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April 13, 2010

By Hand Delivery

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington D.C., 20246

Re: Compliance Filing of the New York Independent System Operator, Inc. and the New York Transmission Owners, Docket No. OA08-52-008

Dear Ms. Bose:

In compliance with the Commission's October 15, 2009 order ("October 2009 Order")[1] and the November 25, 2009 Notice of Extension of Time,[2] the New York Independent System Operator, Inc. ("NYISO") and the New York Transmission Owners ("NYTOs")[3] (together "Joint Filing Parties") respectfully submit revisions to Attachment Y of the NYISO's Open Access Transmission Tariff ("OATT"). The October 2009 Order conditionally accepted compliance filings made by the Joint Filing Parties on January 14, 2009 ("January 2009 Filing") and May 19, 2009 ("May 2009 Filing"), and directed the Joint Filing Parties to submit a further compliance filing to address "certain discrete issues" identified in the October 2009 Order. On December 11, 2009, the Joint Filing Parties submitted a compliance filing addressing all of the compliance issues identified in the October 2009 Order other than: (1) the use of Transmission Congestion Contract[4] ("TCC") revenues and bilateral contracts to offset Location-Based Marginal Pricing ("LBMP") energy savings in calculating the benefits of an economic project for purposes of cost allocation and recovery;

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[1] *New York Independent System Operator, Inc.*, 129 FERC ¶ 61,044 (2009) ("October 2009 Order").

[2] *New York Independent System Operator, Inc. and New York Transmission Owners*, Notice of Extension of Time, Docket Nos. OA08-52-004 and -006 (Nov. 25, 2009).

[3] Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("ConEdison"), the Long Island Power Authority ("LIPA"), the New York Power Authority ("NYPA"), New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc. ("O&R"); Rochester Gas and Electric Corporation, and Niagara Mohawk Power Corporation d/b/a National Grid.

[4] Capitalized terms are defined in accordance with the NYISO's tariffs or agreements.

and (2) the metric for determining the level of Installed Capacity ("ICAP") savings that would result from relieving congestion on the bulk power system during the study phase of the NYISO economic planning process.[5] On those issues, the NYISO requested a 120-day extension of time to submit a compliance filing. This compliance filing addresses these remaining issues identified in the October 2009 Order.

I. LIST OF DOCUMENTS SUBMITTED

The Joint Filing Parties submit the following documents:

1. This filing letter;

2. A clean version of the modifications to OATT Attachment Y ("Attachment I");

3. A blacklined version of the modifications to OATT Attachment Y ("Attachment II"); and

4. A detailed example illustrating the proposed procedure for forecasting TCC Reductions ("Attachment III").

II. BACKGROUND

A. Order No. 890

Order No. 890 required transmission providers to adopt as part of their OATTs an open, transparent, and coordinated planning process at both a regional and a local level, and to "submit, as part of a compliance filing in this proceeding, a proposal for a coordinated and regional planning process that complies with the planning principles and other requirements in this Final Rule."[6] Recognizing that some transmission providers — particularly Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") — already have in place substantial planning processes, the Commission held that "[i]n the alternative, a transmission provider (including an RTO or an ISO…), may make a compliance filing in this proceeding describing its existing coordinated and regional planning process, including the appropriate language in its tariff, and show that this existing process is consistent with or superior to the requirements in this Final Rule."[7]

B. Initial Filings

The NYISO submitted its initial compliance filing on December 7, 2007 ("December 2007 Filing") which proposed to adopt a new Comprehensive System Planning Process

[5] *See* October 2009 Order at P 54.

[6] Order No. 890 at P 437.

[7] *Id.*

("CSPP") based on the Comprehensive Reliability Planning Process ("CRPP") then in place under OATT Attachment Y. On June 18, 2008, the Joint Filing Parties supplemented the December 2007 Filing with a tariff proposal governing cost allocation and cost recovery for regulated transmission reliability projects ("June 2008 Filing").

C. October 16, 2008 Order and March 31, 2009 Order

In an order issued on October 16, 2008,[8] the Commission found that the tariff proposals in the December 2007 and June 2008 Filings were substantially consistent with the planning directives set forth in Order Nos. 890 and 890-A, and conditionally accepted those proposals for filing subject to the submission of a compliance filing addressing certain identified issues. The Commission directed the NYISO to submit a compliance filing addressing, *inter alia*, the LTPP, the committee decision-making process, the manner in which stakeholders are able to replicate NYISO planning studies, the dispute resolution processes applicable to the planning process, the cost allocation methodology for economic upgrades, and certain aspects of the mechanism for evaluating economic upgrades.

On March 31, 2009, the Commission issued an order on the rehearing requests submitted in response to the October 2008 Order.[9] Importantly, the Commission clarified that it had accepted for filing the NYISO-NYTO Reliability Agreement, clarified aspects of the rate filing mechanism under Rate Schedule 10, and upheld the supermajority voting rule, as well as other aspects of the process for evaluating economic upgrades. The Commission also supplemented its directive in the October 2008 Order that the NYISO report on the results of voting on economic upgrades by ordering that the NYISO "include in such report the reasons stated by the parties that vetoed the project for their decision."[10]

D. Initial Compliance Filings

On January 14, 2009 and May 19, 2009, the NYISO submitted compliance filings in response to the October 2008 Order (respectively, the "January 14 Filing" and the "May 19 Filing"). The January 14 Filing addressed all of the Commission's directives in the October 2008 Order except for two: (1) additional specifications for the methodology for allocating costs of economic projects developed under the CARIS; and (2) the additional metrics to be used by beneficiaries of economic projects to evaluate those projects for voting purposes.

The May 19 Filing proposed additional revisions to Attachment Y to address the two issues from the October 2008 Order not addressed in the January 14 Filing. The May 19 Filing proposed a detailed methodology for allocating the costs of economic projects to project beneficiaries, and provided further details on the additional metrics, for information

[8] *New York Independent System Operator, Inc.*, 125 FERC ¶ 61,068 (2008) ("October 2008 Order").

[9] *New York Independent System Operator, Inc.*, 126 FERC ¶ 61,320 (2009) ("March 31 Order").

[10] March 31 Order at P 38.

only, for use by project beneficiaries in analyzing proposed economic upgrades. These details included an ICAP metric for the initial CARIS cycle that will be determined in accordance with the rules and procedures guiding the calculation of the Installed Reserve Margin ("IRM") and Local Capacity Requirements ("LCR") in the NYISO Manuals. The May 19 Filing also noted that the NYISO and its stakeholders were developing an ICAP cost metric that estimates the financial impacts that CARIS projects may have on ICAP costs to Load Zones for subsequent CARIS cycles. The May 19 Filing also amended Attachment Y to require that project beneficiaries voting against an economic project report to the NYISO their rationale for their votes within 30 days of the date the vote is held.[11]

E. October 2009 Order and Subsequent Compliance Filing

In an order issued on October 15, 2009 ("October 2009 Order"),[12] the Commission conditionally accepted for filing the tariff amendments submitted by the Joint Filing Parties in the January 14 and May 19 Compliance Filings, and directed the submission of an additional compliance filing, to be made within 60 days, to address certain discrete issues. Specifically, the October 2009 Order required that the Joint Filing Parties: (1) explain how the NYISO will analyze and select the preferred reliability solutions from competing alternatives, ensuring that transmission, generation, and demand resources are considered on a comparable basis; (2) revise Attachment Y to require that beneficiaries voting against approval of a project must provide a detailed explanation of, along with supporting data on, the reason for that decision; (3) require that the NYISO's reports to the Commission on the results of voting on proposed economic projects include certain specified information; (4) revise Sections 12.1 and 15.5(a) of Attachment Y to clarify that a summary of all comments of interested parties provided during the ESPWG and TPAS review will be sent to the Operating and Business Issues Committees (as appropriate) in order to inform their deliberations; (5) provide additional details regarding the MW impact methodology used in calculating the ICAP metric; (6) clarify the economic project cost allocation methodology by providing additional details on the use of Transmission Congestion Contract ("TCC") revenues and bilateral contracts to offset reductions in Locational Based Marginal Prices ("LBMPs") from an economic transmission upgrade; and (7) correct a typographical error in proposed Section 15.4b(i) of OATT Attachment Y.

On November 3, 2009, the NYISO requested a 120-day extension of time to submit the proposed tariff revisions to address the two remaining issues: (1) use of TCC revenues and bilateral contracts to offset LBMP reductions; and (2) tariff revisions detailing the ICAP cost metric developed through its stakeholder process for subsequent CARIS cycles. The

[11] The Joint Filing Parties included the amendment in order to address an additional directive issued by the Commission in its March 31, 2009 rehearing order mandating that the NYISO report such information to the Commission in its reports on the voting processes used for proposed economic upgrades. *See New York Independent System Operator, Inc.*, 126 FERC ¶ 61,320 at P 38 (2009).

[12] *New York Independent System Operator, Inc.*, 129 FERC ¶ 61,044 (2009).

Commission granted the extension on November 25, 2009.[13] On December 11, 2009, the Joint Filing Parties submitted a compliance filing addressing all of the compliance issues identified in the October 2009 Order other than these two remaining issues.

III. DESCRIPTION OF PROPOSED TARIFF REVISIONS

A. Identification of Project Beneficiaries

Paragraph 54 of the October 2009 Order identifies the project beneficiary identification issues addressed in this filing:

> NYISO states that '[n]et reductions in TCC revenues will reflect the forecasted impact of the project on TCC auction revenues and day-ahead residual congestion rents allocated to load in each zone, excluding the congestion rents that accrue to any Incremental TCCs that may be made feasible as a result of this project.' Although this section of the tariff further outlines the factors involved in this calculation, it leaves further details of the net reductions calculation to unspecified sections of NYISO's manuals. To clarify this provision, we direct NYISO to specifically identify the relevant provisions in its manuals and to file a compliance filing within 60 days hereof revising section 15.4.b of its tariff to incorporate those provisions into its tariff. Further, while subsections 15.4.b(i) and (v) refer to information regarding bilateral contracts, these provisions do not make explicit what contract data will be used or how it will be used in the calculation of LBMP load savings. Accordingly, the Commission directs NYISO to file a compliance filing to revise section 15.4.b of Attachment Y, within 60 days of the issuance of this order, to provide details regarding how and what contract data NYISO will use to offset LBMP load savings.

The Joint Filing Parties have developed new tariff language to address these issues.

1. Forecasted TCC Reductions

Transmission projects affect LBMPs, which in turn affect the amounts that Loads pay for the electricity they consume. However, the NYISO also collects congestion rents, which result from differences between the amounts paid to generators and importers for the energy they provide and the amounts collected from Loads and exporters for the energy they consume,[14] and transmission projects can decrease these congestion rents because they may reduce differences between prices at locations where larger amounts of electricity are produced and prices at locations where larger amounts of energy are consumed. Reductions in congestion rents will generally lead to reduced prices for TCCs, since the holders of TCCs

[13] *New York Independent System Operator, Inc. and New York Transmission Owners,* Notice of Extension of Time, Docket Nos. OA08-52-004 and -006 (Nov. 25, 2009).

[14] Part of this difference is also attributable to transmission losses.

receive the difference in LBMPs at different points in the system, to the extent that the difference is attributable to transmission congestion. In New York, revenues from the sale of TCCs and from certain TCCs that are retained by the Transmission Owners, are used to offset some of the costs that must be collected from customers through the Transmission Service Charge ("TSC") assessed by each Transmission Owner other than NYPA and through the NYPA Transmission Adjustment Charge ("NTAC"). Consequently, a new transmission project that results in reducing transmission congestion could reduce the TCC revenues that are passed on to customers by the Transmission Owners. In addition, reductions in congestion resulting from transmission projects can reduce the revenues that Loads derive from certain TCCs they hold that do not affect TSCs or the NTAC. As a result, it is necessary to take the effect of a transmission project on these TCC revenues into account when forecasting the net impact that a transmission project will have on the amount that Load in any given Zone can expect to pay for the electricity it consumes.

To address the Commission's directive that they insert into Attachment Y the details of how these reductions in TCC revenues will be forecasted for purposes of calculating Net Zonal Benefits associated with a proposed project, the Joint Filing Parties propose to add a new appendix, Appendix B, to Attachment Y, and to cross-reference that new appendix in Section 15.4.b(iii) of Attachment Y, which now reads:

> Net reductions in TCC revenues will reflect the forecasted impact of the project on TCC auction revenues and day-ahead residual congestion rents allocated to load in each zone, excluding the congestion rents that accrue to any Incremental TCCs that may be made feasible as a result of this project. This impact will include forecasts of: (1) the total impact of that project on the Transmission Service Charge offset applicable to loads in each zone (which may vary for loads in a given zone that are in different Transmission Districts); (2) the total impact of that project on the NYPA Transmission Adjustment Charge offset applicable to loads in that zone; and (3) the total impact of that project on payments made to LSEs serving load in that zone that hold Grandfathered Rights or Grandfathered TCCs, to the extent that these have not been taken into account in the calculation of item (1) above. <u>These forecasts shall be performed using the procedure described in Appendix B to this Attachment Y.</u>

The NYISO developed new Appendix B with its stakeholders and other interested parties in the Electric System Planning Working Group. Appendix B contains a detailed, ten-step approach to forecasting reductions in TCC revenues. This Appendix B Procedure performs the following functions:

- First, it forecasts the revenue that would be realized from the TCC auction, as well as the value of other TCCs that have been allocated outside the TCC auction process, both with the project in place and without the project in place.

- Next, it estimates how that forecasted revenue from the TCC auction would be allocated among the Transmission Owners, both with and without the project in place.

- Then, it forecasts the impact of the project on the TSCs charged by all of the Transmission Owners except NYPA, and on the NTAC, by comparing the offsets to those TSCs and the NTAC that would be calculated with the project in place to the offsets that would be calculated without the project in place.

- Finally, it multiplies the forecasted impact of the project on each Transmission Owner's TSC and on the NTAC by the forecasted amount of the Load in each Zone that is subject to each of those TSCs and the NTAC, and adds the forecasted impact of the project on the value of other TCCs and Grandfathered Rights that benefit Load in each Zone, to determine the total forecasted impact of that project on TCC revenues allocated to Load in each Zone.

a. Steps 1-3: Forecasting the Value of Grandfathered Rights, Grandfathered TCCs, Incremental TCCs and TCC Auction Revenue

In New York, not all of the transmission system is available to support TCCs that are sold in auctions administered by the NYISO. Instead, Grandfathered Rights and Grandfathered TCCs have been allocated to the recipients of service under transmission agreements that were in existence before the creation of the NYISO. Transfer capability that is needed to support these Grandfathered Rights and Grandfathered TCCs cannot be used to support other TCCs that are purchased in the auction unless those TCCs are offered for sale in the auction by their holders, and even if those Grandfathered TCCs are offered for sale, the revenues from their sale will go to their holders. Therefore, the Appendix B Procedure estimates the congestion rents that will be collected on the New York electricity system during each of the ten years following the proposed commercial operation date of a transmission project, and deducts the congestion rents that the NYISO forecasts would be paid to the holders of Grandfathered Rights[15] and Grandfathered TCCs, both with and without the project in place.

In addition, developers of transmission projects are eligible for Incremental TCCs, which reflect the TCCs that become feasible on the New York electricity system as a result of that project. Procedures for determining Incremental TCCs are set forth in detail in Section 2C of Attachment M of the OATT. As with Grandfathered Rights and Grandfathered TCCs, the estimate of congestion rents that would be paid to the holders of Incremental TCCs

[15] Recipients of Grandfathered Rights are not actually paid congestion rents. Instead entities with Grandfathered Rights are not assessed congestion charges, to the extent that they schedule and consummate transactions in accordance with the provisions of those rights. Consequently, the procedure proposed herein is actually based on an imputed payment to the owner of a Grandfathered Right, which is the congestion charges it would avoid paying if one assumes that the Grandfathered Right is always exercised.

awarded in conjunction with earlier transmission projects should be deducted from overall congestion rents, since the transfer capability needed to support those Incremental TCCs cannot be used to support other TCCs that are purchased in the auction unless those Incremental TCCs are offered for sale in the auction by their holders, and if those Incremental TCCs are offered for sale, the revenues from their sale will go to their holders.[16] Additionally, the value of the Incremental TCCs that are expected to be created as a result of the project being evaluated should not be included when assessing the impact of a transmission project on congestion rents that would have been collected on the system before implementation of the expansion, so the Appendix B procedure also estimates the congestion rents that will accrue to those Incremental TCCs for each year included in the analysis, and deducts them from the estimate of the total congestion rents to be collected on the New York electricity system with the project in place.

The remainder is an estimate of the value of the congestion rents that are expected to be collected on the portion of the New York electricity system in existence before implementation of the project that will be available to support TCCs that can be purchased in NYISO-administered auctions, both with and without the project in place, for each year included in the analysis. For several reasons, most prominently the requirement that TCC holders post collateral to insure against failure to meet their obligations in the event that they are required to make payments in association with the TCCs they hold, the price of a TCC in one of these auctions will, on average, be less than the value of that TCC. Consequently, TCC revenues will generally be less than the forecast of congestion rents that would be realized on the portion of the system that is available to support TCCs. To account for this, when estimating the revenues that one could reasonably expect to realize from the TCC auction, the Appendix B Procedure multiplies the forecasted value of congestion rents collected on that portion of the system by a TCC Revenue Factor, which is intended to reflect the expected ratio of: (1) revenue realized in the TCC auction from the sale of a TCC to (2) the payments that a purchaser of that TCC would expect to be paid, on average. While the NYISO's Business Issues Committee has approved NYISO Procedures that would initially set that factor at 0.9, it may be necessary to revise this factor in light of analysis that the NYISO anticipates conducting in the near future. Accordingly, the Appendix B Procedure specifies that the TCC Revenue Factor will be contained in the ISO Procedures.

b. Steps 4-6: Forecasting the Allocation of TCC Auction Revenues among the Transmission Owners

The next task is to forecast how these TCC auction revenues will be allocated. In New York, TCC revenues fund three different revenue streams: (1) payments to holders of

[16] The Incremental TCCs that would be awarded in conjunction with earlier transmission projects may not yet be known at the time that this evaluation is performed for a subsequent project, since final awards of Incremental TCCs for the earlier project will not be determined until it has entered commercial operation. Under the proposed procedure, the ISO would use a projection of those Incremental TCCs in such cases.

Original Residual TCCs; (2) payments to recipients of Existing Transmission Capability for Native Load ("ETCNL"); and (3) residual auction revenues.

Certain Transmission Owners have been allocated Original Residual TCCs. A Transmission Owner that has been allocated Original Residual TCCs receives the price determined for those TCCs in the auction. In addition, certain Transmission Owners were allocated Existing Transmission Capability for Native Load. This ETCNL is subject to reduction before each TCC auction, as in some cases, it may not be possible to accommodate injections and withdrawals corresponding to all ETCNL at the same time as injections and withdrawals corresponding to all other Grandfathered TCCs, Grandfathered Rights, Incremental TCCs, and Original Residual TCCs.[17] In such cases, reducing ETCNL as necessary to eliminate all such infeasibilities, ensures that the auction will be "revenue-adequate" (i.e., that revenues realized as a result of the sale of TCCs in the auction will be sufficient to pay all claims on those revenues). To the extent that a given amount of ETCNL survives the reduction process, a Transmission Owner that has been allocated ETCNL receives the price determined in the auction for the corresponding number of TCCs with the ETCNL's injection and withdrawal locations.

Correspondingly, the Appendix B Procedure forecasts the auction payments that would be made to Transmission Owners that have been allocated Original Residual TCCs and ETCNL (using the results of the TCC auction preceding the most recently conducted CARIS to estimate how much ETCNL will survive the reduction process), which in each case are equal to the product of the TCC Revenue Factor and the NYISO's forecast of the revenue that the holders of the corresponding TCCs would realize for each of the years included in the analysis, and deducts those payments from the forecasted TCC auction revenues for each of those years to arrive at annual forecasts for residual auction revenues, again both with and without the project in place. These residual auction revenues are allocated among the Transmission Owners using the facility flow-based methodology, which is described in detail in Section 3.7 of OATT Attachment N. The Appendix B Procedure allocates these revenues among the Transmission Owners in the same proportions as were used to allocate residual auction revenues in the most recent Centralized TCC Auction.

c. Steps 7 and 8: Forecasting the Impact of the Project on TSC Offsets and the NTAC Offset

Having determined the annual allocation of TCC revenues both with and without the project, the next steps are to determine the impact of the project on the TSC for each Transmission Owner other than NYPA and on the NTAC. As is described in Section 2.1 of Part I of Attachment H of the OATT, the equation used to calculate the TSCs for these Transmission Owners contain offset terms, which reduce the amount of revenue to be collected through the TSC. These offset terms include payments received by those

[17] Some Grandfathered TCCs are also subject to reduction in these circumstances.

Transmission Owners in conjunction with some of the Grandfathered TCCs and Grandfathered Rights they were allocated, the revenues received by those Transmission Owners in association with their Original Residual TCCs and ETCNL, and the portion of residual auction revenues allocated to each Transmission Owner. Therefore, the differences between the sum of the forecasts of each of these revenue sources for each Transmission Owner with the project in place and the sum of these forecasts without the project in place are summed to determine the net impact of the project on the total revenue that each Transmission Owner other than NYPA should collect through its TSC in each year. This difference is then divided by the amount of Energy that the Transmission Owner is expected to serve in that year, since the TSC is applied on an equal dollar-per-megawatt-hour basis to all Loads in each Transmission District (*i.e.*, the area served by a given Transmission Owner), with the exception of certain Loads that are not subject to the TSC.[18]

Similarly, the equation used in Section 2.1 of Part II of Attachment H to calculate the NTAC contains offset terms that reduce the amount of revenue to be collected through the NTAC, which include payments received by NYPA in conjunction with some of the Grandfathered TCCs and Grandfathered Rights NYPA was allocated, the revenues received by NYPA in association with its Original Residual TCCs (NYPA was not allocated any ETCNL), and the portion of residual auction revenues allocated to NYPA. Therefore, the differences between the forecasts of each of these revenue sources for NYPA with the project in place and the sum of these forecasts without the project in place are summed to determine the net impact of the project on the total revenue that NYPA should collect through the NTAC in each year. This difference is then divided by the amount of Energy that is expected to be served in the New York Control Area ("NYCA") in that year, since the NTAC is applied on an equal dollar-per-megawatt-hour basis to all Loads in the NYCA, with the exception of certain Loads that are not subject to the NTAC.[19]

d. Steps 9 and 10: Forecasting the Net Impact of the Project on TCC Revenues Allocated to Load in Each Zone

There are three components of the net impact of each project on TCC revenues allocated to Load in a given Zone. First is the impact on the TSC paid by the Load in that Zone in each year. In some Zones all Loads are served by the same Transmission Owner, while in other Zones the Loads may be served by multiple Transmission Owners, so the impact of a given project on the TSC paid by Loads in a given Zone may differ, depending on which Transmission District the Load is in. Therefore, in order to determine the net impact of

[18] In addition, in the event that Incremental TCCs that may be awarded to a Transmission Owner at some point in the future would affect its TSC, the procedure takes the impact of the project being evaluated on payments made in association with those Incremental TCCs taken into account.

[19] In the event that Incremental TCCs that may be awarded to NYPA at some point in the future would affect its NTAC, the procedure takes the impact of the project being evaluated on payments made in association with those Incremental TCCs into account.

each project on TCC revenues allocated to Load in each Zone, the Appendix B Procedure multiplies the dollar-per-megawatt-hour impact of that project on each Transmission Owner's TSC by the amount of Load expected to be served in that Zone in each year served by that Transmission Owner (and is subject to its TSC), and sums the result for all Transmission Owners.

The second component is the impact on the NTAC paid by Load in that Zone. The Appendix B Procedure multiplies the dollar-per-megawatt-hour impact of that project on the NTAC by the amount of Load expected to be served in that Zone (and is subject to the NTAC) in each year.

The third component is the impact of the project on the payments made in association with other TCCs and Grandfathered Rights that benefit Load in each Zone. This includes the impact of the project on TCC payments made to municipally owned utilities, since the project's impact on these payments affects the net amount that Load in each Zone will have to pay for electricity. It also includes the impact of the project on Incremental TCCs that were identified previously for projects that are being funded through this procedure, since payments made in association with those TCCs help to defray the cost of those earlier projects, and if the current project reduces those revenues, Loads in the affected Zones would be adversely affected since they would be assessed a larger share of those costs.

Payments to be made in association with all such TCCs and Grandfathered Rights were forecasted earlier in the procedure, so the difference between these forecasted payments in each year with the project in place and the forecasted payments without the project in place is added to the other two components to arrive at the forecasted net impact of a given project on TCC revenues allocated, directly or indirectly, to Load in a given Zone for each of the ten years following the proposed commercial operation date of the transmission project.

e. Illustrative Example

Attachment III to this transmittal letter contains a detailed example illustrating the Appendix B Procedure.

2. Bilateral Contracts

In Paragraph 54 of the October 2009 Order, FERC notes that the tariff states that the LBMP Load savings would be adjusted by information from bilateral contracts, but that "these provisions do not make explicit what contract data will be used or how it will be used in the calculation of LBMP load savings." Accordingly, the Commission directed that the Joint Filing Parties amend Attachment Y to "provide details regarding how and what contract data NYISO will use to offset LBMP load savings."

a. What Contract Data will be Used

The Joint Filing Parties have amended Section 15.4.b(v) to clarify that the contract information that will be used to calculate offsets to LBMP reductions consists of information on (1) contracts that are not indexed to LBMP, (2) contracts that are partially indexed to LBMP (*e.g.,* a contract that sets the price at a fixed level plus 80 percent of LBMP), and (3) generation owned by Load Serving Entities.

To clarify further what contract data must be submitted, the Joint Filing Parties have added subsection (C) to 15.4.b(v) which reads:

> (C) All bilateral contract information and information on LSE-owned generation submitted to the ISO must include the following information:
>
> (1) Contract quantities on an annual basis:
>
> (a) For non-generator specific contracts, the Energy (in MWh) contracted to serve each Zone for each year.
>
> (b) For generator specific contracts or LSE-owned generation, the name of the generator(s) and the MW or percentage output contracted or self-owned for use by Load in each Zone for each year.
>
> (2) For all Load Serving Entities serving Load in more than one Load Zone, the quantity (in MWh or percentage) of bilateral contract energy to be applied to each Zone, by year over the term of the contract.
>
> (3) Start and end dates of the contract.
>
> (4) Terms in sufficient detail to determine that either pricing is not indexed to LBMP, or, if pricing is indexed to LBMP, the manner in which prices are connected to LBMP.
>
> (5) Identify any changes in the pricing methodology on an annual basis over the term of the contract.

In addition, the Joint Filing Parties have added subsections (A) and (B) to Section 15.4.b(v), which state that "[a]ll bilateral contract information submitted to the ISO must identify the source of the contract information, including citations to any public documents including but not limited to annual reports or regulatory filings," and that "[a]ll non-public bilateral contract information will be protected in accordance with the ISO's Code of Conduct, as set forth in Section 4.0 of Attachment F of the OATT, and Article 6 of the Services Tariff."

b. How Contract Data will be Used

Regarding the question of how information on bilateral contracts and LSE-owned generation will be used, the Joint Filing Parties have developed a formula to calculate adjusted LBMP savings, which differs from the calculation of the LBMP savings for Load in each Zone in that it excludes any impact of the project on Load served under bilateral contracts, in cases where the amount paid for energy under those contracts is not indexed to LBMP or where Load is served by LSE-owned generation in that Zone. The formula for calculating adjusted LBMP savings also incorporates into the annual Net Zonal Savings calculation an adjustment for all contracts that are partially indexed to LBMP. This adjustment revises the LBMP savings in proportion to the specific index in each such contract.

This formula is reflected in a new subsection (D) of Section 15.4.b(v), which reads:

> (D) Bilateral contract and LSE-owned generation information will be used to calculate the adjusted LBMP savings for each Load Zone as follows:
>
> $AdjLBMPS_{y,z}$, the adjusted LBMP savings for each Load Zone *z*, in each year *y*, shall be calculated using the following equation:
>
> $$AdjLBMPS_{y,z} = \max\left[0, TL_{y,z} - \sum_{b \in B_{y,z}} \left(BCL_{b,y,z} \cdot \left(1 - Ind_{b,y,z}\right)\right) - SG_{y,z}\right] \cdot \left(LBMP1_{y,z} - LBMP2_{y,z}\right),$$
>
> Where:
>
> $TL_{y,z}$ is the total annual amount of Energy forecasted to be consumed by Load in year *y* in Load Zone *z*;
>
> $B_{y,z}$ is the set of blocks of Energy to serve Load in Load Zone *z* in year *y* that are sold under bilateral contracts for which information has been provided to the ISO that meets the requirements set forth elsewhere in this Section 15.4.b(v);
>
> $BCL_{b,y,z}$ is the total annual amount of Energy sold into Load Zone *z* in year *y* under bilateral contract block *b*;
>
> $Ind_{b,y,z}$ is the ratio of (1) the increase in the amount paid by the purchaser of Energy, under bilateral contract block *b*, as a result of an increase in the LBMP in Load Zone *z*, in year *y* to (2) the increase in the amount that a purchaser of that amount of

Energy would pay if the purchaser paid the LBMP for that Load Zone in that year for all of that Energy (this ratio shall be zero for any bilateral contract block of Energy that is sold at a fixed price or for which the cost of Energy purchased under that contract otherwise insensitive to the LBMP in Load Zone *z* in year *y*);

$SG_{y,z}$ is the total annual amount of Energy in Load Zone *z*, that is forecasted to be served by LSE-owned generation in that Zone in year *y*;

$LBMP1_{y,z}$ is the forecasted annual Load-weighted average LBMP for Load Zone *z*, in year *y*, calculated under the assumption that the project is not in place; and

$LBMP2_{y,z}$ is the forecasted annual Load-weighted average LBMP for Load Zone *z*, in year *y*, calculated under the assumption that the project is in place.

3. Calculation of Net Zonal Savings

To forecast the Net Zonal Savings that Load within a Load Zone is expected to realize as a result of a project, it is necessary to subtract the forecasted reductions in TCC revenues allocated to Load in that Load Zone from the adjusted LBMP savings calculated above for that Load Zone. As outlined above, the TCC revenue reductions are to be calculated pursuant to proposed Appendix B to Attachment Y of the OATT, while adjusted LBMP savings are calculated pursuant to Section 15.4.b(v)(D) of Attachment Y. To produce the Net Zonal Savings associated with a proposed project, these two calculations are then combined in Section 15.4.b(vi) of Attachment Y, which reads:

(vi) NZS_z, the Net Zonal Savings for each Load Zone *z* resulting from a given project, shall be calculated using the following equation:

$$NZS_z = \max\left[0, \sum_{y=PS}^{PS+9}\left(\left(AdjLBMPS_{y,z} - TCCRevImpact_{y,z}\right)\cdot DF_y\right)\right],$$

Where:

PS is the year in which the project is expected to enter commercial operation;

$AdjLBMPS_{y,z}$ is as calculated in Section 15.4.b(v);

$TCCRevImpact_{y,z}$ is the forecasted impact of TCC revenues allocated to Load Zone *z* in year *y*, calculated using the procedure described in Appendix B to this Attachment Y; and

DF_y is the discount factor applied to cash flows in year *y* to determine the present value of that cash flow in year *PS*.

This tariff language also clarifies that Net Zonal Savings will be calculated as the present value of net savings resulting from the project that are forecasted for Load in each Load Zone, over the ten-year period that begins with the projected start of commercial operation of the project. It will be set to zero in the event that this calculation would otherwise yield a negative result.

B. CARIS and Economic Project Additional ICAP Cost Metric

The May 2009 Filing provided a more detailed description of the additional metrics provided during the CARIS Phase I study for information purposes as directed by the Commission. The NYISO included the ICAP metric utilized in the initial CARIS cycle, which employed a megawatt impact methodology. The NYISO also explained that for subsequent CARIS cycles, the NYISO was developing, through its stakeholder process, an ICAP cost metric that estimates the financial impacts that CARIS projects may have on installed capacity costs to Load Zones. Paragraph 81 of the October 2009 Order directs "NYISO to file a compliance filing within 60 days hereof to revise section 11.3.e(vi) of its tariff to incorporate the megawatt impact methodology used in calculating the ICAP metric into that tariff. Further, NYISO is directed to file a compliance filing containing revised tariff sheets reflecting the new ICAP cost metric with the Commission once it completes the stakeholder process addressing that metric."

In the December 11, 2009 compliance filing, the Joint Filing Parties submitted a new subsection (A) to Section 11.3.e(vi) to describe the megawatt impact methodology used in calculating the ICAP cost metric. Under that methodology, the NYISO determines the quantity of generation that would be displaced by the proposed economic project. It performs this calculation by determining first the loss of load expectation ("LOLE") for the relevant year in the New York Control Area both with and without the project. If the LOLE with the project is lower than the base system LOLE for that year, then the NYISO will reduce generation proportionally in each of the NYISO's zones until the LOLE equals the base system LOLE for that year. The quantities of reduced generation in each zone are then summed to produce the total generation (expressed in megawatts) displaced by the proposed project. This is the megawatt impact of the proposed project.

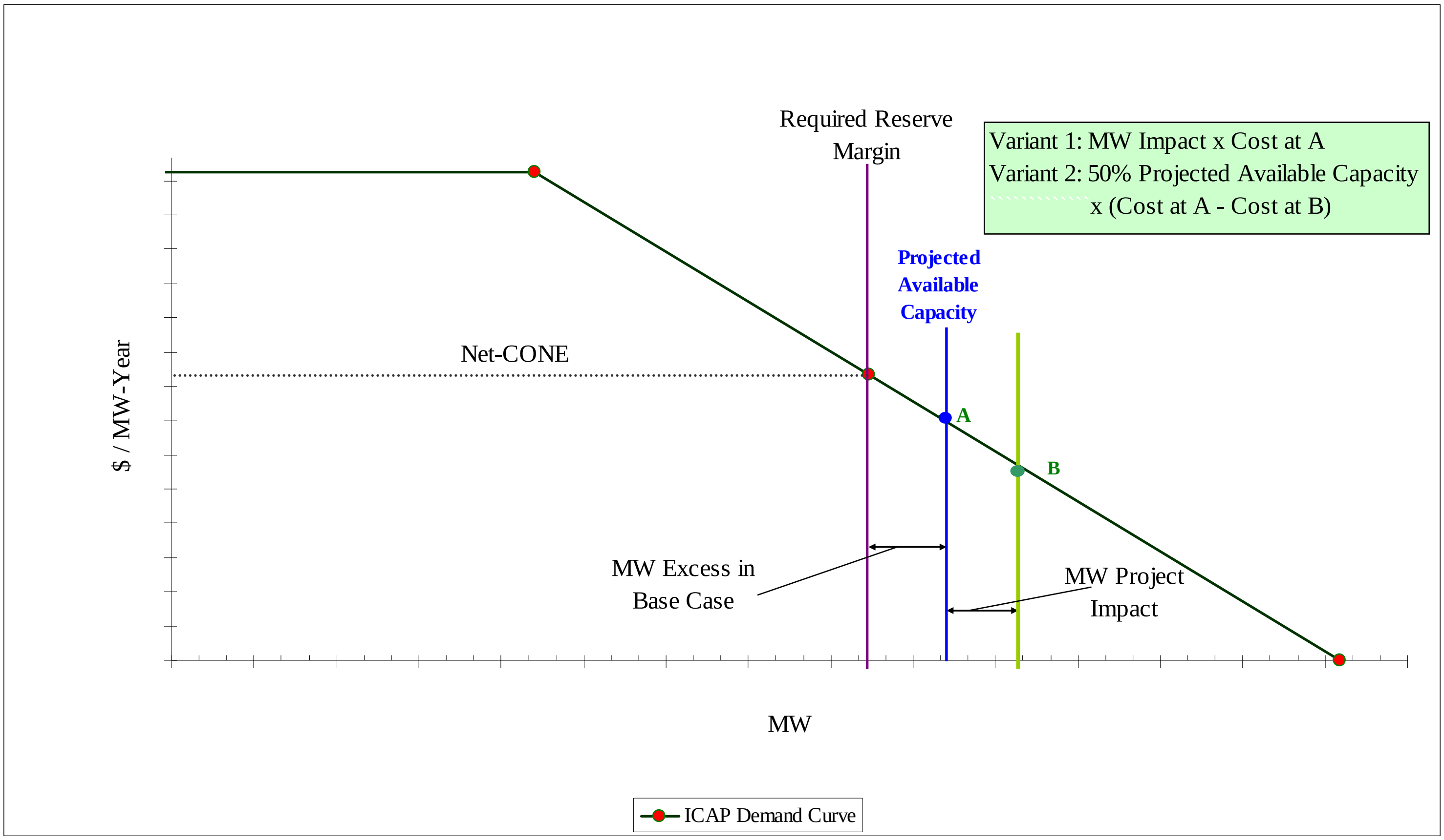
The NYISO has now concluded its stakeholder process on the ICAP cost metric, and has developed two variants of this metric that the Joint Filing Parties propose to adopt as part of Attachment Y. The Joint Filing Parties emphasize that both of these variations, to be reflected in a new subsection (B) to Section 11.3.e(vi), are for informational purposes only, and are calculated for the purpose of providing market participants with additional information on the potential ICAP cost impacts of a new resource. The ICAP cost metrics included in this tariff filing are indicative measures of the additional potential benefits of new resources. The metrics are not precise determinants of capacity prices and are not reflective of any New York City ICAP bid price mitigation levels that may or may not apply, or other factors that may be relevant, such as price hedges through bilateral contracts or other arrangements. Both metrics would be calculated in Phase I and Phase II of the CARIS process.

The first variant of the ICAP cost metric focuses on the Installed Capacity costs that are avoided by the proposed project, and is based on the megawatt impact methodology described above. Specifically, under the first approach, the NYISO would forecast the cost per megawatt-year of Installed Capacity for each study year as follows:

To calculate the forecasted Installed Capacity cost per megawatt-year, the NYISO would obtain the Net Cost of New Entry (“CONE”)[20] from the current ICAP Demand Curve process, and then escalate Net CONE for each study year. For purposes of this discussion, the following simplified diagram of the Demand Curve illustrates the calculations:

[20] The CONE is equal to the localized, levelized cost to build a new peaking unit. *See* Market Administration and Control Area Services Tariff § 5.14.1(b). Against this number is netted anticipated revenues from energy and ancillary services sales.

Simplified ICAP Demand Curve Based Calculations



To account for the impact of excess, or surplus capacity, in future years, the NYISO would first determine a proxy for the applicable Minimum Installed Capacity Requirement for the year where the NYCA LOLE reaches 0.1. This establishes the requirement for the minimum projected Installed Capacity margin for the relevant region in that year Any surplus above the minimum Installed Capacity margin is indicated in the Load and Capacity tables in the CARIS. A future demand curve can then be constructed from these values and an adjustment to the Net CONE would be made based on the excess capacity and the slope of the appropriate ICAP Demand Curve to determine the forecasted cost per megawatt-year of Installed Capacity. The ICAP cost metric would then be calculated by multiplying that forecasted cost per megawatt-year by the megawatt impact quantity -- that is, the amount of generation displaced by the proposed project -- determined under the megawatt impact methodology set forth in Section 11.3.e(vi)(A). The NYISO will perform this calculation separately for the New York City and Long Island Localities, and for the Rest of State ("ROS") region. The NYISO will make this calculation for the ten years following the proposed commercial operation date of the proposed project.

The second variant of the cost impact metric would attempt to quantify the aggregate change in ICAP costs resulting from the proposed project. In separate calculations for the New York City and Long Island Localities, and for the ROS region, the NYISO would forecast Installed Capacity costs per megawatt-year during the study years both with and without the proposed project in place. The forecasted cost per megawatt-year without the project would be as calculated in variant 1 above. Insertion of the project potentially has two impacts on the projected demand curve. The first is on the proxy Minimum Installed Capacity Requirement (which can move the demand curve). Secondly, because more capacity may be available with the project in place than without it, there would be more excess capacity over the projected proxy Minimum Installed Capacity Requirement. Both of these impacts are determined by the megawatt impact methodology, and based on their sum and the slope of the demand curve, the forecasted cost per megawatt-year of Installed Capacity with the project is determined.

Under this second variant of the ICAP metric, the NYISO would take the difference between these two numbers -- that is, the forecasted cost per megawatt-year of Installed Capacity without the project in place, and the forecasted cost per megawatt-year of Installed Capacity with the project in place. This difference represents the difference between the ICAP market price with the proposed project in place, and the ICAP market price without the proposed project in place. For ROS, the NYISO will measure the cost impact of a proposed economic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in Rest of State under the assumption that the proposed economic project is in place, with that projection based on the latest available ICAP Demand Curve for the Rest of State and the amount of Installed Capacity available in the ROS; (ii) subtracting that forecasted cost per megawatt-year from the forecasted cost per megawatt-year of Installed Capacity in ROS that would be calculated with the assumption that the proposed economic project is not in place; and (iii) multiplying that difference by fifty percent of assumed amount of Installed Capacity available in ROS as calculated from the relevant Load and Capacity tables developed for the CARIS process. For each Locality, the NYISO would run the same calculation, but in the second step would subtract the greater of the forecasted cost per megawatt-year in that Locality with the proposed economic project in place or the forecasted ROS Installed Capacity cost per megawatt-year with the proposed economic project in place.

The quantity by which the difference in forecasted costs per megawatt-year is multiplied -- that is, fifty percent of assumed amount of Installed Capacity available in ROS as calculated from the relevant Load and Capacity tables developed for the CARIS process -- is an approximation of the quantity of capacity that would be subject to the ICAP spot market overall (although it does not reflect how much capacity would be subject to the spot market in each Load Zone). By multiplying the price delta by the quantity of capacity assumed to be subject to the spot market, the metric reflects the projected aggregate reduction in Installed Capacity cost resulting from the proposed project.

As a final matter, this second variation of the ICAP metric would be calculated beginning with the year that the proposed project is to commence commercial operation, and would end at the earlier of : (1) the year when the NYCA, with the proposed project in place, first reaches an LOLE of 0.1; or (2) ten years after the projected commercial operation date of the project.

IV. PROPOSED EFFECTIVE DATE

The Joint Filing Parties respectfully request that the Commission accept these proposed compliance tariff revisions with an effective date of April 13, 2010.

V. SERVICE

This filing will be posted on the NYISO's website at www.nyiso.com. In addition, the NYISO will e-mail an electronic link to this filing to the official representative of each party to this proceeding, to each its customers, to each participant on its stakeholder committees, to the New York Public Service Commission, and to the New Jersey Board of Public Utilities. The NYISO will also make a paper copy available to any interested party that requests one.

VI. CONCLUSION

Wherefore, for the foregoing reasons, the New York Independent System Operator, Inc. respectfully requests that the Commission accept for filing the proposed tariff revisions with an effective date of April 13, 2010.

Respectfully Submitted,

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Attachment II

Attachment Y

New York ISO Comprehensive System Planning Process

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(vi) The calculation of the ICAP cost metric will be determined as set forth below. The ICAP cost metric will be highly dependent on the rules and procedures guiding the calculation of the IRM, LCR, and the ICAP Demand Curves, both for the next capability period and future capability periods. In each CARIS cycle, the ISO will review, with the ESPWG and, as appropriate, other ISO committees, the results of the ICAP cost metric.

(A) The ICAP metric, in the form of a megawatt impact, will be computed based on a methodology that: (1) determines the base system loss of load expectation ("LOLE") for the applicable horizon year; (2) adds the proposed economic project; and (3) calculates the LOLE for the system with the addition of the proposed economic project. If the system LOLE is lower than that of the base system, the NYISO will reduce generation in all New York Control Area ("NYCA") zones proportionally (*i.e.*, based on proportion of zonal capacity to total NYCA capacity) until the base system LOLE is achieved. That amount of reduced generation is the NYCA megawatt impact.

(B) The ISO will calculate both of the following ICAP cost metrics described in subsections (1) and (2) below by first determining the megawatt impact described above in (A) and then:

(1) For Rest of State, the ISO will measure the cost impact of a proposed economic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in Rest of State under the assumption that the proposed economic project is not in place, with that forecast based on the latest available ICAP Demand Curve for the NYCA and the amount of Installed Capacity available in the NYCA, as shown in the Load and Capacity table developed for that year; and (ii) multiplying that forecasted cost per megawatt-year for Rest of State in that year by the sum of the megawatt impact for all Load Zones contained within Rest of State, as calculated in accordance with subsection (A) of this Section 11.3.e(vi).

For each Locality, the ISO will measure the cost impact of a proposed economic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in that Locality under the assumption that the proposed economic project is not in place, with that forecast based on the latest available ICAP Demand Curve for that Locality and the amount of Installed Capacity available in that Locality as shown in the relevant Load and Capacity table developed for that year, and (ii) multiplying that forecasted cost per megawatt-year for that Locality in each year by the sum of the megawatt impact for all Load Zones contained within that Locality, as calculated in accordance with subsection (A) of this Section 11.3.e(vi).

This ICAP cost metric will then be presented for each applicable planning year as a stream of present value benefits for each Locality and for Rest of State. The applicable planning years start with the proposed commercial operation date of the proposed economic project and end ten years after the proposed commercial operation date of the proposed economic project.

(2) For Rest of State, the ISO will measure the cost impact of a proposed economic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in Rest of State under the assumption that the proposed economic project is in place, with that forecast based on the latest available ICAP Demand Curve for the NYCA and the amount of Installed Capacity available in the NYCA; (ii) subtracting that forecasted cost per megawatt-year from the forecasted cost per megawatt-year of Installed Capacity in Rest of State calculated in subsection (1) under the assumption that the proposed economic project is not in place; and (iii) multiplying that difference by fifty percent (50%) of the assumed amount of Installed Capacity available in Rest of State as calculated from the relevant Load and Capacity tables developed for the CARIS process.

For each Locality, the ISO will measure the cost impact of a proposed economic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in that Locality under the assumption that the proposed economic project is in place, with that forecast based on the latest available ICAP Demand Curve for that Locality and the amount of Installed Capacity available in that Locality as shown in the relevant Load and Capacity table developed for that year; (ii) subtracting the greater of that forecasted cost per megawatt-year with the proposed economic project in place or the forecasted Rest of State Installed Capacity cost per megawatt-year with the proposed economic project in place from the forecasted cost of Installed Capacity in that Locality calculated in subsection (1) under the assumption that the proposed economic project is not in place; and (iii) multiplying that difference by fifty percent (50%) of assumed amount of Installed Capacity available in that Locality, as taken from the relevant Load and Capacity tables developed for the CARIS process.

This ICAP cost metric will then be represented for each applicable planning year as a stream of present value benefits for each Locality and for Rest of State. The applicable planning years start with the proposed commercial operation date of the proposed economic project and end with the earlier of: (i) the year when the system, with the proposed economic project in place, reaches an LOLE of 0.1, or (ii) ten years after the proposed commercial operation date of the proposed economic project.

(3) The forecast of Installed Capacity costs per megawatt-year are developed by: first, escalating the Net Cost of New Entry ("CONE") for the NYCA or a Locality from the most recently completed ICAP Demand Curves for each year of the planning period; second, determining the future proxy Locational Minimum Installed Capacity Requirement or Minimum Installed Capacity Requirement for the NYCA as the actual amount of Installed Capacity in the Locality or the NYCA for the year that NYCA reaches 0.1 LOLE; third, reducing the cost per megawatt-year in each year from the escalated Net CONE to reflect the excess Installed Capacity from the Load and Capacity table above the future proxy Minimum Installed Capacity Requirement with the adjustment calculated from the excess and the slope of the ICAP Demand Curve.

The forecasts of Installed Capacity costs for Localities or Rest of State performed in subsections (1) and (2) above shall, in addition to the assumptions listed above, be based upon: (i) the forecasted Net CONE for the Locality (the NYCA in the case of the Rest of State forecast); (ii) the amount of Installed Capacity required to meet the future proxy Locational Minimum Installed Capacity Requirement (the Minimum Installed Capacity Requirement for the NYCA in the case of the Rest of State forecast); (iii) the slope of the relevant ICAP Demand Curve, and (iv) the smallest quantity where the cost of Installed Capacity on that ICAP Demand Curve reaches zero.

11.4 Planning Participant Data Input

At the NYISO's request, Market Participants, Developers and other parties shall provide, in accordance with the schedule set forth in the NYISO Comprehensive Reliability Planning Process Manual, the data necessary for the development of the CARIS. This input will include but not be limited to existing and planned additions to the New York State Transmission System (to be provided by Transmission Owners and municipal electric utilities); proposals for merchant transmission facilities (to be provided by merchant developers); generation additions and retirements (to be provided by generator owners and developers); demand response programs (to be provided by demand response providers); and any long-term firm transmission requests made to the NYISO. The relevant Transmissions Owners will assist the NYISO in developing the potential solution cost estimates to be used by the NYISO to conduct benefit/cost analysis of each of the potential solutions.

(iii) Net reductions in TCC revenues will reflect the forecasted impact of the project on TCC auction revenues and day-ahead residual congestion rents allocated to load in each zone, excluding the congestion rents that accrue to any Incremental TCCs that may be made feasible as a result of this project. This impact will include forecasts of: (1) the total impact of that project on the Transmission Service Charge offset applicable to loads in each zone (which may vary for loads in a given zone that are in different Transmission Districts); (2) the total impact of that project on the NYPA Transmission Adjustment Charge offset applicable to loads in that zone; and (3) the total impact of that project on payments made to LSEs serving load in that zone that hold Grandfathered Rights or Grandfathered TCCs, to the extent that these have not been taken into account in the calculation of item (1) above. These forecasts shall be performed using the procedure described in Appendix B to this Attachment Y.

(iv) Estimated TCC revenues from any Incremental TCCs created by a proposed regulated economic transmission project over the ten-year period commencing with the project's commercial operation date will be added to the net load savings used for the cost allocation and beneficiary determination.

(v) The NYISO will solicit bilateral contract information from all Load Serving Entities, which will provide the NYISO with bilateral energy contract data for modeling contracts that do not receive benefits, in whole or in part, from LBMP reductions, and for which the time period covered by the contract is within the ten-year period beginning with the commercial operation date of the project. Bilateral contract payment information that is not provided to the NYISO will not be included in the calculation of the present value of the annual zonal LBMP savings in section (i) above.

(A) All bilateral contract information submitted to the ISO must identify the source of the contract information, including citations to any public documents including but not limited to annual reports or regulatory filings

(B) All non-public bilateral contract information will be protected in accordance with the ISO's Code of Conduct, as set forth in Section 4.0 of Attachment F of the OATT, and Article 6 of the Services Tariff.

(C) All bilateral contract information and information on LSE-owned generation submitted to the ISO must include the following information:

(1) Contract quantities on an annual basis:

(a) For non-generator specific contracts, the Energy (in MWh) contracted to serve each Zone for each year.

(b) For generator specific contracts or LSE-owned generation, the name of the generator(s) and the MW or percentage output contracted or self-owned for use by Load in each Zone for each year.

(2) For all Load Serving Entities serving Load in more than one Load Zone, the quantity (in MWh or percentage) of bilateral contract Energy to be applied to each Zone, by year over the term of the contract.

(3) Start and end dates of the contract.

(4) Terms in sufficient detail to determine that either pricing is not indexed to LBMP, or, if pricing is indexed to LBMP, the manner in which prices are connected to LBMP.

(5) Identify any changes in the pricing methodology on an annual basis over the term of the contract.

(D) Bilateral contract and LSE-owned generation information will be used to calculate the adjusted LBMP savings for each Load Zone as follows:

$AdjLBMPS_{y,z}$, the adjusted LBMP savings for each Load Zone *z* in each year *y*, shall be calculated using the following equation:

$$AdjLBMPS_{y,z} = \max\left[0, TL_{y,z} - \sum_{b \in B_{y,z}} \left(BCL_{b,y,z} \cdot \left(1 - Ind_{b,y,z}\right)\right) - SG_{y,z}\right] \cdot \left(LBMP1_{y,z} - LBMP2_{y,z}\right),$$

Where:

$TL_{y,z}$ is the total annual amount of Energy forecasted to be consumed by Load in year *y* in Load Zone *z*;

$B_{y,z}$ is the set of blocks of Energy to serve Load in Load Zone *z* in year *y* that are sold under bilateral contracts for which information has been provided to the ISO that meets the requirements set forth elsewhere in this Section 15.4.b(v);

$BCL_{b,y,z}$ is the total annual amount of Energy sold into Load Zone *z* in year *y* under bilateral contract block *b*;
$Ind_{b,y,z}$ is the ratio of (1) the increase in the amount paid by the purchaser of Energy, under bilateral contract block *b*, as a result of an increase in the LBMP in Load Zone *z* in year *y* to (2) the increase in the amount that a purchaser of that amount of Energy would pay if the purchaser paid the LBMP for that Load Zone in that year for all of that Energy (this ratio shall be zero for any bilateral contract block of Energy that is sold at a fixed price or for which the cost of Energy purchased under that contract otherwise insensitive to the LBMP in Load Zone *z* in year *y*);

$SG_{y,z}$ is the total annual amount of Energy in Load Zone *z* that is forecasted to be served by LSE-owned generation in that Zone in year *y*;

$LBMP1_{y,z}$ is the forecasted annual Load-weighted average LBMP for Load Zone *z* in year *y*, calculated under the assumption that the project is not in place; and

$LBMP2_{y,z}$ is the forecasted annual Load-weighted average LBMP for Load Zone *z* in year *y*, calculated under the assumption that the project is in place.

(vi) NZS_z, the Net Zonal Savings for each Load Zone *z* resulting from a given project, shall be calculated using the following equation:

$$NZS_z = \max\left[0, \sum_{y=PS}^{PS+9}\left(\left(AdjLBMPS_{y,z} - TCCRevImpact_{y,z}\right)\cdot DF_y\right)\right],$$

Where:

PS is the year in which the project is expected to enter commercial operation;

$AdjLBMPS_{y,z}$ is as calculated in Section 15.4.b(v);

$TCCRevImpact_{y,z}$ is the forecasted impact of TCC revenues allocated to Load Zone *z* in year *y*, calculated using the procedure described in Appendix B to this Attachment Y; and

DF_y is the discount factor applied to cash flows in year *y* to determine the present value of that cash flow in year *PS*.

c. Load zones not benefiting from a proposed project will not be allocated any of the costs of the project under this Attachment Y. There will be no “make whole” payments to non-beneficiaries.

APPENDIX B

PROCEDURE FOR FORECASTING THE NET REDUCTIONS IN TCC REVENUES THAT WOULD RESULT FROM A PROPOSED PROJECT

For the purpose of determining the allocation of costs associated with a proposed project as described in Section 15.4.b of this Attachment Y, the ISO shall use the procedure described herein to forecast the net reductions in TCC revenues allocated to Load in each Load Zone as a result of a proposed project.

Definitions

The following definitions will apply to this appendix:

Pre-CARIS Centralized TCC Auction: The last Centralized TCC Auction that had been completed as of the date the input assumptions were determined for the CARIS in which the Project was identified as a candidate for development under the provisions of this Attachment Y.

Project: The proposed transmission project for which the evaluation of the net benefits forecasted for Load in each Load Zone, as described in Section 15.4.b of this Attachment Y, is being performed.

TCC Revenue Factor: A factor that is intended to reflect the expected ratio of (1) revenue realized in the TCC auction from the sale of a TCC to (2) the Congestion Rents that a purchaser of that TCC would expect to realize. The value to be used for the TCC Revenue Factor shall be stated in the ISO Procedures.

Steps 1 Through 6 of the Procedure

For each Project, the ISO will perform Steps 1 through 6 of this procedure twice for each of the ten (10) years following the proposed commercial operation date of the Project: once under the assumption that the Project is in place in each of those years, and once under the assumption that the Project is not in place in each of those years.

Forecasting the Value of Grandfathered TCCs and TCC Auction Revenue

Step 1. The ISO shall forecast Congestion Rents collected on the New York electricity system in each year, which shall be equal to:

(a) the product of:

(i) the forecasted Congestion Component of the Day-Ahead LBMP for each hour at each Load Zone or Proxy Generator Bus and

(ii) forecasted withdrawals scheduled in that hour in that Load Zone or Proxy Generator bus,

summed over all locations and over all hours in that year, minus:

(b) the product of:

(i) the forecasted Congestion Component of the Day-Ahead LBMP for each hour at each Generator bus or Proxy Generator Bus and

(ii) forecasted injections scheduled in that hour at that Generator bus or Proxy Generator Bus,

summed over all locations and over all hours in that year.

Step 2. The ISO shall forecast:

(a) payments in each year associated with any Incremental TCCs that the ISO projects would be awarded in conjunction with that Project (which will be zero for the calculation that is performed under the assumption that the Project is not in place);

(b) payments in each year associated with any Incremental TCCs that the ISO has awarded, or that the ISO projects it would award, in conjunction with other projects that have entered commercial operation or are expected to enter commercial operation before the Project enters commercial operation; and

(c) payments that would be made to holders of Grandfathered Rights and imputed payments that would be made to the Primary Holders of Grandfathered TCCs that would be in effect in each year, under the following assumptions:

(i) all Grandfathered Rights and Grandfathered TCCs expire at their stated expiration dates;

(ii) imputed payments to holders of Grandfathered Rights are equal to the payments that would be made to the Primary Holder of a TCC with the same Point of Injection and Point of Withdrawal as that Grandfathered Right; and

(iii) in cases where a Grandfathered TCC is listed in Table 1 of Attachment M of the OATT, the number of those TCCs held by their Primary Holders shall be set to the number of such TCCs remaining at the conclusion of the ETCNL reduction procedure conducted before the Pre-CARIS Centralized TCC Auction.

Step 3. The ISO shall forecast TCC auction revenues for each year by subtracting:

(a) the forecasted payments calculated for that year in Steps 2(a), 2(b) and 2(c) of this procedure

from:

(b) the forecasted Congestion Rents calculated for that year in Step 1 of this procedure, and multiplying the difference by the TCC Revenue Factor.

Forecasting the Allocation of TCC Auction Revenues Among the Transmission Owners

Step 4. The ISO shall forecast the following:

(a) payments in each year to the Primary Holders of Original Residual TCCs and

(b) payments in each year to the Primary Holders of TCCs that correspond to the amount of ETCNL remaining at the conclusion of the ETCNL reduction procedure conducted before the Pre-CARIS Centralized TCC Auction,

and multiply each by the TCC Revenue Factor to determine the forecasted payments to the Primary Holders of Original Residual TCCs and the Transmission Owners that have been allocated ETCNL.

Step 5. The ISO shall forecast residual auction revenues for each year by subtracting:

(a) the sum of the forecasted payments for each year to the Primary Holders of Original Residual TCCs and the Transmission Owners that have been allocated ETCNL, calculated in Step 4 of this procedure

from:

(b) forecasted TCC auction revenues for that year calculated in Step 3 of this procedure.

Step 6. The ISO shall forecast each Transmission Owner's share of residual auction revenue for each year by multiplying:

(a) the forecast of residual auction revenue calculated in Step 5 of this procedure and

(b) the ratio of:

(i) the amount of residual auction revenue allocated to that Transmission Owner in the Pre-CARIS Centralized TCC Auction to

(ii) the total amount of residual auction revenue allocated in the Pre-CARIS Centralized TCC Auction.

Steps 7 Through 10 of the Procedure

The ISO will perform Steps 7 through 10 of this procedure once for each of the ten (10) years following the proposed commercial operation date of the Project, using the results of the preceding calculations performed both under the assumption that the Project is in place in each of those years, and under the assumption that the Project is not in place in each of those years.

Forecasting the Impact of the Project on TSC Offsets and the NTAC Offset

Step 7. The ISO shall calculate the forecasted net impact of the Project on the TSC offset for each megawatt-hour of electricity consumed by Load in each Transmission District (other than the NYPA Transmission District) in each year by:

(a) summing the following, each forecasted for that Transmission District for that year under the assumption that the Project is in place:

(i) forecasted Congestion Rents associated with any Incremental TCCs that the ISO has awarded, or that the ISO projects it would award, as calculated in Step 2(b) of this procedure, in conjunction with other projects that have entered commercial operation or are expected to enter commercial operation before the Project enters commercial operation, if those Congestion Rents would affect the TSC for that Transmission District;

(ii) forecasted Congestion Rents associated with any Grandfathered TCCs and forecasted imputed Congestion Rents associated with any Grandfathered Rights held by the Transmission Owner serving that Transmission District that would be paid to that Transmission Owner for that year, as calculated in Step 2(c) of this procedure, if those Congestion Rents would affect the TSC for that Transmission District;

(iii) the payments that are forecasted to be made for that year to the Primary Holders of Original Residual TCCs and ETCNL that have been allocated to the Transmission Owner serving that Transmission District, as calculated in Step 4 of this procedure; and

(iv) that Transmission District's forecasted share of residual auction revenues for that year, as calculated in Step 6 of this procedure for the Transmission Owner serving that Transmission District;

(b) subtracting the sum of items (i) through (iv) above, each forecasted for that Transmission District for that year under the assumption that the Project is not in place; and

(c) dividing this difference by the amount of Load forecasted to be served in that Transmission District in that year, stated in terms of megawatt-hours, net of any Load served by municipally owned utilities that is not subject to the TSC.

Step 8. The ISO shall calculate the forecasted net impact of the Project on the NTAC offset for each megawatt-hour of electricity consumed by Load in each year by:

(a) summing the following, each forecasted for that year under the assumption that the Project is in place:

(i) forecasted Congestion Rents associated with any Incremental TCCs that the ISO has awarded, or that the ISO projects it would award, as calculated in Step 2(b) of this procedure, in conjunction with other projects that have entered commercial operation or are expected to enter commercial operation before the Project enters commercial operation, if those Congestion Rents would affect the NTAC;

(ii) forecasted Congestion Rents associated with any Grandfathered TCCs and forecasted imputed Congestion Rents associated with any Grandfathered Rights held by NYPA that would be paid to NYPA for that year, as calculated in Step 2(c) of this procedure, if those Congestion Rents would affect the NTAC;

(iii) the payments that are forecasted to be made for that year to NYPA in association with Original Residual TCCs allocated to NYPA, as calculated in Step 4 of this procedure; and

(iv) NYPA's forecasted share of residual auction revenues for that year, as calculated in Step 6 of this procedure;

(b) subtracting the sum of items (i) through (iv) above, each forecasted for that year under the assumption that the Project is not in place; and

(c) dividing this difference by the amount of Load expected to be served in the NYCA in that year, stated in terms of megawatt-hours, net of any Load served by municipally owned utilities that is not subject to the NTAC.

Forecasting the Net Impact of the Project on TCC Revenues Allocated to Load in Each Zone

Step 9. The ISO shall calculate the forecasted net impact of the Project in each year in each Load Zone on payments made in conjunction with TCCs and Grandfathered Rights that benefit Load but which do not affect TSCs or the NTAC, which shall be the sum of:

(a) Forecasted Congestion Rents paid or imputed to municipally owned utilities serving Load in that Load Zone that own Grandfathered Rights or Grandfathered TCCs that were not included in the calculation of the TSC offset in Step 7(a)(ii) of this procedure or the NTAC offset in Step 8(a)(ii) of this procedure, which the ISO shall calculate by:

(i) summing forecasted Congestion Rents that any such municipally owned utilities serving Load in that Load Zone would be paid for that year in association with any such Grandfathered TCCs and any forecasted imputed Congestion Rents that such a municipally owned utility would be paid for that year in association with any such Grandfathered Rights, as calculated in Step 2(c) of this procedure under the assumption that the Project is in place; and

(ii) subtracting forecasted Congestion Rents that any such municipally owned utilities would be paid for that year in association with any such Grandfathered TCCs, and any forecasted imputed Congestion Rents that such a municipally owned utility would be paid for that year in association with any such Grandfathered Rights, as calculated in Step 2(c) of this procedure under the assumption that the Project is not in place.

(b) Forecasted Congestion Rents collected from Incremental TCCs awarded in conjunction with projects that were previously funded through this procedure, if those Congestion Rents are used to reduce the amount that Load in that Load Zone must pay to fund such projects, which the ISO shall calculate by:

(i) summing forecasted Congestion Rents that would be collected for that year in association with any such Incremental TCCs, as calculated in Step 2(b) of this procedure under the assumption that the Project is in place; and

(ii) subtracting forecasted Congestion Rents that would be collected for that year in association with any such Incremental TCCs, as calculated in Step 2(b) of this procedure under the assumption that the Project is not in place.

Step 10. The ISO shall calculate the forecasted net reductions in TCC revenues allocated to Load in each Load Zone as a result of a proposed Project by summing the following:

(a) the product of:

(i) the forecasted net impact of the Project on the TSC offset for each megawatt-hour of electricity consumed by Load, as calculated for each Transmission District (other than the NYPA Transmission District) in Step 7 of this procedure; and

(ii) the number of megawatt-hours of energy that are forecasted to be consumed by Load in that year, in the portion of that Transmission District that is in that Load Zone, for Load that is subject to the TSC;

summed over all Transmission Districts;

(b) the product of:

(i) the forecasted net impact of the Project on the NTAC offset for each megawatt-hour of electricity consumed by Load, as calculated in Step 8 of this procedure; and

(ii) the number of megawatt-hours of energy that are forecasted to be consumed by Load in that year in that Load Zone, for Load that is subject to the NTAC; and

(c) the forecasted net impact of the Project on payments and imputed payments made in conjunction with TCCs and Grandfathered Rights that benefit Load but which do not affect TSCs or the NTAC, as calculated in Step 9 of this procedure.

Additional Notes Concerning the Procedure

For the purposes of Steps 2(c) and 4(b) of this procedure, the ISO will utilize the currently effective version of Attachment L of the OATT to identify Existing Transmission Agreements and Existing Transmission Capacity for Native Load.

Each Transmission Owner, other than NYPA, will inform the ISO of any Grandfathered Rights and Grandfathered TCCs it holds whose Congestion Rents should be taken into account in Step 7 of this procedure because those Congestion Rents affect its TSC.

NYPA will inform the NYISO of any Grandfathered Rights and Grandfathered TCCs it holds whose Congestion Rents should be taken into account in Step 8 of this procedure because those Congestion Rents affect the NTAC.

Attachment I

Attachment Y

New York ISO Comprehensive System Planning Process

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(vi) The calculation of the ICAP cost metric will be determined ~~in accordance with the NYISO manuals~~ as set forth below. The ICAP cost metric will be highly dependent on the rules and procedures guiding the calculation of the IRM, ~~and~~ LCR, and the ICAP Demand Curves, both for the next capability period and future capability periods. In each CARIS cycle, the ~~NY~~ISO will ~~work~~ review, with the ESPWG and, ~~to the extent needed, the ICAP Working Group~~as appropriate, other ISO committees, ~~to determine whether~~ the results of the ICAP cost metric ~~should be adjusted~~.

(A) ~~For the initial CARIS study cycle, t~~The ICAP metric, in the form of ~~will be based on~~ a megawatt impact, will be computed based on a methodology that: (1) determines the base system loss of load expectation ("LOLE") for the applicable horizon year; (2) adds the proposed economic project; and (3) calculates the LOLE for the system with the addition of the proposed economic project. If the system LOLE is lower than that of the base system, the NYISO will reduce generation in all New York Control Area ("NYCA") zones proportionally (*i.e.*, based on proportion of zonal capacity to total NYCA capacity) until the base system LOLE is achieved. That amount of reduced generation is the NYCA megawatt impact.

(B) The ISO will calculate both of the following ICAP cost metrics described in subsections (1) and (2) below by first determining the megawatt impact described above in (A) and then:

(1) For Rest of State, the ISO will measure the cost impact of a proposed economic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in Rest of State under the assumption that the proposed economic project is not in place, with that forecast based on the latest available ICAP Demand Curve for the NYCA and the amount of Installed Capacity available in the NYCA, as shown in the Load and Capacity table developed for that year; and (ii) multiplying that forecasted cost per megawatt-year for Rest of State in that year by the sum of the megawatt impact for all Load Zones contained within Rest of State, as calculated in accordance with subsection (A) of this Section 11.3.e(vi).

For each Locality, the ISO will measure the cost impact of a proposed economic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in that Locality under the assumption that the proposed economic project is not in place, with that forecast based on the latest available ICAP Demand Curve for that Locality and the amount of Installed Capacity available in that Locality as shown in the relevant Load and Capacity table developed for that year, and (ii) multiplying that forecasted cost per megawatt-year for that Locality in each year by the sum of the megawatt impact for all Load Zones contained within that Locality, as calculated in accordance with subsection (A) of this Section 11.3.e(vi).

This ICAP cost metric will then be presented for each applicable planning year as a stream of present value benefits for each Locality and for Rest of State. The applicable planning years start with the proposed commercial operation date of the proposed economic project and end ten years after the proposed commercial operation date of the proposed economic project.

(2) For Rest of State, the ISO will measure the cost impact of a proposed economic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in Rest of State under the assumption that the proposed economic project is in place, with that forecast based on the latest available ICAP Demand Curve for the NYCA and the amount of Installed Capacity available in the NYCA; (ii) subtracting that forecasted cost per megawatt-year from the forecasted cost per megawatt-year of Installed Capacity in Rest of State calculated in subsection (1) under the assumption that the proposed economic project is not in place; and (iii) multiplying that difference by fifty percent (50%) of the assumed amount of Installed Capacity available in Rest of State as calculated from the relevant Load and Capacity tables developed for the CARIS process.

For each Locality, the ISO will measure the cost impact of a proposed economic project for each planning year by: (i) forecasting the cost per megawatt-year of Installed Capacity in that Locality under the assumption that the proposed economic project is in place, with that forecast based on the latest available ICAP Demand Curve for that Locality and the amount of Installed Capacity available in that Locality as shown in the relevant Load and Capacity table developed for that year; (ii) subtracting the greater of that forecasted cost per megawatt-year with the proposed economic project in place or the forecasted Rest of State Installed Capacity cost per megawatt-year with the proposed economic project in place from the forecasted cost of Installed Capacity in that Locality calculated in subsection (1) under the assumption that the proposed economic project is not in place; and (iii) multiplying that difference by fifty percent (50%) of assumed amount of Installed Capacity available in that Locality, as taken from the relevant Load and Capacity tables developed for the CARIS process.

This ICAP cost metric will then be represented for each applicable planning year as a stream of present value benefits for each Locality and for Rest of State. The applicable planning years start with the proposed commercial operation date of the proposed economic project and end with the earlier of: (i) the year when the system, with the proposed economic project in place, reaches an LOLE of 0.1, or (ii) ten years after the proposed commercial operation date of the proposed economic project.

(3) The forecast of Installed Capacity costs per megawatt-year are developed by: first, escalating the Net Cost of New Entry ("CONE") for the NYCA or a Locality from the most recently completed ICAP Demand Curves for each year of the planning period; second, determining the future proxy Locational Minimum Installed Capacity Requirement or Minimum Installed Capacity Requirement for the NYCA as the actual amount of Installed Capacity in the Locality or the NYCA for the year that NYCA reaches 0.1 LOLE; third, reducing the cost per megawatt-year in each year from the escalated Net CONE to reflect the excess Installed Capacity from the Load and Capacity table above the future proxy Minimum Installed Capacity Requirement with the adjustment calculated from the excess and the slope of the ICAP Demand Curve.

The forecasts of Installed Capacity costs for Localities or Rest of State performed in subsections (1) and (2) above shall, in addition to the assumptions listed above, be based upon: (i) the forecasted Net CONE for the Locality (the NYCA in the case of the Rest of State forecast); (ii) the amount of Installed Capacity required to meet the future proxy Locational Minimum Installed Capacity Requirement (the Minimum Installed Capacity Requirement for the NYCA in the case of the Rest of State forecast); (iii) the slope of the relevant ICAP Demand Curve, and (iv) the smallest quantity where the cost of Installed Capacity on that ICAP Demand Curve reaches zero.

11.4 Planning Participant Data Input

At the NYISO's request, Market Participants, Developers and other parties shall provide, in accordance with the schedule set forth in the NYISO Comprehensive Reliability Planning Process Manual, the data necessary for the development of the CARIS. This input will include but not be limited to existing and planned additions to the New York State Transmission System (to be provided by Transmission Owners and municipal electric utilities); proposals for merchant transmission facilities (to be provided by merchant developers); generation additions and retirements (to be provided by generator owners and developers); demand response programs (to be provided by demand response providers); and any long-term firm transmission requests made to the NYISO. The relevant Transmissions Owners will assist the NYISO in developing the potential solution cost estimates to be used by the NYISO to conduct benefit/cost analysis of each of the potential solutions.

(iii) Net reductions in TCC revenues will reflect the forecasted impact of the project on TCC auction revenues and day-ahead residual congestion rents allocated to load in each zone, excluding the congestion rents that accrue to any Incremental TCCs that may be made feasible as a result of this project. This impact will include forecasts of: (1) the total impact of that project on the Transmission Service Charge offset applicable to loads in each zone (which may vary for loads in a given zone that are in different Transmission Districts); (2) the total impact of that project on the NYPA Transmission Adjustment Charge offset applicable to loads in that zone; and (3) the total impact of that project on payments made to LSEs serving load in that zone that hold Grandfathered Rights or Grandfathered TCCs, to the extent that these have not been taken into account in the calculation of item (1) above. ~~Calculations of net reductions in TCC revenues will be detailed in the NYISO manuals~~These forecasts shall be performed using the procedure described in Appendix B to this Attachment Y.

(iv) Estimated TCC revenues from any Incremental TCCs created by a proposed regulated economic transmission project over the ten-year period commencing with the project's commercial operation date will be added to the net load savings used for the cost allocation and beneficiary determination.

(v) The NYISO will solicit bilateral contract information from all Load Serving Entities, which will provide the NYISO with bilateral energy contract data for modeling contracts that ~~are~~ do not ~~indexed~~ receive benefits, in whole or in part, from~~to~~ LBMP reductions, and for which the time period covered by the contract is within the ten-year period beginning with the commercial operation date of the project. Bilateral contract payment information that is not provided to the NYISO will not be included in the calculation of the present value of the annual zonal LBMP savings in section (i) above. ~~Details regarding the information provided on bilateral contracts will be set forth in the NYISO manuals.~~

(A) All bilateral contract information submitted to the ISO must identify the source of the contract information, including citations to any public documents including but not limited to annual reports or regulatory filings

(B) All non-public bilateral contract information will be protected in accordance with the ISO's Code of Conduct, as set forth in Section 4.0 of Attachment F of the OATT, and Article 6 of the Services Tariff.

(C) All bilateral contract information and information on LSE-owned generation submitted to the ISO must include the following information:

(1) Contract quantities on an annual basis:

(a) For non-generator specific contracts, the Energy (in MWh) contracted to serve each Zone for each year.

(b) For generator specific contracts or LSE-owned generation, the name of the generator(s) and the MW or percentage output contracted or self-owned for use by Load in each Zone for each year.

(2) For all Load Serving Entities serving Load in more than one Load Zone, the quantity (in MWh or percentage) of bilateral contract Energy to be applied to each Zone, by year over the term of the contract.

(3) Start and end dates of the contract.

(4) Terms in sufficient detail to determine that either pricing is not indexed to LBMP, or, if pricing is indexed to LBMP, the manner in which prices are connected to LBMP.

(5) Identify any changes in the pricing methodology on an annual basis over the term of the contract.

(D) Bilateral contract and LSE-owned generation information will be used to calculate the adjusted LBMP savings for each Load Zone as follows:

$AdjLBMPS_{y,z}$, the adjusted LBMP savings for each Load Zone *z* in each year *y*, shall be calculated using the following equation:

$$AdjLBMPS_{y,z} = \max\left[0, TL_{y,z} - \sum_{b \in B_{y,z}} \left(BCL_{b,y,z} \cdot \left(1 - Ind_{b,y,z}\right)\right) - SG_{y,z}\right] \cdot \left(LBMP1_{y,z} - LBMP2_{y,z}\right),$$

Where:

$TL_{y,z}$ is the total annual amount of Energy forecasted to be consumed by Load in year *y* in Load Zone *z*;

$B_{y,z}$ is the set of blocks of Energy to serve Load in Load Zone *z* in year *y* that are sold under bilateral contracts for which information has been provided to the ISO that meets the requirements set forth elsewhere in this Section 15.4.b(v);

$BCL_{b,y,z}$ is the total annual amount of Energy sold into Load Zone *z* in year *y* under bilateral contract block *b*;

$Ind_{b,y,z}$ is the ratio of (1) the increase in the amount paid by the purchaser of Energy, under bilateral contract block *b*, as a result of an increase in the LBMP in Load Zone *z* in year *y* to (2) the increase in the amount that a purchaser of that amount of Energy would pay if the purchaser paid the LBMP for that Load Zone in that year for all of that Energy (this ratio shall be zero for any bilateral contract block of Energy that is sold at a fixed price or for which the cost of Energy purchased under that contract otherwise insensitive to the LBMP in Load Zone *z* in year *y*);

$SG_{y,z}$ is the total annual amount of Energy in Load Zone *z* that is forecasted to be served by LSE-owned generation in that Zone in year *y*;

$LBMP1_{y,z}$ is the forecasted annual Load-weighted average LBMP for Load Zone *z* in year *y*, calculated under the assumption that the project is not in place; and

$LBMP2_{y,z}$ is the forecasted annual Load-weighted average LBMP for Load Zone *z* in year *y*, calculated under the assumption that the project is in place.

(vi) NZS_z, the Net Zonal Savings for each Load Zone *z* resulting from a given project, shall be calculated using the following equation:

$$NZS_z = \max\left[0, \sum_{y=PS}^{PS+9}\left(\left(AdjLBMPS_{y,z} - TCCRevImpact_{y,z}\right) \cdot DF_y\right)\right],$$

Where:

PS is the year in which the project is expected to enter commercial operation;

$AdjLBMPS_{y,z}$ is as calculated in Section 15.4.b(v);~~.~~

$TCCRevImpact_{y,z}$ is the forecasted impact of TCC revenues allocated to Load Zone *z* in year *y*, calculated using the procedure described in Appendix B to this Attachment Y; and

DF_y is the discount factor applied to cash flows in year *y* to determine the present value of that cash flow in year *PS*.

c. Load zones not benefiting from a proposed project will not be allocated any of the costs of the project under this Attachment Y. There will be no “make whole” payments to non-beneficiaries.

APPENDIX B

PROCEDURE FOR FORECASTING THE NET REDUCTIONS IN TCC REVENUES THAT WOULD RESULT FROM A PROPOSED PROJECT

For the purpose of determining the allocation of costs associated with a proposed project as described in Section 15.4.b of this Attachment Y, the ISO shall use the procedure described herein to forecast the net reductions in TCC revenues allocated to Load in each Load Zone as a result of a proposed project.

Definitions

The following definitions will apply to this appendix:

Pre-CARIS Centralized TCC Auction: The last Centralized TCC Auction that had been completed as of the date the input assumptions were determined for the CARIS in which the Project was identified as a candidate for development under the provisions of this Attachment Y.

Project: The proposed transmission project for which the evaluation of the net benefits forecasted for Load in each Load Zone, as described in Section 15.4.b of this Attachment Y, is being performed.

TCC Revenue Factor: A factor that is intended to reflect the expected ratio of (1) revenue realized in the TCC auction from the sale of a TCC to (2) the Congestion Rents that a purchaser of that TCC would expect to realize. The value to be used for the TCC Revenue Factor shall be stated in the ISO Procedures.

Steps 1 Through 6 of the Procedure

For each Project, the ISO will perform Steps 1 through 6 of this procedure twice for each of the ten (10) years following the proposed commercial operation date of the Project: once under the assumption that the Project is in place in each of those years, and once under the assumption that the Project is not in place in each of those years.

Forecasting the Value of Grandfathered TCCs and TCC Auction Revenue

Step 1. The ISO shall forecast Congestion Rents collected on the New York electricity system in each year, which shall be equal to:

(a) the product of:

(i) the forecasted Congestion Component of the Day-Ahead LBMP for each hour at each Load Zone or Proxy Generator Bus and

(ii) forecasted withdrawals scheduled in that hour in that Load Zone or Proxy Generator bus,

summed over all locations and over all hours in that year, minus:

(b) the product of:

(i) the forecasted Congestion Component of the Day-Ahead LBMP for each hour at each Generator bus or Proxy Generator Bus and

(ii) forecasted injections scheduled in that hour at that Generator bus or Proxy Generator Bus,

summed over all locations and over all hours in that year.

Step 2. The ISO shall forecast:

(a) payments in each year associated with any Incremental TCCs that the ISO projects would be awarded in conjunction with that Project (which will be zero for the calculation that is performed under the assumption that the Project is not in place);

(b) payments in each year associated with any Incremental TCCs that the ISO has awarded, or that the ISO projects it would award, in conjunction with other projects that have entered commercial operation or are expected to enter commercial operation before the Project enters commercial operation; and

(c) payments that would be made to holders of Grandfathered Rights and imputed payments that would be made to the Primary Holders of Grandfathered TCCs that would be in effect in each year, under the following assumptions:

(i) all Grandfathered Rights and Grandfathered TCCs expire at their stated expiration dates;

(ii) imputed payments to holders of Grandfathered Rights are equal to the payments that would be made to the Primary Holder of a TCC with the same Point of Injection and Point of Withdrawal as that Grandfathered Right; and

(iii) in cases where a Grandfathered TCC is listed in Table 1 of Attachment M of the OATT, the number of those TCCs held by their Primary Holders shall be set to the number of such TCCs remaining at the conclusion of the ETCNL reduction procedure conducted before the Pre-CARIS Centralized TCC Auction.

Step 3. The ISO shall forecast TCC auction revenues for each year by subtracting:

(a) the forecasted payments calculated for that year in Steps 2(a), 2(b) and 2(c) of this procedure

from:

(b) the forecasted Congestion Rents calculated for that year in Step 1 of this procedure, and multiplying the difference by the TCC Revenue Factor.

Forecasting the Allocation of TCC Auction Revenues Among the Transmission Owners

Step 4. The ISO shall forecast the following:

(a) payments in each year to the Primary Holders of Original Residual TCCs and

(b) payments in each year to the Primary Holders of TCCs that correspond to the amount of ETCNL remaining at the conclusion of the ETCNL reduction procedure conducted before the Pre-CARIS Centralized TCC Auction,

and multiply each by the TCC Revenue Factor to determine the forecasted payments to the Primary Holders of Original Residual TCCs and the Transmission Owners that have been allocated ETCNL.

Step 5. The ISO shall forecast residual auction revenues for each year by subtracting:

(a) the sum of the forecasted payments for each year to the Primary Holders of Original Residual TCCs and the Transmission Owners that have been allocated ETCNL, calculated in Step 4 of this procedure

from:

(b) forecasted TCC auction revenues for that year calculated in Step 3 of this procedure.

Step 6. The ISO shall forecast each Transmission Owner's share of residual auction revenue for each year by multiplying:

(a) the forecast of residual auction revenue calculated in Step 5 of this procedure and

(b) the ratio of:

(i) the amount of residual auction revenue allocated to that Transmission Owner in the Pre-CARIS Centralized TCC Auction to

(ii) the total amount of residual auction revenue allocated in the Pre-CARIS Centralized TCC Auction.

Steps 7 Through 10 of the Procedure

The ISO will perform Steps 7 through 10 of this procedure once for each of the ten (10) years following the proposed commercial operation date of the Project, using the results of the preceding calculations performed both under the assumption that the Project is in place in each of those years, and under the assumption that the Project is not in place in each of those years.

Forecasting the Impact of the Project on TSC Offsets and the NTAC Offset

Step 7. The ISO shall calculate the forecasted net impact of the Project on the TSC offset for each megawatt-hour of electricity consumed by Load in each Transmission District (other than the NYPA Transmission District) in each year by:

(a) summing the following, each forecasted for that Transmission District for that year under the assumption that the Project is in place:

(i) forecasted Congestion Rents associated with any Incremental TCCs that the ISO has awarded, or that the ISO projects it would award, as calculated in Step 2(b) of this procedure, in conjunction with other projects that have entered commercial operation or are expected to enter commercial operation before the Project enters commercial operation, if those Congestion Rents would affect the TSC for that Transmission District;

(ii) forecasted Congestion Rents associated with any Grandfathered TCCs and forecasted imputed Congestion Rents associated with any Grandfathered Rights held by the Transmission Owner serving that Transmission District that would be paid to that Transmission Owner for that year, as calculated in Step 2(c) of this procedure, if those Congestion Rents would affect the TSC for that Transmission District;

(iii) the payments that are forecasted to be made for that year to the Primary Holders of Original Residual TCCs and ETCNL that have been allocated to the Transmission Owner serving that Transmission District, as calculated in Step 4 of this procedure; and

(iv) that Transmission District's forecasted share of residual auction revenues for that year, as calculated in Step 6 of this procedure for the Transmission Owner serving that Transmission District;

(b) subtracting the sum of items (i) through (iv) above, each forecasted for that Transmission District for that year under the assumption that the Project is not in place; and

(c) dividing this difference by the amount of Load forecasted to be served in that Transmission District in that year, stated in terms of megawatt-hours, net of any Load served by municipally owned utilities that is not subject to the TSC.

Step 8. The ISO shall calculate the forecasted net impact of the Project on the NTAC offset for each megawatt-hour of electricity consumed by Load in each year by:

(a) summing the following, each forecasted for that year under the assumption that the Project is in place:

(i) forecasted Congestion Rents associated with any Incremental TCCs that the ISO has awarded, or that the ISO projects it would award, as calculated in Step 2(b) of this procedure, in conjunction with other projects that have entered commercial operation or are expected to enter commercial operation before the Project enters commercial operation, if those Congestion Rents would affect the NTAC;

(ii) forecasted Congestion Rents associated with any Grandfathered TCCs and forecasted imputed Congestion Rents associated with any Grandfathered Rights held by NYPA that would be paid to NYPA for that year, as calculated in Step 2(c) of this procedure, if those Congestion Rents would affect the NTAC;

(iii) the payments that are forecasted to be made for that year to NYPA in association with Original Residual TCCs allocated to NYPA, as calculated in Step 4 of this procedure; and

(iv) NYPA's forecasted share of residual auction revenues for that year, as calculated in Step 6 of this procedure;

(b) subtracting the sum of items (i) through (iv) above, each forecasted for that year under the assumption that the Project is not in place; and

(c) dividing this difference by the amount of Load expected to be served in the NYCA in that year, stated in terms of megawatt-hours, net of any Load served by municipally owned utilities that is not subject to the NTAC.

Forecasting the Net Impact of the Project on TCC Revenues Allocated to Load in Each Zone

Step 9. The ISO shall calculate the forecasted net impact of the Project in each year in each Load Zone on payments made in conjunction with TCCs and Grandfathered Rights that benefit Load but which do not affect TSCs or the NTAC, which shall be the sum of:

(a) Forecasted Congestion Rents paid or imputed to municipally owned utilities serving Load in that Load Zone that own Grandfathered Rights or Grandfathered TCCs that were not included in the calculation of the TSC offset in Step 7(a)(ii) of this procedure or the NTAC offset in Step 8(a)(ii) of this procedure, which the ISO shall calculate by:

(i) summing forecasted Congestion Rents that any such municipally owned utilities serving Load in that Load Zone would be paid for that year in association with any such Grandfathered TCCs and any forecasted imputed Congestion Rents that such a municipally owned utility would be paid for that year in association with any such Grandfathered Rights, as calculated in Step 2(c) of this procedure under the assumption that the Project is in place; and

(ii) subtracting forecasted Congestion Rents that any such municipally owned utilities would be paid for that year in association with any such Grandfathered TCCs, and any forecasted imputed Congestion Rents that such a municipally owned utility would be paid for that year in association with any such Grandfathered Rights, as calculated in Step 2(c) of this procedure under the assumption that the Project is not in place.

(b) Forecasted Congestion Rents collected from Incremental TCCs awarded in conjunction with projects that were previously funded through this procedure, if those Congestion Rents are used to reduce the amount that Load in that Load Zone must pay to fund such projects, which the ISO shall calculate by:

(i) summing forecasted Congestion Rents that would be collected for that year in association with any such Incremental TCCs, as calculated in Step 2(b) of this procedure under the assumption that the Project is in place; and

(ii) subtracting forecasted Congestion Rents that would be collected for that year in association with any such Incremental TCCs, as calculated in Step 2(b) of this procedure under the assumption that the Project is not in place.

Step 10. The ISO shall calculate the forecasted net reductions in TCC revenues allocated to Load in each Load Zone as a result of a proposed Project by summing the following:

(a) the product of:

(i) the forecasted net impact of the Project on the TSC offset for each megawatt-hour of electricity consumed by Load, as calculated for each Transmission District (other than the NYPA Transmission District) in Step 7 of this procedure; and

(ii) the number of megawatt-hours of energy that are forecasted to be consumed by Load in that year, in the portion of that Transmission District that is in that Load Zone, for Load that is subject to the TSC;

summed over all Transmission Districts;

(b) the product of:

(i) the forecasted net impact of the Project on the NTAC offset for each megawatt-hour of electricity consumed by Load, as calculated in Step 8 of this procedure; and

(ii) the number of megawatt-hours of energy that are forecasted to be consumed by Load in that year in that Load Zone, for Load that is subject to the NTAC; and

(c) the forecasted net impact of the Project on payments and imputed payments made in conjunction with TCCs and Grandfathered Rights that benefit Load but which do not affect TSCs or the NTAC, as calculated in Step 9 of this procedure.

Additional Notes Concerning the Procedure

For the purposes of Steps 2(c) and 4(b) of this procedure, the ISO will utilize the currently effective version of Attachment L of the OATT to identify Existing Transmission Agreements and Existing Transmission Capacity for Native Load.

Each Transmission Owner, other than NYPA, will inform the ISO of any Grandfathered Rights and Grandfathered TCCs it holds whose Congestion Rents should be taken into account in Step 7 of this procedure because those Congestion Rents affect its TSC.

NYPA will inform the NYISO of any Grandfathered Rights and Grandfathered TCCs it holds whose Congestion Rents should be taken into account in Step 8 of this procedure because those Congestion Rents affect the NTAC.

Attachment III

ATTACHMENT III

Example Illustrating the Appendix B Procedure for Forecasting the Net Reductions in TCC Revenues That Would Result from a Project

Assumptions

This example is limited to a single hour, instead of examining multiple years. It also ignores all transmission losses and all transmission congestion within zones; consequently, all differences in LBMP are attributable to transmission congestion between zones. It assumes that all load is subject to the NTAC and to the TSC for the Transmission District in which it is located; that all revenues from Grandfathered TCCs held by Transmission Owners other than NYPA affect the TSC offset; and that all revenues from Grandfathered TCCs held by NYPA affect the NTAC offset. It also assumes that there are no imports or exports.

In addition, the following simplifying assumptions apply:

- There are three zones, and two Transmission Districts (not counting the NYPA Transmission District, which is assumed not to serve any load). Forecasted loads for each of the zones and Transmission Districts for this hour are as follows:

Load (MWh)				
	Zone X	Zone Y	Zone Z	NYCA
Transmission District 1	-	2,000	6,000	8,000
Transmission District 2	6,000	4,000	2,000	12,000
Total	**6,000**	**6,000**	**8,000**	**20,000**

- If the project is put in place, it will permit an additional 2000 MW to be transferred from Zone X to Zone Z. As a result, it is projected that the project will permit 2000 Incremental TCCs from Zone X to Zone Z to be defined.

- If the project is not put in place, it is forecasted that the amount of energy generated in each zone and the day-ahead LBMPs in each zone will be as follows:

LBMPs and Generation Without Project in Place				
	Zone X	Zone Y	Zone Z	NYCA
LBMP ($/MWh)	$ 30	$ 45	$ 50	
Generation (MWh)	10,000	5,000	5,000	20,000

- If the project is put in place, it is forecasted that the amount of energy generated in each zone and the day-ahead LBMPs for this hour in each zone will be as follows:

LBMPs and Generation With Project in Place				
	Zone X	Zone Y	Zone Z	NYCA
LBMP ($/MWh)	$ 32	$ 42	$ 42	
Generation (MWh)	12,000	4,500	3,500	20,000

- The Transmission Owner serving Transmission District 2 has 500 MW of Grandfathered TCCs with an injection location of Zone X and a withdrawal location of Zone Z.

- NYPA has 600 MW of Grandfathered TCCs with an injection location of Zone Y and a withdrawal location of Zone Z.

- Municipally owned utilities serving load in Zone Y have 100 MW of Grandfathered TCCs with an injection location of Zone X and a withdrawal location of Zone Y.

- After the application of the ETCNL reduction process in the Centralized TCC Auction preceding the most recently conducted CARIS, the Transmission Owner serving Transmission District 1 has 1500 MW of ETCNL remaining with an injection location of Zone X and a withdrawal location of Zone Z.

- There are no Grandfathered Rights or Original Residual TCCs, nor have any Incremental TCCs been allocated in association with earlier transmission projects.

- The TCC Revenue Factor is 0.9.

- In the Centralized TCC Auction preceding the most recently conducted CARIS, 60 percent of residual auction revenues were allocated to Transmission Owner 1, 30 percent were allocated to Transmission Owner 2, and 10 percent were allocated to NYPA.

Forecasts Performed Under the Assumption the Project Is Not in Place

Step 1: Forecasted Congestion Rents

Given the forecasted day-ahead LBMPs, generation and load without the project in place, forecasted congestion rents are simply equal to the difference between the amount paid by load in each zone and the amount paid to generation in that zone. As the table below demonstrates, $75,000 in congestion rents are collected in this example if the project is not in place.

Congestion Rents Collected Without Project in Place				
	Zone X	**Zone Y**	**Zone Z**	**NYCA**
LBMP ($/MWh)	$ 30	$ 45	$ 50	
Generation (MWh)	10,000	5,000	5,000	20,000
Load (MWh)	6,000	6,000	8,000	20,000
LBMP Revenue for Generators	$ 300,000	$ 225,000	$ 250,000	$ 775,000
LBMP Payments by Load	$ 180,000	$ 270,000	$ 400,000	$ 850,000
Congestion Rents				**$ 75,000**

Step 2: Forecasted Payments to Holders of Grandfathered TCCs

Given the forecasted day-ahead LBMPs, the ISO would forecast that holders of Grandfathered TCCs would receive $14,500 in payments, as calculated in the table below.

Grandfathered TCC Revenue Without Project in Place				
	Quantity	**POI**	**POW**	**Revenue**
Transmission Owner 2	500	X	Z	$ 10,000
NYPA	600	Y	Z	3,000
Municipally Owned Utilities	100	X	Y	1,500
Total				**$ 14,500**

Step 3: Forecasted TCC Auction Revenues

Without the project in place, congestion rents net of payments to holders of Grandfathered TCCs are forecasted to be $75,000 – $14,500 = $60,500. Forecasted TCC auction revenues are simply $60,500 times the TCC Revenue Factor (0.9), or $54,450.

Step 4: Forecasted Payments to Transmission Owners that Have Been Allocated ETCNL

Transmission Owner 1 is the only Transmission Owner that has been allocated ETCNL. Given the forecasted day-ahead LBMPs without the project in place, the holder of 1500 TCCs with an injection location of Zone X and a withdrawal location of Zone Z would be paid 1500 × ($50/MWh – $30/MWh) = $30,000 in this hour. Therefore, it is forecasted that Transmission Owner 1 would receive 0.9 × $30,000 = $27,000 in ETCNL payments, since it is forecasted that TCCs would sell for 90 percent of the congestion rents that a holder of those TCCs would expect to receive.

Step 5: Forecasted Residual Auction Revenues

Forecasted residual auction revenues without the project in place are simply equal to the forecasted TCC auction revenues ($54,450) minus forecasted payments to Transmission Owners with ETCNL ($27,000), or $27,450.

Step 6: Forecasted Share of Residual Auction Revenues for Each Transmission Owner

Based on the past allocation of residual auction revenues, it is forecasted that without the project in place, Transmission Owner 1 would be allocated 60% × $27,450 = $16,470 in residual auction revenues, Transmission Owner 2 would be allocated 30% × $27,450 = $8235 in residual auction revenues, and NYPA would be allocated 10% × $27,450 = $2745 in residual auction revenues.

Forecasts Performed Under the Assumption the Project Is in Place

Step 1: Forecasted Congestion Rents

Given the forecasted day-ahead LBMPs, generation and load with the project in place, forecasted congestion rents are simply equal to the difference between the amount paid by load in each zone and the amount paid to generation in that zone. As the table below demonstrates, $60,000 in congestion rents are collected in this example if the project is not in place, which is $15,000 less than the forecast of congestion rents collected in this hour without the project in place.

Congestion Rents Collected With Project in Place				
	Zone X	**Zone Y**	**Zone Z**	**NYCA**
LBMP ($/MWh)	$ 32	$ 42	$ 42	
Generation (MWh)	12,000	4,500	3,500	20,000
Load (MWh)	6,000	6,000	8,000	20,000
LBMP Revenue for Generators	$ 384,000	$ 189,000	$ 147,000	$ 720,000
LBMP Payments by Load	$ 192,000	$ 252,000	$ 336,000	$ 780,000
Congestion Rents				**$ 60,000**

Step 2: Forecasted Payments to Holders of Incremental TCCs and Grandfathered TCCs

Given the forecasted day-ahead LBMPs, the ISO would forecast that holders of the 2000 Incremental TCCs from Zone X to Zone Z to be defined in association with this project would receive 2000 × ($42/MWh – $32/MWh) = $20,000 in this hour, while holders of Grandfathered TCCs would receive $6000 in payments, as calculated in the table below, $8500 less than they were forecasted to receive without the project in place.

Grandfathered TCC Revenue With Project in Place				
	Quantity	**POI**	**POW**	**Revenue**
Transmission Owner 2	500	X	Z	$ 5,000
NYPA	600	Y	Z	-
Municipally Owned Utilities	100	X	Y	1,000
Total				**$ 6,000**

Step 3: Forecasted TCC Auction Revenues

With the project in place, congestion rents net of payments to holders of Incremental TCCs associated with the project and Grandfathered TCCs are forecasted to be $60,000 –$20,000 – $6000 = $34,000. Forecasted TCC auction revenues are simply $34,000 times the TCC Revenue Factor (0.9), or $30,600.

Step 4: Forecasted Payments to Transmission Owners that Have Been Allocated ETCNL

Transmission Owner 1 is the only Transmission Owner that has been allocated ETCNL. Given the forecasted day-ahead LBMPs with the project in place, the holder of 1500 TCCs with an injection location of Zone X and a withdrawal location of Zone Z would be paid 1500 × ($42/MWh – $32/MWh) = $15,000 in this hour. Therefore, it is forecasted that Transmission Owner 1 would receive 0.9 × $15,000 = $13,500 in ETCNL payments, since it is forecasted that TCCs would sell for 90 percent of the congestion rents that a holder of those TCCs would expect to receive. This is half of the amount it would have received without the project in place.

Step 5: Forecasted Residual Auction Revenues

Forecasted residual auction revenues with the project in place are simply equal to the forecasted TCC auction revenues ($30,600) minus forecasted payments to Transmission Owners with ETCNL ($13,500), or $17,100.

Step 6: Forecasted Share of Residual Auction Revenues for Each Transmission Owner

Based on the past allocation of residual auction revenues, it is forecasted that without the project in place, Transmission Owner 1 would be allocated 60% × $17,100 = $10,260 in residual auction revenues, Transmission Owner 2 would be allocated 30% × $17,100 = $5130 in residual auction revenues, and NYPA would be allocated 10% × $17,100 = $1710 in residual auction revenues.

Forecasts That Compare Values Calculated Under the Assumption the Project Is Not in Place to Values Calculated Under the Assumption the Project Is in Place

Step 7: Forecasted Impact of the Project on the TSC Offset for Each Transmission Owner

As the table below illustrates, with the project in place, TSC offsets for Transmission District 1, which consist of forecasted ETCNL payments received by Transmission Owner 1 and Transmission Owner 1's forecasted share of residual auction revenues, sum to $23,760 for this hour. Without the project in place, these TSC offsets summed to $43,470, so the project has caused a $19,710 reduction in TSC offsets, or approximately $2.46/MWh for the 8000 MWh of load forecasted to be served in Transmission District 1 in this hour. Similarly, the project has caused a forecasted reduction of $8105 in TSC offsets for Transmission District 2 (which include forecasted payments to Transmission Owner 2 for its Grandfathered TCCs and Transmission Owner 2's forecasted share of residual auction revenues), or approximately $0.68/MWh for the 12,000 MWh of load forecasted to be served in Transmission District 1 in this hour.

Impact of Project on TSC Offsets

	With Project in Place				Without Project in Place				Difference	
	Grand-fathered TCC Revenue	ETCNL Payments	Residual Auction Revenues	Total	Grand-fathered TCC Revenue	ETCNL Payments	Residual Auction Revenues	Total	$	$/MWh
Transmission District 1	$ -	$ 13,500	$ 10,260	$ 23,760	$ -	$ 27,000	$ 16,470	$ 43,470	$(19,710)	$ (2.46)
Transmission District 2	$ 5,000	$ -	$ 5,130	$ 10,130	$ 10,000	$ -	$ 8,235	$ 18,235	$ (8,105)	$ (0.68)

Step 8: Forecasted Impact of the Project on the NTAC

As the table below illustrates, with the project in place, NTAC offsets, which consist of forecasted payments to NYPA for its Grandfathered TCCs and NYPA's forecasted share of residual auction revenues, sum to $1710 for this hour. Without the project in place, these TSC offsets summed to $5745, so the project has caused a forecasted reduction of $4035 in NTAC offsets, or approximately $0.20/MWh for the 20,000 MWh of load forecasted to be served in the NYCA in this hour.

Impact of Project on NTAC Offset							
With Project in Place			Without Project in Place			Difference	
Grand-fathered TCC Revenue	Residual Auction Revenues	Total	Grand-fathered TCC Revenue	Residual Auction Revenues	Total	$	$/MWh
-	1,710	1,710	3,000	2,745	5,745	(4,035)	$ (0.20)

Step 9: Forecasted Impact of the Project on Grandfathered TCCs Held by Municipally Owned Utilities

Above, in Step 2, the ISO forecasted that municipally owned utilities would receive $1500 in this hour in payments for the Grandfathered TCCs they hold if the project is not in place, which falls to $1000 if the project is in place. Therefore, the project causes a $500 drop in these payments.

Step 10: Forecasted Net Impact of the Project on TCC Revenues Allocated to Loads in Each Zone

The forecasted net impact of the project on TCC revenues allocated to load in each zone is the sum of the impact of the project on the TSCs paid by load in that zone, the impact of the project on NTACs paid by load in that zone, and the impact of the project on grandfathered TCCs held by municipally owned utilities serving load in that zone. As the table below illustrates, the impact of the project on TSCs and NTACs paid by load in each zone is, in turn, equal to the impact of that project on the TSC and NTAC offsets times the forecasted amount of load in that zone that is subject to that TSC or the NTAC. In this example, since three-fourths of Transmission District 1's load is in Zone Z, three-fourths of the $19,710 impact of the project on Transmission Owner 1's TSC affects load in Zone Z; the remaining impact on Transmission Owner 1's TSC affects load in Zone Y. In contrast, Zones X and Y bear larger shares of the impact of the project on Transmission Owner 2's TSC and the NTAC, but since the project had less of an impact on those charges, the impact of the project on loads in those zones is smaller. Consequently, of the $32,350 total impact of the project on TCC revenues allocated to loads, more than half of the impact falls on load in Zone Z, even though it only includes 40 percent of the load in the NYCA.

Net Impact of Project on TCC Revenues Allocated to Load in Each Zone				
	Zone X	Zone Y	Zone Z	NYCA
TSC Offset for Transmission District 1				
$/MWh Net Impact	$ (2.46)	$ (2.46)	$ (2.46)	
Load Subject to TSC for TD 1	-	2,000	6,000	
Net Impact	$ -	$ (4,928)	$ (14,783)	**$ (19,710)**
TSC Offset for Transmission District 2				
$/MWh Net Impact	$ (0.68)	$ (0.68)	$ (0.68)	
Load Subject to TSC for TD 2	6,000	4,000	2,000	
Net Impact	$ (4,053)	$ (2,702)	$ (1,351)	**$ (8,105)**
NTAC Offset				
$/MWh Net Impact	$ (0.20)	$ (0.20)	$ (0.20)	
Load Subject to NTAC	6,000	6,000	8,000	
Net Impact	$ (1,211)	$ (1,211)	$ (1,614)	**$ (4,035)**
Payments for Grandfathered TCCs Held by Municipally Owned Utilities	$ -	$ (500)	$ -	**$ (500)**
Net Impact on TCC Revenues	**$ (5,263)**	**$ (9,340)**	**$ (17,747)**	**$ (32,350)**

Determining the Net Beneficiaries of the Project

As Sections 15.4.b(i) and (ii) of Attachment Y provide, loads that are net beneficiaries of the project will be determined by subtracting the net impact of the project on TCC revenues allocated to load in each zone from the reduction in LBMP payments that would be made by load in that zone. If the net benefit is negative, load in that zone is not a net beneficiary.

The project causes LBMPs to decrease in this hour for Zones Y and Z, while causing the LBMP to increase for Zone X. Consequently, loads in Zone X do not benefit from the project. Loads in Zones Y and Z benefit. The net benefit for loads in each of these zones is calculated by subtracting the net reduction in TCC revenues allocated to loads in each of those zones from the reduction in LBMP payments that the ISO forecasts would result from this project. As a result, load in Zone Y is left with slightly less than $9000 in net benefits in this hour, while load in Zone Z is forecasted to realize over $46,000 in net benefits. Therefore, load in Zone Z will realize approximately five-sixths of the net benefits forecasted for this project for zones where load is expected to realize net benefits.

Net Benefit for Load in Each Zone			
	Zone X	Zone Y	Zone Z
LBMP Payment with Project in Place	$ 192,000	$ 252,000	$ 336,000
LBMP Payment without Project in Place	$ 180,000	$ 270,000	$ 400,000
Impact of Project on Energy Payments	**$ (12,000)**	**$ 18,000**	**$ 64,000**
Net Impact on TCC Revenues	$ (5,263)	$ (9,340)	$ (17,747)
Net Benefit for Load	**$ (17,263)**	**$ 8,660**	**$ 46,253**
Percentage of Net Benefit (When Positive)	**0.0%**	**15.8%**	**84.2%**