NYISO Installed Capacity Working Group

Response to Multiple Intervenors and Transmission Owners on behalf of New York City Generators

APPENDICES

Appendix A

NYISO: A Ten-Year Review

ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

The New York Independent System Operator: A Ten-Year Review

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Analysis Group

Boston, Massachusetts
April 12, 2010

This White Paper was prepared at the request of the New York Independent System Operator.
The paper reflects the views of the author, and not necessarily the views of the NYISO, or its members.

reactive power and the ability to maintain a specific voltage level under both steady-state and post-contingency operating conditions subject to the limitations of the resource's stated reactive capability." (c) "Black Start is the ability of a generating unit to go from a shutdown condition to an operating condition, and start delivering power without assistance from a power system." http://www.nyiso.com/public/markets_operations/market_data/ancillary/index.jsp.

- The *New York Installed Capacity (ICAP) market*, which "is based on the obligation placed on load serving entities (LSEs) to procure ICAP to meet minimum requirements. The requirements are determined by forecasting each LSE's contribution to its transmission district peak load, plus an additional amount to cover the Installed Reserve Margin. The amount of capacity that each supplying resource is qualified to provide to the New York Control Area (NYCA) is determined by an Unforced Capacity (UCAP) methodology. NYISO ICAP auctions are designed to accommodate LSEs and suppliers' efforts to enter into UCAP transactions. They are open to all registered NYISO customers." http://www.nyiso.com/public/ markets_operations/market_data/icap/index.jsp.
- *Transmission congestion markets*: "Transmission Congestion Contracts (TCCs) enable energy buyers and sellers to hedge transmission price fluctuations. A TCC holder has the right to collect or the obligation to pay congestion rents in the Day-Ahead Market for energy associated with transmission between specified points of injection and withdrawal. The NYISO conducts periodic auctions where TCCs are bought or sold. The auctions maximize the value of TCC awards, based on the bids and transmission line and contingency constraints. An Optimal Power Flow program is used to determine the TCCs awarded in an auction." http://www.nyiso.com/public/markets_operations/market_data/tcc/index.jsp.
- *Demand-response markets*, including the Emergency Demand Response Program ("EDRP"), the ICAP Special Case Resources ("SCR") program, the Day Ahead Demand Response Program ("DADRP") and the Demand Side Ancillary Services Program ("DSASP"). "Both the EDRP and SCR program can be deployed in energy shortage situations to maintain the reliability of the bulk power grid. Both programs are designed to reduce power usage through shutting down of businesses and large power users. Companies, mostly industrial and commercial, sign up to take part in the programs. The companies are paid by the NYISO for reducing energy c*onsumption when asked t*o do so by the NYISO. Reductions are voluntary for EDRP participants. SCR participants are required to reduce power usage and as part of their agreement are paid in advance for agreeing to cut power usage upon request." The NYISO's DADRP "allows energy users to bid their load reductions, or "negawatts", into the Day-Ahead energy market as generators do. Offers determined to be economic are paid at the market clearing price. DADRP allows flexible loads to effectively increase the amount of supply in the market and moderate prices." The DSASP "provides retail customers that can meet telemetry and other qualification requirements with an opportunity to bid their load curtailment capability into the DAM and/or Real-Time Market to provide Operating Reserves and regulation service. Scheduled offers are paid the appropriate marketing clearing price for reserves and/or regulation." http://www.nyiso.com/public/ markets_operations/market_data/demand_response/index.jsp

[108] See, for example:

- From the 2003 NYISO State of the Market Report: "In long-run equilibrium, the market should support the entry of new generation by providing sufficient net revenues (revenue in excess of production costs) to finance new entry….These results indicate that the market in 2003 did not produce sufficient net revenue to support investment in a new gas turbine in NYC. A new gas turbine in NYC would have recovered approximately 60 to 75 percent of the net revenue require annually to support the investment….These results indicate that the market in 2003 did not produce sufficient net revenue to support investment in a new gas turbine or CC upstate." David Patton, "2003 State of the Market Report – New York Electricity Markets," April 2004, pages 36-37, 39.
- From the 2004 NYISO State of the Market Report: "Economic Incentives for New Investment:…These results indicate that the market in 2004 did not produce sufficient net revenue to support investment in a new combustion turbine in NYC. A new gas turbine in NYC would have recovered approximately 50 to 65 percent of the net revenue required annually to support the investment….These results indicate that the market in 2004 did not produce sufficient net revenue to support investment in a new CT or CC in the Capital zone. A new gas turbine in the Capital zone would have recovered approximately 20 percent of the net revenue require annually to support the investment. A new gas CC in the Capital zone would have recovered approximately 75 percent of the net revenue require annually to support the investment. The net revenue results for NYC and upstate NY do not raise significant long-term concerns because: The mild summer conditions and lack of shortages in 2004

reduced the net revenue substantially; and Upstate NY has a capacity surplus, limiting the need for new gas turbines outside NYC. These factors should result in net revenue less than need to support investment in new peaking resources outside of NYC. Despite these results, new investment is continuing in New York in response to solicitations or based on future expectations." David Patton, "2004 State of the Market Report – New York Electricity Markets," May 2005, page 43-44.

- From the 2005 State of the Market Report: "In long-run equilibrium, the market should support the entry of new generation by providing average net revenues that are sufficient to finance new entry. This may not be the case in every year since there are random factors that can cause the net revenue to be higher or lower than the equilibrium value (e.g., weather conditions, generator availability, etc.)…..Despite the increased energy prices, net revenue clearly remained below the levels necessary to justify new investment in gas turbines outside New York City and in combined-cycle units in western New York. Based on market conditions in 2005, there are several locations where it might be profitable to build new capacity. Increased shortage pricing in eastern New York and higher fuel prices raised combined cycle net revenue in the Hudson Valley to levels that might exceed their investment costs. Net revenue for a new gas turbine in 2005 was close to the estimated annual cost….These results are consistent with market conditions in New York City, which was been relatively close to being capacity-deficient in 2005. Although estimated net revenues grew considerably in 2005 to levels that would likely justify new investment in some areas if the net revenues continued over the long-term, there are other factors that affect new investment. The ability to enter into forward contacts is an important factor because it allows the new investor to secure a stable stream of revenues for the project….The regulatory process is also an important factor. Expectations and risk are also important factors. Market participants must anticipate, over the life of the investment, how prices will be affected by the new capacity investment, future load growth, increasing participation in demand response, and the risk associated with changes in the market rules or regulation over the life of the project." David Patton, "2005 State of the Market Report – New York ISO," August 2006, pages viii-ix.
- From the 2006 State of the Market Report: "Regarding long-run price signals, the report shows that prices in 2006 would not support investment in new generation in most locations. These signals are correct in the short-term because there is a surplus of generation in most areas and prices are very competitive. However, investors should expect these signals to improve over the next few years as the surplus dissipates. This analysis also shows that market signals have tended to shift in favor of investment in baseload and intermediate resources that, while more costly to build, are lower cost to run and produce more electricity. Over time, the markets provide efficient incentives to invest in a diverse array of generating resources, demand response resources, and transmission. Any investments that receive regulatory support should be consistent with these signals, except to the extent that they provide benefits not reflected in market prices (e.g., environmental benefits)." D. Patton, "2006 State of the Market Report – New York Electricity Markets," May 2007, page 7.
- From the 2007 State of the Market Report: "The report shows that prices in 2007 would not support investment in new peaking generation in most locations. This is consistent with short-term conditions because there is a surplus of generation in most areas and the summer weather was relatively mild. Price signals will be affected over the next few years by increasing load, unit retirements and additions, and the introduction of new mitigation measures in the capacity market….Over time, the markets provide efficient incentives to invest in a diverse array of generating resources, demand response resources, and transmission. Currently, market conditions appear most favorable for investment in combined-cycle generation, which have constituted most of the recent entry. Depending on the entry costs for a CC (we do not have reliable estimates), it may economic to build [sic] a CC in some areas under the current market conditions." David Patton, "2007 State of the Market Report – New York Electricity Markets," May 2008, page 10.
- From the most recent State of the Market Report: "Long-Term Economic Signals…This comparison for 2008 shows that the Vernon/Greenwood load pocket within New York City is likely the only area of New York where an investment in a new combustion turbine might have been profitable....Prospective investors must consider that net revenues are likely to change in subsequent years for several reasons. First, the retirement of nearly 1 GW of New York City capacity before the Summer 2010 capability period will substantially increase net revenues from the capacity market and, to a lesser degree, the energy and reserves markets. Second, net revenues tend to rise with natural gas prices, so if natural gas prices decline from 2008 levels, it is likely to reduce net revenues. Third, clockwise loop flows around Lake Erie tend to increase energy and reserves prices in

Eastern New York, so the decline in those loop flows will contribute to lower net revenues for generators in Eastern New York." David Patton, "2008 State of the Market Report: New York ISO," September 2009, page vi.

[109] Order No. 890 required all jurisdictional transmission providers (including NYISO) to file proposals for a coordinated and regional planning process that would comply with eight planning principles and a cost-recovery principle: coordination; openness; transparency; information exchange; comparability; dispute resolution; regional participation (including regional scope, existing institutions, existing regional planning processes in various parts of the country); economic planning studies; and cost allocation relating to new projects "that do not fit under the existing structure, such as regional projects involving several transmission owners or economic projects that are identified through the study process described above, rather than through individual requests for service." Order No. 890, pages 320-321.

[110] David Patton, who serves as the independent market monitor and advisor in several regions of the U.S. (including wholesale electricity markets in Texas, New England, Midwest ISO, and New York, as well as the Regional Greenhouse Gas Initiative's carbon dioxide auction market), reported in 2009 that:

"The NYISO operates the most complete set of electricity markets in the U.S. These markets include:

- Day-Ahead and real-time markets that jointly optimize energy, operating reserves and regulation.
- A capacity market that ensures the NYISO markets produce efficient long-term economic signals to govern decisions to invest in new generation and demand response resources (and maintain existing resources); and
- A market for transmission rights that allows participants to hedge the congestion costs associated with using the transmission network;

The energy and ancillary services markets establish prices that reflect the value of energy in prices at each location on the network. They deliver significant benefits by coordinating the commitment and dispatch of generation to ensure that the lowest cost resources are started and dispatched each day to meet the systems demands at the lowest cost. The coordination that is provided by the markets is essential due to the physical characteristics of electricity and the transmission network used to deliver it to customers. This coordination affects not only the prices and production costs of electricity, but also the reliability with which it is delivered. In addition, the markets provide transparent price signals that facilitate efficient forward contracting and are a primary component of the long-term incentives that guide generation and transmission investment and retirement decisions. Relying on private investment shifts the risks and costs of poor decisions and project management from New York's consumers to the investors. Indeed, moving away from costly regulated investment was the primary impetus for the move to competitive electricity markets.

The NYISO markets are at the forefront of market design and have been a model for market development in other areas. The NYISO was the first RTO market to:

- Jointly optimize energy and operating reserves, which efficiently allocates resources to provide these products.
- Impose locational requirements in its operating reserve and capacity markets. The locational requirements play a crucial role in signaling the need for resources in transmission-constrained areas.
- Introduce capacity demand curves that reflect the value of incremental capacity to the system and provide for increased stability in market signals.
- Operating reserve demand curves that contribute to efficient prices during shortage conditions when resources are insufficient to satisfy both the energy and operating reserve needs of the system.

In addition to its leadership in these areas, the NYISO remains the only market to have:

- An optimized real-time commitment system to start gas turbines and schedule external transactions economically. Other RTOs generally rely on operators to start gas turbines.
- A mechanism that allows gas turbines to set energy prices when they are economic. Gas turbines frequently do not set prices in other areas, which distorts the energy prices.
- A real-time dispatch system that is able to optimize over multiple periods (up to one hour). The market anticipates upcoming needs and moves resources to efficiently satisfy the needs.
- A mechanism that allows demand-response resources to set energy prices when they are needed. This is essential for ensuring that price signals are efficient during shortages.

Appendix B

FERC Order Rejecting Tariff Revisions

118 FERC ¶ 61,182
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

New York Independent System Operator, Inc. Docket Nos. ER07-360-000
EL07-39-000

ORDER REJECTING PROPOSED TARIFF REVISION
AND INSTITUTING HEARING AND SETTLEMENT JUDGE PROCEDURES

(Issued March 6, 2007)

1. On December 22, 2006, the New York Independent System Operator, Inc. (New York ISO) filed proposed revisions to its Market Administration and Control Area Services Tariff, specifically to Attachment H, section 4.5(b). These proposed revisions, filed under section 205 of the Federal Power Act (FPA),[1] would modify the installed capacity (ICAP) market mitigation measures applicable to certain generating units serving New York City (in-city generation) by, among other things, lowering the price cap for capacity offered into the in-city ICAP market. As discussed below, the Commission will reject the proposed revisions but will institute a proceeding under section 206 of the FPA[2] to investigate the justness and reasonableness of the New York ISO's in-city ICAP market.

Background

2. The instant filing involves price/market power mitigation for the New York City ICAP market (the in-city ICAP market).[3] The ICAP market reflects the obligation placed

[1] 16 U.S.C. § 824d (2000).

[2] 16 U.S.C. § 824e (2000).

[3] The market for this capacity, which is "[t]he capability to generate or transmit electrical power, measured in megawatts ("MW")," is distinct from the market for "energy," which is "[a] quantity of electricity that is bid, produced, purchased, consumed,
(continued)

The New York ISO Board of Directors' Decision concludes that "the improved market outcomes that the Proposal would produce outweigh its analytical shortcomings" notwithstanding the fact that the Decision also noted that "the Proposal is hardly supported by rigorous analysis."[12]

17. As a consequence, we must reject the New York ISO's filing. Nevertheless, upon consideration of the pleadings filed in this case and the problems they identify with the current in-city ICAP market rules, we will institute an investigation under section 206 of the FPA in Docket No. EL07-39-000.[13] The proceeding should consider the justness and reasonableness of the New York ISO's in-city ICAP market, and whether and how market rules need to be revised to provide a level of compensation that will attract and retain needed infrastructure and thus promote long-term reliability while neither over-compensating nor under-compensating generators.

18. In cases where, as here, the Commission institutes an investigation on its own motion under section 206 of the FPA, section 206(b) requires that the Commission establish a refund effective date that is no earlier than 60 days after publication of notice of the Commission's initiation of the investigation, but no later than five months subsequent. Consistent with our general policy of providing maximum protection to customers,[14] we will set the refund effective date at the earliest date allowed, 60 days from the date of publication of notice of the initiation of the investigation in Docket No. EL07-39-000.

19. Section 206(b) also requires that, if no final decision is rendered by the refund effective date or by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to section 206, whichever is earlier, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such a decision. Based on our review of the filings, if this case does not settle, and if we were instead to institute a paper hearing immediately, we expect that we

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[12] New York ISO Proposal, Board of Directors' Decision at 6.

[13] The purpose of the in-city ICAP market is to compensate generators for providing capacity, and to provide an incentive to build new in-city generation and new transmission to bring in outside generation. *See Consolidated Edison Co.*, 84 FERC ¶ 61,287, at 62,357 (1998) (discussing consequences of price cap in in-city ICAP market).

[14] *See, e.g., Seminole Elec. Coop., Inc. v. Florida Power & Light Co.*, 65 FERC ¶ 61,413 at 63,139 (1993); *Canal Elec. Co.*, 46 FERC ¶ 61,153 at 61,539, *reh'g denied*, 47 FERC ¶ 61,275 (1989).

Appendix C

FERC Order On Complaint re ICIP

125 FERC ¶ 61,311
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Independent Power Producers of New York, Inc., Astoria Generating Company, L.P., ConsumerPowerline, Inc., East Coast Power, LLC, Energy Curtailment Specialists, Inc., NRG Energy, Inc., and TC Ravenswood, LLC — Docket No. EL09-4-000

v.

New York Independent System Operator, Inc.

ORDER ON COMPLAINT

(Issued December 18, 2008)

1. On October 14, 2008, Independent Power Producers of New York, Inc.(IPPNY); Astoria Generating Company, L.P.; ConsumerPowerline, Inc.; East Coast Power, LLC; Energy Curtailment Specialists, Inc.; NRG Energy, Inc.; and TC Ravenswood, LLC (collectively, In-City Suppliers) filed a complaint against the New York Independent System Operator, Inc. (NYISO) under sections 206 and 306 of the Federal Power Act (FPA), alleging that NYISO violated its tariff in not adjusting the New York City Installed Capacity (ICAP) Demand Curves (NYC Demand Curves) following the elimination of a New York City tax exemption for utilities and that the rates derived from the NYC Demand Curves are unjust and unreasonable (Complaint). For the reasons discussed below, the Commission denies the Complaint.

I. Background

2. In-City Suppliers consists of owners and operators of electric generation facilities in New York City, demand response providers in New York City, and IPPNY, a trade association representing the independent power industry in New York State.

3. In 2003, the Commission accepted tariff sheets to NYISO's Market Administration and Control Area Service Tariff (Services Tariff) which established the ICAP Demand Curves in three areas – New York City, Long Island and the entire New York Control Area – with the goal of stabilizing prices and sending better price signals to

currently approved Demand Curve has become unjust and unreasonable.[17] By focusing only on the change in the tax element of the Demand Curve and not considering changes in all other factors including, for example, alternative city property tax abatement and incentive programs that are available and in some cases may be more advantageous than the property tax exemption at issue here, In-City Suppliers have not met their section 206 burden.

34. We note that adjusting the Demand Curve off-cycle to account for the elimination of a tax exemption that does not apply to existing suppliers translates into immediately higher capacity payments for existing suppliers, not a higher payment for capacity for new entrants. Capacity payments for new entrants would depend on updated Demand Curves in effect when they enter the market.[18] Further, Complainants have not shown that it is reasonable to believe that developers of new capacity would base their decisions to build solely on capacity prices in effect for only the next couple of years rather than considering both current and expected future prices based on the expected triennial demand curve revisions. Thus, we agree with NYISO that it is reasonable to await the scheduled three year update to account for the elimination of the tax exemption and other changes which will apply to Demand Curves for the 2011-12 Capability Year.

35. The Commission must balance the need for an out-of-cycle adjustment to provide proper price signals to encourage new economic capacity entry against the value of price stability, and certainty to customers in the market. The ICAP Demand Curve process is based on the premise that price stability and certainty are important to the market.

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[17] *Id.* We note that our action in another order issued today in Docket No. ER08-283-002 granting rehearing, in part, of the January 29, 2008 Order that accepted the subject demand curves is distinguishable from the instant case in that it concerns a correction of the underlying ICAP Demand Curve methodology rather than, as here, a proposed change in an input to the methodology. *See New York Indep. Sys. Operator, Inc.*, 125 FERC ¶ 61,299 (2008).

[18] Moreover, in response to In-City Suppliers' argument that the current Demand Curves send inappropriate price signals that discourage the entry of new capacity, the establishment of the Demand Curves based on the cost of new entry does not guarantee that the price established in the monthly auctions will equal or exceed that cost. The mechanism still involves the market setting the price, i.e., the monthly auctions establish the supply/demand intersect point at which, in times like these of excess capacity, the price will be expected to fall below the reference point cost of new entry. So, even if the demand curve were raised to reflect only the impact of the elimination of the tax exemption, the auctions still would not necessarily result in prices that for the next few years would be at a level to recover the cost of new entry. They are no less just and reasonable because of that fact.

Further, the adverse affect of price increases on customers in the current market for existing capacity also must be weighed against the uncertain potential benefit to the market that such price increases may encourage new economic entry. To reopen and start anew the lengthy review process now would re-ignite the debate over all of the factors that determine the Demand Curves and would promote confusion and uncertainty rather than stability in the market with uncertain future benefits.

36. We also find that NYISO did not violate its tariff and acted reasonably and within its discretion in deciding not to file under section 205 to adjust the Demand Curves in response to the elimination of the tax exemption. The NYISO Services Tariff states that a periodic review of the ICAP Demand Curves shall be performed every three years in accordance with ISO Procedures.[19] The NYISO ICAP Manual, in turn, provides in section 5.6.7 that "[o]nce the ICAP Demand Curves have been approved by the FERC, they shall remain binding for the 3-year period until the next review, absent exigent circumstances." As NYISO points out, and the NYISO Board found, the ICAP Manual does not define what "exigent circumstances" means in that context. In its decision to exercise its discretion to not file under section 205 to modify the Demand Curves, the NYISO Board found that because the fundamental purpose of the ICAP Demand Curves is to preserve the reliability of the New York electric system, the term "exigent circumstances" in this context should mean circumstances "in which there is a significant likelihood that reliability would be compromised because of a lack of capacity, and an off-cycle resetting of the Demand Curves would materially contribute to reliability being maintained."[20] The NYISO Board considered the matter and determined that reliability was not likely to be compromised because of a lack of capacity; nor would a mid-cycle resetting of the Demand Curves contribute to reliability being maintained. We find that this was a reasonable interpretation of NYISO's own ICAP Manual procedures and, in light of the facts as discussed earlier herein and in its Answer, and consistent with Commission precedent, [21] NYISO reasonably exercised its discretion in adopting the finding of the Board that such "exigent circumstances" warranting a reopening of the Demand Curve setting process and filing under section 205 to re-set the Demand Curves do not exist here.

37. Further, we find that the In-City Suppliers' arguments, that the ISO Agreement informs the issue and that NYISO is required by that agreement to make a section 205

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[19] Market Services Tariff, Original Vol. No. 2, Seventh Revised Sheet No. 157, section 5.12.1(b).

[20] NYISO November 3, 2008 Answer, Attachment 1, at 3.

[21] *See, e.g., New York Indep. Sys. Operator, Inc*., 112 FERC ¶ 61,283, at P 39 (2005).

Appendix D

MST Sixth Revised Sheet No.157

pursuant to this Section. The ICAP Demand Curves will be translated into Unforced Capacity terms in accordance with the ISO Procedures.

A periodic ~~independent~~ review of the ICAP Demand Curves ~~will~~ shall be performed every three (3) years in accordance with the ISO Procedures to determine ~~whether~~ the parameters of the ICAP Demand Curves ~~should be adjusted. Among other criteria, the~~ for the next three Capability Years. The periodic review ~~will determine~~ shall assess: (i) the current localized levelized embedded cost of gas turbines (the "Incremental Unit") in each NYCA Locality and the Rest of State ~~and associated~~ to meet capacity requirements; (ii) the likely projected annual Energy and Ancillary Services revenues of the Incremental Unit over the period covered by the adjusted ICAP Demand Curves, net of the costs of producing such Energy and Ancillary Services, under conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity requirement; (iii) 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; and (iv) the appropriate translation of the annual net revenue requirement of the Incremental Unit, determined from the factors specified above, into monthly values that take into account seasonal differences in the amount of capacity available in the ICAP Spot Market Auctions. ~~Each periodic independent review, which will include stakeholder input in accordance with the ISO Procedures, will be completed by September 1 of the applicable Capability Year in time to determine the ICAP Demand Curves to be applied for the three subsequent Capability Years in accordance with the ISO Procedures.~~

The periodic review shall be conducted in accordance with the schedule and procedures specified in the ISO Procedures. A proposed schedule will be reviewed with the stakeholders not

Appendix E

GE LMS100 Basin Electric

GE
Energy

LMS100® Installation and Operating Experience at Basin Electric

Authors:

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Basin Electric Power Cooperative

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GE Aviation

Figure #1 Groton Generation Station, Groton SD

The distinguishing feature of the LMS100 is its standard off-engine tube and shell heat exchanger (intercooler), piping, variable bleed valve (VBV) system and cooling water skid for cooling the combustion air. Figure #2 shows the return pipe between the heat exchanger and the high-pressure compressor (HPC) inlet collector. This five-foot diameter pipe contains a pressure balanced bellows expansion joint to prevent any thermal movement from imparting a load on the HPC inlet collector. On the opposite side is an identical five foot diameter pipe for the Low Pressure Compressor (LPC), two 36 inch diameter VBV's, two pressure balanced bellows expansion joints-- one on each side of the VBV's -- and a discharge stack that can be seen in the background in Figure #2. The intercooler cooling water supply skid (Figure #3) also provides the lube oil cooling. A propylene glycol/water mix is used to allow winter operation. Flow rate for the GT heat exchanger is approximately 6,000 gpm.

A new 70 x 140 x 20 foot steel building (Figure #1) houses the air compressors, water pump skids, and water demineralizer trailers. Portions of the building are walled off for the electrical, battery, control and communications room as well as office, lunchroom, restroom, and locker room.

Two Mark VIe programmable control systems were installed, one for controlling the GTG package and the other for the balance of plant. Most of the I/O is located near the equipment so the majority of cables connecting the field to the control system are fiber optics for communication. The overall plot plan covers 3.85 acres measuring 600 x 280 feet.

Commissioning Process and Experience

GE constructed a full load test facility in Houston, Texas. The LMS100 test unit was constructed to production drawings. The same engineers and technicians who completed installation and commissioning at the Basin Electric site also completed the assembly, installation and maintenance of the development unit. Therefore, the processes, tooling, procedures, manuals and training were completed and validated on an actual power plant before the installation and commissioning of the Basin Electric project.

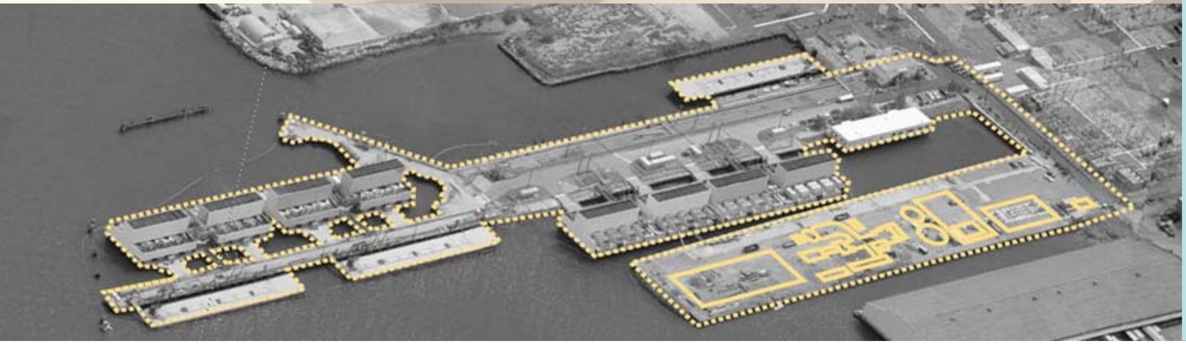
The installation phase of the project began in mid-August 2005 with site mobilization of the general contractor, TIC (The Industrial Company). Construction commenced towards the end of summer. The goal was to complete the civil works underground piping and electrical in time for delivery of the GTG at the beginning of November, before the onset of winter. The main equipment arrived on site November 15, 2005 and the erection and assembly process began. The goal for the installation phase was to have mechanical installation complete by March 15, 2006, and first fire of the GTG on April 19, 2006. The GTG achieved first fire on schedule. After achieving this milestone, the team commenced the testing and commissioning phase.

Three specific GE processes were invaluable in assuring a smooth start-up and commissioning of the Basin Electric unit. First, the Safety Management and Reliability Tracking (SMART) system is used which records and tracks every event. An engineer is assigned to determine root cause, develop and implement a solution. Second, the event is not closed out in SMART until the Event Review Board (ERB), made up of senior engineers and managers from the gas turbine and packaging groups, reviews and approves the root cause analysis (RCA) and solution. The

Appendix F

South Pier Site Rendering

Proposed Project



Location

- On a pier adjacent to the existing Gowanus Generating facility
- Within the Greenwood load pocket (among the most constrained in the U.S.)

Technology

- One LMS100 unit with an SCR and CO catalyst

Appendix G

BEL LMS100 Site Rendering

Appendix H

SDUs Should Be Included in CONE

APPENDIX H

Deliverability Upgrades should be Included in the Cost of New Entry

In this Appendix we explain in detail why System Delivery Upgrade (SDU) costs for a new peaking proxy unit in Zone J should be included in the CONE calculations in the current NYISO Demand Curve Reset process. We address the TOs comments on the rationale for excluding deliverability costs which were presented in a memo to Dave Lawrence dated April 21, 2010. The TOs comments in that memo can be summarized as follows:

- There is sufficient deliverability to serve current and projected load levels
- Units which pay deliverability costs are not needed for reliability
- Inclusion of deliverability costs is not appropriate unless in the future NYISO reliability planning studies demonstrate that a resource adequacy deficiency and transmission capability deficiency are contributing to a future reliability violation

Our position for why SDUs should be included in the CONE is based on the following:

- The NYISO Deliverability Interconnection Standard for Installed Capacity Suppliers is a Tariff Requirement Designed to Assure Reliability
- The NYISO Demand Curve Reset RFP Specifically Includes Deliverability Impacts
- SDUs are needed for reliability
- The Class Year 2008 Deliverability Study shows some need for SDUs in ROS
- The current projected surplus does not translate to deliverability as defined by the NYISO Deliverability Interconnection Standard
- There are deliverability constraints that may trigger costs in Zone J
- Deliverability rights of retiring plants have value – transfer of rights is not “free”
- SDUs, like System Upgrade Facilities and Attachment Facilities are part of a developer’s interconnection costs

SDUs represent a cost that is associated with capacity and reliability. SDU costs therefore cannot be de-coupled from the proxy reliability unit that sets CONE.

The NYISO Deliverability Interconnection Standard for Installed Capacity Suppliers is a Tariff Requirement, Designed to Assure Reliability

New generation projects larger than 2 MW in New York must satisfy the FERC-approved NYISO Deliverability Interconnection Standard (NDIS) in order to become a qualified Installed Capacity Supplier. The NDIS is designed to ensure the proposed generation project is deliverable within the Capacity Region where the project will interconnect.[1] To participate in the NYISO capacity market, a project is required to elect Capacity Resource Interconnection Service (CRIS) and undergo a deliverability assessment, based on the Deliverability Test Methodology as defined in the NYISO Open Access Transmission Tariff (OATT). The project developer must fund the SDUs identified for its project in the Class Year Deliverability Study.

In brief, the Deliverability Test Methodology is based on simulating generation-to-generation transfers within a Capacity Region. For a given Capacity Region, a generation/load mix is split into two groups of generation and load, one upstream and one downstream, for each zone or sub-zone tested within the Capacity Region. Simulation of power transfers within each Capacity Region determines the ability of the network to deliver capacity from generation in one (or more) surplus zone(s) to another deficient zone (s) within the Capacity Region. Simulating the power transfers determines the transmission constraint limits by uniformly increasing generation in the exporting zone and decreasing generation in the importing zone and identifying any "bottled" capacity that may not be fully deliverable under all conditions.

Per Attachment S of the NYISO OATT, every developer is responsible for the cost of the new interconnection facilities required for the reliable interconnection of its new generation or merchant transmission project in compliance with the NYISO Minimum Interconnection Standard (NMIS).[2] In addition, every Developer electing CRIS is also responsible for the cost of any facilities required for the reliable interconnection of its project in compliance with the NDIS. NYISO evaluates an Interconnection Request for compliance with (i) the NMIS through the Interconnection Study process and (i) the NDIS through the Class Year Deliverability Study. The Interconnection Studies conducted under the Standard Large Facilities Interconnection Procedures identify the Attachment Facilities (AFs) and System Upgrade Facilities (SUFs) required for the reliable interconnection in compliance with the NMIS. However, the AFs and SUFs only allow a project to participate in the Energy and Ancillary Services Markets. A project electing CRIS will not receive capacity revenues as an Installed Capacity Supplier if deliverability problems are identified through the Class Year Deliverability Study and the Developer elects not to pay for its share of SDUs. NYISO cannot ignore SDU costs in the Demand Curve Reset process for projects that intend to participate in the capacity market.

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[1] The three Capacity Regions in New York State are Zone J, Zone K, and: Zones A-I (ROS).

[2] Sheet No 653.03

The NYISO OATT prescribes the processes for determining AFs, SUFs, and SDUs for an interconnecting project. A generation developer must pay for all of these interconnection costs in order to qualify as an Installed Capacity Supplier. SDU costs are site-specific and not all sites will trigger SDUs. This is also true for SUF costs that are site-specific, and some level of SUF costs have been included in the last two Demand Curve Reset processes. Therefore it goes without saying that now that a new cost component (SDUs) has emerged in the process, this component should also be captured in the setting of CONE.

A project that does not elect to be an Installed Capacity Supplier, and does not pay for required SDU costs, will not have a capacity obligation and will not contribute to system reliability.[3] If the Demand Curve is set without including a reasonable and appropriate level of SDU costs, the capacity revenues that the Demand Curve will provide may be insufficient to attract new entry.

The NYISO Demand Curve Reset RFP Specifically Includes Deliverability Impacts

Page 3 of NYISO's Demand Curve RFP specifically states that the consultant's report includes costs required to address deliverability impacts:

> Total installed costs as of May, 2011; the localized, levelized embedded cost of a peaking unit…., <u>including transmission and deliverability impacts</u>, in Zone J and in Zone K…" (emphasis added)

NYISO did not differentiate among AFs, SUFs, and SDUs. All of the costs for generators to address the "transmission and deliverability impacts" should be included in the consultant's report. NYISO would be inconsistent with its own RFP requirements if it now decided to ignore SDU costs.

SDUs are needed for Reliability

The TOs argument that SDUs are not needed for reliability is misleading. We strongly disagree with the TOs position for the following reasons:

The TOs statement that SDUs are not needed for reliability is inconsistent with the NYISO OATT. Attachment S of the NYISO OATT defines SDUs as: "The least costly configuration of commercially available components of electrical equipment that can be used, consistent with Good Utility Practice and <u>Applicable Reliability Requirements</u>, to make modifications or additions to Byways and Highways and Other Interfaces on the existing New York State Transmission System that are required for the proposed project <u>to connect reliably</u> to the system in a manner that meets the NIDS at the requested level of CRIS" (emphasis added).

[3] System reliability here is defined within the context of Loss of Load Expectation (LOLE), the capacity-based criterion used to assess Resource Adequacy.

Attachment S also states that CRIS is required "…..to enable the New York State Transmission System to deliver electric capacity from the Large Generating Facility, Small Generating facility or Merchant Transmission Facility, pursuant to the terms of the NYISO OATT…". NYISO's OATT is clear: SDUs are based on reliability requirements. If an interconnecting unit which has elected CRIS rejects its SDU allocation, it cannot participate in the NYISO's capacity market and cannot support system reliability.

SDUs are therefore inherently part of Installed Capacity (ICAP). A generating unit cannot supply ICAP unless it is deliverable. SDUs, like SUFs and AFs are based on reliability requirements. LOLE, the NYISO index used to assess reliability, is a capacity based resource adequacy criterion. Without SDUs there is no capacity, and reliability is compromised. If SUFs and AFs are included in CONE, so should SDUs.

Class Year 2008 Deliverability Study shows some Need for SDUs

NYISO has conducted Deliverability Studies for Class Years (CY) 2007 and 2008 so as to comply with the NYISO OATT. As noted above, the NYISO OATT requires the determination of SDUs in the event CRIS is selected. The results for the Class Year 2008 study show that deliverability for the ROS Capacity Region is primarily constrained at the UPNY-SENY interface. To qualify for CRIS the CY 2008 projects in ROS would be responsible for SDUs sufficient to create 257 MW additional transfer capacity on the UPNY-SENY interface at an estimated cost of $80.4 million[4]. The need for SDUs in CY 2008 for the ROS region demonstrates the importance of assessing the deliverability impacts within Zone J for the proxy peaking unit and subsequently including applicable SDU costs in the CONE.

There were no Zone J projects in the CY 2007 Deliverability Study and just one Zone J project in the CY 2008 Deliverability Study, the Hudson Transmission Project. This project primarily consists of back-to-back AC/DC converter station and an HVAC cable that would withdraw energy from the PJM system and inject it into Zone J. Hudson was not subjected to the NDIS as described above because it is considered External Installed Capacity associated with Unforced Capacity Deliverability Rights (UDRs) into Zone J. Under NYISO's OATT, such projects have to demonstrate deliverability to the NYCA interface with the UDR transmission facility.

The need for SDUs in CY 2008 for ROS demonstrates the importance of assessing the deliverability impacts within a traditionally constrained zone like Zone J. If the assessment for Zone J shows the need for SDUs, the costs for those SDUs should be included in CONE. Absent such an assessment, at least a "proxy amount" of SDU costs should be included in the CONE as part of the Demand Curve Reset process.

[4] $80.4 million is the cost for 452 MW of transfer capability created based on the discrete nature of the recommended upgrade. The actual allocated cost to CY 2008 developers based on the 257 MW needed to qualify for CRIS is $45.7 million ((257/452)*80.4)

The current projected surplus does not translate to deliverability as defined by the NYISO Deliverability Interconnection Standard

The TOs argument that there is sufficient deliverability to serve current and projected load levels is misleading.

This argument is based primarily on the results of the 2009 Reliability Needs Assessment (RNA) which show that the NYISO system may not need new resources in the 3-year Demand Curve reset period. However, it is important to note that the RNA is based on a LOLE resource adequacy analysis. This LOLE analysis considers available transmission capability into the study zones and does not assess whether or not capacity can be moved without any constraints within a particular Capacity Zone.[5] The TOs cannot argue that there is sufficient deliverability based on the results of the RNA resource adequacy analysis that didn't specifically address deliverability per the NDIS. The RNA did not quantify the specific impacts of the NDIS and did not determine whether or not capacity can be deliverable within a zone. We also note that the argument that there is surplus and therefore no need for new entry is not relevant for the Demand Curve Reset process. It does not matter if the current state-wide bulk power system has a surplus. CONE is based on the costs of a proxy peaking unit being added in each study year regardless of need. The sloped demand curve already provides a mechanism that sets clearing prices below net CONE when the market is long.

The NDIS was designed to address intra-zonal deliverability. Therefore, while the RNA results have shown that there is sufficient inter-zonal deliverability for the 3-year Demand Curve reset period, it has not been shown that there is sufficient intra-zonal deliverability for the same period, especially for Zone J. One cannot therefore argue against the need for SDUs based on the RNA analysis which did not specifically address deliverability as per the NDIS. To the extent SDUs are needed to insure intra-zonal deliverability, the costs for those SDUs should therefore be included in the CONE.

There are Deliverability Constraints that may Trigger Costs in Zone J

The OATT does not specify where the Demand Curve proxy plant may interconnect, and the NDIS puts pressure on a generating unit planning to interconnect in Zone J. Optimal interconnection points that would not trigger SDUs may be difficult to find in Zone J. We highlight the deliverability issues at some select sites in Zone J based on information available in the public domain.

Transmission "headroom" at Astoria East is already at a premium even before taking into account the potential impacts of the NDIS. In the "Request for Rehearing" of Con Edison,

[5] The RNA results are based on a system-wide resource adequacy study which is done using the GE MARS Transportation Model to quantify expected LOLE values. The transfer limits used in the GE MARS model are based on inter-zonal deliverability and not intra-zonal deliverability. The NDIS on the other hand was designed specifically to address intra-zonal deliverability issues.

filed in response to FERC's January 15, 2009 Order conditionally accepting the NYISO and TOs Compliance Filing of the Deliverability Plan, Con Edison argued that the second phase of Astoria Energy LLC's generating facility (AE-2) is not deliverable at its original interconnection point, the Astoria East 138 kV s/s.[6] In the testimony provided by their expert witness, Dr Mayer Sasson, Con Edison noted that "The test results showed… that the entire output of the AE-2 facility would not be deliverable in Zone J" at the Astoria East 138 kV s/s. Con Edison's analysis was based on the existing generation at the s/s, the area load, and the available s/s export capability. Dr Sasson's testimony also notes that AE-2 would be fully deliverable if it interconnected at a proposed new 345 kV s/s which would tie into NYPA's 345 kV lines Q35L and Q35M.

Transmission headroom on Staten Island is also limited. In the "Answer and Leave to File Answer" of Con Edison, filed in the FERC Linden VFT Docket seeking authorization to charge negotiated rates, Con Edison argued that the output of the Linden VFT project is not deliverable to market areas outside of Staten Island.[7] Linden VFT connects to the Goethals s/s on Staten Island. In their argument Con Edison argued that Linden VFT's capacity is not deliverable throughout Zone J, based on an analysis that compared the supply resources attached to Staten Island with the capacity of the feeders that deliver power from those resources to load on Staten Island and in Brooklyn.

While the above examples are not exhaustive and not indicative of all the potential interconnecting points in Zone J, they do show that there are deliverability constraints in Zone J which may trigger SDUs under the NDIS. It is therefore important that the interconnection costs for the proxy peaking unit take into account the SDUs that may be required to insure that new capacity promotes system reliability.

Deliverability rights of retiring plants have value – transfer of rights is not "free

In another presentation made by the TOs at the December 8, 2009 ICAPWG meeting, the TOs noted that including SDU costs in CONE was not justified because retirements free up deliverability rights which new generators can utilize after 3 years.

Regarding the TO position that deliverability rights of retiring plants can be used by other generators, it is important to note that these rights have value and the transfer of such rights will likely have an associated cost. The issue of tradable capacity deliverability rights has been discussed in the NYISO Stakeholder process, including a presentation made by Dr David Patton, the Independent Market Advisor, at one of the Interconnection Issues Task Force Meetings[8]. Deliverability rights have value, and any new generator wishing to use the deliverability rights of a retiring generator would have to pay for those rights. Whether or not the cost of acquiring the deliverability rights may be lower or higher than the SDU costs

[6] Docket No. ER04-449-018

[7] Docket ER07-543-000

[8] Presentation dated January 15, 2007.

that the new unit may trigger is impossible to quantify in the abstract. The bottom line is that the new generating unit will have to pay for deliverability rights or else pay for SDUs.

SDUs, like System Upgrade Facilities and Attachment Facilities are part of a developer's interconnection costs

As noted above SDUs, like SUFs and AFs are needed for reliability. As such they should all be included in CONE.

SDUs are part of a developer's interconnection costs and represent a cost that is associated with capacity and reliability. SDU costs therefore cannot be de-coupled from the proxy reliability unit that sets CONE.

The CONE for a proxy unit should be based on all costs that a developer is expected to incur. Interconnection costs for deliverability are a legitimate cost that must be taken into account. A developer factors these costs into the assessment of the economics of the proposed entry.

SDU costs therefore cannot be ignored and should be included in the CONE as part of the Demand Curve Reset process.