

Attachment IV

6.1 Schedule 1 - ISO Annual Budget Charge and Other Non-Budget Charges and Payments

6.1.1 Introduction

The ISO shall bill each Transmission Customer each Billing Period to recover the ISO's annual budgeted costs as set forth in Article 6.1.2 of this Rate Schedule 1.

The ISO shall separately bill each Transmission Customer under this Rate Schedule 1 for certain other charges and payments not related to the ISO annual budget charge. Specifically, the ISO shall bill each Transmission Customer on a quarterly basis to recover NERC and NPCC charges as set forth in Article 6.1.3 of this Rate Schedule 1. The ISO shall also bill each Transmission Customer each Billing Period to recover the following costs or allocate the following received payments under this Rate Schedule 1:

- (i) bad debt loss charges as set forth in Article 6.1.4;
- (ii) Working Capital Fund charges as set forth in Article 6.1.5;
- (iii) non-ISO facilities payment charges as set forth in Article 6.1.6;
- (iv) charges to recover costs for payments made to Suppliers pursuant to incremental cost recovery for units that responded to Local Reliability Rules I-R3 and I-R5 as set forth in Article 6.1.7;
- (v) charges to recover and payments to allocate residual costs as set forth in Article 6.1.8;
- (vi) charges for Special Case Resources and Curtailment Service Providers called to meet reliability needs as set forth in Article 6.1.9;
- (vii) charges to recover DAMAP costs as set forth in Article 6.1.10;

- (viii) charges to recover Import Curtailment Guarantee Payment costs as set forth in Article 6.1.11;
- (ix) charges to recover Bid Production Cost guarantee payment costs as set forth in Article 6.1.12;
- (x) charges to recover and payments to allocate settlements of disputes as set forth in Article 6.1.13; and
- (xi) payments to allocate financial penalties collected by the ISO as set forth in Article 6.1.14.

Transmission Customers who are retail access customers being served by an LSE shall not pay these charges to the ISO; the LSE shall pay these charges.

6.1.2 ISO Annual Budget Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge for the ISO's recovery of its annual budgeted costs. The ISO annual budgeted costs that are recoverable through this Rate Schedule 1 are set forth in Section 6.1.2.1 of this Rate Schedule 1. The ISO shall calculate the charge for the recovery of these ISO annual budgeted costs from each Transmission Customer on the basis of its participation in physical market activity as indicated in Section 6.1.2.2 of this Rate Schedule 1. The ISO shall calculate this charge for each Transmission Customer on the basis of its participation in non-physical market activity, the Special Case Resource program, and the Emergency Demand Response program as indicated in Section 6.1.2.4 of this Rate Schedule 1. The ISO shall use the revenue collected through Section 6.1.2.4 of this Rate Schedule 1 to recover any of its annual budgeted costs for the immediately preceding calendar year that it has not already recovered under Section 6.1.2.2 of this Rate Schedule for that year. The ISO shall credit any additional revenue collected through Section

6.1.2.4 of this Rate Schedule 1 for the remainder of the calendar year to each Transmission Customer on the basis of its physical market activity as indicated in Section 6.1.2.5 of this Rate Schedule 1.

6.1.2.1 ISO Annual Budgeted Costs

The ISO annual budgeted costs to be recovered through Article 6.1.2 of this Rate Schedule 1 include, but are not limited to, the following costs associated with the operation of the NYS Transmission System by the ISO and the administration of the ISO Tariffs and ISO Related Agreements by the ISO:

- Processing and implementing requests for Transmission Service including support of the ISO OASIS node;
- Coordination of Transmission System operation and implementation of necessary control actions by the ISO and support for these functions;
- Performing centralized security constrained dispatch to optimally re-dispatch the NYS Power System to mitigate transmission Interface overloads and provide balancing services;
- Costs related to the ISO's administration and operation of the LBMP market and all other markets administered by the ISO;
- Costs related to the ISO's administration of Control Area Services;
- Costs related to the ISO's administration of the ISO's Market Power Mitigation Measures and the ISO's Market Monitoring Plan;
- Costs related to the maintenance of reliability in the NYCA;
- Costs related to the provision of Transmission Service;
- Preparation of settlement statements;
- NYS Transmission System studies, when the costs of the studies are not recoverable from a Transmission Customer;
- Engineering services and operations planning;
- Data and voice communications network service coordination;

- Metering maintenance and calibration scheduling;
- Record keeping and auditing;
- Training of ISO personnel;
- Development and maintenance of information, communication and control systems;
- Professional services;
- Carrying costs on ISO assets, capital requirements and debts;
- Tax expenses, if any;
- Administrative and general expenses;
- Insurance premiums and deductibles related to ISO operations;
- Any indemnification of or by the ISO pursuant to Section 2.11.2 of this ISO OATT or Section 12.4 of the Services Tariff;
- Regulatory fees; and
- The ISO's share of the expenses of Northeast Power Coordinating Council, Inc. or its successor.

6.1.2.2 Calculation of the ISO Annual Budget Charge for Transmission Customers Participating in Physical Market Activity

The ISO shall charge, and each Transmission Customer that participates in physical market activity shall pay, an ISO annual budget charge each Billing Period as calculated according to the following formula.

$$\text{ISO Annual Budget Charge}_{c,p} = \left(\text{InjectionUnits}_{c,p} \times \left(0.28 \times \frac{\text{ISOCosts}_{\text{Annual}}}{\text{TotalEstWithdrawalUnits}_{\text{Annual}}} \right) \right) + \left(\text{WithdrawalUnits}_{c,p} \times \left(0.72 \times \frac{\text{ISOCosts}_{\text{Annual}}}{\text{TotalEstWithdrawalUnits}_{\text{Annual}}} \right) \right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

ISO Annual Budget Charge $_{c,P}$ = The amount, in \$, of the ISO annual budgeted costs for which Transmission Customer c is responsible for Billing Period P .

ISOCosts $_{\text{Annual}}$ = The sum, in \$, of the ISO's annual budgeted costs for the current calendar year.

InjectionUnits $_{c,P}$ = The Injection Billing Units, in MWh, for Transmission Customer c in Billing Period P , except for Scheduled Energy Injections resulting from CTS Interface Bids.

WithdrawalUnits $_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in Billing Period P , except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

TotalEstWithdrawalUnits $_{\text{Annual}}$ = The sum, in MWh, of estimated Withdrawal Billing Units for all Transmission Customers in the current calendar year as determined by the ISO in the summer prior to the current calendar year, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

6.1.2.3 Review and Modification of the ISO Annual Budget Charge Allocation Methodology

The current 72%/28% cost allocation methodology between Withdrawal Billing Units and Injection Billing Units for the ISO annual budget charge shall remain unchanged through at least December 31, 2016 and shall continue to remain unchanged until such point in time that a study is conducted and the results of the study warrant changing the 72%/28% cost allocation. The following provisions prescribe the process and timeline for the review and, if warranted by the results of a future study, modification of the 72%/28% cost allocation on a going forward basis:

- (i) A vote of the Management Committee will be taken in the third calendar quarter of 2015 on whether a new study should be conducted during late-2015 and 2016 to allow modification of the 72%/28% cost allocation, if warranted by the results of the study, to be implemented by January 1, 2017. A positive vote by 58% of

the Management Committee will be required to go forward with the study, but there will no longer be a “material change” standard as was historically applied to the determination of whether a study should be conducted.

- (ii) If the Management Committee vote discussed in (i) above determines that a study should not be conducted, the 72%/28% cost allocation between Withdrawal Billing Units and Injection Billing Units shall be extended through at least December 31, 2017. In the third calendar quarter of 2016, a vote will be taken on whether a new study should be conducted during late-2016 and 2017 to allow modification of the percentage allocation, if warranted by the results of the study, to be implemented by January 1, 2018. Unless a 58% vote of the Management Committee is registered in favor of declining to go forward with the study, the study will be conducted.
- (iii) If the Management Committee vote in the third calendar quarter of 2016 discussed in (ii) above determines that a study should not be conducted, the current 72%/28% cost allocation shall remain unchanged until such point in time as the Management Committee determines that a study shall be conducted and the results of that study warrant changing the percentage allocation between Withdrawal Billing Units and Injection Billing Units. If the Management Committee vote in the third calendar quarter of 2016 discussed in (ii) above determines that a study should not be conducted, the Management Committee will revisit the issue of conducting a study annually in the third calendar quarter of each year using the same voting standard (*i.e.* the study shall be performed unless 58% of the Management Committee votes not to commission the study) that was

applied to the Management Committee vote in the third calendar quarter of 2016 discussed in (ii) above.

- (iv) If, and when, the Management Committee determines a study shall be conducted:
 - (a) Such study shall be completed, and the results thereof shared with Market Participants, before the end of the second calendar quarter of the year prior to the date on which a possible change to the then current allocation may become effective; and
 - (b) The ISO will present a draft study scope to Market Participants for consideration and comment before the ISO issues the study scope as part of its Request For Proposal process to retain a consultant to perform the study. A meeting shall be held with Market Participants to discuss the components (*e.g.*, categories of costs considered, allocation of benefits, unbundling, etc.) that should be included in the draft study scope before the draft is issued by the ISO.

6.1.2.4 Calculation of the ISO Annual Budget Charge for Transmission Customers Participating in Non-Physical Market Activity, the Special Case Resource Program, or the Emergency Demand Response Program

6.1.2.4.1 Charge for Transmission Customers Engaging in Virtual Transactions

The ISO shall charge, and each Transmission Customer that has its virtual bids accepted and thereby engages in Virtual Transactions shall pay, a charge for such activity each Billing Period as calculated according to the following formula.

$$VTCharge_{c,P} = VTRate \times VTCleared_{c,P}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$VTCharge_{c,p}$ = The amount, in \$, for which Transmission Customer c is responsible for Billing Period P.

$VTRate$ = For calendar year 2012, the applicable rate shall be \$0.0871 per cleared MWh of Virtual Transactions, based on a \$2.6 million projected 2012 annual revenue requirement. For calendar years following 2012, the applicable rate shall be calculated in accordance with the formula set forth in Section 6.1.2.4.4 of this Rate Schedule 1.

$VTcleared_{c,p}$ = The total cleared Virtual Transactions, in MWh, for Transmission Customer c in Billing Period P.

6.1.2.4.2 Charge for Transmission Customers Purchasing Transmission Congestion Contracts

The ISO shall charge, and each Transmission Customer that purchases Transmission Congestion Contracts - excluding Transmission Congestion Contracts that are created prior to January 1, 2010 - shall pay, a charge for such activity each Billing Period as calculated according to the following formula.

$$TCCCharge_{c,p} = TCCRate \times TCCSettled_{c,p}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$TCCCharge_{c,p}$ = The amount, in \$, for which Transmission Customer c is responsible for Billing Period P.

$TCCRate$ = For calendar year 2012, the applicable rate shall be \$0.0372 per settled MWh of Transmission Congestion Contracts, based on a \$4.9 million projected 2012 annual revenue requirement. For calendar years following 2012, the applicable rate shall be calculated in accordance with the formula set forth in Section 6.1.2.4.4 of this Rate Schedule 1.

$TCCSettled_{c,p}$ = The total settled Transmission Congestion Contracts, excluding Transmission Congestion Contracts created prior to January 1, 2010, in MWh, for Transmission Customer c in Billing Period P.

6.1.2.4.3 Charge for Transmission Customers Participating in the Special Case Resource Program or Emergency Demand Response Program

The ISO shall charge, and each Transmission Customer that participates in the ISO's Special Case Resources program or its Emergency Demand Response program shall pay, a charge for such activity each Billing Period as calculated according to the following formula.

$$\text{SCR and EDR Charge}_{c,P} = \text{DRInjections}_{c,P} \times \left(0.28 \times \frac{\text{ISOCosts}_{\text{Annual}}}{\text{TotalEstWithdrawalUnits}_{\text{Annual}}} \right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$\text{SCR and EDR Charge}_{c,P}$ = The amount, in \$, for which Transmission Customer c is responsible for Billing Period P .

$\text{DRInjections}_{c,P}$ = The total Load reduction, in MWh, measured and compensated during testing or an actual event for Transmission Customer c in Billing Period P .

$\text{ISOCosts}_{\text{Annual}}$ = The sum, in \$, of the ISO's annual budgeted costs in the current calendar year.

$\text{TotalEstWithdrawalUnits}_{\text{Annual}}$ = The sum, in MWh, of estimated Withdrawal Billing Units for all Transmission Customers in the current calendar year as determined by the ISO in the summer prior to the current calendar year.

6.1.2.4.4 Re-setting of Rate for Virtual Transaction and Transmission Congestion Contracts Related Charges

For each calendar year after calendar year 2012, the ISO shall use the following formula to calculate (i) the rate for the charge to Transmission Customers engaging in Virtual Transactions as determined in Section 6.1.2.4.1 of this Rate Schedule 1, and (ii) the rate for the charge to Transmission Customers purchasing Transmission Congestion Contracts as determined in Section 6.1.2.4.2 of this Rate Schedule 1.

$$\text{ResetRate} = \frac{\text{AnnRevRequirement} - \text{Over/UnderCollection}}{\text{3YearRollingAvgBillUnits}}$$

Where:

ResetRate = For each calendar year after calendar year 2012, this rate will be used for either (i) the VTRate in the formula in Section 6.1.2.4.1 of this Rate Schedule 1, or (ii) the TCCRRate in the formula in Section 6.1.2.4.2 of this Rate Schedule 1.

AnnRevRequirement = The product, in \$, of (i) the prior year's annual revenue requirement for either (A) Virtual Transaction market activity or (B) Transmission Congestion Contract market activity, and (ii) an escalation factor. The ISO shall calculate the escalation factor as the percentage change in the ISO budget between (i) the ISO budget for the calendar year two years prior to the current calendar year ("Calendar Year Minus 2") and (ii) the ISO budget for the calendar year one year prior to the current calendar year ("Calendar Year Minus 1").

Over/Under Collection = The ISO shall calculate the amount, in \$, that it has over or under collected for the prior year's annual revenue requirement for either (A) Virtual Transaction market activity or (B) Transmission Congestion Contract market activity, as the case may be, as follows: (i) The ISO shall divide the annual revenue requirements for the applicable market activity for Calendar Year Minus 2 and for Calendar Year Minus 1 into twelve equal monthly revenue requirements for each of these calendar years. (ii) The ISO shall then calculate the amount of revenue, in \$, that it over or under collected for each of the months from July of Calendar Year Minus 2 through June of Calendar Year Minus 1, which shall be calculated as (a) the revenue amount, in \$, that the ISO collected for each month for the applicable market activity, minus (b) the monthly revenue requirement, in \$, for that month as determined above. If the result of this calculation is positive, then the ISO overcollected for that month. If the result of this calculation is negative, then the ISO undercollected for that month. (iii) The ISO shall then calculate the total over or under collection amount, in \$, for the period of July of Calendar Year Minus 2 through June of Calendar Year Minus 1, which shall be equal to (a) the sum, in \$, of the revenue that the ISO overcollected for each month during this period (i.e., the sum of the positive monthly results determined above), minus (b) the sum, in \$, of the absolute value of the revenue that the ISO undercollected for each month during this period (i.e., the sum of the absolute value of the negative monthly results determined above).

3YearRollingAvgBillUnits = The ISO shall calculate the three year rolling average of billing units, in MWh, using twelve-month averages of the appropriate billing units for the period between July of the calendar year four years prior to the current calendar year ("Calendar Year Minus 4") and June of Calendar Year Minus 1.

The annual rate computed through the formula in this Section 6.1.2.4.4 shall be subject to a 25% maximum increase or decrease for each year.

6.1.2.5 Credit for Transmission Customers Participating in Physical Market Activity After Recovery of ISO Annual Budgeted Costs for the Preceding Year

The ISO shall use the revenue collected each Billing Period pursuant to Section 6.1.2.4 of this Rate Schedule 1 to recover any of its annual budgeted costs for the immediately preceding calendar year that it has not already recovered under Section 6.1.2 of this Rate Schedule for that year. Once it has recovered its annual budgeted costs for the immediately preceding calendar year, the ISO shall distribute each Billing Period for the remainder of the calendar year any additional revenue collected pursuant to Section 6.1.2.4 of this Rate Schedule to each Transmission Customer that participates in physical market activity as calculated according to the following formula.

$$\text{ISO Annual Budget Credit}_{c,p} = \left(\text{NonPhysicalActivityRevenue}_p \times \left(0.28 \times \frac{\text{InjectionUnits}_{c,p}}{\text{TotalInjectionUnits}_p} \right) \right) + \left(\text{NonPhysicalActivityRevenue}_p \times \left(0.72 \times \frac{\text{WithdrawalUnits}_{c,p}}{\text{TotalWithdrawalUnits}_p} \right) \right)$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

ISO Annual Budget Credit_{c,p} = The amount, in \$, that Transmission Customer c will receive for Billing Period P.

NonPhysicalActivityRevenue_p = The sum, in \$, of the revenue collected by the ISO for Billing Period P through the charges to Transmission Customers for non-physical market activity, the Special Cases Resource program, and the Emergency Demand Response program as calculated in Section 6.1.2.4 of this Rate Schedule 1, **less the amount the ISO is using to recover the annual budgeted costs for the immediately preceding calendar year that it did not recover 1) under Section 6.1.2.2 of this Rate Schedule for that year or 2) through NonPhysicalActivityRevenue previously used for this purpose in the current calendar year provided, however, NonPhysicalActivityRevenue_p shall not be less than zero**

$\text{InjectionUnits}_{c,P}$ = The Injection Billing Units, in MWh, for Transmission Customer c in Billing Period P , except for Scheduled Energy Injections resulting from CTS Interface Bids.

$\text{WithdrawalUnits}_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in Billing Period P , except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

$\text{TotalInjectionUnits}_P$ = The sum, in MWh, of Injection Billing Units for all Transmission Customers in Billing Period P , except for Scheduled Energy Injections resulting from CTS Interface Bids.

$\text{TotalWithdrawalUnits}_P$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in Billing Period P , except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

Following the end of calendar year 2017, the ISO shall review the credits that have been made to Transmission Customers participating in physical market activity pursuant to this Section 6.1.2.5 and shall present the results of its review to Market Participants for comment.

6.1.3 NERC and NPCC Charges

The ISO receives an invoice from NERC and NPCC (as defined below) on a quarterly basis for the recovery of the upcoming calendar quarter's costs related to the dues, fees, and related charges of:

- (i) the NERC for its service as the Electric Reliability Organization for the United States ("ERO"), recovered pursuant to FERC Docket Nos. RM05-30-000, RR06-1-000 and RR06-3-000 and related dockets, and
- (ii) the Northeast Power Coordinating Council: Cross-Border Regional Entity, Inc. ("NPCC"), or its successors, incurred to carry out functions that are delegated by the NERC and that are related to ERO matters pursuant to Section 215 of the FPA.

The ISO shall charge on a quarterly basis, and each Transmission Customer taking service under the ISO Tariffs shall pay, a charge for the recovery of the NERC and NPCC costs in accordance with Section 6.1.3.1 of this Rate Schedule 1.

Notwithstanding any applicable provisions of this ISO OATT or of the ISO Services Tariff, the ISO may supply to NERC the name of any LSE failing to pay any amounts due to NERC and the amounts not paid.

6.1.3.1 Calculation of NERC and NPCC Charges

The ISO shall charge, and each Transmission Customer shall pay, a charge on a quarterly basis to recover the NERC and NPCC costs invoiced to the NYISO by NERC and NPCC for the upcoming calendar quarter. This charge shall be calculated according to the following formula.

$$\text{NERC\&NPCC Charge}_{c,Q} = \text{NERC\&NPCC Costs}_Q \times \frac{\text{TUWithdrawalUnits}_{c,M}}{\text{TUTotalWithdrawalUnits}_M}$$

Where:

c = Transmission Customer.

Q = The relevant calendar quarter, for which the NERC and NPCC costs apply.

$\text{NERC\&NPCC Charge}_{c,Q}$ = The amount of the NERC and NPCC costs invoiced to the ISO, in \$, for which Transmission Customer c is responsible for calendar quarter Q .

$\text{NERC\&NPCC Costs}_Q$ = The NERC and NPCC costs, in \$, invoiced to the ISO for calendar quarter Q .

M = The month in which the ISO charges Transmission Customers to recover NERC and NPCC costs for calendar quarter Q .

$\text{TUWithdrawalUnits}_{c,M}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in its four-month true-up invoice that is issued with its regular monthly invoice in month M , except for Withdrawal Billing Units for Wheels Through and Exports.

$\text{TUTotalWithdrawalUnits}_M$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in their four-month true-up invoices that are issued with their

regular monthly invoices in month M, except for Withdrawal Billing Units for Wheels Through and Exports.

In calculating the Withdrawal Billing Units for this NERC and NPCC charge, the ISO shall use the LSE bus meter data that have been submitted by the meter authorities for use in the calculation of the four-month true-up of the Transmission Customer's monthly invoice pursuant to Sections 7.4.1.1.2 and 7.4.1.1.3 of the ISO Services Tariff and Sections 2.7.4.2.1(ii) and 2.7.4.2.1(iii) of this ISO OATT. This calculation of the NERC and NPCC charge shall not be subject to correction or adjustment.

6.1.4 Bad Debt Loss Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of bad debt losses in accordance with the methodology established in Attachment U of this ISO OATT.

6.1.5 Working Capital Fund Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge for the collection and maintenance of the Working Capital Fund in accordance with the methodology established in Attachment V of this ISO OATT.

6.1.6 Non-ISO Facilities Payment Charge

The ISO shall charge, and each Transmission Customer shall pay, a charge in accordance with Section 6.1.6.1 of this Rate Schedule 1 for the recovery of the costs of the ISO's monthly payments to the owners of facilities that are needed for the economic and reliable operation of the NYS Transmission System. At present, the ISO makes such payments to:

- (i) Consolidated Edison Co. of New York, Inc. for the purchase, installation, operation, and maintenance of phase angle regulators at the Branchburg-Ramapo Interconnection between the ISO and PJM Interconnection, LLC, and
- (ii) Rochester Gas & Electric Corporation for the installation of a 135 MVAR Capacitor Bank at Rochester Station 80 on the cross-state 345 kV system.

6.1.6.1 Calculation of Non-ISO Facilities Payment Charge

6.1.6.1.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a non-ISO facilities payment charge for each Billing Period. This charge shall be equal to the sum of the hourly non-ISO facilities payment charges for the Transmission Customer, as calculated according to the following formula, for each hour in the relevant Billing Period.

$$\text{Non-ISO Facilities Payment Charge}_{c,h} = \frac{\text{NonISOFacilitiesCosts}_M}{N} \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

M = The relevant month.

h = A given hour in the relevant Billing Period in month M .

N = Total number of hours h in month M .

$\text{Non-ISO Facilities Payment Charge}_{c,h}$ = The amount, in \$, for which Transmission Customer c is responsible for hour h .

$\text{NonISOFacilitiesCosts}_M$ = The sum, in \$, of the ISO's bills for month M for the non-ISO facilities from (i) Consolidated Edison Co. of New York (less the one-half of such bill paid by PJM Interconnection, LLC) and (ii) Rochester Gas and Electric Corporation.

$\text{WithdrawalUnits}_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

$\text{TotalWithdrawalUnits}_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply Station Power as third-party providers, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

6.1.6.1.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT.

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a non-ISO facilities payment charge for each Billing Period. This charge shall be equal to the sum of the daily non-ISO facilities payment charges for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

Non-ISO Facilities Payment Charge $_{c,d}$ =

$$\frac{\text{NonISOFacilitiesCosts}_M}{N} \times \frac{\text{StationPower}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant Billing Period in month M.

N = Number of days d in month M.

$\text{StationPower}_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.6.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.6.1.2 shall be determined for day d.

6.1.6.1.3 Non-ISO Facilities Payment Credit

The ISO shall credit each Transmission Customer based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the non-ISO facilities payment charge under Section 6.1.6.1.2 of this Rate Schedule 1 for each Billing Period. This credit shall be equal to the sum of daily payments for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

Non-ISO Facilities Payment Credit_{c,d} =

$$\text{NonISOFacPayCharge}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant Billing Period.

Non-ISO Facilities Payment Credit_{c,d} = The amount, in \$, that Transmission Customer c will receive for day d.

NonISOFacPayCharge_d = The sum of non-ISO facilities payment charges, in \$, for all Transmission Customers as calculated in Section 6.1.6.1.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.6.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.6.1.3 shall be determined for day d.

6.1.7 Charge to Recover Payments Made to Suppliers Pursuant to Incremental Cost Recovery for Units Responding to Local Reliability Rules I-R3 and I-R5

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge for the recovery of the costs of payments to Suppliers pursuant to the incremental cost

recovery for units that responded to either (i) Local Reliability Rule I-R3 or (ii) Local Reliability Rule I-R5, as applicable, for each Billing Period. This charge shall be equal to the sum of the daily charges for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period. The ISO shall perform this calculation separately to recover as applicable either (i) the payment costs related to Local Reliability I-R3, or (ii) the payment costs related to Local Reliability Rule I-R5.

Local Reliability Rules Payment Recovery Charge_{c,d} =

$$\text{LRRPayment}_d \times \frac{\text{TDWithdrawalUnits}_{c,d}}{\text{TDTotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

Local Reliability Rules Payment Recovery Charge_{c,d} = The amount, in \$, for which Transmission Customer c is responsible for day d.

LRRPayment_d - The amount, in \$, paid in day d to Suppliers pursuant to the incremental cost recovery for units that responded, as applicable, to either (i) Local Reliability Rule I-R3 in the Consolidated Edison Transmission District or (ii) Local Reliability Rule I-R5 in the LIPA Transmission District.

TDWithdrawalUnits_{c,d} = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d in either (i) the Consolidated Edison Transmission District (in the case of Local Reliability Rule I-R3) or (ii) the LIPA Transmission District (in the case of Local Reliability Rule I-R5), except for the Withdrawal Billing Units to supply Station Power as a third-party provider.

TDTotalWithdrawalUnits_d = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day d in either (i) the Consolidated Edison Transmission District (in the case of Local Reliability Rule I-R3) or (ii) the LIPA Transmission District (in the case of Local Reliability Rule I-R5), except for the Withdrawal Billing Units to supply Station Power as third-party providers.

6.1.8 Residual Costs Payment/Charge

The ISO's payments for market transactions by Transmission Customers will not equal the ISO's payments to Suppliers for market transactions. Part of the difference consists of Day-Ahead Congestion Rent. The remainder comprises a residual adjustment, which the ISO shall calculate and each Transmission Customer shall receive or pay on the basis of its Withdrawal Billing Units. The most significant component of the residual adjustment is the residual costs payment or charge calculated in accordance with Section 6.1.8.1 of this Rate Schedule 1.

6.1.8.1 Calculation of Residual Costs Payment/Charge

6.1.8.1.1 Transmission Customers Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall calculate, and each Transmission Customer shall receive or pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a residual costs payment or a residual costs charge for each Billing Period. The payment or charge for the relevant Billing Period shall be equal to (i) the sum of the hourly residual costs payments for the Transmission Customer as calculated according to the following formula for each hour in the relevant Billing Period, minus (ii) the sum of the hourly residual costs charges for the Transmission Customer as calculated in the following formula for each hour in the relevant Billing Period. If the result of this determination is positive, the ISO shall pay the Transmission Customer a residual costs payment for the relevant Billing Period. If the result of this determination is negative, the ISO shall charge the Transmission Customer a residual costs charge for the relevant Billing Period.

Residual Costs Payment/Charge_{c,h} =

$$\left(\text{CustomerPayments}_h - \text{ISOPayments}_h \right) \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

Residual Costs Payment/Charge c,h = The amount, in \$, for hour h that Transmission Customer c will receive (if positive) or for which Transmission Customer c is responsible (if negative).

WithdrawalUnits c,h = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h , except for the Withdrawal Billing Units to supply Station Power as a third-party provider, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

TotalWithdrawalUnits h = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h , except for the Withdrawal Billing Units to supply Station Power as third-party providers, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

CustomerPayments h = The ISO's receipts, in \$, for each hour h from Transmission Customers that equal the sum of the following components, which could be either positive or negative amounts:

- (i) payments of the Energy component and Marginal Losses Component of LBMP for Energy scheduled in the LBMP Market in hour h in the Day-Ahead Market;
- (ii) payments of the Energy component, Marginal Losses Component, and Congestion Component of LBMP for Energy purchased in the Real-Time LBMP Market for hour h that was not scheduled Day-Ahead;
- (iii) payments of the Energy component, Marginal Losses Component, and Congestion Component of LBMP for Energy by Suppliers that provided less Energy in the real-time dispatch for hour h than they were scheduled Day-Ahead to provide in hour h for the LBMP Market;
- (iv) the Marginal Losses Component of the TUC payments made in accordance with this ISO OATT for Bilateral Transactions that were scheduled in hour h in the Day-Ahead Market; and

- (v) the Marginal Losses Component and Congestion Component of the real-time TUC payments made in accordance with this ISO OATT for Bilateral Transactions that were not scheduled in hour h in the Day-Ahead Market.
- (vi) the M2M settlement between the ISO and PJM Interconnection, L.L.C. for hour h, determined in accordance with Section 8 of Schedule D to Attachment CC to this ISO OATT.

$ISO\text{Payments}_h$ = The ISO's payments, in \$, in each hour h to Suppliers that equal the sum of the following components, which could be either positive or negative amounts:

- (i) payments of the Energy component and Marginal Losses Components of LBMP for Energy to Suppliers that were scheduled to provide in the LBMP Market in hour h in the Day-Ahead Market;
- (ii) payments to Suppliers of the Energy component, Marginal Losses Component, and Congestion Component of LBMP for Energy provided to the ISO in the Real-Time Dispatch for hour h that those Suppliers were not scheduled to provide Energy in hour h in the Day-Ahead Market;
- (iii) payments of the Energy component and Marginal Losses Component of LBMP for Energy to LSEs that consumed less Energy in the real-time dispatch than those LSEs were scheduled Day-Ahead to consume in hour h; and
- (iv) payments of the Marginal Losses Component and Congestion Component of the real-time TUC to Transmission Customers that reduced their Bilateral Transaction schedules for hour h after the Day-Ahead Market.

6.1.8.1.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT.

The ISO shall calculate, and each Transmission Customer shall receive or pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a residual costs payment or a residual costs charge for each Billing Period. The payment or charge for the relevant Billing Period shall be equal to (i) the sum of the daily residual costs payments for the Transmission Customer as calculated according to the following formula for each day in the relevant Billing Period, minus (ii) the sum of the daily residual costs charges for the Transmission Customer as calculated in the following formula for each day in the relevant Billing Period. If the result of this determination is positive, the ISO shall pay the Transmission Customer a residual costs payment for the relevant Billing Period. If the result of this determination is negative, the ISO shall charge the Transmission Customer a residual costs charge for the relevant Billing Period.

Residual Costs Payment/Charge_{c,d} =

$$\frac{(\text{CustomerPayments}_d - \text{ISOPayments}_d)}{\text{TotalWithdrawalUnits}_d} \times \text{StationPower}_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

StationPower_{c,d} = The Withdrawal Billing Units, in MWh, of Transmission Customer c that it used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.8.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.8.1.2 shall be determined for day d.

6.1.8.1.3 Residual Costs Adjustment

The ISO shall calculate, and each Transmission Customer shall receive or pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a residual costs adjustment for each Billing Period. This adjustment shall be equal to the sum of the daily adjustments (positive and negative) for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period. If the summed amount is positive for the Billing Period, the ISO shall pay the Transmission Customer the adjustment amount. If the summed amount is negative for the Billing Period, the ISO shall charge the Transmission Customer the adjustment amount.

Residual Costs Adjustment_{c,d} =

$$\text{ResidCharge/PaymentCosts}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant Billing Period.

Residual Costs Adjustment_{c,d} = The amount, in \$, for day d that Transmission Customer c will receive (if positive) or for which Transmission Customer c is responsible (if negative).

ResidCharge/PaymentCosts_d = (i) If Transmission Customers were responsible for a residual costs charge for day d pursuant to Section 6.1.8.1.2 of this Rate Schedule 1, the (positive) amount, in \$, of the costs that the ISO has collected through the residual costs charges for all Transmission Customers for day d. (ii) If Transmission Customers received a residual costs payment for day d pursuant to Section 6.1.8.1.2 of this Rate Schedule 1, the (negative) amount, in \$, of the revenue that the ISO has paid through the residual costs payments to all Transmission Customers for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.8.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.8.1.3 shall be determined for day d.

6.1.9 Recovery of Special Case Resources and Curtailment Services Providers Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of Special Case Resources and Curtailment Service Providers costs for each Billing Period. This charge shall be equal to the sum of the hourly charges for the Transmission Customer, as calculated in Sections 6.1.9.1 and 6.1.9.2 of this Rate Schedule 1, for each hour in the relevant Billing Period and, where applicable, for each Subzone.

6.1.9.1 Recovery of Costs for Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of a Local System

Pursuant to this Section 6.1.9.1, the ISO shall recover the costs of payments to Special Case Resources and Curtailment Service Providers that were called to meet the reliability needs of a local system. To do so, the ISO shall charge, and each Transmission Customer that serves Load in the Subzone for which the reliability services of the Special Case Resources and Curtailment Service Providers were called shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula for each Subzone.

Local Reliability SCR and CSP Charge_{c,h} =

$$\text{LocalReliabilityCosts}_h \times \frac{\text{SZWithdrawalUnits}_{c,h}}{\text{SZTotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

Local Reliability SCR and CSP Charge_{c,h} = The amount, in \$, for which Transmission Customer c is responsible for hour h for the relevant Subzone.

LocalReliabilityCosts_h = The payments, in \$, for hour h in the relevant Subzone made to Suppliers for Special Case Resources and Curtailment Service Providers called to meet the reliability needs of that Subzone.

SZWithdrawalUnits_{c,h} = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits_h = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.9.2 Recovery of Costs for Payments for Special Case Resources and Curtailment Service Providers Called to Meet the Reliability Needs of the NYCA

Pursuant to this Section 6.1.9.2, the ISO shall recover the costs of payments to Special Case Resources and Curtailment Service Providers called to meet the reliability needs of the NYCA. To do so, the ISO shall charge, and each Transmission Customer ~~that serves Load in the NYCA~~ shall pay based on its Withdrawal Billing Units ~~that are not used~~ except for Withdrawal Billing Units for Wheels through, Exports or to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula.

NYCA Reliability SCR and CSP Charge_{c,h} =

$$\text{NYCAReliabilityCosts}_h \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

NYCA Reliability SCR and CSP Charge_{c,h} = The amount, in \$, for which Transmission Customer c is responsible for hour h.

NYCAReliabilityCosts_h = The payments, in \$, for hour h made to Suppliers for Special Case Resources and Curtailment Service Providers called to meet the reliability needs of the NYCA.

WithdrawalUnits_{c,h} = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units [for Wheels through, Exports or](#) to supply Station Power as a third-party provider.

TotalWithdrawalUnits_h = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units [for Wheels through, Exports or](#) to supply Station Power as third-party providers.

6.1.10. Recovery of Day-Ahead Margin Assurance Payment Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of DAMAP costs for each Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the charges and credits for the Transmission Customer, as calculated in Sections 6.1.10.1 and 6.1.10.2 of this Rate Schedule 1, for each hour or each day, as applicable, in the relevant Billing Period and for each Subzone, where applicable.

6.1.10.1 Recovery of Costs of DAMAPs Resulting from Meeting the Reliability Needs of a Local System

Pursuant to this Section 6.1.10.1, the ISO shall recover the costs for DAMAPs incurred to compensate Resources for meeting the reliability needs of a local system.

6.1.10.1.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula for each Subzone.

$$\text{Local Reliability DAMAP Charge}_{c,h} = \text{DAMAPCosts}_h \times \frac{\text{SZWithdrawalUnits}_{c,h}}{\text{SZTotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

Local Reliability DAMAP Charge_{c,h} = The amount, in \$, for which Transmission Customer c is responsible for hour h for the relevant Subzone.

DAMAPCosts_h = The DAMAP costs, in \$, for hour h in the relevant Subzone incurred to compensate Resources meeting the reliability needs of that Subzone.

SZWithdrawalUnits_{c,h} = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits_h = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.10.1.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$\text{Local Reliability DAMAP Charge}_{c,d} = \frac{\text{DAMAPCosts}_d}{\text{SZTotalWithdrawalUnits}_d} \times \text{SZStationPower}_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

SZStationPower_{c,d} = The Withdrawal Billing Units, in MWh, of Transmission Customer c in day d in the relevant Subzone that are used to supply Station Power as a third-party provider, except for Withdrawal Billing Units for Wheels Through and Exports.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.1.2 shall be determined for day d .

6.1.10.1.3 Local Reliability DAMAP Credit

The ISO shall calculate, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.10.1.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

Local Reliability DAMAP Credit_{c,d} =

$$\text{LocRelDAMAPCharge}_d \times \frac{\text{SZWithdrawalUnits}_{c,d}}{\text{SZTotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant Billing Period.

Local Reliability DAMAP Credit_{c,d} = The amount, in \$, that Transmission Customer c will receive for day d for the relevant Subzone.

LocRelDAMAPCharge_d = The sum of charges, in \$, for all Transmission Customers in the relevant Subzone as calculated in Section 6.1.10.1.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.1.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.1.3 shall be determined for day d.

6.1.10.2 Recovery of Costs of All Remaining DAMAPs

Pursuant to this Section 6.1.10.2, the ISO shall recover the costs of all DAMAPs not recovered through Section 6.1.10.1 of this Rate Schedule 1 from all Transmission Customers.

6.1.10.2.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an hourly charge in accordance with the following formula.

$$\text{Remaining DAMAP Charge}_{c,h} = \text{RemainingDAMAPCosts}_h \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

Remaining DAMAP Charge_{c,h} = The amount, in \$, for which Transmission Customer c is responsible for hour h.

RemainingDAMAPCosts_h = The DAMAP costs, in \$, for hour h not recovered by the ISO through Section 6.1.10.1 of this Rate Schedule 1.

WithdrawalUnits_{c,h} = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h, except for the Withdrawal Billing Units to supply Station Power as a third-party provider, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

TotalWithdrawalUnits_h = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h, except for the Withdrawal Billing Units to supply Station Power as third-party providers, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

6.1.10.2.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$\text{Remaining DAMAP Charge}_{c,d} = \frac{\text{RemainingDAMAPCosts}_d}{\text{TotalWithdrawalUnits}_d} \times \text{StationPower}_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

StationPower_{c,d} = The Withdrawal Billing Units, in MWh, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.2.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.2.2 shall be determined for day d.

6.1.10.2.3 Remaining DAMAP Credit

The ISO shall calculate, and each Transmission Customer shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.10.2.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$\text{Remaining DAMAP Credit}_{c,d} = \text{RemainingDAMAPCharge}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant Billing Period.

Remaining DAMAP Credit_{c,d} = The amount, in \$, that Transmission Customer c will receive for day d.

RemainingDAMAPCharge_d = The sum of charges, in \$, for all Transmission Customers as calculated in Section 6.1.10.2.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.10.2.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.10.2.3 shall be determined for day d.

6.1.11 Recovery of Import Curtailment Guarantee Payment Costs

6.1.11.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a charge each Billing Period to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for that Billing Period. The charge for the relevant Billing Period shall

be equal to the sum of the hourly charges for the Transmission Customer, as calculated in accordance with the following formula, for each hour in the relevant Billing Period.

$$\text{Import Curtailment Guarantee Charge}_{c,h} = \text{ImportCurtGuarCosts}_h \times \frac{\text{WithdrawalUnits}_{c,h}}{\text{TotalWithdrawalUnits}_h}$$

Where:

c = Transmission Customer.

h = A given hour in the relevant Billing Period.

$\text{Import Curtailment Guarantee Charge}_{c,h}$ = The amount, in \$, for which Transmission Customer c is responsible for hour h .

$\text{ImportCurtGuarCosts}_h$ = The costs, in \$, for the Import Curtailment Guarantee Payments to Import Suppliers for hour h .

$\text{WithdrawalUnits}_{c,h}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in hour h , except for the Withdrawal Billing Units to supply Station Power as a third-party provider, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

$\text{TotalWithdrawalUnits}_h$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in hour h , except for the Withdrawal Billing Units to supply Station Power as third-party providers, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

6.1.11.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a charge for each Billing Period to recover the costs of all Import Curtailment Guarantee Payments paid to Import Suppliers for that Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the daily charges for the Transmission Customer, as calculated in accordance with the following formula, for each day in the relevant Billing Period.

$$\text{Import Curtailment Guarantee Charge}_{c,d} = \frac{\text{ImportCurtGuarCosts}_d}{\text{TotalWithdrawalUnits}_d} \times \text{StationPower}_{c,d}$$

Where:

d = A given day in the relevant Billing Period.

StationPower_{c,d} = The Withdrawal Billing Units, in MWh, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.11.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.11.2 shall be determined for day d.

6.1.11.3 Import Curtailment Guarantee Credit

The ISO shall credit each Transmission Customer based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.11.2 of this Rate Schedule 1 above for each Billing Period. This credit shall be equal to the sum of daily payments for the Transmission Customer, as calculated according to the following formula, for each day in the relevant Billing Period.

$$\text{Import Curtailment Guarantee Credit}_{c,d} = \text{ImpCurtGuarCharge}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

d = A given day in the relevant Billing Period.

Import Curtailment Guarantee Credit_{c,d} = The amount, in \$, that Transmission Customer c will receive for day d.

ImpCurtGuarCharge_d = The sum of charges, in \$, for all Transmission Customers as calculated in Section 6.1.11.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.11.1 of this Rate Schedule 1 above, except that the variables in this Section 6.1.11.3 shall be determined for day d.

6.1.12 Recovery of Bid Production Cost Guarantee Payment and Demand Reduction Incentive Payment Costs

The ISO shall charge, and each Transmission Customer shall pay, a charge for the recovery of BPCG and Demand Reduction Incentive Payment costs for each Billing Period. The charge for the relevant Billing Period shall be equal to the sum of the charges and credits for the Transmission Customer, as calculated in Sections 6.1.12.1 through 6.1.12.6 of this Rate Schedule 1, for each day in the relevant Billing Period and for each Subzone, where applicable.

6.1.12.1 Costs of Demand Reduction BPCGs and Demand Reduction Incentive Payments

After accounting for imbalance charges paid by Demand Reduction Providers, the ISO shall recover the costs associated with Demand Reduction Bid Production Cost guarantee payments and Demand Reduction Incentive Payments from Transmission Customers pursuant to the methodology established in Attachment R of this ISO OATT.

6.1.12.2 Costs of BPCGs for Additional Generating Units Committed to Meet Forecast Load

If the sum of all Bilateral Transaction schedules, excluding schedules of Bilateral Transactions with Trading Hubs as their POWs, and all Day-Ahead Market purchases to serve Load in the Day-Ahead schedule is less than the ISO's Day-Ahead forecast of Load, the ISO may commit Resources in addition to the reserves that it normally maintains to enable it to respond to contingencies to meet the ISO's Day-Ahead forecast of Load. The ISO shall recover a portion of the costs associated with Bid Production Cost guarantee payments for the additional Resources committed Day-Ahead to meet the Day-Ahead forecast of Load from Transmission

Customers pursuant to the methodology established in Attachment T of this ISO OATT. The ISO shall recover the residual costs of such Bid Production Cost guarantee payments not recovered through the methodology in Attachment T of the ISO OATT pursuant to Section 6.1.12.6 of this Rate Schedule 1.

6.1.12.3 Costs of BPCGs Resulting from Meeting the Reliability Needs of a Local System

Pursuant to this Section 6.1.12.3, the ISO shall recover the costs for Bid Production Cost guarantee payments incurred to compensate Suppliers for their Resources, other than Special Case Resources, that are committed or dispatched to meet the reliability needs of a local system.

6.1.12.3.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$\text{Local Reliability BPCG Charge}_{c,d} = \text{BPCGCosts}_d \times \frac{\text{SZWithdrawalUnits}_{c,d}}{\text{SZTotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

Local Reliability BPCG Charge_{c,d} = The amount, in \$, for which Transmission Customer c is responsible for day d for the relevant Subzone.

BPCGCosts_d = The Bid Production Cost guarantee payments, in \$, made to Suppliers for Resources for day d in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone, except for the Bid Production Cost guarantee payments made to Suppliers for Special Case Resources.

SZWithdrawalUnits_{c,d} = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits_d = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.12.3.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$\text{Local Reliability BPCG Charge}_{c,d} = \frac{\text{BPCGCosts}_d}{\text{SZTotalWithdrawalUnits}_d} \times \text{SZStationPower}_{c,d}$$

Where:

SZStationPower_{c,d} = The Withdrawal Billing Units, in MWh, of Transmission Customer c in day d in the relevant Subzone that are used to supply Station Power as a third-party provider, except for Withdrawal Billing Units for Wheels Through and Exports.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.3.1 above,

6.1.12.3.3 Local Reliability BPCG Credit

The ISO shall calculate, and each Transmission Customer that serves Load in the Subzone where the Resource is located shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.12.3.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$\text{Local Reliability BPCG Credit}_{c,d} = \text{LocRelBPCGCharge}_d \times \frac{\text{SZWithdrawalUnits}_{c,d}}{\text{SZTotalWithdrawalUnits}_d}$$

Where:

Local Reliability BPCG Credit_{c,d} = The amount, in \$, that Transmission Customer c will receive for day d for the relevant Subzone.

LocRelBPCGCharge_d = The sum of charges, in \$, for all Transmission Customers in the relevant Subzone as calculated in Section 6.1.12.3.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.3.1 above.

6.1.12.4 Cost of BPCGs for Special Case Resources Called to Meet the Reliability Needs of a Local System

Pursuant to this Section 6.1.12.4, the ISO shall recover the costs of Bid Production Cost guarantee payments incurred to compensate Special Case Resources called to meet the reliability needs of a local system. To do so, the ISO shall charge, and each Transmission Customer that serves Load in the Subzone where the Special Case Resource is located shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula for each Subzone.

$$\text{Local Reliability SCR BPCG Charge}_{c,d} = \text{BPCGCosts}_d \times \frac{\text{SZWithdrawalUnits}_{c,d}}{\text{SZTotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

Local Reliability SCR BPCG Charge_{c,d} = The amount, in \$, for which Transmission Customer c is responsible for day d for the relevant Subzone.

BPCGCosts_d = The Bid Production Cost guarantee payments, in \$, made to Suppliers for Special Case Resources for day d in the relevant Subzone arising as a result of meeting the reliability needs of that Subzone.

SZWithdrawalUnits_{c,d} = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as a third-party provider.

SZTotalWithdrawalUnits_d = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day d in the relevant Subzone, except for Withdrawal Billing Units for Wheels Through, Exports, and to supply Station Power as third-party providers.

6.1.12.5 Cost of BPCG for Special Case Resources Called to Meet the Reliability Needs of the NYCA

Pursuant to this Section 6.1.12.5, the ISO shall recover the costs for Bid Production Cost guarantee payments to compensate Special Case Resources called to meet the reliability needs of the NYCA. To do so, the ISO shall charge, and each Transmission Customer ~~that serves Load in the NYCA~~ shall pay based on its Withdrawal Billing Units ~~that are not~~ used except for Withdrawal Billing Units for Wheels through, Exports or to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$\text{NYCA Reliability SCR BPCG Charge}_{c,d} = \text{BPCGCosts}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

NYCA Reliability SCR BPCG Charge_{c,d} = The amount, in \$, for which Transmission Customer c is responsible for day d.

BPCGCosts_d = The Bid Production Cost guarantee payments, in \$, made to Suppliers for Special Case Resources called to meet the reliability needs of the NYCA for day d.

WithdrawalUnits_{c,d} = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d, except for the Withdrawal Billing Units for Wheels through, Exports or to supply Station Power as a third-party provider.

TotalWithdrawalUnits_d = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day d, except for the Withdrawal Billing Units for Wheels-through, Exports or to supply Station Power as third-party providers.

6.1.12.6 Costs of All Remaining BPCGs

Pursuant to this Section 6.1.12.6, the ISO shall recover the costs of all Bid Production Cost guarantee payments not recovered through Sections 6.1.12.1, 6.1.12.2, 6.1.12.3, 6.1.12.4, and 6.1.12.5 of this Rate Schedule 1, including the residual costs of Bid Production Cost guarantee payments for additional Resources not recovered through the methodology in Attachment T of this ISO OATT, from all Transmission Customers.

6.1.12.6.1 Transmission Customer Charge Based on Withdrawal Billing Units Not Used to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$\text{Remaining BPCG Charge}_{c,d} = \text{RemainingBPCGCosts}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

c = Transmission Customer.

d = A given day in the relevant Billing Period.

$\text{Remaining BPCG Charge}_{c,d}$ = The amount, in \$, for which Transmission Customer c is responsible for day d .

$\text{RemainingBPCGCosts}_d$ = The BPCG costs, in \$, for day d not recovered by the ISO through Sections 6.1.12.1, 6.1.12.2, 6.1.12.3, 6.1.12.4, and 6.1.12.5 of this Rate Schedule 1.

$\text{WithdrawalUnits}_{c,d}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in day d , except for the Withdrawal Billing Units to supply Station Power as a third-party provider, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

$\text{TotalWithdrawalUnits}_d$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in day d , except for the Withdrawal Billing Units to supply Station Power as third-party providers, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

6.1.12.6.2 Transmission Customer Charge Based on Withdrawal Billing Units to Supply Station Power Under Part 5 of this ISO OATT

The ISO shall charge, and each Transmission Customer shall pay based on its Withdrawal Billing Units used to supply Station Power as a third-party provider, a daily charge in accordance with the following formula.

$$\text{Remaining BPCG Charge}_{c,d} = \frac{\text{RemainingBPCGCosts}_d}{\text{TotalWithdrawalUnits}_d} \times \text{StationPower}_{c,d}$$

Where:

$\text{StationPower}_{c,d}$ = The Withdrawal Billing Units, in MWh, of Transmission Customer c used to supply Station Power as a third-party provider for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.6.1 of this Rate Schedule 1 above.

6.1.12.6.3 Remaining BPCG Credit

The ISO shall calculate, and each Transmission Customer shall receive based on its Withdrawal Billing Units that are not used to supply Station Power as a third-party provider, an amount of the revenue collected through the charge under Section 6.1.12.6.2 of this Rate Schedule 1. This credit shall be calculated according to the following formula for each day in the relevant Billing Period.

$$\text{Remaining BPCG Credit}_{c,d} = \text{RemainingBPCGCharge}_d \times \frac{\text{WithdrawalUnits}_{c,d}}{\text{TotalWithdrawalUnits}_d}$$

Where:

$\text{Remaining BPCG Credit}_{c,d}$ = The amount, in \$, that Transmission Customer c will receive for day d.

$\text{RemainingBPCGCharge}_d$ = The sum of charges, in \$, for all Transmission Customers as calculated in Section 6.1.12.6.2 of this Rate Schedule 1 for day d.

The definitions of the remaining variables are identical to the definitions for such variables set forth in Section 6.1.12.6.1 of this Rate Schedule 1 above.

6.1.13 Dispute Resolution Payment/Charge

The ISO shall calculate, and each Transmission Customer shall receive or pay, a dispute resolution payment or charge in accordance with Section 6.1.13.1 of this Rate Schedule 1 for the distribution of funds received by the ISO or the recovery of funds incurred by the ISO in the settlement of a dispute.

6.1.13.1 Calculation of the Dispute Resolution Payment/Charge

The ISO shall calculate, and each Transmission Customer shall receive or pay, a dispute resolution payment or a dispute resolution charge for each Billing Period as calculated according to the following formula.

$$\text{Dispute Resolution Payment/ Charge}_{c,P} = \text{DisputeResolutionCosts}_P \times \frac{\text{WithdrawalUnits}_{c,P}}{\text{TotalWithdrawalUnits}_P}$$

Where:

c = Transmission Customer.

P = The relevant Billing Period.

$\text{Dispute Resolution Payment/Charge}_{c,P}$ = The amount, in \$, for Billing Period P that (i) Transmission Customer c will receive if the ISO is distributing funds that it has collected in the settlement of a dispute, or (ii) Transmission Customer c will be responsible for if the ISO is recovering funds that it has incurred in the settlement of a dispute.

$\text{DisputeResolutionCosts}_P$ = The amount, in \$, for Billing Period P that (i) the ISO has collected in the settlement of a dispute or (ii) the ISO has incurred in the settlement of a dispute.

$\text{WithdrawalUnits}_{c,P}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c in Billing Period P , except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

$\text{TotalWithdrawalUnits}_P$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers in Billing Period P , except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

6.1.14 Credit for Financial Penalties

The ISO shall distribute to each Transmission Customer each Billing Period in accordance with the following formula any payments that it has collected from Transmission Customers to satisfy: (i) Financial Impact Charges issued pursuant to Sections 4.5.3.2 and 4.5.4.2 of the ISO Services Tariff; (ii) ICAP sanctions issued pursuant to Section 5.12.12 of the ISO Services Tariff; (iii) ICAP deficiency charges pursuant to Section 5.14.3.1 of the ISO Services Tariff, except as provided in Section 5.14.3.2 of the ISO Services Tariff; (iv) market power mitigation financial penalties pursuant to Section 23.4.3.6 of Attachment H of the ISO Services Tariff, except as provided in Section 23.4.4.3.2 of Attachment H of the ISO Services Tariff; and (v) any other financial penalties set forth in the ISO Services Tariff or this ISO OATT. The ISO will perform this calculation separately for the allocation of the revenue from each financial penalty.

$$\text{Financial Penalties Credit}_{c,p} = \text{PenaltyRevenue}_p \times \frac{\text{WithdrawalUnits}_{c,p}}{\text{TotalWithdrawalUnits}_p}$$

Where:

c = Transmission Customer.

P = A given day in the relevant Billing Period.

$\text{Financial Penalties Credit}_{c,p}$ = The amount, in \$, that Transmission Customer c will receive for Billing Period P .

PenaltyRevenue_p = The sum, in \$, of revenue that the ISO has collected for Billing Period P from a Transmission Customer for one of the financial penalties indicated in this Article 6.1.14 of this Rate Schedule 1.

$\text{WithdrawalUnits}_{c,p}$ = The Withdrawal Billing Units, in MWh, for Transmission Customer c for Billing Period P , except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

$\text{TotalWithdrawalUnits}_p$ = The sum, in MWh, of Withdrawal Billing Units for all Transmission Customers for Billing Period P, except for Scheduled Energy Withdrawals resulting from CTS Interface Bids.

14.1 Transmission Service Charge (“TSC”)

14.1.1 Applicability of the Transmission Service Charge to Wholesale Customers

Each month, each wholesale Transmission Customer shall pay to the appropriate Transmission Owner the applicable Wholesale Transmission Service Charge (“Wholesale TSC”) calculated in accordance with Section 14.1.2.2 of this Attachment for the first two months of LBMP implementation and in accordance with Section 14.1.2.1 of this Attachment thereafter. The TSC shall apply to Transmission Service:

14.1.1.1 from one or more Interconnection Points between the NYCA and another Control Area to one or more Interconnection Points between the NYCA and another Control Area (“Wheels Through”);¹

14.1.1.2 from the NYCA to one or more Interconnection Points between the NYCA and another Control Area, including transmission to deliver Energy purchased from the LBMP Market and delivered to such a Control Area Interconnection Point (“Exports”);¹ or

14.1.1.3 to serve Load within the NYCA; except, the Wholesale TSC shall not apply to:

14.1.1.3.1 a Transmission Owner’s use of its own system to provide bundled retail service to its Native Load Customers pursuant to a retail service tariff on file with the PSC or, in the case of LIPA, has been approved by the Long Island Power Authority’s Board of Trustees;

¹The TSC shall not apply to Wheels Through or Exports scheduled with the ISO to destinations within the New England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

14.1.1.3.2 Transmission Service pursuant to an Existing Transmission Agreement whereby the otherwise applicable TSC does not apply pursuant to Attachment K; or

14.1.1.3.3 retail Transmission Service pursuant to any tariff or rate schedule of a Transmission Owner that explicitly provides for other transmission charges in lieu of the Wholesale TSC, subject to any applicable provisions of the Federal Power Act.

Each Transmission Owner subject to FERC and/or PSC jurisdiction may file with FERC a separate TSC applicable to retail access in accordance with its retail access program filed with the PSC. To the extent that LIPA's rates for service are established by the Long Island Power Authority's Board of Trustees pursuant to Article 5, Title 1-A of the New York Public Authorities Law, Section 1020-f(u) and 1020-s and are not subject to FERC jurisdiction, this requirement will not apply to LIPA.

14.1.2 Wholesale TSC Calculation

Sections 14.1.2-14.1.6 do not apply to the development of the NYPA TSC, which is described in Section 14.1.7.

14.1.2.1 Wholesale TSC Formula

Beginning with the second month of the Capability Period corresponding to the initial auction for Long Term TCCs through the end of the LBMP Transition Period, each Transmission Owner, except NYPA shall calculate its TSC applicable to Transmission Service to serve Load within or exiting the NYCA at its Transmission District as follows:

$$\text{WHOLESALE TSC} = \{(\text{RR}\div 12) + (\text{CCC}\div 12) + (\text{LTPP}\div 12) - \text{SR} - \text{ECR} - \text{CRR} - \text{WR} - \text{Reserved}\}/(\text{BU}\div 12).$$

Where:

RR = The Annual Transmission Revenue Requirement, as stated in Table 1 of this Attachment.

Gross Receipts Tax ("GRT") treatment by each individual company is described in Section 14.1.7. Revenues from grandfathered agreements listed on Attachment H-1 are treated as a revenue credit in the RR.

CCC = The annual Scheduling, System Control and Dispatch Costs of the individual Transmission Owner (*i.e.*, the transmission component of control center costs) as stated on Table 1 of this Attachment.

LTPP = The Transmission Owner's annual Net LBMP Transition Period Payment ("LTPP") (expressed as a positive value) or receipt (expressed as a negative value) as described in Attachment K, Section 17.6 (Note - The LTPP will be established once for the entire LBMP Transition Period after the Initial Auction, as defined in Attachment M, for Long Term TCCs). Prior to a 205 Filing under the FPA by the Transmission Owners, the LTPP will be set at zero.

$SR = SR_1 + SR_2.$

SR_1 will equal the revenues from the Direct Sale by the Transmission Owner of Original Residual TCCs, TCCs derived from Existing Transmission Capacity for Native Load, and Grandfathered TCCs associated with ETAs, the expenses for which are included in the Transmission Owner's Revenue Requirements where the Transmission Owner is the Primary Owner of said TCCs.

SR_2 will equal the Transmission Owner's revenues from the Centralized TCC Auction allocated pursuant to Attachments N. SR_2 includes revenues from: (a) TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auction; (b) the sale of Grandfathered TCCs associated with ETAs, if the expenses for those ETAs are included in the Transmission Owner's Revenue Requirements;

and (c) TCCs derived from Existing Transmission Capacity for Native Load that are sold in the Centralized TCC Auction.

Revenue from TCCs associated with Residual Transmission Capacity includes payments for Original Residual TCCs that the Transmission Owners sell through the Centralized TCC Auction and the allocation of revenue for other TCCs sold through the Centralized TCC Auction (per the Facility Flow-Based Methodology described in Attachment N).

SR_1 shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (*i.e.*, January actual data will be used in February to calculate the TSC effective in March). SR_1 for a month in which a Direct Sale is applicable shall equal the total nominal revenue that the Transmission Owner will receive under each applicable TCC sold in the Direct Sale divided by the duration of the TCC (in months). SR_2 shall equal the Transmission Owner's share of Net Auction Revenue for all rounds of a Centralized TCC Auction, as calculated pursuant to Attachment N, divided equally among the months covered by the Centralized TCC Auction. SR_2 shall be adjusted after each Centralized TCC Auction and the revised SR_2 shall be effective at the start of each Capability Period;

ECR = The Transmission Owner's share of Net Congestion Rents in a month, calculated pursuant to Attachment N;

CRR = The Transmission Owner's Congestion Payments received from Grandfathered TCCs and Imputed Revenues from Grandfathered Rights from ETA's, the expenses for which are included in the Transmission Owner's Revenue Requirement;

WR = The Transmission Owner's revenues from external sales (Wheels Through and Export Transactions) not associated with Existing Transmission Agreements included in Attachment L, Tables 18.1, 18.2 and 18.3 and wheeling revenue, associated with OATT

reservations extending beyond the start-up of the ISO. (*i.e.*, grandfathered OATT agreements)

14.1.2.1.1 Elements of the WR Component

The WR component will equal the sum of: (1) TSC revenues received from new external transactions (Wheels Through and Export Transactions); (2) transmission revenues received under grandfathered OATT agreements and actual revenues under Schedule 1 to the grandfathered OATT agreements, but not under Schedules 2 through 6 to the grandfathered OATT agreements; and (3) any revenues related to pre-OATT grandfathered arrangements if the transmission owner increased its OATT revenue requirement to derive its RR component to reflect the fact that revenues related to such transactions are at risk due to options available to the customers resulting from the current restructuring, and the customer retains its grandfathered arrangement.

In each subcomponent of the WR component above, the revenues will include the Gross Receipts Tax (“GRT”) when the Transmission Owner has included the GRT in the RR.

14.1.2.1.2 Treatment of Schedule 1 Associated with Grandfathered OATT Service

All customers under grandfathered OATT service agreements must continue to pay the Schedule 1 charge applicable under the individual OATT, absent a settlement to the contrary. The revenues received from Schedule 1 charges paid by grandfathered OATT customers will be treated as revenue credit in the WR component as part of the wheeling revenue associated with OATT reservations extending beyond the start-up of the ISO.

$$\text{Reserved} = \text{Reserved}_1 + \text{Reserved}_2 + \text{Reserved}_3 + \text{Reserved}_4$$

Reserved_1 will equal the Transmission Owner's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for the Transmission Owner's ETCNL TCCs.

Reserved₂ will equal the Transmission Owner's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for the Transmission Owner's RCRR TCCs. Reserved₃ will equal the value that a Transmission Owner receives for the sale of its ETCNL TCCs in a month, with the value for each ETCNL TCC sold divided equally over the months remaining until the expiration of that ETCNL TCC. Reserved₄ will equal the value that a Transmission Owner receives for the sale of its RCRR TCCs in a month, with the value for each RCRR TCC sold divided equally over the months remaining until the expiration of that ETCNL TCC.

BU = The Transmission Owner's Billing Units (annual MWh) for the Transmission District (see Table 1 of this Attachment) The Transmission Owner's BU has been adjusted upward to include subtransmission and distribution losses.

The RR, SR and CRR will not include expenses for the Transmission Owner's purchase of TCCs or revenues from the sale of said TCCs or from the collection of Congestion Rents for said TCCs. The ECR, CRR, WR, and Reserved shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (*e.g.*, January actual data will be used in February to calculate the TSC effective in March). The TSC shall not apply to the scheduled quantities physically Curtailed by the ISO.

Each Member System is responsible for calculating: (1) the RR component of its TSC charge; (2) the CCC component of its TSC charge; and (3) the BU component of its TSC charge.

The LTPP component of each Member System's TSC charge is initially set at zero. Any changes must be made by unanimous consent of the Transmission Owners (See ISO OATT Original Sheet No. 267). The Member Systems will make a Section 205 filing to propose any change to the LTPP.

The NYISO is responsible for calculating (1) the SR component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO

operation; (2) the ECR component of each Member System's TSC charge based on information derived from ISO operation; (3) the CRR component of each Member System's TSC charge based on information derived from ISO operation; (4) the Reserved component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO operation; and (5) the WR component of each Member System's TSC charge based on information provided by the Member System and information derived from ISO operation. Any calculations that the ISO is responsible for are subject to review and comment by all affected parties.

The RR term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when a Transmission Owner determines that a change to its RR is required under Section 205.

The CCC term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when the Transmission Owner determines that a change to the CCC is required.

SR: The revenue from the Direct Sale of TCCs will be determined monthly and will enter the TSC formula through the SR term with a two-month lag (*e.g.*, January actual data will be used in February to calculate the SR term used in the TSC for March). The revenue that a Transmission Owner receives from a TCC sold in a Centralized Auction will be divided equally among the months for which the TCC is sold. The revenue from these TCCs will enter the TSC formula month-by-month through the SR term, beginning with the first month of the period covered by the Centralized Auction. The ISO is responsible for calculating the SR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation. The ECR revenue will be calculated monthly and will enter the TSC formula with a two-month lag (*e.g.*, January actual data will be used in February to calculate the ECR term used

in the TSC for March). The ISO is responsible for calculating the ECR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation.

The CRR revenue will be calculated monthly and will enter the TSC formula with a two-month lag (*e.g.*, January actual data will be used in February to calculate the CRR term used in the TSC for March). Each Transmission Owner will identify for the ISO each ETA ("Identified ETA"), under which the Transmission Owner is a customer, the expenses for which are included in the Transmission Owner's RR. The ISO shall calculate that Transmission Owner's Congestion Payments received from Grandfathered TCCs and Imputed Revenues from Grandfathered Rights from the Transmission Owner's Identified ETAs. If the inclusion of the costs under an Identified ETA in the Transmission Owner's RR is subject to refund, then the CRR shall be subject to adjustment. If the costs under one or more of the Identified ETAs are removed from the RR and the Transmission Owner is required to recalculate its TSC with the adjusted RR, then in recalculating the TSC, the Transmission Owner shall reverse the portion of the CRR that was attributed to each such ETA. The Transmission Owner shall rebill the customers based on the recalculated TSC. To the extent the Transmission Owner owes a refund to the customer, it shall comply with any applicable refund obligations, including payment of interest to the extent due pursuant to 18 C.F.R. § 35.19a(a)(2)(iii), or its successor. If the reversal of the CRR results in a higher TSC than was charged, the customer shall pay in the time prescribed for payment of TSCs the Transmission Owner the difference between the TSC payments it made and the rebilled amounts, with interest thereon from the dates payments were made to the date that the rebilled amounts are due. Said interest will be calculated in the same manner as interest on over-payments as specified in 18 C.F.R. § 35.19a(a)(2)(iii), or its successor.

The Reserved will be calculated monthly and will enter the TSC formula with a two-month lag (e.g., January actual data will be used in February to calculate the ETCNL TCC term used in the TSC for March). The ISO shall calculate a Transmission Owner's Reserved.

WR: The revenue that a Transmission Owner collects for new external sales will be calculated monthly and will enter the WR term in the TSC formula with a two-month lag (i.e., January actual data will be used in February to calculate the WR term used in the TSC for March). The ISO is responsible for calculating new external sales subcomponent of the WR component of each Transmission Owner's TSC. The Transmission Owner will not adjust the ISO's calculation. The actual revenue that a Transmission Owner collects for grandfathered OATT service that extends beyond ISO start-up, and revenues related to pre-OATT grandfathered arrangements as provided for under numbers (2) and (3) of Original Sheet No. 214A, will also be calculated monthly and will enter the WR term in the TSC formula based upon the prior month's information. For the first month the credit will be equal to the actual revenues received under those-grandfathered agreements to be included in the WR component.

The BU term will be updated based on Transmission Owner filings to FERC (or a NYISO filing to FERC on behalf of LIPA) under the FPA. These filings will be made when the Transmission Owner determines that a change to its BU is required.

14.1.2.2 Implementation of TSC

At the start of LBMP implementation, certain variables of the TSC equation will not be available. For the first and second month of LBMP implementation, the only terms in the TSC equation that will be known by each Transmission Owner are its Annual Transmission Revenue Requirement (RR), Scheduling, System Control and Dispatch Costs (CCC), Revenues from the Sale of TCCs in the Transitional Auction (SR₂), Wheeling Revenues Associated with continuing OATT reservations (WR) and Billing Units (BU), which have been approved by or filed with FERC or, in the case of LIPA, approved by the Long Island

Power Authority's Board of Trustees. (Billing Units for “metered” retail customers are based on manual meter readings). For these two months each Transmission Owner shall calculate its TSC using the following equation:

$$\text{WHOLESALE TSC} = [(RR \div 12) + (CCC \div 12) - SR - WR] / BU \div 12$$

LTPP will not be available until after the Initial Auction as defined in Attachment M for Long Term TCCs. For the third month of LBMP implementation until the second month of the Capability Period corresponding to the initial auction for Long Term TCCs, each Transmission Owner shall calculate its TSC using the following equation:

$$\text{WHOLESALE TSC} = \{(RR \div 12) + (CCC \div 12) - SR - ECR - CRR - WR\} / (BU \div 12)$$

From the second month of the Capability Period corresponding to the initial auction for Long Term TCCs , until the conclusion of the LBMP Transition Period, the TSC shall be calculated using the equation in Section 14.1.2.1.

After the conclusion of the LBMP Transition Period, the LTPP component will no longer be applicable and each Transmission Owner shall calculate its Wholesale TSC using the following equation:

$$\text{WHOLESALE TSC} = \{(RR \div 12) + (CCC \div 12) - SR - ECR - CRR - WR - \text{Reserved}\} / (BU \div 12)$$

14.1.3 Filing and Posting of Wholesale TSCs

The Transmission Owners shall coordinate with the ISO to update certain components of the Wholesale TSC formula on a monthly basis or Capability Period basis. Each Transmission Owner may update its Wholesale TSC calculation to change its RR, CCC, or BU component value(s). Such updates, however, shall be subject to necessary FERC filings under the FPA. Each Transmission Owner will calculate its monthly Wholesale TSC and provide the ISO with the Wholesale TSC by no later than the fourteenth of each month, for posting on the OASIS to become effective on the first of the next calendar

month. Beginning with the implementation of LBMP, the monthly Wholesale TSCs for each of the Transmission Districts shall be posted on the OASIS by the ISO no later than the fifteenth of each month [or as soon thereafter as is reasonably possible but in no event later than the 20th of the month](#) to become effective on the first of the next calendar month.

14.1.4 TSC Calculation Information

The Annual Transmission Revenue Requirements (“RR”); Scheduling, System Control and Dispatch Costs (“CCC”), Billing Units (“BU”) and Rates of the Transmission Owners, except NYPA, for the purpose of calculating the respective Transmission District-based Wholesale TSC are shown in Table 1 below.

TABLE 1 - WHOLESALE TSC CALCULATION INFORMATION

Transmission Owner	Revenue Requirement (RR)	Scheduling System Control and Dispatch Costs (CCC)	Annual Billing Units (BU) MWh	Rate \$/MWh ¹
Central Hudson Gas & Electric Corp.	\$16,375,919	\$1,309,980	4,723,659	\$3.7441
Consolidated Edison Co. of NY, Inc.	\$385,900,000	\$21,000,000	49,984,628	\$8.1405
LIPA	\$105,602,083	\$3,453,343	20,618,939	\$5.2891
New York Electric & Gas Corporation ²	\$94,143,899	\$1,633,000	14,817,111	\$6.4639
Niagara Mohawk Power Corporation	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9	See Attachment H, Section 14.1.9

Orange and Rockland Utilities, Inc.	\$21,034,831	\$942,579	3,595,947	\$6.1117
Rochester Gas and Electric Corporation	\$25,795,509	\$583,577	6,967,556	\$3.7860

¹The rate column represents the unit rate prior to crediting; the actual rate will be determined pursuant to the applicable TSC formula rate.

²NYSEG's RR, BU and unit Rate prior to adjustment pursuant to Attachment H, are subject to retroactive modification pursuant to the provisions of the Settlement Agreement approved by the Commission in its March 26, 2004 order issued in Docket No. EL04-56-000. For any Transmission Customer that "opts out" of the Settlement Agreement as described in paragraph 1.E thereof, the applicable NYSEG "RR" shall be \$100,541,739; the "BU" shall be 13,741,901 MWh; and, the "Rate" prior to adjustment pursuant to Attachment H, shall be \$7.4235 effective as of March 1, 2004.

14.1.5 Treatment of Gross Receipts Tax

14.1.5.1 Central Hudson Gas & Electric Corporation

Central Hudson's TSC shall be increased by dividing the following surcharge factors into the total of all applicable rates and charges to reflect the New York State GRT (0.94922 in the MTA regions and 0.95750 in the non-MTA regions), which is not specifically provided for in the transmission rate, to the extent such tax is imposed on Central Hudson as a result of the transmission service provided to such Customer. Central Hudson shall make an appropriate filing pursuant to Section 205 of the Federal Power Act to implement any change in the specified tax rate prior to altering the tax rate under this provision.

14.1.5.2 Consolidated Edison Company of New York, Inc.

The GRT is included in Con Edison's TSC rate. Con Edison will not charge separately for GRT.

14.1.5.3 LIPA

The GRT is included in LIPA's TSC rate. LIPA will not charge separately for GRT.

14.1.5.4 New York State Electric & Gas Corporation

The Transmission Customer shall pay an amount sufficient to reimburse NYSEG for any amounts payable by NYSEG as sales, excise, value-added, gross receipts or other applicable taxes with respect to the total amount payable to NYSEG pursuant to the Tariff. The total of all rates and charges will be divided by the appropriate tax factor listed below, depending upon the geographic location of the Transmission Customer's Point(s) of Delivery

Within the Metropolitan Commuter Transportation District:	0.984583
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Not within the Metropolitan Commuter Transportation District:	0.986823
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These tax factors incorporate the taxes imposed on the Transmission Provider's electric revenues pursuant to New York law and represents the Franchise Tax on Gross Earnings, the Gross Income Tax, and where applicable the Metropolitan Commuter Transportation District Surcharge.

This Provision shall be effective upon commencement of services under the ISO OATT.

14.1.5.5 Niagara Mohawk Power Corporation

For the settled Niagara Mohawk TSC rate, the GRT is included in the RR and there will be no separate GRT tax assessed; For the filed Niagara Mohawk TSC rate, GRT initially is included in the RR and there will be no separate GRT assessed; however, this issue with regard to GRT is subject to final Commission action in Docket No. OA96-194-000, including all stipulations executed in connection therewith.

14.1.5.6 Orange and Rockland Utilities, Inc.

The Transmission Customer's rate will be increased to reflect the gross receipts tax ("GRT") which is not specifically provided for in the transmission rate and ancillary service rates, that a governmental authority may impose on Orange and Rockland as a result of the Transmission Service provided to such Transmission Customer pursuant to Sections 186 and 186-a of the New York Tax Law. The current effective GRT rate for the Section 186-a tax is 3.25% from October 1, 1998 through October 31, 1999 and 2.5% on and after January 1, 2000. The maximum locality rate allowable under state law for each locality is specified below. However, if the actual locality rate is less than the maximum locality rate permitted under state law, O&R shall charge the actual tax rate levied by the locality. The currently effective GRT rate for the Section 186 tax is .75%.

Airmont	1.0%
Bloomingburg	1.0%
Chestnut Ridge	1.0%
Goshen	1.0%
Grandview on Hudson	1.0%
Greenwood Lake	1.0%
Harriman	1.0%
Haverstraw	1.0%
Highland Falls	1.0%
Hillburn	1.0%
Kaser	1.0%
Kiryas Joel	1.0%
Middletown	1.0%
Monroe	1.0%

Montebello	1.0%
New Hempstead	1.0%
New Square	1.0%
Nyack	1.0%
Otisville	1.0%
Piermont	1.0%
Pomona	1.0%
Port Jervis	1.0%
Sloatsburg	1.0%
South Nyack	1.0%
Spring Valley	1.0%
Suffern	1.0%
Unionville	1.0%
Upper Nyack	1.0%
Warwick	1.0%
Washingtonville	1.0%
Wesley Hills	1.0%
West Haverstraw	1.0%
Wurtsboro	1.0%

14.1.5.7 Rochester Gas & Electric Corporation

The Transmission Customer's rate will be increased to reflect the gross receipts tax which is not specifically provided for in the transmission rate and ancillary service rates, that a governmental authority may impose on RG&E as a result of the Transmission Service provided to such Transmission Customer pursuant to Sections 186 and 186-a of the New York Tax Law. The currently effective GRT rate

for the Section 186-a tax is 3.5% and each locality rate is specified below. The currently effective GRT rate for the Section 186 tax is .75%.

City of Rochester	3.0%
Leroy	1.0%
Manchester	1.0%
Perry	1.0%
Shortsville	1.0%
Warsaw	1.0%
Hilton	1.0%
Pittsford	1.0%
Caledonia	1.0%
Wolcott	1.0%
Avon	1.0%
Leicester	1.0%
Nunda	1.0%
Genesco	1.0%
Mt. Morris	1.0%
Sodus Point	1.0%
Livonia	1.0%
Meridian	1.0%
City of Canandaigua	1.0%
Fairport	1.0%
Brockport	1.0%
Scottsville	1.0%
East Rochester	1.0%

14.1.6 TSC For Retail Access Customers ("RTSC")

Customers who apply for unbundled Transmission Service in accordance with the provisions of a Transmission Owner's retail access program filed with the PSC or, in the case of LIPA, approved by the Long Island Power Authority's Board of Trustees, will be responsible for paying a retail transmission service charge as detailed in Section 5 of this Tariff.

14.1.7 NYPA Transmission Service Charge

The NYPA TSC for service to its directly connected Loads (Reynolds Metals, GM-Massena, Town of Massena and the City of Plattsburgh) shall, at the Eligible Customer's option, be (a) \$1.30 per kilowatt-month or (b) no more than \$3.75 per MWh; not to exceed \$60.00 per MW Day applied to peak MWh scheduled any hour each day; not to exceed \$300.00 per MW-Week applied to the peak MWh scheduled any hour each week. The TSC applicable to service over the Vermont intertie² and the Ontario-Hydro intertie shall be the same as (b). The TSC applicable to service over the Hydro-Quebec intertie shall be no more than \$4.62 per MWh; not to exceed \$73.85 per MW-Day applied to peak MWh scheduled each day; not to exceed \$369.23 per MW-Week applied to the peak MWh scheduled any hour each week. NYPA shall coordinate with the ISO to update its TSC. Such updates shall be subject to FERC filings.

14.1.8 Discounting

Each Transmission Owner may advise the ISO of discounts to its TSC applicable during a specified period to all deliveries to a particular Interconnection between the NYCA and another Control Area. The ISO shall post the discounts on the OASIS for the specified period.

²The NYPA TSC shall not apply to service over the Vermont intertie provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

Three principal requirements apply to discounts for Transmission Service as follows: (1) any offer of a discount made by a Transmission Owner must be announced to all Eligible Customers solely by posting on the OASIS; (2) any customer-initiated requests for discounts (including requests for use by a Transmission Owner's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS; and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount that the Transmission Owner agrees to and advises the ISO of, the same discounted Transmission Service rate will be offered to all Transmission Customers for the same period for all deliveries to a particular Interconnection between the NYCA and another Control Area. The ISO will post the discounts on the OASIS for the specified period.

TABLE 2

Applicable Wholesale TSC for Exports from

New York State, by Transmission Circuit

Ckt.Id	From/To	kV	From Co./To Ext.	Wholesale TSC Paid
5018	Ramapo / Branchburg	500	O&R/PJM	Con Ed/O&R
398	Pleasant Valley/ Long Mtn	345	CHG&E / NE	Con Ed
B3402	Farragut / Hudson	345	Con Ed / PJM	Con Ed
C3403	Farragut / Hudson	345	Con Ed / PJM	Con Ed
A2253	Goethals / Linden	230	Con Ed / PJM	Con Ed
FE	Smithfield / Falls Village	69	CHG&E/NE	CHG&E
1385	Northport / Norwalk ¹	138	LIPA / NE	LIPA
393	Alps / Berkshire	345	NMPC / NE	NMPC
69	So. Ripley / Erie East	230	NMPC / PJM	NMPC
E205W	Rotterdam / Bear Swamp	230	NMPC / NE	NMPC
BP76	Packard / Beck	230	NMPC / OH	NMPC
171	Falconer / Warren	115	NMPC / PJM	NMPC
6	Hoosick / Bennington	115	NMPC / NE	NMPC
7	Whitehall / Blissville	115	NMPC / NE	NMPC
1	Dennison / Rosemont	115	NMPC / HQ	NMPC
2	Dennison / Rosemont	115	NMPC / HQ	NMPC
37-HS	Stolle Road / Homer City	345	NYSEG / PJM	NYSEG
30-HW	Watercure / Homer City	345	NYSEG / PJM	NYSEG
70-EH	Hillside / East Towanda	230	NYSEG / PJM	NYSEG
952	Goudey / Laurel Lake	115	NYSEG / PJM	NYSEG
956	No. Waverly / East Sayre	115	NYSEG / PJM	NYSEG
J	So. Mahwah / Waldwick	345	O&R / PJM	Con Ed/O&R
K	So. Mahwah / Walkwick	345	O&R / PJM	Con Ed/O&R
7040	Massena / Chateaugay	765	NYPA / HQ NYPA	NYPA
PA302	Niagara / Beck A	345	NYPA / OH	NYPA
PA301	Niagara / Beck B	345	NYPA / OH	NYPA
L34P	Moses / St. Lawrence	230	NYPA / OH	NYPA
L33P	Moses / St. Lawrence	230	NYPA / OH	NYPA
PA27	Niagara / Beck	230	NYPA / OH	NYPA
PV-20	Plattsburgh / Grand Isle	115	NYPA / NE	NYPA

¹ All scheduling over the Northport - Norwalk Intertie is conducted by LIPA pursuant to Section 5.7 of this Tariff.

TABLE 3

**Applicable Wholesale TSC for Municipal Utilities,
Electric Cooperatives and Loads**

Except for those municipal utilities and electric cooperatives that continue to take transmission service under an Existing Transmission Agreement, the following Loads shall be obligated to pay the noted Transmission District - based TSC as applicable in accordance with Section 2.7 of this Tariff.

Load	TSC Paid	Load	TSC Paid	Load	TSC Paid
		Greene	NYSEG	Sherrill	NMPC
		Green Island	NMPC	Silver Springs	NYSEG
		Greenport	LIPA	Skaneateles	NMPC
		Groton	NYSEG	Solvay	NMPC
		Hamilton	NYSEG	Spencerport	RG&E
		Holley	NMPC	Springville	NMPC
		Ilion	NMPC	Steuben	NYSEG
Akron	NMPC	Lake Placid	NMPC	Theresa	NMPC
Andover	NMPC	Little Valley	NMPC	Tupper Lake	NMPC
Angelica	RG&E	Marathon	NYSEG	Watkins Glen	NYSEG
Arcade	NMPC	Mayville	NMPC	Wellsville	NMPC
Bath	NYSEG	Mohawk	NMPC	Westfield	NMPC
Bergen	NMPC	Oneida -Madison	NMPC/ NYSEG	Massena	NYPA
Boonville	NMPC	Otsego	NYSEG	Freeport	LIPA
Brolton	NMPC	Penn Yan	NYSEG	Jamestown	NMPC
Castile	NYSEG	Philadelphia	NMPC	Rockville Ctr.	LIPA

Churchville	NMPC	Plattsburgh	NYPA	Alcoa	(1)
Delaware	NYSEG	Richmondville	NMPC	Reynolds	NYPA
Endicott	NYSEG	Rouses Point	NYSEG	Gen. Motors (Massena, NY)	NYPA
Fairport	NMPC	Salamanca	NMPC	Cornwall	NMPC
Frankfort	NMPC	Sherburne	NYSEG		

Notes: (1) - Load is treated as an entity external to the NYCA.

14.1.9 Niagara Mohawk Power Corporation Wholesale TSC Formula Components RR, CCC and BU and Sources of Data Inputs

Niagara Mohawk Power Corporation (“NMPC”) will calculate and update each of its RR, CCC, and BU components annually using the formulas for each component contained in Attachment 1 and in accordance with the update procedures set forth in Section 14.1.9.4. With the exception of forecasted information, the cost data used in the Formula Rate will be cost data from NMPC’s annual FERC Form 1, NMPC’s Annual Report to the New York State Public Service Commission, or NMPC’s official books of record.

14.1.9.1 Definitions

Capitalized terms used in this calculation will have the following definitions:

Allocation Factors

14.1.9.1.1 Electric Wages and Salaries Allocation Factor shall be fixed at 0.835.

14.1.9.1.2 Gross Transmission Plant Allocation Factor shall equal the total investment in Transmission Plant in Service, Transmission Related Electric General Plant, Transmission

Related Common Plant and Transmission Related Intangible Plant divided by Gross Electric Plant.

14.1.9.1.3 Transmission Wages and Salaries Allocation Factor shall be fixed at 0.13.

14.1.9.1.4 Gross Electric Plant Allocation Factor shall equal Gross Electric Plant divided by the sum of Total Gas Plant, Total Electric Plant, and total Common Plant.

Ratebase and Expense Items

14.1.9.1.5 Administrative and General Expense shall equal expenses as recorded in FERC Account Nos. 920-935. FERC Account No. 926 shall be adjusted by reversing the adjustment to the deferred pension costs booked per the NYPSC Statement of Policy for Accounting and Ratemaking Treatment for Pension and Post-Retirement Benefits Other than Pensions. In addition, Administrative and General Expenses shall exclude the actual Post-Employment Benefits Other than Pensions ("PBOP") expenses included in FERC Account No. 926, and shall add back the FERC accepted Post Employment Benefit Other than Pensions of \$88,644,000 annually or \$7,387,000 per month or any other amount subsequently approved by FERC under Section 205 or 206 of the Federal Power Act.

14.1.9.1.6 Amortization of Investment Tax Credits shall equal credits as recorded in FERC Account No. 420, per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).

14.1.9.1.7 Amortization of Debt Discount Expense shall equal expenses as recorded in FERC Account No. 428.

- 14.1.9.1.8 Amortization of Loss on Reacquired Debt shall equal expenses as recorded in FERC Account No. 428.1.
- 14.1.9.1.9 Amortization of Premium on Debt –Credit shall equal the expenses as recorded in FERC Account 429.
- 14.1.9.1.10 Amortization of Gain on Reacquired Debt--Credit shall equal the expenses as recorded in FERC Account No. 429.1.
- 14.1.9.1.11 Common Plant shall equal the balance of plant recorded in FERC Account Nos. 389-399. Common Plant shall be defined as the plant common to NMPC's gas and electric functions per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).
- 14.1.9.1.12 Common Plant Depreciation Expense shall equal the common plant depreciation expenses as recorded in FERC Account No. 403 associated with Common Plant per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).
- 14.1.9.1.13 Common Plant Depreciation Reserve shall equal the common plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Common Plant per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).
- 14.1.9.1.14 Depreciation Expense for Transmission Plant in Service shall equal depreciation expenses as recorded in FERC Account No. 403 calculated using the depreciation rates set forth in the following table:

Depreciation Rates

<u>FERC Account/NMPC Internal Account No.</u>		<u>Annual Rate</u>
350	Land –Rights of Way and Easements	1.32

352	Structures and Improvements	2.08
353	Station Equipment	2.44
353.55	Station Equipment – EMS	3.40
354	Towers and Fixtures	1.71
355	Poles and Fixtures	2.00
356	Overhead Conductors and Devices	1.60
357	Underground Conduit	1.33
358	Underground Conductors and Devices	1.48
359	Roads and Trails	1.33
370	Meters	
	Meters	5.05
	Installation	5.05

14.1.9.1.15 Distribution Plant shall equal the plant balance as recorded in FERC Account Nos. 360 – 374.

14.1.9.1.16 Equity AFUDC Component of Depreciation Expense shall equal the activity recorded in FERC Account No. 419.1.

14.1.9.1.17 Electric Environmental Remediation Expense shall be the environmental remediation expense as recorded in NMPC's internal Account 930.200.

- 14.1.9.1.18 Electric General Plant shall equal the plant balance recorded in FERC Account Nos. 389-399. Electric General Plant shall be defined as the general plant associated with NMPC's electric function.
- 14.1.9.1.19 Electric General Plant Depreciation Expense shall equal general plant depreciation expenses as recorded in FERC Account No. 403 associated with Electric General Plant.
- 14.1.9.1.20 Electric General Plant Depreciation Reserve shall equal the general plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Electric General Plant.
- 14.1.9.1.21 Electric Property Insurance shall equal property insurance recorded in FERC Account No. 924.
- 14.1.9.1.22 Electric Research and Development Expense shall equal research and development expenses as recorded in NMPC internal Account No. 930.210.
- 14.1.9.1.23 Gain on Reacquired Debt shall equal the balance as recorded in FERC Account No. 257.
- 14.1.9.1.24 Gross Electric Plant shall equal Total Electric Plant plus an allocation of Common Plant determined by multiplying Common Plant by the Electric Wages and Salaries Allocation Factor.
- 14.1.9.1.25 Gross Plant (Gas & Electric) shall equal Total Gas Plant plus Total Electric Plant plus Total Common Plant.

- 14.1.9.1.26 Gross Transmission Investment shall equal the total of Transmission Plant in Service, Transmission Related Electric General Plant, Transmission Related Common Plant and Transmission Related Intangible Plant.
- 14.1.9.1.27 Intangible Electric Plant shall equal the balance of plant recorded in FERC Account Nos. 301-303. Intangible Electric Plant shall be defined as the intangible plant associated with NMPC's electric functions.
- 14.1.9.1.28 Intangible Electric Plant Depreciation Expense shall equal the intangible electric plant depreciation expenses as recorded in FERC Account No. 403 associated with Intangible Electric Plant.
- 14.1.9.1.29 Intangible Electric Plant Depreciation Reserve shall equal the intangible plant depreciation reserve balance as recorded in FERC Account No. 108 associated with Intangible Electric Plant.
- 14.1.9.1.30 Loss on Reacquired Debt shall equal the loss on reacquired debt as recorded in FERC Account No. 189.
- 14.1.9.1.31 Materials and Supplies shall equal materials and supplies balance as recorded in FERC Account No. 154 per 18 C.F.R. Parts 101 (Electric) and 201 (Gas).
- 14.1.9.1.32 Payroll Taxes shall equal the electric payroll tax expenses related to FICA and federal and state unemployment as recorded in NMPC's internal Account Nos. 408.100, 408.110 and 408.130.
- 14.1.9.1.33 Plant Held for Future Use shall equal the balance as recorded in FERC Account No. 105 for transmission uses within 5 years.

- 14.1.9.1.34 Prepayments shall equal prepayment balance as recorded in FERC Account No. 165 per 18 C.F.R. Parts 101 (Electric) and 201 (Gas) less prepaid state and Federal income taxes.
- 14.1.9.1.35 Real Estate Tax Expenses shall equal electric real estate tax expense as recorded in NMPC's internal Account No. 408.140 and 408.180.
- 14.1.9.1.36 Regulatory Assets and Liabilities shall equal state and federal regulatory asset balances in FERC Account Nos. 182.3 and 254, assets and liabilities solely related to FAS109, and excess AFUDC.
- 14.1.9.1.37 Total Accumulated Deferred Income Taxes shall equal the sum of deferred tax balances recorded in FERC Account Nos. 281 - 283 plus accumulated deferred investment tax credits as reflected in FERC Account No. 255, minus the deferred tax balance in FERC Account No. 190. Total Accumulated Deferred Income Taxes shall exclude the specifically identified generation-related stranded cost deferred taxes.
- 14.1.9.1.38 Total Electric Plant shall equal the sum of Transmission Plant, Distribution Plant, Electric General Plant and Intangible Electric Plant.
- 14.1.9.1.39 Total Gas Plant shall equal the plant balance recorded in 18 C.F.R. Part 201, FERC Account Nos. 301-399. Total Gas Plant shall exclude Common Plant.
- 14.1.9.1.40 Transmission Depreciation Reserve shall equal electric transmission plant related depreciation reserve balance as recorded in FERC Account No. 108, plus Transmission Related General Plant Accumulated Depreciation, Transmission Related Amortization of Other Utility Plant, and Common Plant Accumulated Depreciation associated with Gross Electric Plant.

14.1.9.1.41 Transmission Operation and Maintenance Expense shall equal the sum of electric expenses as recorded in FERC Account Nos. 560, 562-574.

14.1.9.1.42 Transmission Plant shall equal the gross plant balance as recorded in FERC Account Nos. 350-359.

14.1.9.1.43 Transmission Related Bad Debt Expense shall equal Bad Debt Expense as reported in Account 904 related to NMPC's wholesale transmission billing.

14.1.9.1.44 Unamortized Discount on Long-Term Debt shall equal the balance in FERC Account No. 226.

14.1.9.1.45 Wholesale Metering Investment shall equal the gross plant investment associated with any Revenue or Remote Terminal Unit ("RTU") meters and associated equipment connected to an internal or external tie at voltages equal to or greater than 23 kV. The gross plant investment shall be determined by multiplying the number of such existing wholesale meters recorded in FERC Account No. 370.3 and in blanket metering accounts by the average cost of the meters plus the average costs of installation. To the extent future gross plant investment for Wholesale Metering can be specifically identified, actual gross meter costs will be used.

Forecast and True-up Related Terms

14.1.9.1.46 Forecast Period shall mean the calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available, as of the beginning of the Update Year.

14.1.9.1.47 Forecasted Transmission Plant Additions ("FTPA") shall mean the sum of:

14.1.9.1.47.1 NMPC's actual Transmission Plant additions during the first quarter (January 1 through March 31) of the Forecast Period; and

14.1.9.1.47.2 NMPC's forecasted transmission investment for the Forecast Period less the amount (i), divided by 2.

14.1.9.1.48 Interest on refunds, surcharges, or adjustments, as applicable, shall mean interest calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii) (or as such provision may be renumbered in the future).

14.1.9.1.49 Actual Transmission Revenue Requirement shall mean the current Historical Transmission Revenue Requirement (as defined in Attachment 1).

14.1.9.1.50 Actual Scheduling, System Control and Dispatch cost shall mean the most recently established CCC (as defined in Attachment 1).

14.1.9.1.51 Actual Billing Units shall mean the most recently established BU (as defined in Attachment 1).

14.1.9.1.52 Prior Year Transmission Revenue Requirement shall equal RR less Annual True-Up ("ATU"), as defined in Attachment 1, for the most recently ended calendar year as of the beginning of the Update Year.

14.1.9.1.53 Prior Year Scheduling, System Control and Dispatch shall equal the CCC, as defined in Attachment 1, for the prior calendar year.

14.1.9.1.54 Prior Year Billing Units shall equal the BU, as defined in Attachment 1, for the prior calendar year.

- 14.1.9.1.55 Prior Year Unit Rate shall equal the sum of RR, as defined in Attachment 1, for the most recently ended Prior Year Revenue Requirement and the Prior Year Scheduling, System Control and Dispatch divided by the Prior Year Billing Units.
- 14.1.9.1.56 Annual Update shall mean the calculation of the RR, CCC, and BU components with Data Inputs for an Update Year in accordance with Section 14.1.9.4.
- 14.1.9.1.57 Data Input shall mean any data required for the calculation of RR, CCC and BU, in accordance with the Formula Rate.
- 14.1.9.1.58 Formal Challenge shall mean a challenge presented in accordance with Section 14.1.9.4.3.2.
- 14.1.9.1.59 Informational Filing shall mean the filing that NMPC makes in accordance with Section 14.1.9.4 to establish the Annual Update for an Update Year.
- 14.1.9.1.60 Interested Party shall mean a person that is (i) a party to FERC Docket No. ER08-552, (ii) the New York State Public Service Commission; (iii) a transmission customer under this Tariff that pays charges based on the Formula Rate during the calendar year prior to the submission of the Informational Filing; or (iv) a state regulatory authority having jurisdiction over the retail electric rates of such a transmission customer, provided that such regulatory authority or such customer notifies NMPC of that fact no later than 30 days prior to the Publication Date. An Interested Person includes employees of or consultants to such person.
- 14.1.9.1.61 Material Accounting Change shall mean an accounting policy or practice, including, but not limited to, a policy or practice affecting the allocation of costs or revenues, employed by NMPC during an Update Year that differs from the

corresponding policy or practice in effect during any of the three previous calendar years which change affects any Data Input for the Update Year by \$1.0 million or more, as compared to the previous calendar year.

14.1.9.1.62 Preliminary Challenge shall mean a challenge presented by an Interested Party in accordance with Section 14.1.9.4.2.1.

14.1.9.1.63 Publication Date shall be the date of an Informational Filing for an Update Year.

14.1.9.1.64 Review Period shall be the period ending one-hundred and fifty (150) days after the Publication Date, unless extended in accordance with Section 14.1.9.4.2.1.

14.1.9.1.65 Formula Rate shall be the formulas set forth in Attachment 1.

14.1.9.1.66 Update Year shall be the period from July 1 of a given calendar year through June 30 of the subsequent calendar year for a particular Annual Update.

All references to FERC accounts in the above definitions are references to 18 C.F.R. Part 101, unless specifically noted otherwise. In the event that the above-referenced FERC accounts are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

14.1.9.2 Calculation of RR

The RR component shall equal the (a) Historical Transmission Revenue Requirement plus (b) the Forecasted Transmission Revenue Requirement plus (c) the Annual True-Up, determined in accordance with the Formula Rate.

14.1.9.3 Fixed Formula Inputs

Formula Rate inputs for (i) the authorized return on common equity (“ROE”), (ii) any cap on the common equity component of the capital structure, (iii) amount and amortization period of extraordinary property losses, (iv) depreciation and/or amortization rates, (v) PBOP expenses, and (vi) the electric wages and salaries allocation factor and transmission wages and salaries allocation factor shall be stated values until changed by the FERC pursuant to Section 205 or Section 206 of the Federal Power Act. An application under Section 205 or 206 or a proceeding initiated by FERC *sua sponte* under Section 206 to modify any of these stated values under the Formula Rate other than the ROE, the cap on the common equity component of the capital structure or the allocation factors in (vi) shall not be deemed to open for review other components of the Formula Rate.

14.1.9.4 Annual Update Process

14.1.9.4.1 Annual Updates

14.1.9.4.1.1 On or before June 14th of each year, NMPC shall recalculate its RR, CCC, and BU components, applying the Data Inputs called for in the Formula Rate to produce the Annual Update for the upcoming Update Year, and:

14.1.9.4.1.1.1 shall post such Annual Update and a “workable” excel file containing that year’s Annual Update on the NYISO’s Internet website;

14.1.9.4.1.1.2 shall file such Annual Update with the FERC as the Informational Filing.

The submission of such Informational Filing with FERC shall not require any action by the agency; and

14.1.9.4.1.1.3 shall serve the Annual Update electronically on all Interested Parties.

14.1.9.4.1.2 If the date for making the Informational Filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall coincide with the NYISO posting requirement for July rates.

14.1.9.4.1.3 The Annual Update for the Update Year:

14.1.9.4.1.3.1 shall use the Data Inputs specified in NMPC's Formula Rate, and therefore, to the extent specified in NMPC's Formula Rate, be based upon NMPC's FERC Form No. 1 data for the most recent calendar year; to the extent specified in NMPC's Formula Rate, be based upon the books and records of NMPC consistent with FERC accounting policies, and, to the extent specified in NMPC's Formula Rate, be based on projections for the upcoming calendar year;

14.1.9.4.1.3.2 shall provide supporting documentation for Data Inputs in the form of the data provided in Attachment C to the Offer of Settlement dated April 6, 2009, in Docket No. ER08-552; and, with respect to Billing Units, shall include monthly documents in PDF format with redacted names and revised reference numbers for each entity to protect confidentiality, showing the Billing Units for each month of the most recently completed calendar billing year (the six-month updated BUs), including NMPC's Transmission Owner Load ("TOL"), consisting of metered loads for the December through November timeframe showing the calendar billing year BUs reported to the NYISO by NMPC. The total MWh of generation (including load modifiers) and net interchange for each NMPC transmission zone will be displayed. National Grid will also provide a document as a "workable" Excel file summarizing the TOL for disputed station service, High Load Factor Fitzpatrick and any other entity excluded from the Billing Units calculation in Attachment 1, Schedule 6.12, of the Formula Rate. The summary will be

labeled to show the reason for exclusion, consistent with the definition of Billing Units and will reconcile to the totals shown on Attachment 1, Schedule 6.12.

14.1.9.4.1.3.3 shall provide notice of and describe all Material Accounting Changes, which description shall include an explanation of the purpose for and the circumstances giving rise to the Material Accounting Change, including references to any relevant orders, policies or notices of the Securities and Exchange Commission, the FERC or a retail regulator, which explanation may incorporate by reference any applicable disclosure statements filed with any such agency;

14.1.9.4.1.3.4 shall provide notice of the date and location of the meeting to be held in accordance with Section 14.1.9.4.2.2;

14.1.9.4.1.3.5 shall be subject to challenge and review only in accordance with the procedures set forth in this Section 14.1.9.4, provided that such procedures shall not preclude investigation of the Annual Update by FERC, including through hearing procedures;

14.1.9.4.1.3.6 shall not seek to modify NMPC's Formula Rate and shall not be subject to challenge by an Interested Party seeking to modify NMPC's Formula Rate (*i.e.*, all such modifications to the Formula Rate will require, as applicable, a Federal Power Act Section 205 or Section 206 proceeding), provided that an Interested Party may propose for consideration a change to the Formula Rate, as provided in Section 14.1.9.4.3.5;

14.1.9.4.1.3.7 shall include a list of the email addresses of Interested Parties upon which the Annual Update was served; and

14.1.9.4.1.3.8 shall provide a description of, and workpapers for, any correction of an error discovered by NMPC that affects the calculation of any charges under the Formula Rate during a prior year within the period applicable under Section 14.1.9.4.4.

14.1.9.4.1.4 The fixed Formula Rate inputs set forth in Section 14.1.9.3 shall not be subject to adjustment in an Annual Update.

14.1.9.4.2 Annual Review Procedures

Each Annual Update shall be subject to the following review procedures:

14.1.9.4.2.1 Any Interested Party shall have up to one hundred fifty (150) days after the Publication Date (unless such period is extended with the written consent of NMPC) to review the calculations and to notify NMPC in writing of any specific challenges to the accuracy of any Data Input in the Annual Update or the conformance of any such Data Input with the requirements of the Formula Rate ("Preliminary Challenge"); provided, however, that each Interested Party shall make a good faith effort to submit Preliminary Challenges at the earliest practicable date so that they may be resolved as soon as possible, and provide NMPC with a non-binding list of potential Preliminary Challenges it may present, based on its review of the Annual Update and on responses to information requests provided to that point, within ninety (90) days of the Publication Date. Any Preliminary Challenge shall be posted on the NYISO's internet website and served by electronic service on all Interested Parties by the next business day following the date it is provided to NMPC.

14.1.9.4.2.2 Within thirty (30) days of the Publication Date, NMPC shall hold a meeting open to all Interested Parties, at which meeting: (a) NMPC shall present and explain the

Annual Update; (b) NMPC shall respond to questions from Interested Parties, to the extent such questions can be answered immediately; and (c) Interested Parties shall identify any areas of potential Preliminary Challenges, to the extent they have identified them at the time of the meeting.

14.1.9.4.2.3 Interested Parties shall have up to one hundred thirty (130) days after each annual Publication Date (unless such period is extended with the written consent of NMPC) to serve reasonable information requests on NMPC; provided, however, that the Interested Parties shall make a good faith effort to submit consolidated sets of information requests that limit the number and overlap of questions to the extent practicable. Such information requests may be directed to matters relevant to the accuracy of the Data Inputs included in the Annual Update and the conformance of those Data Inputs with the requirements of the corresponding provisions of the Formula Rate, including: (a) the reasons for any change in a Data Input from the corresponding Data Input in an earlier Annual Update; (b) the reasons for any change in a Data Input based on actual costs from the corresponding Data Input based on a cost projection in an earlier Annual Update; (c) any reports or other materials provided to fulfill the requirements of a state or federal regulatory agency that explain the basis for projected or actual costs reflected in a Data Input; and (d) the impact of any Material Accounting Change identified in the Annual Update on the charges produced by the Formula Rate.

14.1.9.4.2.4 NMPC shall make a good faith effort to respond to information requests pertaining to the Annual Update within ten (10) business days of receipt of such requests. NMPC may give reasonable priority to responding to requests that satisfy the practicable coordination and consolidation provision of Section 14.1.9.4.2.3, above.

NMPC's responses to information requests shall not be entitled to protection as privileged settlement communications; provided, however, that: (a) any communications between NMPC and any Interested Party in connection with efforts to negotiate a resolution of a Preliminary Challenge or Formal Challenge shall be entitled to such protection; (b) if NMPC's response to an information request contains proprietary or trade secret information or critical energy infrastructure information, NMPC and the Interested Party or Parties receiving such information shall enter into a confidentiality agreement materially similar to the model protective order used by the FERC to protect the confidentiality of such information; and (c) nothing herein shall require NMPC to provide information that is protected by the attorney-client privilege, the attorney work product doctrine, or any other legally recognized privilege.

14.1.9.4.3 Resolution of Challenges

14.1.9.4.3.1 NMPC and the Interested Parties shall negotiate in good faith throughout the Review Period to attempt to resolve any Preliminary Challenges.

14.1.9.4.3.2 If NMPC and any Interested Party or Parties have not resolved any Preliminary Challenge to the Annual Update within the Review Period, an Interested Party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of NMPC to continue efforts to resolve a Preliminary Challenge) to present the subject matter of the Preliminary Challenge to the FERC as a Formal Challenge, which shall be served on NMPC and all other Interested Parties by electronic service on the date of such filing and posted on the NYISO's internet website, however, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 14.1.9.4.2 if the FERC already has initiated a proceeding to investigate the

Annual Update. By no later than five (5) business days after the end of the Review Period, NMPC shall apprise Interested Parties of the resolution of all Preliminary Challenges that have been resolved and of the impact of the resolution of all such Preliminary Challenges on the Annual Update. Within an additional fifteen (15) business days, NMPC shall submit a supplement to its Informational Filing to the FERC, with electronic service upon the Interested Parties, reflecting the impact of all successfully resolved Preliminary Challenges.

14.1.9.4.3.3 Any response by NMPC to a Formal Challenge must be submitted to the FERC within twenty-one (21) days of the date of the filing of the Formal Challenge, and shall be posted on the NYISO's Internet website and served on all Interested Parties by electronic service on the date of such filing.

14.1.9.4.3.4 In any proceeding initiated by the FERC concerning the Annual Update or in response to a Formal Challenge, NMPC shall bear the burden of proving that the Data Inputs in that year's Annual Update are correct and conform to the terms of the Formula Rate and refunds or adjustments may be made, in either case with interest, to charges collected under the Formula Rate if the FERC concludes that the Data Inputs are incorrect or do not conform to the terms of the Formula Rate. In all other respects, any such proceeding shall be governed by the rules and requirements applicable to proceedings under Section 206 of the Federal Power Act.

14.1.9.4.3.5 An Interested Party may propose that resolution of a Preliminary Challenge or Formal Challenge concerning a Material Accounting Change necessitates changes to the Formula Rate to ensure that the resulting charges, including the effect of the Material Accounting Change, are just and reasonable. If NMPC agrees to such a proposed change

to the Formula Rate to resolve a Preliminary Challenge, NMPC shall file the change to the Formula Rate with the FERC for approval pursuant to Section 205 of the Federal Power Act. If NMPC does not agree to such a proposed change, the Interested Party may file the proposed change with the FERC for approval pursuant to Section 206 of the Federal Power Act concurrent with its submission of a Formal Challenge; provided that if FERC approves the proposed change, the change to the Formula Rate shall take effect as of the beginning of the Update Year during which the Section 206 filing is made, and refunds or surcharges shall be made, in either case with interest, to charges under the Formula Rate after the beginning of such Update Year to reflect the proposed change.

14.1.9.4.3.6 Nothing herein shall be deemed to limit in any way the right of NMPC to file unilaterally, pursuant to Section 205 of the Federal Power Act and the regulations thereunder, changes to NMPC's Formula Rate (including changes in connection with any incentive mechanism) or any of its Data Inputs (including, but not limited to, any fixed Data Inputs) or the right of any other party to file for such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder. All parties reserve all rights to challenge, or take any position in response to, any such filing by any other party.

14.1.9.4.4 Changes to Data Inputs

14.1.9.4.4.1 Any changes to the Data Inputs for an Annual Update, including but not limited to revisions resulting from any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall take effect as of the beginning of the Update Year and the impact of such changes shall be incorporated into the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. §

35.19(a)) in the Annual Update for the next effective Update Year. This mechanism shall apply in lieu of mid-Update Year adjustments and any refunds or surcharges, except that, if an error in a Data Input is discovered and agreed upon within the Review Period, the impact of such change shall be incorporated prospectively into the charges produced by the Formula Rate during the remainder of the year preceding the next effective Update Year, in which case the impact reflected in subsequent charges shall be reduced accordingly.

14.1.9.4.4.2 The impact of an error affecting a Data Input on charges collected during the Formula Rate during the five (5) years prior to the Update Year in which the error was first discovered shall be corrected by incorporating the impact of the error on the charges produced by the Formula Rate during the five-year period into the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 35.19(a)) in the Annual Update for the next effective Update Year. Charges collected before the five-year period shall not be subject to correction.

14.2 Attachment 1 to Attachment H

14.2.1 Schedules

Table of Contents

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Forecasted Transmission Revenue Requirement	Schedule 2
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Transmission Investment Base (Part 1 of 2)	Schedule 6 Page 2 of 2
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Capital Structure	Schedule 8
Expenses	Schedule 9
Other	Schedule 10
System Dispatch Expense - Component CCC	Schedule 11
Billing Units - Component BU	Schedule 12

Niagara Mohawk Power Corporation

Calculation of RR Pursuant to Attachment H, Section 14.1.9.2

	Year
--	------

Attachment 1

Schedule 1

Calculation of RR

14.1.9.2 The RR component shall equal the (a) Historical Transmission Revenue Requirement plus (b) the Forecasted Transmission Revenue Requirement plus (c) the Annual True-Up, determined in accordance with the formula below.

Historical Transmission Revenue Requirement (Historical TRR)

Line No.

1	<u>Historical Transmission Revenue Requirement (Historical TRR)</u>			
2				
3	14.1.9.2 (a)	Historical TRR shall equal the sum of NMPC's (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation Expense, (C)		
4		Transmission Related Real Estate Tax Expense, (D) Transmission Related Amortization of Investment Tax Credits,		
5		(E) Transmission Operation and Maintenance Expense, (F) Transmission Related Administrative and General Expenses, (G) Transmission		
6		Related Payroll Tax Expense, (H) Billing Adjustments, and (I) Transmission Related Bad Debt Expense less		
7		(J) Revenue Credits, and (K) Transmission Rents, all determined for the most recently ended calendar year as of the beginning of the update year.		
8		Reference		
9		<u>Section:</u>	0	
10		Return and Associated Income Taxes (A)	#DIV/0!	Schedule 8, line 64
11		Transmission-Related Depreciation Expense (B)	#DIV/0!	Schedule 9, Line 6, column 5
12		Transmission-Related Real Estate Taxes (C)	#DIV/0!	Schedule 9, Line 12, column 5
13		Transmission - Related Investment Tax Credit (D)	#DIV/0!	Schedule 9, Line 16, column 5
14		Transmission Operation & Maintenance Expense (E)	\$0	Schedule 9, Line 23, column 5
15		Transmission Related Administrative & General Expense (F)	#DIV/0!	Schedule 9, Line 38, column 5
16		Transmission Related Payroll Tax Expense (G)	\$0	Schedule 9, Line 44, column 5
17		Sub-Total (sum of Lines 10 - Line 16)	#DIV/0!	
18				
19		Plus: Billing Adjustments (H)	\$0	Schedule 10, Line 1
20		Plus : Bad Debt Expenses (I)	\$0	Schedule 10, Line 4
21		Less: Revenue Credits (J)	\$0	Schedule 10, Line 7
22		Less: Transmission Rents (K)	\$0	Schedule 10, Line 14
23				
24		Total Historical Transmission Revenue Requirement (Sum of Line 17 -		
25		Line 22)	#DIV/0!	

Niagara Mohawk Power Corporation
Forecasted Transmission Revenue Requirement
Attachment H, Section 14.1.9.2

Attachment 1
Schedule 2

0

Shading denotes an input

Line No.

14.1.9.2

1	(b) FORECASTED TRANSMISSION REVENUE REQUIREMENTS		
2	Forecasted TRR shall equal (1) the Forecasted Transmission Plant Additions (FTPA) multiplied by the Annual FTRRF, plus (2) the Mid-Year Trend		
3	Adjustment (MYTA), plus (3) the Tax Rate Adjustment (TRA), as shown in the following formula:		
4			
5	Forecasted TRR = (FTPA * FTRRF) + MYTA + TRA		
6			
7		<u>Period</u>	<u>Reference</u>
8			
9			
10	(1) Forecasted Transmission Plant Additions (FTPA)		\$0
11	Annual Transmission Revenue Requirement Factor (FTRRF)		#DIV/0!
12	Sub-Total (Lines 10*11)		#DIV/0!
13	Plus Mid-Year Trend Adjustment (2) (MYTA)		\$0
14	Forecasted Transmission Revenue Requirement (Line 12 + Line 13)		#DIV/0!
15			
16	(2) MID YEAR TREND ADJUSTMENT (MYTA)		
17	The Mid-Year Trend Adjustment shall be the difference, whether positive or negative, between		
18	(i) the Historical TRR Component (E) based on actual data for the first three months of the Forecast Period,		
19	and (ii) the Historical TRR Component (E) based on data for the first three months of the year prior to the Forecast Period.		
20			
21	(3) The Tax Rate Adjustment (TRA)		
22	The Tax Rate Adjustment shall be the amount, if any, required to adjust Historical TRR Component (A) for any change in the Federal Income Tax Rate		
23	and/or the State Income Tax Rate that takes effect during the first five months of the Forecast Period.		
24			
25	14.1.9.2(c) ANNUAL FORECAST TRANSMISSION REVENUE REQUIREMENT FACTOR		
26	The Annual Forecast Transmission Revenue Requirement Factor (Annual FTRRF) shall equal the sum of Historical TRR components (A) through (C),		
27	divided by the year-end balance of Transmission Plant in Service determined in accordance with Section 14.1.9.2 (a), component (A)1(a).		
28			
29			
30	Investment Return and Income Taxes	(A)	#DIV/0!
31	Depreciation Expense	(B)	#DIV/0!
32	Property Tax Expense	(C)	#DIV/0!
33	Total Expenses (Lines 30 thru 32)		#DIV/0!
34	Transmission Plant	(a)	#DIV/0!
	Annual Forecast Transmission Revenue Requirement Factor		
35	(Lines 33/ Line 34)		#DIV/0!

Source

Workpaper 8, Section I, Line 16
Line 35

Workpaper 9, line 31, variance
column

Workpaper 9

Schedule 1, Line 10

Schedule 1, Line 11

Schedule 1, Line 12

Schedule 6, Page 1, Line 12

Niagara Mohawk Power Corporation

Annual True-up (ATU)

Attachment H Section 14.1.9.2 (c)

Attachment 1

Schedule 3

Line No.		0	Year	Source:
1				
2	14.1.9.2(d)	The Annual True-Up (ATU) shall equal (1) the difference between the Actual Transmission Revenue Requirement and the Prior Year		
3		Transmission Revenue Requirement, plus (2) the difference between the Actual Scheduling, System Control and Dispatch costs		
4		and Prior Year Scheduling, System Control and Dispatch costs, plus (3) the difference between the Prior Year Billing Units and the Actual Year		
5		Billing Units multiplied by the Prior Year Unit Rate, plus (4) Interest on the net differences.		
6				
7	(1)	Revenue Requirement (RR) of rate effective July 1 of prior year	\$0	Schedule 4, Line 1, Col (d)
8		Less: Annual True-up (ATU) from rate effective July 1 of prior year	\$0	Schedule 4, Line 1, Col (c)
9		Prior Year Transmission Revenue Requirement	\$0	Line 7 - Line 8
10				
11		Actual Transmission Revenue Requirement	#DIV/0!	Schedule 4, Line 2, Col (a)
12		Difference	#DIV/0!	Line 11 - Line 9
13				
14	(2)	Prior Year Scheduling, System Control and Dispatch costs (CCC)	\$0	Schedule 4, Line 1, Col (e)
15		Actual Scheduling, System Control and Dispatch costs (CCC)	\$0	Schedule 4, Line 2, Col (e)
16		Difference	\$0	Line 15 - Line 14
17				
18	(3)	Prior Year Billing Units (MWH)	\$0	Schedule 4, Line 1, Col (f)
19		Actual Billing Units	-	Schedule 4, Line 2, Col (f)
20		Difference	-	Line 18 - Line 19
21		Prior Year Indicative Rate	#DIV/0!	Schedule 4, Line 1, Col (g)
22		Billing Unit True-Up	#DIV/0!	Line 20 * Line 21
23				
24		Total Annual True-Up before Interest	#DIV/0!	(Line 12 + Line 16 + Line 22)
25				
26	(4)	Interest	#DIV/0!	Line 57
27				
28		Annual True-up RR Component	#DIV/0!	(Line 24 + Line 26)
29				
30	Interest Calculation per 18 CFR § 35.19a			
31	(1)	(2)	(3)	(4)
32	Quarters	Annual	Accrued Prin	Monthly
33		Interest	& Int. @ Beg	(Over)/Under
34		Rate (a)	Of Period	Recovery
35				
36	3rd QTR '07		0	
37	July	0.00%		#DIV/0!
38	August	0.00%		#DIV/0!
39	September	0.00%		#DIV/0!

40									
41	4th QTR '07		#DIV/0!		92	92	1.0000	#DIV/0!	#DIV/0!
42	October	0.00%		#DIV/0!	31	92	1.0000	#DIV/0!	#DIV/0!
43	November	0.00%		#DIV/0!	30	61	1.0000	#DIV/0!	#DIV/0!
44	December	0.00%		#DIV/0!	31	31	1.0000	#DIV/0!	#DIV/0!
45									
46	1st QTR '08		#DIV/0!		91	91	1.0000	#DIV/0!	#DIV/0!
47	January	0.00%		#DIV/0!	31	91	1.0000	#DIV/0!	#DIV/0!
48	February	0.00%		#DIV/0!	29	60	1.0000	#DIV/0!	#DIV/0!
49	March	0.00%		#DIV/0!	31	31	1.0000	#DIV/0!	#DIV/0!
50									
51	2nd QTR								
52	'08		#DIV/0!		91	91	1.0000	#DIV/0!	#DIV/0!
53	April	0.00%		#DIV/0!	30	91	1.0000	#DIV/0!	#DIV/0!
54	May	0.00%		#DIV/0!	31	61	1.0000	#DIV/0!	#DIV/0!
55	June	0.00%		#DIV/0!	30	30	1.0000	#DIV/0!	#DIV/0!
56									
57	Total (over)/under Recovery			#DIV/0!	(line 24)	#DIV/0!			#DIV/0!

(a) Interest rates shall be the interest rates as reported on the FERC Website <http://www.ferc.gov/legal/acct-matts/interest-rates.asp>

Niagara Mohawk Power Corporation Wholesale TSC Calculation Information
2008 Forecast using 2007 Historical Data and 2008 Forecast

	(a)	(b)	See Note (**) below. (c)	(d)	(e)	(f)	(g)
	Historical Transmission Revenue Requirement (Historical TRR)	Forecasted Transmission Revenue Requirement	Annual True Up (**)	Revenue Requirement (RR)	Scheduling System Control and Dispatch Costs (CCC)	Annual Billing Units (BU) MWh	Rate \$/MWh (*)
1 Prior Year Rates Effective _____	-	-	-	-	-	-	#DIV/0!
Current Year Rates Effective July 1,							
2 2008	#DIV/0!	#DIV/0!		#DIV/0!	-	-	#DIV/0!
3 Increase/(Decrease)							#DIV/0!
4 Percentage Increase/(Decrease)							#DIV/0!
1.) Information directly from Niagara Mohawk Prior Year Informational Filing							
2.)							
(a) Schedule 1, Line 24							
(b) Schedule 2, Line 14							
(c) Schedule 3, Line 28							
(d) Attachment H, Section 14.1.9.2 The RR Component shall equal Col (a) Historical Transmission Revenue Requirement plus Col (b) the Forecasted Transmission Revenue Requirement plus Col (c) the Annual True-Up							
(e) Schedule 11 - Annual Scheduling, System Control and Dispatch Costs. (i.e. the Transmission Component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts from the prior calendar year excluding any NY Independent System Operating (NYISO) system control and load dispatch expenses already recovered under Schedule 1 of the NYISO Tariff.							
(f) Schedule 12 - Billing Units shall be the total Niagara Mohawk load as reported to the NYISO for the calendar year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR, and Reserved components of Attachment H of the NYISO TSC rate including Niagara Mohawk's external sales, load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service.							
(g) (Col (d) + Col (e)) / Col (f)							

(*) The rate column represents the unit rate prior to adjustments; the actual rate will be determined pursuant to the applicable TSC formula rate.

(**) There was no true-up for this period. This is illustrative only.

0

Shading denotes an input

Line
No.

Source

Definition

1	14.1.9.1 1. <u>Electric Wages and Salaries Factor</u>	83.5000%		Fixed per settlement
2				
3	14.1.9.1 3. <u>Transmission Wages and Salaries Allocation Factor</u>	13.0000%		Fixed per settlement
4				
5				
6				
7				
8	14.1.9.1 2. <u>Gross Transmission Plant Allocation Factor</u>			
9	Transmission Plant in Service	#DIV/0!	Schedule 6, Page 2, Line 3, Col 5	Gross Transmission Plant Allocation Factor shall equal the total investment in
10	Plus: Transmission Related General	\$0	Schedule 6, Page 2, Line 5, Col 5	Transmission Plant in Service, Transmission Related Electric General Plant,
11	Plus: Transmission Related Common	\$0	Schedule 6, Page 2, Line 10, Col 5	Transmission Related Common Plant and Transmission
12	Plus: Transmission Related Intangible Plant	\$0	Schedule 6, Page 2, Line 15, Col 5	Related Intangible Plant
13	Gross Transmission Investment	#DIV/0!	Sum of Lines 9 - 13	divided by Gross Electric Plant.
14				
15	Total Electric Plant		FF1 207.104	
16	Plus: Electric Common	\$0	Schedule 6, Page 2, Line 10, Col 3	
17	Gross Electric Plant in Service	\$0	Line 15 + Line 16	
18				
19	Percent Allocation	#DIV/0!	Line 13 / Line 17	
20				
21	14.1.9.1 4. <u>Gross Electric Plant Allocation Factor</u>			
22				
23	Total Electric Plant in Service	\$0	Line 15	Gross Electric Plant Allocation Factor shall equal
24	Plus: Electric Common Plant	\$0	Schedule 6, Page 2, Line 10, Col 3	Gross Electric Plant divided by the sum of Total Gas Plant,
25	Gross Electric Plant in Service	\$0	Line 23 + Line 24	Total Electric Plant, and Total Common Plant
26				
27	Total Gas Plant in Service		FF1 201.8d	
28	Total Electric Plant in Service	\$0	Line 15	
29	Total Common Plant in Service	\$0	Schedule 6, Page 2, Line 10, Col 1	
30	Gross Plant in Service (Gas & Electric)	-	Sum of Lines 27-Lines 29	
31				
32	Percent Allocation	#DIV/0!	Line 25 / Line 30	

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 1 of 2)
Attachment H, section 14.1.9.2

Line No.

1 14.1.9.2 (a) Transmission Investment Base

2

3 A.1. Transmission Investment Base shall be defined as (a) Transmission Plant in Service, plus (b) Transmission Related Electric General Plant, plus

4 (c) Transmission Related Common Plant, plus (d) Transmission Related Intangible Plant, plus (e) Transmission Related Plant Held for Future Use, less

5 (f) Transmission Related Depreciation Reserve, less (g) Transmission Related Accumulated Deferred Taxes, plus (h) Transmission Related

6 Regulatory Assets net of Regulatory Liabilities, plus (i) Transmission Related Prepayments, plus (j) Transmission Related Materials and Supplies,

7 plus (k) Transmission Related Cash Working Capital.

8

9

10		Reference	2007	Reference
11		Section:		
12	Transmission Plant in Service	(a)	#DIV/0!	Schedule 6, page 2, line 3, column 5
13	General Plant	(b)	\$0	Schedule 6, page 2, line 5, column 5
14	Common Plant	(c)	\$0	Schedule 6, page 2, line 10, column 5
15	Intangible Plant	(d)	\$0	Schedule 6, page 2, line 15, column 5
16	Plant Held For Future Use	(e)	\$0	Schedule 6, page 2, line 19, column 5
17	Total Plant (Sum of Line 12 - Line 16)		#DIV/0!	
18				
19	Accumulated Depreciation	(f)	#DIV/0!	Schedule 6, page 2, line 29, column 5
20	Accumulated Deferred Income Taxes	(g)	#DIV/0!	Schedule 7, line 6, column 5
21	Other Regulatory Assets	(h)	#DIV/0!	Schedule 7, line 11, column 5
22	Net Investment (Sum of Line 17 -Line 21)		#DIV/0!	
23				
24	Prepayments	(i)	#DIV/0!	Schedule 7, line 15, column 5
25	Materials & Supplies	(j)	#DIV/0!	Schedule 7, line 21, column 5
26	Cash Working Capital	(k)	\$0	Schedule 7, line 28, column 5
27				
28	Total Investment Base (Sum of Line 22 - Line 26)		#DIV/0!	

Transmission Investment Base (Part 1 of 2)

Attachment H Section 14.1. 9.2 (a) A. 1.

Page 2 of 2

0

Shading denotes an input

Line	(1)	(2)	(3) = (1)*(2)	(4)	(5) = (3)*(4)	FERC Form 1/PSC Report Reference for col (1)	Definition
No.	Total	Allocation Factor	Electric Allocated	Allocation Factor	Transmission Allocated		
1	<u>Transmission Plant</u>					FF1 207.58g	14.1.9.2(a)A.1.(a)
2	Wholesale Meter Plant				#DIV/0!	Workpaper 1, Line 45	Transmission Plant in Service shall equal balance of total investment in Transmission Plant
3	Total Transmission Plant in Service (Line 1+ Line 2)				#DIV/0!		plus Wholesale Metering Investment
4							
5	<u>General Plant</u>	100.00%	\$0	13.00%	(c) \$0	FF1 207.99g	14.1.9.2(a)A.1.(b)
6							Transmission Related Electric General Plant shall
7							equal the balance of investment in Electric General
8							Plant multiplied by the Transmission Wages and
9							Salaries Allocation Factor
10	<u>Common Plant</u>	83.50%	(a) \$0	13.00%	(c) \$0	FF1 201. 8h	14.1.9.2(a)A.1.(c)
11							Transmission Related Common Plant shall equal Common
12							Plant multiplied by the Electric Wages and Salaries
13							Allocation Factor and further multiplied the
14							Transmission Wages and Salaries Allocation Factor.
15	<u>Intangible Plant</u>	100.00%	-	13.00%	(c) \$0	FF1 205.5g	14.1.9.2(a)A.1.(d)
16							Transmission Related Intangible Plant shall equal Intangible
17							Electric Plant multiplied by the Transmission Wages and
18							Salaries Allocation Factor.
19	<u>Transmission Plant Held for Future Use</u>	\$0			\$0	Workpaper 10, Line 1	14.1.9.2(a)A.1.(e)
							Transmission Related Plant Held for Future Use shall equal

the balance in Plant Held for Future Use
associated with
property planned to be used for
transmission service within
five years

Transmission Related Depreciation Reserve shall equal the
balance of: (i) Transmission Depreciation Reserve, plus (ii)
the product of Electric General Plant Depreciation Reserve
multiplied by the Transmission Wages and Salaries
Allocation Factor, plus (iii) the product of Common Plant
Depreciation Reserve multiplied by the Electric Wages and
Salaries Allocation Factor and further multiplied by the
Transmission Wages and Salaries Allocation Factor plus (iv)
the product of Intangible Electric Plant Depreciation Reserve
multiplied by the Transmission Wages and Salaries
Allocation Factor plus (v) depreciation reserve associated with
the Wholesale Metering Investment

20
21
22
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30
31
32
33
34
35
36

Transmission Accumulated
Depreciation

Transmission Accum. Depreciation							\$0	FF1 219.25b	14.1.9.2(a)A.1.(f)
General Plant Accum.Depreciation		100.00%		\$0	13.00%	(c)	\$0	FF1 219.28b	
Common Plant Accum Depreciation		83.50%	(a)	\$0	13.00%	(c)	\$0	FF1 356.1	end of year balance
Amortization of Other Utility Plant		100.00%		\$0	13.00%	(c)	\$0	FF1 200.21c	
Wholesale Meters	#DIV/0!						#DIV/0!	Workpaper 1, Line 46	
Total Depreciation (Sum of line 24 - Line 28)							#DIV/0!		

- Allocation Factor Reference
(a) Schedule 5, line 1
(b) Schedule 5, line 32 - not used on this Schedule
(c) Schedule 5, line 3
(d) Schedule 5, line 19 - not used on this Schedule

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Investment Base (Part 2 of 2)

Attachment 1
Schedule 7

Attachment H Section 14.1.9.2 (a) A. 1.

Shading denotes an input

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Line No.	(1) Total	(2) Allocation Factor	(3) = (1)*(2) Electric Allocation Factor	(4) Allocation Factor	(5) = (3)*(4) Transmission Allocated	FERC Form 1/PSC Report Reference for col (1)	Definition	
1	Transmission Accumulated Deferred Taxes							
2	Accumulated Deferred Taxes (281-282)	100.00%	\$0	#DIV/0!	(d)	#DIV/0!	FF1 275.2k 14.1.9.2(a)A.1.(g)	Transmission Related Accumulated Deferred Income Taxes
3	Accumulated Deferred Taxes (283)	\$0	100.00%	\$0	#DIV/0!	(d)	#DIV/0!	Workpaper 2, Line 5 (link) shall equal the electric balance of Total Accumulated Deferred
4	Accumulated Deferred Taxes (190)	100.00%	\$0	#DIV/0!	(d)	#DIV/0!	FF1 234.8c	Income Taxes (FERC Accounts 190, 55,281, 282, and 283 net of
5	Accumulated Deferred Inv. Tax Cr (255)	100.00%	\$0	#DIV/0!	(d)	#DIV/0!	FF1 267.8h	stranded costs), multiplied by the Gross Transmission Plant
6	Total (Sum of line 2 - Line 5)		\$0			#DIV/0!		Allocation Factor.
7								
8	Other Regulatory Assets							
9	FAS 109 (Asset Account 182.3)	100.00%	\$0	#DIV/0!	(d)	#DIV/0!	FF1 232 lines 2,4,9,17 14.1.9.2(a)A.1.(h)	Transmission Related Regulatory Assets shall be Regulatory
10	FAS 109 (Liability Account 254)	100.00%	\$0	#DIV/0!	(d)	#DIV/0!	FF1 278.1 lines 4&21(f)	Assets net of Regulatory Liabilities multiplied by the Gross
11	Total (line 9 + Line 10)	\$0	\$0			#DIV/0!		Transmission Plant Allocation Factor.
12								
13	Transmission Prepayments					FF1 111.57c 14.1.9.2(a)A.1.(i)		Transmission Related Prepayments shall be the product of
14	Less: Prepaid State and Federal Income Tax					FF1 263 lines 2 & 9 (h)		Prepayments excluding Federal and State taxes multiplied by
15	Total Prepayments	\$0	#DIV/0!	#DIV/0!	#DIV/0!	(d)	#DIV/0!	the Gross Electric Plant Allocation Factor and further
16								
17								
18	Transmission Material and Supplies						14.1.9.2(a)A.1.(j)	Transmission Related Materials and Supplies shall equal: (i)
19	Trans. Specific O&M Materials and Supplies					\$0	FF1 227.8	the balance of Materials and Supplies assigned to
20	Construction Materials and Supplies	#DIV/0!	#DIV/0!	#DIV/0!	(d)	#DIV/0!	FF1 227.5	Transmission plus (ii) the product of Material and Supplies

21	Total (Line 19 + Line 20)	<u>#DIV/0!</u>		assigned to Construction multiplied by the Gross Electric
22				Plant Allocation Factor and further multiplied by Gross
23				Transmission Plant Allocation Factor.
24				
25	<u>Cash Working Capital</u>			14.1.9.2(a)A.1.(k))
26	Operation & Maintenance Expense	\$0	Schedule 9, Line 23	Transmission Related Cash Working Capital shall be an
27		0.1250	x 45 / 360	allowance equal to the product of: (i) 12.5% (45 days/ 360 days = 12.5%)
28	Total (line 26 * line 27)	<u>\$0</u>		multiplied by (ii) Transmission Operation and Maintenance Expense.
29				
30	Allocation Factor Reference			
	(a) Schedule 5, line 1 - not used on this Schedule			
	(b) Schedule 5, line 32			
	(c) Schedule 5, line 3 - not used on this Schedule			
	(d) Schedule 5, line 19			

Attachment 1
Schedule 8

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The Cost of Capital Rate shall equal the proposed Weighted Costs of Capital plus Federal Income Taxes and State Income Taxes.

the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's long-term debt outstanding during the year and the sum of (a) the ratio of actual long-term debt to total capital at year-end; and (b) the extent, if any, by which the ratio of NMPC's actual common equity to total capital at year-end exceeds fifty percent (50%). Long term debt shall be defined as the average of the beginning of the year and end of year balances of the following: long term debt less the unamortized Discounts on Long-Term Debt less the unamortized Loss on Reacquired Debt plus unamortized Gain on Reacquired Debt. Cost to maturity of NMPC's long-term debt shall be defined as the cost of long term debt included in the debt discount expense and any loss or gain on reacquired debt.

the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NMPC's preferred stock then outstanding and the ratio of actual preferred stock to total capital at year-end;

the return on equity component shall be the product of the allowed return on equity of 11.5% and the ratio of NMPC's actual common equity to total capital at year-end, provided that such ratio shall not exceed fifty percent (50%).

				CAPITALIZATION	COST OF		WEIGHTED	
			Source:	RATIOS	CAPITAL	Source:	COST OF	EQUITY
							CAPITAL	PORTION
(i)	Long-Term Debt	\$0	Workpaper. 6, Line 16b	#DIV/0!	#DIV/0!	Workpaper 6, Line 17c	#DIV/0!	
(ii)	Preferred Stock		FF1 112.3c	#DIV/0!	#DIV/0!	Workpaper 6, Line 24d	#DIV/0!	#DIV/0!
(iii)	Common Equity		FF1 112.16c - FF1 112.3,12,15c	#DIV/0!	11.50%		#DIV/0!	#DIV/0!
	Total Investment Return	\$0		#DIV/0!			#DIV/0!	#DIV/0!

Federal Income

14.1.9.2.2.(b) Tax shall equal = (A. + [B / C] X Tax Rate)

$$\frac{\text{Federal Income Tax Rate}}{1 - \text{Federal Income Tax Rate}}$$

where A is the sum of the preferred stock component and the return on equity component, each as determined in Sections (a)(ii) and for the ROE set forth in (a)(iii) above, B is the Equity AFUDC component of Depreciation Expense for Transmission Plant in Service as defined at Section 14.1.9.1.16 (FF1 117.38c), and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.

$$= \frac{\left(\frac{\text{\#DIV/0!} + (\$0)}{1} \right) / \left(\frac{\text{\#DIV/0!}}{-0} \right) \times \text{\#DIV/0!}}{\text{\#DIV/0!}}$$

$$\text{14.1.9.2.2.(c) State Income Tax shall equal} = \frac{\left(\frac{A + [B / C] + \text{Federal Income Tax Rate}}{1 - \text{State Income Tax Rate}} \right) \times \text{State Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

where A is the sum of the preferred stock component and the return on equity component as determined in (a)(ii) and (a)(iii) above, B is the Equity AFUDC component of Depreciation Expense for Transmission Plant in Service as defined at Section 14.1.9.1.16 above, and C is the Transmission Investment Base as shown at Schedule 6, Page 1 of 2, Line 28.

$$= \frac{\left(\frac{\text{\#DIV/0!} + (\$0)}{1} \right) / \left(\frac{\text{\#DIV/0!}}{-0} \right) + \left(\frac{\text{\#DIV/0!}}{0} \right) \times \text{\#DIV/0!}}{\text{\#DIV/0!}}$$

$$\text{(a)+(b)+(c) Cost of Capital Rate} = \frac{\text{\#DIV/0!}}{\text{\#DIV/0!}}$$

14.1.9.2(a) A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate

59

Transmission
Investment

60 Base #DIV/0! Schedule 6, page 1 of 2, Line 28

61

Cost of Capital

62 Rate #DIV/0! Line 53

63

= Investment Return
and Income Taxes

64 #DIV/0! Line 60 X Line 62

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Transmission Expenses

Attachment 1
Schedule 9

Attachment H Section 14.1.9.2

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Shading denotes an input

Line No.	(1) Total	(2) Allocation Factor	(3) = (1)*(2) <u>Electric</u> <u>Allocated</u>	(4) Allocation Factor	(5) = (3)*(4) Transmission <u>Allocated</u>	FERC Form 1/ PSC Report Reference for col (1)	Definition
<u>Depreciation Expense</u>							
1					\$0	FF1 336.7f	14.1.9.2.B. Transmission Related Depreciation Expense shall equal the sum of: (i) Depreciation Expense for Transmission Plant in Service, plus (ii) the product of Electric General Plant Depreciation Expense multiplied by the Transmission Wages and Salaries Allocation Factor plus (iii) Common Plant Depreciation Expense multiplied by the Electric Wages and Salaries Allocation Factor, further multiplied by the Transmission Wages and Salaries Allocation Factor plus (iv) Intangible Electric Plant Depreciation Expense multiplied by the Transmission Wages and Salaries Factor plus (v) depreciation expense associated with the Wholesale Metering Investment.
2		100.0000%	\$0	13.0000% (c)	\$0	FF1 336.10f	
3		83.5000% (a)	\$0	13.0000% (c)	\$0	FF1 356.1	
4		100.0000%	\$0	13.0000% (c)	\$0	FF1 336.1f	
5					#DIV/0!	Workpaper 1, Line 47	
6					#DIV/0!		
7							
8							
9							
10							
11							
12	<u>Real Estate Taxes</u>	100.0000%	\$0	#DIV/0! (d)	#DIV/0!	FF1 263.25i	14.1.9.2.C. Transmission Related Real Estate Tax Expense shall equal the electric Real Estate Tax Expenses multiplied by the Gross Transmission Plant Allocation Factor.
13							
14							
15							
16	<u>Amortization of Investment Tax Credits</u>	#DIV/0! (b)	#DIV/0!	#DIV/0! (d)	#DIV/0!	FF1 117.58c	14.1.9.2.D. Transmission Related Amortization of Investment Tax Credits shall
17							equal the product of Amortization of Investment Tax Credits multiplied
18							by the Gross Electric Plant Allocation Factor and further multiplied by
19							the Gross Transmission Plant Allocation Factor.
20	<u>Transmission Operation and Maintenance</u>						
21	Operation and Maintenance				\$0	FF1 321.112b	14.1.9.2.E. Transmission Operation and Maintenance Expense shall equal the sum of electric expenses as recorded in FERC Account Nos. 560, 562-574.
22	less Load Dispatching - #561				\$0	FF1 321.84-92b	
23	O&M (Line 21 - Line 22)	\$0			\$0		
24							
25	<u>Transmission Administrative and General</u>						
26	Total Administrative and General					FF1 323.197b	14.1.9.2.F. Transmission Related Administrative and General Expenses shall equal the product of electric Administrative and General Expenses,
27	less Property Insurance (#924)					FF1 323.185b	excluding the sum of Electric Property Insurance, Electric Research and

28	less Pensions and Benefits (#926)					FF1 323.187b	Development Expense and Electric Environmental Remediation Expense,
29	less: Research and Development Expenses (#930)	\$0				Workpaper 12, Line 3	
30	Less: 50% of NY PSC Regulatory Expense					FF1 351.4h	and 50% of the NYPSC Regulatory Expense multiplied by the Transmission Wages and Salaries Allocation Factor,
31	Less: 18a Charges (Temporary Assessment)					FF1 351.1.h, Workpaper 16, Line 15, Column f	
32	less: Environmental Remediation Expense	\$0				Workpaper 11, Line 3	plus the sum of Electric Property Insurance multiplied by the Gross
33	Subtotal (Line 26-27-28-29-30-31-32)	\$0	100.0000 %	\$0	13.0000% (c)	\$0	Transmission Plant Allocation Factor, plus transmission-specific Electric
34	PLUS Property Insurance alloc. using Plant Allocation	\$0	100.0000 %	\$0	#DIV/0! (d)	#DIV/0! Line 27	
35	PLUS Pensions and Benefits	\$88,644,000	100.0000 %	\$88,644,000	13.0000% (c)	\$11,523,720 Workpaper 3	Research and Development Expense, and transmission-specific Electric Environmental Remediation Expense. In addition, Administrative
36	PLUS Transmission-related research and development	\$0				\$0 Workpaper 12	
37	PLUS Transmission-related Environmental Expense	\$0				\$0 Workpaper 11	and General Expenses shall exclude the actual Post-Employment Benefits Other than Pensions ("PBOP") included in FERC Account 926,
38	Total A&G (Line 33+34+35+36+37)	\$88,644,000		\$88,644,000		#DIV/0!	and shall add back in the amounts shown on Workpaper 3, page 1,
39							or other amount subsequently approved by FERC under Section 205 or 206.
40	<u>Payroll Tax Expense</u>						14.1.9.2.G. Transmission Related Payroll Tax Expense shall equal the product of
41	Federal Unemployment					FF1 263.4i	electric Payroll Taxes multiplied by the Transmission Wages and
42	FICA					FF1 263.3i	Salaries Allocation Factor.
43	State Unemployment					FF1 263.17i	
44	Total (Line 41+42+43)	\$0	100.0000 %	\$0	13.0000% (b)	\$0	

Allocation Factor Reference

- (a) Schedule 5, line 1
- (b) Schedule 5, line 32
- (c) Schedule 5, line 3
- (d) Schedule 5, line 19

Niagara Mohawk Power Corporation
Annual Revenue Requirements of Transmission Facilities
Billing Adjustments, Revenue Credits, Rental Income

Attachment 1
Schedule 10

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Attachment H Section
14.1.9.2 (a)

Shading denotes an input

Line No.	(1) Total	Source	Definition
1			14.1.9.2.H. Billing Adjustments shall be any adjustments made in accordance with Section 14.1.9.4.4 below.
2			
3			
4	\$0	Workpaper 4, Line 4	14.1.9.2.I. Transmission Related Bad Debt Expense shall equal
5			Bad Debt Expense as reported in Account 904 related to NMPC's wholesale transmission billing.
6			
7	\$0	Workpaper 5, Line 11	14.1.9.2.J. Revenue Credits shall equal all Transmission revenue recorded in FERC account 456
8			excluding (a) any NMPC revenues already reflected in the WR, CRR, SR, ECR and Reserved
9			components in Attachment H of the NYISO TSC rate; (b) any revenues associated
10			with expenses that have been excluded from NMPC's revenue requirement; and (c) any
11			revenues associated with transmission service provided under this TSC rate, for which the
12			load is reflected in the calculation of BU.
13			
14	\$0	Workpaper 7	14.1.9.2.K. Transmission Rents shall equal all Transmission-related rental income recorded in FERC
15			account 454.615
16			
17			14.1.9.4(d)
18			1 Any changes to the Data Inputs for an Annual Update, including but not limited to
19			revisions resulting from any FERC proceeding to consider the Annual Update, or
20			as a result of the procedures set forth herein, shall take effect as of the beginning
21			of the Update Year and the impact of such changes shall be incorporated into the
22			charges produced by the Formula Rate (with interest determined in accordance
23			with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update
24			Year. This mechanism shall apply in lieu of mid-Update Year adjustments and
25			any refunds or surcharges, except that, if an error in a Data Input is discovered
26			and agreed upon within the Review Period, the impact of such change shall be
27			incorporated prospectively into the charges produced by the Formula Rate during
28			the remainder of the year preceding the next effective Update Year, in which case
29			the impact reflected in subsequent charges shall be reduced accordingly.
30			2 The impact of an error affecting a Data Input on charges collected during the
31			Formula Rate during the five (5) years prior to the Update Year in which the error

was first discovered shall be corrected by incorporating the impact of the error on the charges produced by the Formula Rate during the five-year period into the charges produced by the Formula Rate (with interest determined in accordance with 18 C.F.R. § 38.19(a)) in the Annual Update for the next effective Update Year. Charges collected before the five-year period shall not be subject to correction.

32
33
34
35
36

(b)	List of Items excluded from the Revenue Requirement	Reason
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Niagara Mohawk Power Corporation
System, Control, and Load Dispatch Expenses (CCC)
Attachment H, Section
14.1.9.5

The CCC shall equal the annual Scheduling, System Control and Dispatch Costs (i.e., the transmission component of control center costs) as recorded in FERC Account 561 and its associated sub-accounts using information from the prior calendar year, excluding NYISO system control and load dispatch expense already recovered under Schedule 1 of the NYISO Tariff.

1	<u>Scheduling and Dispatch Expenses</u>			<u>0</u>	<u>Source</u>
2					
3	Accounts	561	Load Dispatching		FF1 321.84b
4	Accounts	561.1	Reliability		FF1 321.85b
5	Accounts	561.2	Monitor and Operate Transmission System		FF1 321.86b
6	Accounts	561.3	Transmission Service and Schedule		FF1 321.87b
7	Accounts	561.4	Scheduling System Control and Dispatch		FF1 321.88b
8	Accounts	561.5	Reliability, Planning and Standards Development		FF1 321.89b
9	Accounts	561.6	Transmission Service Studies		FF1 321.90b
10	Accounts	561.7	Generation Interconnection Studies		FF1 321.91b
11	Accounts	561.8	Reliability, Planning and Standards Dev. Services		FF1 321.92b
12					
13	Total Load Dispatch Expenses (sum of Lines 3 - 11)				sum lines 3 - 11
14					
15	Less Account 561 directly recovered under Schedule 1 of the NY ISO Tariff				
16					
17	Accounts	561.4	Scheduling System Control and Dispatch		line 7
18	Accounts	561.8	Reliability, Planning and Standards Dev. Services		line 11
19	Total NYISO Schedule 1				line 17 + line 18
20					
21	Total CCC Component				line 13 - line 19

Attachment 1
Schedule 12
Page 1 of 1

Niagara Mohawk Power Corporation

Billing Units - MWH

Attachment H, Section 14.1.9.6

BU shall be the total Niagara Mohawk load as reported to the NYISO for the calendar billing year prior to the Forecast Period, including the load for customers taking service under Niagara Mohawk's TSC Rate. The total Niagara Mohawk load will be adjusted to exclude (i) load associated with wholesale transactions being revenue credited through the WR, CRR, SR, ECR and Reserved components of Workpaper H of the NYISO TSC rate including Niagara Mohawk's external sales, load associated with grandfathered OATT agreements, and any load related to pre-OATT grandfathered agreements; (ii) load associated with transactions being revenue credited under Historical TRR Component J; and (iii) load associated with netted station service.

Line No.		<u>Dec 06- Nov 07</u>	<u>SOURCE</u>
1	Subzone 1		NIMO TOL (transmission owner load)
2	Subzone 2		NIMO TOL (transmission owner load)
3	Subzone 3		NIMO TOL (transmission owner load)
4	Subzone 4		NIMO TOL (transmission owner load)
5	Subzone 29		NIMO TOL (transmission owner load)
6	Subzone 31		NIMO TOL (transmission owner load)
7	Total NIMO Load report to NYISO	0.000	sum lines 1-6
8	LESS: All non-retail transactions		
9	Watertown		FF1 page 329.11.j
10	High Load Factor Fitzpatrick		NIMO TOL (transmission owner load)
11	Disputed Station Service		NIMO TOL (transmission owner load)
12	Other non-retail transactions		All other non-retail transactions (Sum of 300,000 series PTID's from TOL)
13	Total Deductions	0.000	sum lines 9 - 12
14	PLUS: TSC Load		
15	NYMPA Muni's, Misc. Villages, Jamestown (X1)**		FF1 page 329.19.j ****
16	NYPA Niagara Muni's (X2)		FF1 page 329.1.j ****
17	Total additions	0.000	sum lines 15 -17
18	Total Billing Units	0.000	line 7 - line 13 + line 18

In 2007, the volumes were not detailed in FERC Form 1 as shown. Detail for 2007 will be provided as requested.

On 8/31/07, the contracts for Jamestown and the NYPA Niagara Municipal expired. The previous contract was billed at demand.

The 2007 energy values for the NYPA Niagara Municipals and Jamestown are proxy numbers representing a full year of metered load for December 2006 - November 2007 as billed in January - December. These entities transitioned to the TSC rate on September 1, 2007 for billing effective October 2007. However, the full year billing load was included above.

**

One of the Misc Villages at Line 15 is reported on the TOL file with one of the NYPA Niagara Muni's labeled X2.

14.2.2 NYPA Transmission Adjustment Charge (“NTAC”)

14.2.2.1 Applicability of the NYPA Transmission Adjustment Charge

Each Billing Period, the ISO shall charge, and each Transmission Customer shall pay, the applicable NYPA Transmission Adjustment Charge (“NTAC”) calculated in accordance with Section 14.2.2.2.2 of this Attachment for the first two (2) months of LBMP and in accordance with Section 14.2.2.2.1 of this Attachment thereafter. The NTAC shall apply to Transmission Service:

14.2.2.1.1 from one or more Interconnection Points between the NYCA and another Control Area to one or more Interconnection Points between the NYCA and another Control Area (“Wheels Through”);¹ or

14.2.2.1.2 from the NYCA to one or more Interconnection Points between the NYCA and another Control Area, including transmission to deliver Energy purchased from the LBMP Market and delivered to such a Control Area Interconnection (“Exports”);¹ or

14.2.2.1.3 to serve Load within the NYCA.

In summary the NTAC will be applied to all Energy Transactions, including internal New York State Loads and Wheels Through and Exports out of the NYCA at a uniform, non-discountable rate.

14.2.2.2 NTAC Calculation

14.2.2.2.1 NTAC Formula

Beginning with January 2001, NYPA shall calculate the NTAC applicable to Transmission Service to serve New York State Load, Wheels Through and Exports as follows:

¹ The NTAC shall not apply to Wheels Through or Exports scheduled with the ISO to destinations within the New England Control Area provided that the conditions listed in Section 2.7.2.1.4 of this Tariff are satisfied.

$$NTAC = \{(RR \div 12) - (EA) - (IR \div 12) - SR - CRN - WR - ECR - NR - NT\} / (BU \div 12)$$

Where:

RR = NYPA's Annual Transmission Revenue Requirement, which includes the Scheduling, System Control and Dispatch Costs of NYPA's control center, as approved by FERC;

EA = Monthly Net Revenues from Modified Wheeling Agreements, Facility Agreements and Third Party TWAs, and Deliveries to directly connected Transmission Customers;

SR = $SR_1 + SR_2$

SR_1 will equal the revenues from the Direct Sale by NYPA of Original Residual TCCs, and Grandfathered TCCs associated with ETAs, the expenses for which are included in NYPA's Revenue Requirement where NYPA is the Primary Owner of said TCCs.

SR_2 will equal NYPA's revenues from the Centralized TCC Auction allocated pursuant to Attachment M; this includes revenues from: (a) TCCs associated with Residual Transmission Capacity that are sold in the Centralized TCC Auction; and (b) the sale of Grandfathered TCCs associated with ETAs, if the expenses for these ETAs are included in NYPA's Revenue Requirement.

Revenue from TCCs associated with Residual Transmission Capacity includes payments for Original Residual TCCs that the Transmission Providers sell through the Centralized TCC Auction and the allocation of revenue for other TCCs sold through the Centralized TCC Auction (per the Facility Flow-Based Methodology described in Attachment N).

SR_1 shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (*i.e.*, January actual data will be used in February to calculate the NTAC effective in March). SR_1 for a month in which a Direct Sale is applicable shall equal the total nominal revenue that NYPA will receive under each applicable TCC sold in a Direct Sale divided by the duration of the TCC (in months).

SR_2 shall equal the Transmission Owner's share of Net Auction Revenue for all rounds of a Centralized TCC Auction, as calculated pursuant to Attachment N, divided equally among the months covered by the Centralized TCC Auction. SR_2 shall be adjusted after each Centralized TCC Auction, and the revised SR_2 shall be effective at the start of each Capability Period;

ECR = NYPA's share of Net Congestion Rents in a month, calculated pursuant to Attachment N.

The computation of ECR is exclusive of any Congestion payments or Rents included in the CRN term;

CRN = Monthly Day-Ahead Congestion Rents in excess of those required to offset Congestion paid by NYPA's SENY governmental customers associated with the NYPA OATT Niagara/St. Lawrence Service reservations, net of the Initial Cost.

IR = A. The amount that NYPA will credit to its RR assessed to the SENY Load on account of the foregoing NYPA Niagara/St. Lawrence OATT reservations for SENY governmental customers. Such annual revenues will be computed as the product ("Initial Cost") of NYPA's current OATT system rate of \$2.23 per kilowatt per month and the 600 MW of TCCs (or the amount of TCCs reduced by Paragraph C below). In the event NYPA sells these TCCs (or any part thereof), all revenues from these sales will offset the NTAC and the Initial Cost will be concomitantly reduced to reflect the net amount of Niagara/St. Lawrence OATT Reservations, if any, retained by NYPA for the

SENY Load. The parties hereby agree that the revenue offset to NTAC will be the greater of the actual sale price obtained by NYPA for the TCCs sold or that computed at the applicable system rate in accordance with Paragraph B below;

B. The system rate of \$2.23 per kilowatt per month will be benchmarked to the RR for NYPA transmission initially accepted by FERC ("Base Period RR") for the purposes of computing the Initial Cost. Whenever an amendment to the RR is accepted by FERC ("Amended RR"), the system rate for the purpose of computing the Initial Cost will be increased (or decreased) by the ratio of the Amended RR to the Base Period RR and the effect of Paragraph A on NTAC will be amended accordingly.

C. If prior to the Centralized TCC Auction all Grandfathered Transmission Service including NYPA's 600 MW Niagara/St. Lawrence OATT reservations held on behalf of its SENY governmental customers are found not to be feasible, then such OATT reservations will be reduced until feasibility is assured. A reduction, subject to a 200 MW cap on the total reduction as described in Attachment M, will be applied to the NYPA Niagara/St. Lawrence OATT reservations held on behalf of its SENY governmental customers.

WR = NYPA's revenues from external sales (Wheels Through and Exports) not associated with Existing Transmission Agreements in Attachment L, Tables 1 and 2 and Wheeling revenues from OATT reservations extending beyond the start-up of the ISO;

NR = NYPA Reserved₁ + NYPA Reserved₂

NYPA Reserved₁ will equal NYPA's Congestion payments for a month received pursuant to Section 20.2.3 of Attachment N of this Tariff for NYPA's RCRR TCCs. NYPA Reserved₂ will equal the value that NYPA receives for the sale of RCRR TCCs in a month, with the value for each RCRR TCC sold divided equally over the months remaining until the expiration of that RCRR TCC.

NT = The amount of actual NYPA transmission revenues minus NYPA's monthly revenue requirement.

BU = Annual Billing Units are New York State Loads and Loads associated with Wheels Through and Exports in megawatt-hours ("MWh").

The RR and SR will not include expenses for NYPA's purchase of TCCs or revenues from the sale of such purchased TCCs or from the collection of Congestion Rents for such TCCs.

The ECR, EA, CRN, WR, NR, and NT shall be updated prior to the start of each month based on actual data for the calendar month prior to the month in which the adjustment is made (*i.e.*, January actual data will be used in February to calculate the NTAC effective in March).

The NTAC shall be calculated as a \$/MWh charge and shall be applied to Actual Energy Withdrawals, except for Wheels Through and Exports in which case the NTAC shall be applied to scheduled Energy quantities. The NTAC shall not apply to scheduled quantities that are Curtailed by the ISO.

14.2.2.2.2 Implementation of NTAC

At the start of LBMP implementation certain variables of the NTAC equation will not be available. For the first and second months of LBMP implementation, the only terms in the NTAC equation that will be known by NYPA are its historical Annual Transmission Revenue Requirement (RR) and the historical Billing Units (BU), which have been approved by or filed with FERC. For these two months NYPA shall calculate the NTAC using the following equation:

$$\text{NTAC} = \{(\text{RR} \div 12) - (\text{EA}) - (\text{IR} \div 12)\} / (\text{BU} \div 12)$$

SR₂ shall not be available until after the first Centralized TCC Auction. For the third month of LBMP implementation until the second month of the Capability Period corresponding to the first Centralized TCC Auction, NYPA shall recalculate the NTAC using the following equation:

$$\text{NTAC} = \{(\text{RR} \div 12) - (\text{EA}) - (\text{IR} \div 12) - \text{WR} - \text{CRN} - \text{SR}_1 - \text{ECR}\} / (\text{BU} \div 12)$$

Prior to and during implementation of LBMP those current NYPA transmission customers wishing to terminate their Third Party TWAs shall notify the ISO. The ISO shall duly inform NYPA of such conversion so that NYPA can calculate revenues (EA) to be derived from Existing Transmission Wheeling Agreements.

14.2.2.2.3

NYPA's recovery pursuant to NTAC initially is limited to expenses and return associated with its transmission system as that system exists at the time of FERC approval of the NTAC ("base period revenue requirement"). Additions to its system may be included in the computation of NTAC only if: a) upgrades or expansions do not exceed \$5 million on an annual basis; or b) such upgrades or expansions have been unanimously approved by the Transmission Owners. Notwithstanding the above, NYPA may invest in transmission facilities in excess of \$5 million annually without unanimous Transmission Owners' authorization outside the NTAC recovery mechanism. In that case, NYPA cannot recover any expenses or return associated with such additions under NTAC and any TCC or other revenues associated with such additions will not be considered NYPA transmission revenue for purposes of developing the NTAC nor be used as a credit in the allocation of NTAC to transmission system users.

14.2.2.3 Filing and Posting of NTAC

NYPA shall coordinate with the ISO to update certain components of the NTAC formula on a monthly or Capability Period basis. NYPA may update the NTAC calculation to change the RR, initially approved by FERC, and such updates shall be submitted to FERC. An integral part of the agreement

between the other Transmission Owners and NYPA is NYPA's consent to the submission of its RR for FERC review and approval on the same basis and subject to the same standards as the Revenue Requirements of the Investor-Owned Transmission Owners. Each January, beginning with January 2001, the ISO shall inform NYPA of the prior year's actual New York internal Load requirements and the actual Wheels Through and Exports and shall post this information on the OASIS. NYPA shall change the BU component of the NTAC formula to reflect the prior calendar year's information, with such change to take effect beginning with the March NTAC of the current year. NYPA will calculate the monthly NTAC and provide this information to the ISO by no later than the fourteenth day of each month, for posting on the OASIS to become effective on the first day of the next calendar month. Beginning with LBMP implementation, the monthly NTAC shall be posted on the OASIS by the ISO no later than the fifteenth day of each month [or as soon thereafter as is reasonably possible but in no event later than the 20th of the month](#) to become effective on the first day of the next calendar month.

14.2.2.4 NTAC Calculation Information

NYPA's Annual Transmission Revenue Requirement (RR), for facilities owned as of January 31, 1997, and Annual Billing Units (BU) of the NTAC are:

$$\text{RR} = \$165,449,297$$

$$\text{BU} = 133,386,541\text{MWh}$$

NYPA's Annual Transmission Revenue Requirement is subject to Commission approval in accordance with Section 14.2.2.2.3 of this Attachment.

14.2.2.4.1 Amended RR

NYPA's Amended Annual Transmission Revenue Requirement (Amended RR), effective August 1, 2012, is:

Amended RR = \$183,096,025

14.2.2.5 Billing

The New York State Loads, Wheels Through, and Exports will be billed based on the product of:
(i) the NTAC; and (ii) the Customer's billing units for the Billing Period. The billing units will be based on the metered energy for all Transactions to supply Load in the NYCA during the Billing Period, and hourly Energy schedules for the Billing Period for all Wheels Through and Exports.