 101.5 percent of the Minimum ICAP Requirement (as it did three years ago), then a new generator considering entry could earn enough money over its lifespan to support its decision to enter even if new capacity is not needed in order to meet the IRM. New entry would be supported whenever the amount of generation counting towards the IRM reaches approximately 101.5 percent of that requirement, which is the amount of capacity one would then expect to see in the market in the long-run equilibrium.

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 customers greatly exceeds any plausible estimate of the value to end-use customers of the reliability provided by that additional capacity. Since it has not been shown that the cost of this excess capacity to end-use customers is consistent with its value to them, and since provision of this excess capacity is not required to comply with NYSRC Reliability Rules, the NYISO should eliminate this excess capacity assumption when establishing its 2011-14 ICAP demand curves.[[16]]

Given that Section 5.14.1(b) of the Market Service Tariff provides that the periodic demand curve review shall assess "the current Localized levelized embedded cost of a peaking unit for each NYCA Locality and the Rest of State to meet minimum capacity requirements," the TOs request that the report include demand curves calculated with the intent of ensuring that the demand curves provide sufficient ICAP revenue to induce the development of additional capacity when the amount of ICAP provided in the NYCA, NYC and Long Island is equal to the minimum capacity requirement for each of those

[16] "Comments of the Transmission Owners, NYPA and LIPA on the Data and Assumptions Being Used in the 2011-14 ICAP Demand Curve Analysis," May 20, 2010, at 4.

regions, as well as the alternative proposed by NERA, along with the impact of each demand curve on the risk of insufficient capacity to meet reliability criteria and on consumer payments for installed capacity.

We note that NERA has not provided any basis for basing this assumption on 1.5 times the amount of capacity that would be provided by a peaking unit. While we do not believe that the NYISO should be making any surplus capacity assumption, to the extent that the NYISO nevertheless makes such an assumption, it should be based on the amount of capacity that would be provided by a peaking unit, not 1.5 times that amount.

In addition, NERA's final report should contain the details of the calculations that led to the proposed surplus capacity assumptions. In particular, the 7% surplus capacity calculation for Long Island appears to be erroneous: the summer DMNC of an LMS100 generator on Long Island, as reported in NERA's model, is 194.2 MW, so 1.5 times that capacity divided by the 5609.6 MW Long Island ICAP requirement for the 2010-11 Capability Year yields 5.2% of the Long Island requirement, which should round to 5%. The final report should also explain how NERA took into account the likelihood that Long Island ICAP prices would be set by the ICAP demand curve for the NYCA, not the ICAP demand curve for Long Island, when estimating the capacity revenues that a new generator on Long Island would receive.

5. Seasonality Adjustment

In contrast to past demand curve updates, the model used by NERA to perform this update includes an adjustment to reflect seasonal price differences, and the need to modify the demand curve to reflect the impact of lower prices in the winter on the total amount of ICAP revenue that a new generator could expect to earn.

In the past, the NYISO has performed this adjustment based on the assumption that the difference between winter and summer capacity prices is driven by the ratio of the amount of capacity that could be sold in the winter to the amount of capacity that could be sold in the summer. There have been significant differences between the ratio of the amount of capacity that could be sold in the winter to the amount of capacity that could be sold in the summer, on one hand, and the ratio of the amount of capacity *actually sold* in the winter to the amount *actually sold* in the summer, on the other hand. For example, at the time of the last demand curve resets, the NYISO had completed four years of ICAP markets under the demand curves, with the following ratios of winter capacity sales to summer capacity sales:

	Actual Ratio of Winter Sales to Summer Sales		
Capability Year	**NYCA**	**NYC**	**LI**
2003-04	1.017	1.072	0.945
2004-05	1.015	1.058	1.042
2005-06	1.007	1.065	1.031
2006-07	1.018	1.082	1.046

Despite these results, the NYISO performed its adjustments for the 2008-11 ICAP demand curves under the assumption that the ratio of the amount of ICAP provided in the winter to the amount provided in the summer would be 1.050 to 1.056 for the NYCA, 1.087 to 1.095 for NYC, and 1.056 for Long Island.

As we explained in our May 20, 2010 comments, that procedure was flawed:

> The need for a seasonality adjustment primarily derives from the fact that ICAP prices are generally lower in the winter capability period because the amount of capacity that can be provided during the winter is based on winter Demonstrated Maximum Net Capability (DMNC) ratings, which are generally higher. (This impact is partially offset by the fact that the hypothetical entrant generator, whose cost of entry is used to set the demand curve, can sell more unforced capacity during the winter.) However, the difference between winter and summer capacity prices is driven by the ratio of the amount of capacity *actually sold* in the winter to the amount *actually sold* in the summer, not the ratio of the amount of capacity that *could be sold* in the winter to the amount of capacity that *could be sold* in the summer. Capacity that could be sold in the winter, but is not actually sold, does not cause winter UCAP prices to be less than summer capacity prices, and should not be considered when calculating the seasonal adjustments that are necessary to account for differences between winter and summer capacity prices.[[17]]

Unfortunately, NERA used the same procedure to perform this adjustment that the ISO has used in the past. Based on the answers to questions at the July 16 ICAP Working Group meeting, our understanding is that the ISO directed NERA to use this procedure.

There are two fundamental flaws with the ISO's procedure. First, the ratio of the amount of capacity that could be sold in the winter to the amount of capacity that could be sold in the summer does not necessarily have anything to do with the ratio of winter capacity sales to summer capacity sales that will actually be observed in long-run equilibrium conditions. Second, even if that ratio were consistent with long-run equilibrium conditions, it might not be consistent with what would be observed in the short run, which could lead to the development of either more or less capacity than was anticipated.[18]

In the past, the TOs recommended that the ISO forecast the ratio of the amount of capacity that would actually be sold in the winter to the amount that would actually be sold in the summer over the three-year period to which the demand curves would be applied. However, the ISO has been hesitant to adopt this recommendation, at least in part because it would prefer not to prepare such a forecast. The procedure that NERA is using to forecast net energy revenues suggests an alternative approach.

NERA described its approach to forecasting energy revenues as follows:

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[17] *Id.* at 4-5.

[18] For an example illustrating how a reduced ratio of winter ICAP sales to summer ICAP sales during surplus capacity conditions can lead to procurement of excessive amounts of ICAP, see Appendix A of Affidavit of Michael D. Cadwalader, appended to "Motion to Intervene and Protest of the New York Transmission Owners," Docket No. ER08-283-000, Dec. 31, 2007.

> By making no other adjustments other than for Installed Capacity levels, however, we are effectively using econometrics to answer the question "what would peaker revenues have been for the three-year historic period had the system been at capacity levels equal to or slightly in excess of the minimum Installed Capacity requirement?" We do so understanding that the next three years will not precisely mirror the last three…. We believe that not adjusting to normalize out potential anomalies or more exactly predict conditions for the next three years provides the most objective set of net revenue parameters, reduces estimation errors and should be expected to smooth out…. Using actual experienced conditions tracks, albeit with a lag, the revenue opportunities that existing generators actually encountered. An entrant can be assured that the net revenues used in setting the Demand Curve will over time reflect events in the market and will not face the uncertainty of judgmental adjustments to "normal conditions" or "forecast conditions."[[19]]

If NERA were to use the average ratio of winter UCAP sales to summer UCAP sales during the past three years when performing the seasonality adjustment, that would ensure that over time, the adjustment reflected the actual ratio of winter UCAP sales to summer UCAP sales made over a new generator's lifespan. This would eliminate the need to perform any forecasts of the ratio of the amount of capacity sold in the winter to the amount sold in the summer.

In contrast, it is clear that the approach the ISO has been using leads to seasonality adjustments which do not even out over time. Instead, the ratio of winter sales to summer sales has historically been much lower than the ratio of the amount of capacity available in the winter to the amount of capacity available in the summer, which is the measure the ISO has historically used to forecast the amount by which winter prices will be suppressed below summer prices.

The table below compares actual winter-to-summer sales ratios for the last several years to the ratios of winter capacity available to summer capacity available, which the ISO used the last demand curve reset and directed NERA to use for this demand curve reset. As it shows, if the ISO had simply based its 2008-11 demand curves on the average winter-to-summer sales ratios observed over three preceding capability years (excluding the 2007-08 capability year because those data were not yet available when the ISO was setting the demand curves for the 2008-09 through 2010-11 capability years), it would have used a 1.013 ratio for the NYCA for the 2008-09 and 2009-10 capability years. This is much closer to the ratios that were actually observed than the 1.050 and 1.055 ratios the ISO actually used. The ISO would have used a 1.068 ratio for NYC for the 2008-09 and 2009-10 capability years, which is much closer to the ratios that were actually observed than the 1.087 ratio the ISO actually used. And the ISO would have used a 1.040 ratio for LI for the 2008-09 and 2009-10 capability years. The ratios actually observed for those two years were 1.032 and 1.058, which average to 1.045; using a ratio of 1.040 would have been closer to that average observed winter-to-summer sales ratio than the 1.056 ratio the ISO actually used.

[19] Draft Report at 42.

Capability Year	NYCA Actual Ratio of Winter Sales to Summer Sales	NYCA Ratio of Winter Capacity Available to Summer Capacity Available	NYC Actual Ratio of Winter Sales to Summer Sales	NYC Ratio of Winter Capacity Available to Summer Capacity Available	LI Actual Ratio of Winter Sales to Summer Sales	LI Ratio of Winter Capacity Available to Summer Capacity Available
2004-05	1.015		1.058		1.042	
2005-06	1.007		1.065		1.031	
2006-07	1.018		1.082		1.046	
2004-07 Average	***1.013***		***1.068***		***1.040***	
2007-08	1.021		1.101		1.041	
2008-09	1.017	1.050	1.070	1.087	1.032	1.056
2009-10	1.022	1.055	1.044	1.087	1.058	1.056
2007-10 Average	***1.020***		***1.072***		***1.044***	
2010-11		1.056		1.095		1.056
2011-12 through 2013-14		1.052		1.098		1.062

Therefore, the TOs recommend that the seasonality adjustment for the 2011-14 demand curves be based on the average winter-to-summer sales ratio calculated over the 2007-10 period (1.020 for the NYCA, 1.072 for NYC and 1.044 for LI), adjusted as necessary to reflect any differences between winter-to-summer sales ratios that have been observed given the installed reserve margins over this period and the winter-to-summer sales ratios that would be observed given the installed reserve margins assumed by NERA in each of its Monte Carlo simulations, instead of the 1.052, 1.098 and 1.062 values provided to NERA by the ISO.

We also request that the report include a quantification of the impact on consumer payments for capacity during the current demand curve period resulting from the use of potential capacity instead of historic sales in performing the seasonality adjustment.

6. Shape and Slope of Demand Curves

NERA recommends that the demand curves retain their current shape and slope. NERA provides several reasons for this recommendation, first stating:

> We do remain concerned, however, that moving the zero crossing point towards the origin increases the importance of having accurate information on the average excess level and standard deviation. With a steep slope, if there is an understatement of the average level of excess and standard deviation, the demand curve will be under-compensatory and sufficient capacity may not develop.[[20]]

In other words, the analysis underlying NERA's ICAP demand curve proposal assumes that there is very little chance that the amount of ICAP provided will be less than the ICAP requirement. However, this overlooks a countervailing factor. If the ICAP demand curve is based on an overestimate of the cost of entry, then the probability that the amount of ICAP provided is far more than the ICAP requirement could increase substantially. Other providers of capacity might withdraw from the market instead of accepting such low prices. Consequently, NERA's analysis may assume that entrant generators would receive less revenue than they would actually receive. As a result, the demand curve that NERA is developing may be overcompensatory.

NERA also notes:

[20] *Id.* at 69.

> 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.[[21]]

In our view, this describes a benefit of making the demand curves steeper. If an older unit is not needed for reliability reasons and if its absence will have little impact on the energy market, it probably should retire. The point that the potential for retirement or mothballing may mitigate any price decrease that would otherwise follow from the use of a steeper demand curve is valid, but even if we assume that the supply curve is horizontal, meaning that no price reduction is possible, using a steeper demand curve would still reduce the quantity of ICAP that must be purchased.

NERA also argues:

> 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 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.[[22]]

This assumes that we 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 we may never reach such a point. The amount of UCAP provided in recent years has been far above the ISO's expectations. One possible explanation is that the ISO has, in fact, systematically overestimated the cost of entry in its demand curve analyses. If the ISO has been doing that, the amount of capacity developed would exceed the amount of capacity the ISO expected would be provided. Instead, capacity would developed up to the point on the demand curve where the price on the demand curve is equal to the actual cost of entry. If that is the reason for a substantial portion of the capacity surpluses we have observed in recent years, then NERA's approach would never let us adjust the demand curves, because we would never reach the point where the amount of capacity provided is close to the amount the ISO assumed when it developed the demand curves.

In addition, re-evaluating the demand curve shape and slope when there is a capacity surplus ensures that there is little risk to reliability should any adjustments prove to have unintended effects.

Fundamentally, the TOs believe that there needs to be a full evaluation of alternate demand curve shapes and slopes for the ICAP demand curves for all three NYCA capacity zones. For the third consecutive time, such an analysis has not been performed. When Levitan & Associates performed the first demand curve reset analysis, they stated,

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[21] *Id.*

[22] *Id.* at 70.

"We recommend a more complete and rigorous analysis of likely suppliers and their combined impact on regional capacity markets under alternative zero-crossing point options."[23] Yet this analysis has never been performed.

The TOs view the analysis of the shape and slope of the demand curves in the draft report as one-sided in that it considers the risk of providing insufficient compensation to potential new entrants into the capacity market, but gives no consideration to the risk of over-compensating existing generators for capacity that is not needed to meet reliability criteria, to the detriment of New York consumers. We note that the NYISO Board has recently reaffirmed its commitment to consider consumer impacts in exercising its responsibilities. It is important, therefore, that in making its determinations with respect to the demand curves the Board has relevant information concerning the potential impact of those determinations on New York consumers. In order for the Board to be in a position to strike an appropriate balance between reliability and cost, the TOs request that NERA define the reliability benefits in various levels of surplus capacity (e.g. 108%, 109% and 112%) and corresponding costs to load.

7. Special Case Resource Evaluation

In the Draft Report, NERA states, "[t]hrough the stakeholder process, the prevalent understanding was that in the next reset, NYISO would consider whether Special Case Resources should be considered as the possible peaking unit."[24] This evaluation should be initiated at least one year before the RFP for the NYISO consultant is issued. A shortage of time has been cited as justification for not evaluating SCRs, as well as other demand curve shapes and slopes during the current reset period. Therefore, these issues should be addressed on their own with sufficient time to come to a well-reasoned decision. It should also be noted that the New York State Reliability Council has requested the NYISO to perform a study on SCRs analogous to the recently-completed wind study. This evaluation should be included as a potential project under the 2011 NYISO budget.

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[23] "Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator," Levitan & Associates, Aug. 16, 2004, at 66.

[24] Draft Report at 7-8.