31.5 Cost Allocation and Cost Recovery

31.5.1 The Scope of Attachment Y Cost Allocation

31.5.1.1 Regulated Responses

The cost allocation principles and methodologies in this Attachment Y cover only

regulated transmission solutions to Reliability Needs, regulated transmission responses to

congestion identified in the CARIS, and regulated Public Policy Transmission Projects whether   
proposed by a Responsible Transmission Owner or a Transmission Owner or Other Developer.   
The cost allocation principles and methodology for: (i) regulated transmission solutions to   
Reliability Needs are contained in Sections 31.5.3.1 and 31.5.3.2 of this Attachment Y, (ii)   
regulated transmission responses to congestion identified in the CARIS are contained in Sections

31.5.4.1 and 31.5.4.2 of this Attachment Y, and (iii) regulated Public Policy Transmission Projects are contained in Sections 31.5.5 and 31.5.6 of this Attachment Y.

31.5.1.2 Market-Based Responses

The cost allocation principles and methodologies in this Attachment Y do not apply to market-based solutions to Reliability Needs, to market-based responses to congestion identified in the CARIS, or to Other Public Policy Projects. The cost of a market-based project shall be the responsibility of the developer of that project.

31.5.1.3 Interconnection Cost Allocation

The cost allocation principles and methodologies in this Attachment Y do not apply to the   
interconnection costs of generation projects and merchant transmission projectsMerchant   
Transmission Facilities. Interconnection costs are determined and allocated in accordance with   
Attachment P, Attachment S, Attachment X and Attachment Z of the ISO OATT. Cost related to

the deliverability of a resource will be addressed under the ISO’s deliverability procedures in Attachment S of the ISO OATT.

31.5.1.4 Individual Transmission Service Requests

The cost allocation principles and methodologies in this Attachment Y do not apply to the cost of transmission expansion projects undertaken in connection with an individual request for Transmission Service. The cost of such a project is determined and allocated in accordance with Section 3.7 or Section 4.5 of the ISO OATT.

31.5.1.5 LTP Facilities

The cost allocation principles and methodologies in this Attachment Y do not apply to the   
cost of transmission projects included in LTPs or LTP updates. Each Transmission Owner will   
recover the cost of such transmission projects in accordance with its then existing rate recovery   
mechanisms.

31.5.1.6 Regulated Non-Transmission Projects

Costs related to regulated non-transmission projects will be recovered by Responsible   
Transmission Owners, Transmission Owners and Other Developers in accordance with the   
provisions of New York Public Service Law, New York Public Authorities Law, or other   
applicable state law. Nothing in this section shall affect the Commission’s jurisdiction over the   
sale and transmission of electric energy subject to the jurisdiction of the Commission.

31.5.1.7 Eligibility for Cost Allocation and Cost Recovery

Any entity, whether a Responsible Transmission Owner, Other Developer, or

Transmission Owner, shall be eligible for cost allocation and cost recovery as set forth in Section

31.5 of this Attachment Y and Rate Schedule 10 of the ISO OATT for any transmission project

proposed to satisfy an identified Reliability Need, regulated economic transmission project, or   
Public Policy Transmission Project that is determined by the ISO to be eligible under Sections

31.2, 31.3, or 31.4, as applicable. Interregional Transmission Projects identified in accordance   
with the Interregional Planning Protocol, and that have been accepted in each region’s planning   
process, shall be eligible for interregional cost allocation and cost recovery, as set forth in   
Section 31.5 of this Attachment Y and Rate Schedule 10 of the ISO OATT. The ISO’s share of   
the cost of an Interregional Transmission Project selected pursuant to this Attachment Y to meet   
a Reliability Need, congestion identified in the CARIS, or a Public Policy Transmission Need   
shall be eligible for cost allocation consistent with the cost allocation methodology applicable to   
the type of regional transmission project that would be replaced through the construction of such   
Interregional Transmission Project.

31.5.2 Cost Allocation Principles Required Under Order No. 1000

31.5.2.1 In compliance with Commission Order No. 1000, the ISO shall implement

the specific cost allocation methodology in Section 31.5.3.2, 31.5.4.4, and

31.5.5.4 in accordance with the following Regional Cost Allocation Principles (“Order No. 1000 Regional Cost Allocation Principles”):

Regional Cost Allocation Principle 1: The ISO shall allocate the cost of   
transmission facilities to those within the transmission planning region that   
benefit from those facilities in a manner that is at least roughly commensurate   
with estimated benefits. In determining the beneficiaries of transmission   
facilities, the ISO’s CSPP will consider benefits including, but not limited to, the   
extent to which transmission facilities, individually or in the aggregate provide for

maintaining reliability and sharing reserves, production cost savings and

congestion relief, and/or meeting Public Policy Requirements.

Regional Cost Allocation Principle 2: The ISO shall not involuntarily allocate any of the costs of transmission facilities to those that receive no benefit from transmission facilities.

Regional Cost Allocation Principle 3: In the event that the ISO adopts a benefit to cost threshold in its CSPP to determine which transmission facilities have   
sufficient net benefits to be selected in a regional transmission plan for the   
purpose of cost allocation, such benefit to cost threshold will not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation. If the ISO chooses to adopt such a threshold in its CSPP it will not   
include a ratio of benefits to costs that exceeds 1.25 unless the ISO justifies and   
the Commission approves a higher ratio.

Regional Cost Allocation Principle 4: The ISO’s allocation method for the cost of a transmission facility selected pursuant to the process in the CSPP shall   
allocate costs solely within the ISO’s transmission planning region unless another entity outside the region or another transmission planning region voluntarily   
agrees to assume a portion of those costs. Costs for an Interregional Transmission Project must be assigned only to regions in which the facility is physically   
located. Costs cannot be assigned involuntarily to another region. The ISO shall not bear the costs of required upgrades in another region.

Regional Cost Allocation Principle 5: The ISO’s cost allocation method and   
data requirements for determining benefits and identifying beneficiaries for a

transmission facility shall be transparent with adequate documentation to allow a   
stakeholder to determine how they were applied to a proposed transmission   
facility, as consistent with confidentiality requirements set forth in this   
Attachment Y and the ISO Code of Conduct in Attachment F of the OATT.   
Regional Cost Allocation Principle 6: The ISO’s CSPP provides a different cost   
allocation method for different types of transmission facilities in the regional   
transmission plan and each cost allocation method is set out clearly and explained   
in detail in this Section 31.5.

31.5.2.2 In compliance with Commission Order No. 1000, the ISO shall implement

the specific cost allocation methodology in Section 31.5.7 of this Attachment Y in   
accordance with the following Interregional Cost Allocation Principles:   
Interregional Cost Allocation Principle 1: The ISO shall allocate the cost of   
new Interregional Transmission Projects to each region in which an Interregional   
Transmission Project is located in a manner that is at least roughly commensurate   
with estimated benefits of the Interregional Transmission Project in each of the   
regions. In determining the beneficiaries of Interregional Transmission Projects,   
the ISO will consider benefits including, but not limited to, those associated with   
maintaining reliability and sharing reserves, production cost savings and   
congestion relief, and meeting Public Policy Requirements.   
Interregional Cost Allocation Principle 2: The ISO shall not involuntarily   
allocate any of the costs of an Interregional Transmission Project to a region that   
receives no benefit from an Interregional Transmission Project that is located in   
that region, either at present or in a likely future scenario.

Interregional Cost Allocation Principle 3: In the event that the ISO adopts a   
benefit-cost threshold ratio to determine whether an Interregional Transmission   
Project has sufficient net benefits to qualify for interregional cost allocation, this   
ratio shall not be so large as to exclude an Interregional Transmission Project with   
significant positive net benefits from cost allocation. If the ISO chooses to adopt   
such a threshold, they will not include a ratio of benefits to costs that exceeds 1.25   
unless the Parties justify and the Commission approves a higher ratio.   
Interregional Cost Allocation Principle 4: The ISO’s allocation of costs for an   
Interregional Transmission Project shall be assigned only to regions in which the   
Interregional Transmission Project is located. The ISO shall not assign costs   
involuntarily to a region in which that Interregional Transmission Project is not   
located. The ISO shall, however, identify consequences for other regions, such as   
upgrades that may be required in a third region. The ISO’s interregional cost   
allocation methodology includes provisions for allocating the costs of upgrades   
among the beneficiaries in the region in which the Interregional Transmission   
Project is located to the transmission providers in such region that agree to bear   
the costs associated with such upgrades.

Interregional Cost Allocation Principle 5: The ISO’s cost allocation

methodology and data requirements for determining benefits and identifying

beneficiaries for an Interregional Transmission Project shall be transparent with   
adequate documentation to allow a stakeholder to determine how they were   
applied to a proposed Interregional Transmission Project, as consistent with the

confidentiality requirements set forth in this Attachment Y and the ISO Code of Conduct in Attachment F of the OATT.

Interregional Cost Allocation Principle 6: Though Order No. 1000 allows the ISO to provide a different cost allocation methodology for different types of   
interregional transmission facilities, such as facilities needed for reliability,   
congestion relief, or to achieve Public Policy Requirements, the ISO has chosen to adopt one interregional cost allocation methodology for all Interregional   
Transmission Planning Projects. The interregional cost allocation methodology is set out clearly and explained in detail in Section 31.5.7 of this Attachment Y. The share of the cost related to any Interregional Transmission Project assigned to the ISO shall be allocated as described in Section 31.5.7.1.

31.5.3 Regulated Responses to Reliability Needs

31.5.3.1 Cost Allocation Principles

The ISO shall implement the specific cost allocation methodology in Section 31.5.3.2 of this

Attachment Y in accordance with the Order No. 1000 Regional Cost Allocation Principles as set   
forth in Section 31.5.2.1. This methodology shall apply to cost allocation for a regulated   
transmission solution to an identified Reliability Need, including the ISO’s share of the costs of   
an Interregional Transmission Project proposed as a regulated transmission solution to an   
identified Reliability Need allocated in accordance with Section 31.5.7 of this Attachment Y.   
 The specific cost allocation methodology in Section 31.5.3.2 incorporates the following elements:

31.5.3.1.1 The focus of the cost allocation methodology shall be on solutions to

Reliability Needs.

31.5.3.1.2 Potential impacts unrelated to addressing the Reliability Needs shall not be

considered for the purpose of cost allocation for regulated solutions.

31.5.3.1.3 Primary beneficiaries shall initially be those Load Zones or Subzones

identified as contributing to the reliability violation.

31.5.3.1.4 The cost allocation among primary beneficiaries shall be based upon their

relative contribution to the need for the regulated solution.

31.5.3.1.5 The ISO will examine the development of specific cost allocation rules

based on the nature of the reliability violation (e.g., thermal overload, voltage, stability, resource adequacy and short circuit).

31.5.3.1.6 Cost allocation shall recognize the terms of prior agreements among the

Transmission Owners, if applicable.

31.5.3.1.7 Consideration should be given to the use of a materiality threshold for cost

allocation purposes.

31.5.3.1.8 The methodology shall provide for ease of implementation and

administration to minimize debate and delays to the extent possible.

31.5.3.1.9 Consideration should be given to the “free rider” issue as appropriate.

The methodology shall be fair and equitable.

31.5.3.1.10 The methodology shall provide cost recovery certainty to investors to the

extent possible.

31.5.3.1.11 The methodology shall apply, to the extent possible, to Gap Solutions.

31.5.3.1.12 Cost allocation is independent of the actual triggered project(s), except

when allocating cost responsibilities associated with meeting a Locational

Minimum Installed Capacity Requirement (“LCR”), and is based on a separate process that results in NYCA meeting its LOLE requirement.

31.5.3.1.13 Cost allocation for a solution that meets the needs of a Target Year

assumes that backstop solutions of prior years have been implemented.

31.5.3.1.14 Cost allocation will consider the most recent values for LCRs. LCRs must

be met for the Target Year.

31.5.3.2 Cost Allocation Methodology

The cost allocation mechanism under this Section 31.5.3.2 sets forth the basis for

allocating costs associated with a Responsible Transmission Owner’s regulated backstop solution or an Other Developer’s or Transmission Owner’s alternative regulated transmission solution   
selected by the ISO as the more efficient or cost-effective transmission solution to an identified   
Reliability Need.

The formula is not applicable to that portion of a project beyond the size of the solution   
needed to provide the more efficient or cost effective solution appropriate to the Reliability Need   
identified in the RNA. Nor is the formula applicable to that portion of the cost of a regulated   
transmission reliability project that is, pursuant to Section 25.7.12 of Attachment S to the ISO   
OATT, paid for with funds previously committed by or collected from Developers for the   
installation of System Deliverability Upgrades required for the interconnection of generation   
projects or merchant transmission projectsClass Year Transmission Projects.   
 This Section 31.5.3.2 establishes the allocation of the costs related to resolving   
Reliability Needs resulting from resource adequacy, BPTF thermal transmission security, BPTF   
voltage security, dynamic stability, and short circuit issues. Costs will be allocated in   
accordance with the following hierarchy: (i) resource adequacy pursuant to Section 31.5.3.2.1,

(ii) BPTF thermal transmission security pursuant to Section 31.5.3.2.2, (iii) BPTF voltage

security pursuant to Section 31.5.3.2.3, (iv) dynamic stability pursuant to Section 31.5.3.2.4, and

(v) short circuit pursuant to Section 31.5.3.2.5.

31.5.3.2.1 Resource Adequacy Reliability Solution Cost Allocation Formula

For purposes of solutions eligible for cost allocation under this Section 31.5.3.2, this

section sets forth the cost allocation methodology applicable to that portion of the costs of the

solution attributable to resolving resource adequacy. The same cost allocation formula is applied regardless of the project or sets of projects being triggered; however, the nature of the solution set may lead to some terms equaling zero, thereby dropping out of the equation. To ensure that appropriate allocation to the LCR and non-LCR zones occurs, the zonal allocation percentages are developed through a series of steps that first identify responsibility for LCR deficiencies, followed by responsibility for remaining need. The following formula shall apply to the   
allocation of the costs of the solution attributable to resource adequacy:

Resource Adequacy Cost Allocation௜ =

LCRdef௜

Soln Size +

+

Concident Peak௜∗ (1 + IRM − LCRi)

௡ \*

� Coincident Peak௞

௞=1

∗ (1 + IRM − LCRk)

Concident Peak௜∗ (1 + IRM − LCRi)

௠ \*

� Coincident Peak௟

௟=1

∗ (1 + IRM − LCRl)

Soln STWdef   
 Soln Size

Soln Cldef   
 Soln Size \*100%

Where i is for each applicable zone, n represent the total zones in NYCA, m represents   
the zones isolated by the binding interfaces, IRM is the statewide reserve margin, and where   
LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero   
for those zones without an LCR requirement, LCRdefi is the applicable zonal LCR deficiency,   
SolnSTWdef is the STWdef for each applicable project, SolnCIdef is the CIdef for each

applicable project, and Soln\_Size represents the total compensatory MW addressed by each applicable project for all reliability cost allocation steps in this Section 31.5.3.2.   
 Three step cost allocation methodology for regulated reliability solutions:

31.5.3.2.1.1 Step 1 - LCR Deficiency

31.5.3.2.1.1.1 Any deficiencies in meeting the LCRs for the Target Year will be referred   
 to as the LCRdef. If the reliability criterion is met once the LCR deficiencies   
 have been addressed, that is LOLE ≤ 0.1 for the Target Year is achieved, then the   
 only costs allocated will be those related to the LCRdef MW. Cost responsibility   
 for the LCRdef MW will be borne by each deficient locational zone(s), to the   
 extent each is individually deficient.

For a single solution that addresses only an LCR deficiency in the applicable LCR zone, the equation would reduce to:

Allocation௜ =

LCRdef௜Soln\_Size ∗ 100%

Where i is for each applicable LCR zone, LCRdefi represents the applicable zonal LCR   
deficiency, and Soln\_Size represents the total compensatory MW addressed by the applicable   
project.

31.5.3.2.1.1.2 Prior to the LOLE calculation, voltage constrained interfaces will be

recalculated to determine the resulting transfer limits when the LCRdef MW are   
added.

31.5.3.2.1.2 Step 2 - Statewide Resource Deficiency. If the reliability criterion is not   
 met after the LCRdef has been addressed, that is an LOLE > 0.1, then a NYCA   
 Free Flow Test will be conducted to determine if NYCA has sufficient resources   
 to meet an LOLE of 0.1.

31.5.3.2.1.2.1 If NYCA is found to be resource limited, the ISO, using the transfer limits   
 and resources determined in Step 1, will determine the optimal distribution of   
 additional resources to achieve a reduction in the NYCA LOLE to 0.1.

31.5.3.2.1.2.2 Cost allocation for compensatory MW added for cost allocation purposes   
 to achieve an LOLE of 0.1, defined as a Statewide MW deficiency (STWdef), will   
 be prorated to all NYCA zones, based on the NYCA coincident peak load. The   
 allocation to locational zones will take into account their locational requirements.   
 For a single solution that addresses only a statewide deficiency, the equation   
 would reduce to:

Concident Peak௜ ∗ (1 + IRM − LCRi)

௡

Allocation௜ = � Coincident Peak௞ \*

௞=1

∗ (1 + IRM − LCRk)

Soln STWdef

Soln Size

\*100%

Where i is for each applicable zone, n is for the total zones in NYCA, IRM is the   
statewide reserve margin, and LCR is defined as the locational capacity   
requirement in terms of percentage and is equal to zero for those zones without an   
LCR requirement, Soln STWdef is the STWdef for the applicable project, and   
Soln\_Size represents the total compensatory MW addressed by the applicable   
project.

31.5.3.2.1.3 Step 3 - Constrained Interface Deficiency. If the NYCA is not resource   
 limited as determined by the NYCA Free Flow Test, then the ISO will examine   
 constrained transmission interfaces, using the Binding Interface Test.

31.5.3.2.1.3.1 The ISO will provide output results of the reliability simulation program   
 utilized for the RNA that indicate the hours that each interface is at limit in each   
 flow direction, as well as the hours that coincide with a loss of load event. These

values will be used as an initial indicator to determine the binding interfaces that are impacting LOLE within the NYCA.

31.5.3.2.1.3.2 The ISO will review the output of the reliability simulation program   
 utilized for the RNA along with other applicable information that may be   
 available to make the determination of the binding interfaces.

31.5.3.2.1.3.3 Bounded Regions are assigned cost responsibility for the compensatory   
 MW, defined as CIdef, needed to reach an LOLE of 0.1.

31.5.3.2.1.3.4 If one or more Bounded Regions are isolated as a result of binding

interfaces identified through the Binding Interface Test, the ISO will determine   
the optimal distribution of compensatory MW to achieve a NYCA LOLE of 0.1.   
Compensatory MW will be added until the required NYCA LOLE is achieved.

31.5.3.2.1.3.5 The Bounded Regions will be identified by the ISO’s Binding Interface   
 Test, which identifies the bounded interface limits that can be relieved and have   
 the greatest impact on NYCA LOLE. The Bounded Region that will have the   
 greatest benefit to NYCA LOLE will be the area to be first allocated costs in this   
 step. The ISO will determine if after the first addition of compensating MWs the   
 Bounded Region with the greatest impact on LOLE has changed. During this   
 iterative process, the Binding Interface Test will look across the state to identify   
 the appropriate Bounded Region. Specifically, the Binding Interface Test will be   
 applied starting from the interface that has the greatest benefit to LOLE (the   
 greatest LOLE reduction per interface compensatory MW addition), and then   
 extended to subsequent interfaces until a NYCA LOLE of 0.1 is achieved.

31.5.3.2.1.3.6 The CIdef MW are allocated to the applicable Bounded Region isolated as   
 a result of the constrained interface limits, based on their NYCA coincident peaks.   
 Allocation to locational zones will take into account their locational requirements.   
 For a single solution that addresses only a binding interface deficiency, the   
 equation would reduce to:

Allocation௜ =

Concident Peak௜ ∗ (1 + IRM − LCRi)

௠

� Coincident Peak௟ ∗ (1 + IRM − LCRl)

௟=1

SolnCIdef

\* Soln Size \*100%

Where i is for each applicable zone, m is for the zones isolated by the binding

interfaces, IRM is the statewide reserve margin, and where LCR is defined as the locational capacity requirement in terms of percentage and is equal to zero for those zones without an LCR requirement, SolnCIdef is the CIdef for the   
applicable project and Soln\_Size represents the total compensatory MW   
addressed by the applicable project.

31.5.3.2.2 BPTF Thermal Transmission Security Cost Allocation Formula

For purposes of solutions eligible for cost allocation under this Section 31.5.3.2, this   
section sets forth the cost allocation methodology applicable to that portion of the costs of the solution attributable to resolving BPTF thermal transmission security issues. If, after   
consideration of the compensatory MW identified in the resource adequacy reliability solution cost allocation in accordance with Section 31.5.3.2.1, there remains a BPTF thermal transmission security issue, the ISO will allocate the costs of the portion of the solution attributable to   
resolving the BPTF thermal transmission security issue(s) to the Subzones that contribute to the BPTF thermal transmission security issue(s) in the following manner.

31.5.3.2.2.1 Calculation of Nodal Distribution Factors. The ISO will calculate the

nodal distribution factor for each load busmodeled in the power flow case

utilizing the output of the reliability simulation program that identified the

Reliability Need, including the NYCA generation dispatch and NYCA coincident   
peak Load. The nodal distribution factor represents the percentage of the Load   
that flows across the facility subject to the Reliability Need. The sign (positive or

negative) of the nodal distribution factor represents the direction of flow.

31.5.3.2.2.2 Calculation of Nodal Flow. The ISO will calculate the nodal megawatt   
 flow, defined as Nodal Flow, for each load bus modeled in the power flow case   
 by multiplying the amount of Load in megawatts for the bus, defined as Nodal   
 Load, by the nodal distribution factor for the bus. Nodal Flow represents the   
 number of megawatts that flow across the facility subject to the Reliability Need   
 due to the Load.

31.5.3.2.2.3 Calculation of Contributing Load and Contributing Flow. The Nodal   
 Load for a load bus with a positive nodal distribution factor is a contributing   
 Load, defined as CLoad, and the Nodal Flow for that Load is contributing flow,   
 defined as CFlow. To identify contributing Loads that have a material impact on   
 the Reliability Need, the ISO will calculate a contributing materiality threshold,   
 defined as CMT, as follows:

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∑௞=1 ∑௅=1ܥܮ݋ܽ݀௅

Where m is for the total number of Subzones and n is for the total number of load buses in a given Subzone.

31.5.3.2.2.4 Calculation of Helping Load and Helping Flow. The Nodal Load for a   
 load bus with a negative or zero nodal distribution factor is a helping Load,   
 defined as HLoad, and the Nodal Flow for that Load is helping flow, defined as   
 HFlow. To identify helping Loads that have a material impact on the Reliability   
 Need, the ISO will calculate a helping materiality threshold, defined as HMT, as   
 follows:

ܪ𝐻 =

∑௠௞=1 ∑௅=1ܪ𝐻𝐻௅

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∑௞=1 ∑௅=1ܪ𝐻𝐻௅

Where m is for the total number of Subzones and n is for the total number of load buses in a given Subzone.

31.5.3.2.2.5 Calculation of Net Material Flow for Each Subzone. The ISO will

identify material Nodal Flow for each Subzone and calculate the net material flow for each Subzone. For each load bus, the Nodal Flow will be identified as   
material flow, defined as MFlow, if the nodal distribution factor is (i) greater than or equal to CMT, or (ii) less than or equal to HMT. The net material flow for each Subzone, defined as SZ\_NetFlow, is calculated as follows:

௡

ܼܵ\_ܰ݁ݐ𝑁𝑁௝ = � 𝑀𝑀௅

௅=1

Where j is for each Subzone and n is for the total number of load buses in a given Subzone.

31.5.3.2.2.6 Identification of Allocated Flow for Each Subzone. The ISO will identify   
 the allocated flow for each Subzone and verify that sufficient contributing flow is   
 being allocated costs. For each Subzone, if the SZ\_NetFlow is greater than zero,   
 that Subzone has a net material contribution to the Reliability Need and the

SZ\_NetFlow is identified as allocated flow, defined as SZ\_AllocFlow. If the   
SZ\_NetFlow is less than or equal to zero, that Subzone does not have a net   
material contribution to the Reliability Need and the SZ\_AllocFlow is zero for   
that Subzone. If the total SZ\_AllocFlow for all Subzones is less than 60% of the total CFlow for all Subzones, then the CMT will be reduced and SZ\_NetFlow   
recalculated until the total SZ\_AllocFlow for all Subzones is at least 60% of the total CFlow for all Subzones.

31.5.3.2.2.7 Cost Allocation for a Single BPTF Thermal Transmission Security Issue.   
 For a single solution that addresses only a BPTF thermal transmission security   
 issue, the equation for cost allocation would reduce to:

ܤܲ𝐵 ℎݎ݉𝑒 ܥ݋ݏ ܣ𝐴ܿ݅݊௝ =

ܼܵ\_ܣ𝐴ܿ𝐴𝐴௝

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∑௞=1 ܼܵ\_ܣ𝐴ܿ𝐴𝐴௞

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×

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Where j is for each Subzone; m is for the total number of Subzones;

SZ\_AllocFlow is the allocated flow for each Subzone; SolnBTSdef is the number of compensatory MW for the BPTF thermal transmission security issue for the applicable project; and Soln\_Size represents the total compensatory MW   
addressed by the applicable project.

31.5.3.2.2.8 Cost Allocation for Multiple BPTF Thermal Transmission Security Issues.   
 If a single solution addresses multiple BPTF thermal transmission security issues,   
 the ISO will calculate weighting factors based on the ratio of the present value of   
 the estimated costs for individual solutions to each BPTF thermal transmission   
 security issue. The present values of the estimated costs for the individual   
 solutions shall be based on a common base date that will be the beginning of the   
 calendar month in which the cost allocation analysis is performed (the “Base

Date”). The ISO will apply the weighting factors to the cost allocation calculated   
 for each Subzone for each individual BPTF thermal transmission security issue.   
 The following example illustrates the cost allocation for such a solution:   
 • A cost allocation analysis for the selected solution is to be performed during a   
 given month establishing the beginning of that month as the Base Date.   
• The ISO has identified two BPTF thermal transmission security issues, Overload   
 X and Overload Y, and the ISO has selected a single solution (Project Z) to   
 address both BPTF thermal transmission security issues.

• The cost of a solution to address only Overload X (Project X) is Cost(X),

provided in a given year’s dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (X) is N(X).

• The cost of a solution to address only Overload Y (Project Y) is Cost(Y),

provided in a given year’s dollars. The number of years from the Base Date to the year associated with the cost estimate of Project Y is N(Y).

• The discount rate, D, to be used for the present value analysis shall be the current

after-tax weighted average cost of capital for the Transmission Owners.

• Based on the foregoing assumptions, the following formulas will be used:

▪ Present Value of Cost (X) = PV Cost (X) = Cost (X) / (1+D)N(X)

▪ Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / (1+D)N(Y)

▪ Overload X weighting factor = PV Cost (X)/[PV Cost (X) + PV Cost (Y)]   
 ▪ Overload Y weighting factor = PV Cost (Y)/[PV Cost (X) + PV Cost (Y)] • Applying those formulas, if:

Cost (X) = $100 Million and N(X) = 6.25 years

Cost (Y) = $25 Million and N(Y) = 4.75 years D = 7.5% per year

Then:

PV Cost (X) = 100/(1+0.075) 6.25 = 63.635 Million   
PV Cost (Y) = 25/(1+0.075)4.75 = 17.732 Million

Overload X weighting factor = 63.635 / (63.635 + 17.732) = 78.21%   
Overload Y weighting factor = 17.732 / (63.635 + 17.732) = 21.79%

• Applying those weighing factors, if:

Subzone A cost allocation for Overload X is 15%   
Subzone A cost allocation for Overload Y is 70%   
Then:

Subzone A cost allocation % for Project Z =

(15% \* 78.21%) + (70% \* 21.79%) = 26.99%

31.5.3.2.2.9 Exclusion of Subzone(s) Based on De Minimis Impact. If a Subzone is   
 assigned a BPTF thermal transmission security cost allocation less than a de   
 minimis dollar threshold of the total project costs, that Subzone will not be   
 allocated costs; provided however, that the total de minimis Subzones may not   
 exceed 10% of the total BPTF thermal transmission security cost allocation. The   
 de minimis threshold is initially $10,000. If the total allocation percentage of all   
 de minimis Subzones is greater than 10%, then the de minimis threshold will be   
 reduced until the total allocation percentage of all de minimis Subzones is less   
 than or equal to 10%.

31.5.3.2.3 BPTF Voltage Security Cost Allocation

If, after consideration of the compensatory MW identified in the resource adequacy cost   
allocation in accordance with Section 31.5.3.2.1 and BPTF thermal transmission security cost   
allocation in accordance with Section 31.5.3.2.2, there remains a BPTF voltage security issue,   
the ISO will allocate the costs of the portion of the solution attributable to resolving the BPTF   
voltage security issue(s) to the Subzones that contribute to the BPTF voltage security issue(s).   
The cost responsibility for the portion (MW or MVAr) of the solution attributable to resolving   
the BPTF voltage security issue(s), defined as SolnBVSdef, will be allocated on a Load-ratio   
share to each Subzone to which each bus with a voltage issue is connected, as follows:

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Where j is for each Subzone; m is for the total number of Subzones that are subject to   
BPTF voltage cost allocation; Coincident Peak is for the total peak Load for each Subzone;   
SolnBVSdef is for the portion of the solution necessary to resolve the BPTF voltage security   
issue(s); and Soln\_Size represents the total compensatory MW addressed by the applicable   
project.

31.5.3.2.4 Dynamic Stability Cost Allocation

If, after consideration of the compensatory MW identified in the resource adequacy cost allocation in accordance with Section 31.5.3.2.1, BPTF thermal transmission security cost   
allocation in accordance with Section 31.5.3.2.2, and BPTF voltage security cost allocation in accordance with Section 31.5.3.2.3, there remains a dynamic stability issue, the ISO will allocate the costs of the portion of the solution attributable to resolving the dynamic stability issue(s) to all Subzones in the NYCA on a Load-ratio share basis, as follows:

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ܥ݋𝐶𝐶݀𝐶 𝑃݇௝ ܦݕ𝐷𝐷𝐷ܹ   
∑௞=1ܥ݋𝐶𝐶݀𝐶 𝑃݇௞ × ܵ𝑆\_ܵݖ

Where j is for each Subzone; m is for the total number of Subzones; Coincident Peak is   
for the total peak Load for each Subzone; DynamicMW is for the megawatt portion of the   
solution necessary to resolve the dynamic stability issue(s) for the applicable project; and   
Soln\_Size represents the total compensatory MW addressed by the applicable project.

31.5.3.2.5 Short Circuit Issues

If, after the completion of the prior reliability cost allocation steps, there remains a short circuit issue, the short circuit issue will be deemed a local issue and related costs will not be allocated under this process.

31.5.4 Regulated Economic Projects

31.5.4.1 The Scope of Section 31.5.4

As discussed in Section 31.5.1 of this Attachment Y, the cost allocation principles and methodologies of this Section 31.5.4 apply only to regulated economic transmission projects (“RETPs”) proposed in response to congestion identified in the CARIS.

This Section 31.5.4 does not apply to generation or demand side management projects,   
nor does it apply to any market-based projects. This Section 31.5.4 does not apply to regulated   
backstop solutions triggered by the ISO pursuant to the CSPP, provided, however, the cost   
allocation principles and methodologies in this Section 31.5.4 will apply to regulated backstop   
solutions when the implementation of the regulated backstop solution is accelerated solely to   
reduce congestion in earlier years of the Study Period. The ISO will work with the ESPWG to   
develop procedures to deal with the acceleration of regulated backstop solutions for economic   
reasons.

Nothing in this Attachment Y mandates the implementation of any project in response to the congestion identified in the CARIS.

31.5.4.2 Cost Allocation Principles

The ISO shall implement the specific cost allocation methodology in Section 31.5.4.4 of this Attachment Y in accordance with the Order No. 1000 Regional Cost Allocation Principles as set forth in Section 31.5.2.1. The specific cost allocation methodology in Section 31.5.4.4   
incorporates the following elements:

31.5.4.2.1 The focus of the cost allocation methodology shall be on responses to

specific conditions identified in the CARIS.

31.5.4.2.2 Potential impacts unrelated to addressing the identified congestion shall

not be considered for the purpose of cost allocation for RETPs.

31.5.4.2.3 Projects analyzed hereunder as proposed RETPs may proceed on a market

basis with willing buyers and sellers at any time.

31.5.4.2.4 Cost allocation shall be based upon a beneficiaries pay approach. Cost

allocation under the ISO tariff for a RETP shall be applicable only when a super majority of the beneficiaries of the project, as defined in Section 31.5.4.6 of this Attachment Y, vote to support the project.

31.5.4.2.5 Beneficiaries of a RETP shall be those entities economically benefiting

from the proposed project. The cost allocation among beneficiaries shall be based

upon their relative economic benefit.

31.5.4.2.6 Consideration shall be given to the proposed project’s payback period.

31.5.4.2.7 The cost allocation methodology shall address the possibility of cost

overruns.

31.5.4.2.8 Consideration shall be given to the use of a materiality threshold for cost

allocation purposes.

31.5.4.2.9 The methodology shall provide for ease of implementation and

administration to minimize debate and delays to the extent possible.

31.5.4.2.10 Consideration should be given to the “free rider” issue as appropriate. The

methodology shall be fair and equitable.

31.5.4.2.11 The methodology shall provide cost recovery certainty to investors to the

extent possible.

31.5.4.2.12 Benefits determination shall consider various perspectives, based upon the

agreed-upon metrics for analyzing congestion.

31.5.4.2.13 Benefits determination shall account for future uncertainties as appropriate

(e.g., load forecasts, fuel prices, environmental regulations).

31.5.4.2.14 Benefits determination shall consider non-quantifiable benefits as

appropriate (e.g., system operation, environmental effects, renewable integration).

31.5.4.3 Project Eligibility for Cost Allocation

The methodologies in this Section 31.5.4.3 will be used to determine the eligibility of a proposed RETP to have its cost allocated and recovered pursuant to the provisions of this   
Attachment Y.

31.5.4.3.1 The ISO will evaluate the benefits against the costs (as provided by the

Developer) of each proposed RETP over a ten-year period commencing with the   
proposed commercial operation date for the project. The Developer of each   
project will pay the cost incurred by the ISO to conduct the ten-year benefit/cost   
analysis of its project. The ISO, in conjunction with the ESPWG, will develop

methodologies for extending the most recently completed CARIS database as necessary to evaluate the benefits and costs of each proposed RETP.

31.5.4.3.2 The benefit metric for eligibility under the ISO’s benefit/cost analysis will

be expressed as the present value of the annual NYCA-wide production cost

savings that would result from the implementation of the proposed project,

measured for the first ten years from the proposed commercial operation date for the project.

31.5.4.3.3 The cost for the ISO’s benefit/cost analysis will be supplied by the

Developer of the project, and the cost metric for eligibility will be expressed as

the present value of the first ten years of annual total revenue requirements for the project, reasonably allocated over the first ten years from the proposed   
commercial operation date for the project.

31.5.4.3.4 For informational purposes only, the ISO will also calculate the present

value of the annual total revenue requirement for the project over a 30 year period commencing with the proposed commercial operation date of the project.

31.5.4.3.5 To be eligible for cost allocation and recovery under this Attachment Y,

the benefit of the proposed project must exceed its cost measured over the first ten   
years from the proposed commercial operation date for the project, and the   
requirements of section 31.5.4.2 must be met. The total capital cost of the project   
must exceed $25 million. In addition, a super-majority of the beneficiaries must   
vote in favor of the project, as specified in Section 31.5.4.6 of this Attachment Y.

31.5.4.3.6 In addition to calculating the benefit metric as defined in Section

31.5.4.3.2, the ISO will calculate additional metrics to estimate the potential

benefits of the proposed project, for information purposes only, in accordance

with Section 31.3.1.3.5, for the applicable metric. These additional metrics shall include those that measure reductions in LBMP load costs, changes to generator payments, ICAP costs, Ancillary Service costs, emissions costs, and losses. TCC revenues will be determined in accordance with Section 31.5.4.4.2.3. The ISO will provide information on these additional metrics to the maximum extent   
practicable considering its overall resource commitments.

31.5.4.3.7 In addition to the benefit/cost analysis performed by the ISO under this

Section 31.5.4.3, the ISO will work with the ESPWG to consider the development   
and implementation of scenario analyses, for information only, that shed   
additional light on the benefit/cost analysis of a proposed project. These   
additional scenario analyses may cover fuel and load forecast uncertainty,   
emissions data and the cost of allowances, pending environmental or other   
regulations, and alternate resource and energy efficiency scenarios. Consideration   
of these additional scenarios will take into account the resource commitments of   
the ISO.

31.5.4.4 Cost Allocation for Eligible Projects

As noted in Section 31.5.4.2 of this Attachment Y, the cost of a RETP will be allocated to   
those entities that would economically benefit from implementation of the proposed project. This   
methodology shall apply to cost allocation for a RETP, including the ISO’s share of the costs of   
an Interregional Transmission Project proposed as a RETP allocated in accordance with Section

31.5.7 of this Attachment Y.

31.5.4.4.1 The ISO will identify the beneficiaries of the proposed project over a ten-

year time period commencing with the proposed commercial operation date for the project. The ISO, in conjunction with the ESPWG, will develop   
methodologies for extending the most recently completed CARIS database as necessary for this purpose.

31.5.4.4.2 The ISO will identify beneficiaries of a proposed project as follows:

31.5.4.4.2.1 The ISO will measure the present value of the annual zonal LBMP load   
 savings for all Load Zones which would have a load savings, net of reductions in   
 TCC revenues, and net of reductions from bilateral contracts (based on available   
 information provided by Load Serving Entities to the ISO as set forth in   
 subsection 31.5.4.4.2.5 below) as a result of the implementation of the proposed   
 project. For purposes of this calculation, the present value of the load savings will   
 be equal to the sum of the present value of the Load Zone’s load savings for each   
 year over the ten-year period commencing with the project’s commercial   
 operation date. The load savings for a Load Zone will be equal to the difference   
 between the zonal LBMP load cost without the project and the LBMP load cost   
 with the project, net of reductions in TCC revenues and net of reductions from   
 bilateral contracts.

31.5.4.4.2.2 The beneficiaries will be those Load Zones that experience net benefits

measured over the first ten years from the proposed commercial operation date for   
the project. If the sum of the zonal benefits for those Load Zones with load   
savings is greater than the revenue requirements for the project (both load savings   
and revenue requirements measured in present value over the first ten years from

the commercial operation date of the project), the ISO will proceed with the

development of the zonal cost allocation information to inform the beneficiary voting process.

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

31.5.4.4.2.4 Estimated TCC revenues from any Incremental TCCs created by a

proposed RETP over the ten-year period commencing with the project’s

commercial operation date will be added to the Net Load Savings used for the cost allocation and beneficiary determination.

31.5.4.4.2.5 The ISO will solicit bilateral contract information from all Load Serving   
 Entities, which will provide the ISO with bilateral energy contract data for   
 modeling contracts that do not receive benefits, in whole or in part, from LBMP

reductions, and for which the time period covered by the contract is within the   
ten-year period beginning with the commercial operation date of the project.   
Bilateral contract payment information that is not provided to the ISO will not be included in the calculation of the present value of the annual zonal LBMP savings in section 31.5.4.4.2.1 above.

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

31.5.4.4.2.5.2 All non-public bilateral contract information will be protected in

accordance with the ISO’s Code of Conduct, as set forth in Section 12.4 of   
Attachment F of the ISO OATT, and Section 6 of the ISO Services Tariff.

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

(1) Contract quantities on an annual basis:

(a) For non-generator specific contracts, the Energy (in MWh) contracted to serve

each Zone for each year.

(b) For generator specific contracts or LSE-owned generation, the name of the

generator(s) and the MW or percentage output contracted or self-owned for use by Load in each Zone for each year.

(2) For all Load Serving Entities serving Load in more than one Load Zone, the

quantity (in MWh or percentage) of bilateral contract Energy to be applied to each

Zone, by year over the term of the contract.

(3) Start and end dates of the contract.

(4) Terms in sufficient detail to determine that either pricing is not indexed to LBMP,

or, if pricing is indexed to LBMP, the manner in which prices are connected to

LBMP.

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

of the contract.

31.5.4.4.2.5.4 Bilateral contract and LSE-owned generation information will be used to   
 calculate the adjusted LBMP savings for each Load Zone as follows:   
 AdjLBMPSy,z, the adjusted LBMP savings for each Load Zone z in each year y, shall be calculated using the following equation:

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Where:

TLy,z is the total annual amount of Energy forecasted to be consumed by Load in year y in Load Zone z;

By,z is the set of blocks of Energy to serve Load in Load Zone z in year y that are sold under bilateral contracts for which information has been provided to the ISO that meets the requirements set forth elsewhere in this Section 31.5.4.4.2.5

BCLb,y,z is the total annual amount of Energy sold into Load Zone z in year y under bilateral contract block b;

Indb,y,z is the ratio of (1) the increase in the amount paid by the purchaser of Energy,

under bilateral contract block b, as a result of an increase in the LBMP in Load Zone z in year y   
to (2) the increase in the amount that a purchaser of that amount of Energy would pay if the   
purchaser paid the LBMP for that Load Zone in that year for all of that Energy (this ratio shall be

zero for any bilateral contract block of Energy that is sold at a fixed price or for which the cost of   
Energy purchased under that contract otherwise insensitive to the LBMP in Load Zone z in year

y);

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

LBMP1y,z is the forecasted annual load-weighted average LBMP for Load Zone z in year y, calculated under the assumption that the project is not in place; and   
 LBMP2y,z is the forecasted annual load-weighted average LBMP for Load Zone z in year y, calculated under the assumption that the project is in place.

31.5.4.4.2.6 NZSz, the Net Zonal Savings for each Load Zone z resulting from a given   
 project, shall be calculated using the following equation:

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Where:

PS is the year in which the project is expected to enter commercial operation; AdjLBMPSy,z is as calculated in Section 31.5.4.4.2.5;

TCCRevImpacty,z is the forecasted impact of TCC revenues allocated to Load Zone z in year y, calculated using the procedure described in Appendix B in Section 31.7 of this   
Attachment Y; and

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

31.5.4.4.3 Load Zones not benefiting from a proposed RETP will not be allocated

any of the costs of the project under this Attachment Y. There will be no “make whole” payments to non-beneficiaries.

31.5.4.4.4 Costs of a project will be allocated to beneficiaries as follows:

31.5.4.4.4.1 The ISO will allocate the cost of the RETP based on the zonal share of   
 total savings to the Load Zones determined pursuant to Section 31.5.4.4.2 to be   
 beneficiaries of the proposed project. Total savings will be equal to the sum of   
 load savings for each Load Zone that experiences net benefits pursuant to Section

31.5.4.4.2. A Load Zone’s cost allocation will be equal to the present value of the following calculation:

(Zonal Benefits)

Zonal Cost Allocation = Project Cost ∗ �

Total Zonal Benefits for zone with positive net benefits�

31.5.4.4.4.2 Zonal cost allocation calculations for a RETP will be performed prior to

the commencement of the ten-year period that begins with the project’s

commercial operation date, and will not be adjusted during that ten-year period.

31.5.4.4.4.3 Within zones, costs will be allocated to LSEs based on MWhs calculated   
 for each LSE for each zone using data from the most recent available 12 month   
 period. Allocations to an LSE will be calculated in accordance with the following   
 formula:

LSE Intrazonal Cost Allocation = Zonal Cost Allocation ∗ � LSE Zonal MWh �

Total Zonal MWh

31.5.4.4.5 Project costs allocated under this Section 31.5.4.4 will be determined as

follows:

31.5.4.4.5.1 The project cost allocated under this Section 31.5.4.4 will be based on the   
 total project revenue requirement, as supplied by the Developer of the project, for   
 the first ten years of project operation. The total project revenue requirement will   
 be determined in accordance with the formula rate on file at the Commission. If   
 there is no formula rate on file at the Commission, then the Developer shall   
 provide to the ISO the project-specific parameters to be used to calculate the total   
 project revenue requirement.

31.5.4.4.5.2 Once the benefit/cost analysis is completed the amortization period and   
 the other parameters used to determine the costs that will be recovered for the   
 project should not be changed, unless so ordered by the Commission or a court of   
 applicable jurisdiction, for cost recovery purposes to maintain the continued   
 validity of the benefit/cost analysis.

31.5.4.4.5.3 The ISO, in conjunction with the ESPWG, will develop procedures to   
 allocate the risk of project cost increases that occur after the ISO completes its   
 benefit/cost analysis under this Attachment Y. These procedures may include   
 consideration of an additional review and vote prior to the start of construction   
 and whether the developer should bear all or part of the cost of any overruns.

31.5.4.4.6 The Commission must approve the cost of a proposed RETP for that cost

to be recovered through Rate Schedule 10 of the ISO OATT. The developer’s   
filing of its project revenue requirement with the Commission pursuant to Rate   
Schedule 10 must be consistent with the project proposal evaluated by the ISO   
under this Attachment Y in order to be cost allocated to beneficiaries.

31.5.4.5 Collaborative Governance Process and Board Action

31.5.4.5.1 The ISO shall submit the results of its project benefit/cost analysis and

beneficiary determination to the ESPWG and TPAS, and to the identified

beneficiaries of the proposed RETP for comment. The ISO shall make available   
to any interested party sufficient information to replicate the results of the   
benefit/cost analysis and beneficiary determination. The information made   
available will be electronically masked and made available pursuant to a process   
that the ISO reasonably determines is necessary to prevent the disclosure of any   
Confidential Information or Critical Energy Infrastructure Information contained   
in the information made available. Following completion of the review by the   
ESPWG and TPAS of the project benefit/cost analysis, the ISO’s analysis   
reflecting any revisions resulting from the TPAS and ESPWG review shall be   
forwarded to the Business Issues Committee and Management Committee for   
discussion and action.

31.5.4.5.2 Following the Management Committee vote, the ISO’s project benefit/cost

analysis and beneficiary determination will be forwarded, with the input of the   
Business Issues Committee and Management Committee, to the ISO Board for   
review and action. In addition, the ISO’s determination of the beneficiaries’   
voting shares will be forwarded to the ISO Board for review and action. The   
Board may approve the analysis and beneficiary determinations as submitted or   
propose modifications on its own motion. If any changes to the benefit/cost

analysis or the beneficiary determinations are proposed by the Board, the revised   
analysis and beneficiary determinations shall be returned to the Management   
Committee for comment. If the Board proposes any changes to the ISO’s voting

share determinations, the Board shall so inform the LSE or LSEs impacted by the proposed change and shall allow such an LSE or LSEs an opportunity to comment on the proposed change. The Board shall not make a final determination on the   
project benefit/cost analysis and beneficiary determination until it has reviewed   
the Management Committee comments. Upon final approval of the Board,   
project benefit/cost analysis and beneficiary determinations shall be posted by the ISO on its website and shall form the basis of the beneficiary voting described in Section 31.5.4.6 of this Attachment Y.

31.5.4.6 Voting by Project Beneficiaries

31.5.4.6.1 Only LSEs serving Load located in a beneficiary zone determined in

accordance with the procedures in Section 31.5.4.4 of this Attachment Y shall be   
eligible to vote on a proposed project. The ISO will, in conjunction with the   
ESPWG, develop procedures to determine the specific list of voting entities for   
each proposed project. Prior to a vote being conducted, the Developer of the   
RETP must have a completed System Impact Study or System Reliability Impact   
Study, as applicable.

31.5.4.6.2 The voting share of each LSE shall be weighted in accordance with its

share of the total project benefits, as allocated by Section 31.5.4.4 of this

Attachment Y.

31.5.4.6.3 The costs of a RETP shall be allocated under this Attachment Y if eighty

percent (80%) or more of the actual votes cast on a weighted basis are cast in favor of implementing the project.

31.5.4.6.4 If the proposed RETP meets the required vote in favor of implementing

the project, and the project is implemented, all beneficiaries, including those voting “no,” will pay their proportional share of the cost of the project.

31.5.4.6.5 The ISO will tally the results of the vote in accordance with procedures set

forth in the ISO Procedures, and report the results to stakeholders. Beneficiaries   
voting against approval of a project must submit to the ISO their rationale for   
their vote within 30 days of the date that the vote is taken. Beneficiaries must   
provide a detailed explanation of the substantive reasons underlying the decision,   
including, where appropriate: (1) which additional benefit metrics, either   
identified in the tariff or otherwise, were used; (2) the actual quantification of   
such benefit metrics or factors; (3) a quantification and explanation of the net   
benefit or net cost of the project to the beneficiary; and (4) data supporting the   
metrics and other factors used. Such explanation may also include uncertainties,   
and/or alternative scenarios and other qualitative factors considered, including   
state public policy goals. The ISO will report this information to the Commission   
in an informational filing to be made within 60 days of the vote. The   
informational filing will include: (1) a list of the identified beneficiaries; (2) the   
results of the benefit/cost analysis; and (3) where a project is not approved,   
whether the developer has provided any formal indication to the ISO as to the   
future development of the project.

31.5.5 Regulated Transmission Solutions to Public Policy Transmission Needs

31.5.5.1 The Scope of Section 31.5.5

As discussed in Section 31.5.1 of this Attachment Y, the cost allocation principles and   
methodologies of this Section 31.5.5 apply only to regulated Public Policy Transmission   
Projects. This Section 31.5.5 does not apply to Other Public Policy Projects, including   
generation or demand side management projects, or any market-based projects. This Section

31.5.5 does not apply to regulated reliability solutions implemented pursuant to the reliability

planning process, nor does it apply to RETPs proposed in response to congestion identified in the   
CARIS.

A regulated solutionshall only utilize the cost allocation methodology set forth in Section

31.5.3 where it is: (1) a Responsible Transmission Owner’s regulated backstop solution, (2) an alternative regulated transmission solution selected by the ISO as the more efficient or cost   
effective regulated transmission solution to satisfy a Reliability Need, or (3) seeking cost   
recovery where it has been halted or cancelled pursuant to the provisions of Section 31.2.8.2. A regulated economic transmission solution proposed in response to congestion identified in the CARIS, and approved pursuant to Section 31.5.4.6, shall only be eligible to utilize the cost   
allocation principles and methodologies set forth in Section 31.5.4.

31.5.5.2 Cost Allocation Principles

The ISO shall implement the specific cost allocation methodology in Section 31.5.5.4 of this Attachment Y in accordance with the Order No. 1000 Regional Cost Allocation Principles as set forth in Section 31.5.2.1. The specific cost allocation methodology in Section 31.5.5.4   
incorporates the following elements:

31.5.5.2.1 The focus of the cost allocation methodology shall be on regulated Public

Policy Transmission Projects.

31.5.5.2.2 Projects analyzed hereunder as Public Policy Transmission Projects may

proceed on a market basis with willing buyers and sellers at any time.

31.5.5.2.3 Cost allocation shall be based on a beneficiaries pay approach.

31.5.5.2.4 Project benefits will be identified in accordance with Section 31.5.5.4.

31.5.5.2.5 Identification of beneficiaries for cost allocation and cost allocation

among those beneficiaries shall be according to the methodology specified in Section 31.5.5.4.

31.5.5.3 Project Eligibility for Cost Allocation

The Developer of a Public Policy Transmission Project will be eligible for cost allocation   
in accordance with the process set forth in Section 31.5.5.4 when its project is selected by the   
ISO as the more efficient or cost effective regulated Public Policy Transmission Project;   
provided, however, that if the appropriate federal, state, or local agency(ies) rejects the selected   
project’s necessary authorizations, or such authorizations are withdrawn, the costs the Developer   
is eligible to recover under Section 31.4.12.1 shall be allocated in accordance with Section

31.5.5.4.3, except as otherwise determined by the Commission. The Developer of the selected   
regulated transmission solution may recover its costs in accordance with Section 31.5.6 and Rate   
Schedule 10 of the ISO OATT. If the Developer proposed its Public Policy Transmission Project   
in response to a request by the NYPSC or Long Island Power Authority pursuant to Section

31.4.3.2 and its project was not selected by the ISO, the costs that the Developer is eligible to recover pursuant to Section 31.4.3.2 shall be allocated in accordance with Section 31.5.5.4.3, except as otherwise determined by the Commission. The Developer may recover these costs in accordance with Section 31.5.6 and Rate Schedule 10 of the ISO OATT.

31.5.5.4 Cost Allocation for Eligible Projects

As noted in Section 31.5.5.2 of this Attachment Y, the identification of beneficiaries for   
cost allocation and the cost allocation of a selected Public Policy Transmission Project will be   
conducted in accordance with the process described in this Section 31.5.5.4. This Section will   
also apply to the allocation within New York of the ISO’s share of the costs of an Interregional   
Transmission Project proposed as a solution to a Public Policy Transmission Need allocated in   
accordance with Section 31.5.7 of this Attachment Y. The establishment of a cost allocation   
methodology and rates for a proposed solution that is undertaken by LIPA or NYPA as an

Unregulated Transmitting Utility to a Public Policy Transmission Need as determined in

Sections 31.4.2.1 through 31.4.2.3, as applicable, or an Interregional Transmission Project shall   
occur pursuant to Section 31.5.5.4.4 through 31.5.5.4.6, as applicable. Nothing herein shall   
deprive a Transmission Owner or Other Developerof any rights it may have under Section 205   
of the Federal Power Act to submit filings proposing any other cost allocation methodology to   
the Commission or create any Section 205 filing rights for any Transmission Owner, Other   
Developer, the ISO, or any other entity. The ISO shall apply the cost allocation methodology   
accepted by the Commission. The cost allocation methodology that is accepted or approved by   
the Commission for a particular Public Policy Transmission Project in accordance with this   
Section 31.5.5.4 will be set forth in Appendix E (Section 31.8) of this Attachment Y.

31.5.5.4.1 If the Public Policy Requirement that results in the identification by the

NYPSC of a Public Policy Transmission Need prescribes the use of a particular   
cost allocation and recovery methodology, then the ISO shall file that   
methodology with the Commission within 60 days of the issuance by the NYPSC   
of its identification of a Public Policy Transmission Need. Nothing herein shall   
deprive a Transmission Owner or Other Developer of any rights it may have

under Section 205 of the Federal Power Act to submit filings proposing any other   
cost allocation methodology to the Commission or create any Section 205 filing   
rights for any Transmission Owner, Other Developer, the ISO, or any other entity.   
If the Developer files a different proposed cost allocation methodology under   
Section 205 of the Federal Power Act, it shall have the burden of demonstrating   
that its proposed methodology is compliant with the Order No. 1000 Regional   
Cost Allocation Principles taking into account the methodology specified in the   
Public Policy Requirement.

31.5.5.4.2 Subject to the provisions of Section 31.5.5.4.1, the Developer may submit

to the NYPSC for its consideration - no later than 30 days after the ISO’s

selection of the regulated Public Policy Transmission Project - a proposed cost   
allocation methodology, which may include a cost allocation based on load ratio   
share, adjusted to reflect, as applicable, the Public Policy Requirement or Public   
Policy Transmission Need, the party(ies) responsible for complying with the   
Public Policy Requirement, and the party(ies) who benefit from the transmission   
facility.

31.5.5.4.2.1 The NYPSC shall have 150 days to review the Developer’s proposed cost   
 allocation methodology and to inform the Developer regarding whether it   
 supports the methodology.

31.5.5.4.2.2. If the NYPSC supports the proposed cost allocation methodology, the

Developer shall file that cost allocation methodology with the Commission for its   
acceptance under Section 205 of the Federal Power Act within 30 days of the   
NYPSC informing the Developer of its support. The Developer shall have the

burden of demonstrating that the proposed cost allocation methodology is   
compliant with the Order No. 1000 Regional Cost Allocation Principles.

31.5.5.4.2.3 If the NYPSC does not support the proposed cost allocation methodology,   
 then the Developer shall take reasonable steps to respond to the NYPSC’s   
 concerns and to develop a mutually agreeable cost allocation methodology over a   
 period of no more than 60 days after the NYPSC informing the Developer that it   
 does not support the methodology.

31.5.5.4.2.4 If a mutually acceptable cost allocation methodology is developed during   
 the timeframe set forth in Section 31.5.5.4.2.3, the Developer shall file it with the   
 Commission for acceptance under Section 205 of the Federal Power Act no later   
 than 30 days after the conclusion of the 60 day discussion period with the   
 NYPSC. The Developer shall have the burden of demonstrating that the proposed   
 cost allocation methodology is compliant with the Order No. 1000 Regional Cost   
 Allocation Principles.

31.5.5.4.2.5 If no mutually agreeable cost allocation methodology is developed, the   
 Developer shall file its preferred cost allocation methodology with the   
 Commission for acceptance under Section 205 of the Federal Power Act no later   
 than 30 days after the conclusion of the 60 day discussion period with the   
 NYPSC. The Developer shall have the burden of demonstrating that its proposed   
 methodology is compliant with the Order No. 1000 Regional Cost Allocation   
 Principles in consideration of the position of the NYPSC. The filing shall include   
 the methodology supported by NYPSC for the Commission’s consideration. If the   
 Developer elects to use the load ratio share cost allocation methodology

referenced below in Section 31.5.5.4.3, the Developer shall notify the

Commission of its intent to utilize the load ratio share methodology and shall include in its notice the NYPSC supported methodology for the Commission’s consideration.

31.5.5.4.3. Unless the Commission has accepted an alternative cost allocation

methodology pursuant to this Section, the ISO shall allocate the costs of the   
Public Policy Transmission Project to all Load Serving Entities in the NYCA   
using the default cost allocation methodology, based upon a load ratio share   
methodology.

31.5.5.4.4 The NYISO will make any Section 205 filings related to this Section on

behalf of NYPA to the extent requested to do so by NYPA. NYPA shall bear the   
burden of demonstrating that such a filing is compliant with the Order No. 1000   
Regional Cost Allocation Principles. NYPA shall also be solely responsible for   
making any jurisdictional reservations or arguments related to their status as non-  
Commission-jurisdictional utilities that are not subject to various provisions of the   
Federal Power Act.

31.5.5.4.5 The cost allocation methodology and any rates for cost recovery for a

proposed solution to a Public Policy Transmission Need undertaken by LIPA, as an Unregulated Transmitting Utility (for purposes of this section a “LIPA   
project”), shall be established and recovered as follows:

31.5.5.4.5.1 For costs solely to LIPA customers. The cost allocation methodology and   
 rates to be established for a LIPA project, for which cost recovery will only occur   
 from LIPA customers, will be established pursuant to Article 5, Title 1-A of the

New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Prior to the   
adoption of any cost allocation mechanism or rates for such a LIPA project, and   
pursuant to Section 1020-f(u), the Long Island Power Authority’s Board of   
Trustees shall request that the NYDPS provide a recommendation with respect to   
the cost allocation methodology and rate that LIPA has proposed and the Board of   
Trustees shall consider such recommendation in accordance with the requirements   
of Section 1020-f(u). Upon approval of the cost allocation mechanism and/or   
rates by the Long Island Power Authority’s Board of Trustees, LIPA shall provide   
to the ISO, for purposes of inclusion within the ISO OATT and filing with FERC   
on an informational basis only, a description of the cost allocation mechanism and   
the rate that LIPA will charge and collect within the Long Island Transmission   
District.

31.5.5.4.5.2 For Costs for a LIPA Project That May be Allocated to Other

Transmission Districts. A LIPA project that meets a Public Policy Transmission   
Need as determined by the NYPSC pursuant to Section 31.4.2.3(iii) may be   
allocated to market participants outside of the Long Island Transmission District.   
The cost allocation methodology and rate for such a LIPA project shall be   
established in accordance with the following procedures. LIPA’s proposed cost   
allocation methodology and/or rate shall be reviewed and approved by the Long   
Island Power Authority’s Board of Trustees pursuant to Article 5, Title 1-A of the   
New York Public Authorities Law, Sections 1020-f(u) and 1020-s. Prior to the   
adoption of any cost allocation mechanism or rates for such project and pursuant   
to Section 1020-f(u), the Long Island Power Authority’s Board of Trustees shall

request that the NYDPS provide a recommendation with respect to the cost

allocation methodology and rate that LIPA has proposed and the Board of

Trustees shall consider such recommendation in accordance with the requirements   
of Section 1020-f(u). LIPA shall inform the ISO of the cost allocation   
methodology and rate that has been approved by the Long Island Power   
Authority’s Board of Trustees for filing with the Commission.   
 Upon approval by the Long Island Power Authority’s Board of Trustees, LIPA shall submit and request that the ISO file the LIPA cost allocation   
methodology for approval with the Commission. Any cost allocation   
methodology for a LIPA project that allocates costs to market participants outside   
of the Long Island Transmission District shall be reviewed as to whether there is   
comparability in the derivation of the cost allocation for market participants such   
that LIPA has demonstrated that the proposed cost allocation is compliant with   
the Order No. 1000 cost allocation principles, there are benefits provided by the   
project to market participants outside of the Long Island Transmission District,   
and that the proposed allocation is roughly commensurate to the identified   
benefits.

Article 5, Title 1-A of the New York Public Authorities Law, Sections

1020-f(u) and 1020-s, requires that LIPA’s rates be established at the lowest level   
consistent with sound fiscal and operating practices of the Long Island Power   
Authority and which provide for safe and adequate service. Upon approval of a   
LIPA rate by the Long Island Power Authority’s Board of Trustees pursuant to   
Section 1020-f(u), LIPA shall submit, and request that the ISO file, the LIPA rate

with the Commission for review under the same comparability standard as applied to the review of changes in LIPA’s TSC under Attachment H of this tariff.   
 In the event that the cost allocation methodology or rate approved by the Long Island Power Authority’s Board of Trustees did not adopt the NYDPS   
recommendation, the NYDPS recommendation shall be included in the filing for the Commission’s consideration.

31.5.5.4.5.3 Support for Filing. LIPA shall intervene in support of the filing(s) made   
 pursuant to Section 31.5.5.4.5 at the Commission and shall take the responsibility   
 to demonstrate that: (i) the cost allocation methodology and/or rate approved by   
 the Long Island Power Authority’s Board of Trustees meets the applicable   
 standard of comparability, and (ii) the Commission should accept such   
 methodology or rate for filing. LIPA shall also be responsible for responding to,   
 and seeking to resolve, concerns about the contents of the filing that might be   
 raised in such proceeding.

31.5.5.4.5.4 Billing of LIPA Charges Outside of the Long Island Transmission District.   
 For Transmission Districts other than the Long Island Transmission District, the   
 ISO shall bill for LIPA, as a separate charge, the costs incurred by LIPA for a   
 solution to a Public Policy Transmission Need allocated using the cost allocation   
 methodology and rates established pursuant to Section 31.5.5.4.5.2 and accepted   
 for filing by the Commission and shall remit the revenues collected to LIPA each   
 Billing Period in accordance with the ISO’s billing and settlement procedures.

31.5.5.4.6 The inclusion in the ISO OATT or in a filing with the Commission of the

cost allocation and charges for recovery of costs incurred by NYPA or LIPA

related to a solution to a transmission need driven by a Public Policy Requirement   
or Interregional Transmission Project as provided for in Sections 31.5.5.4.4 and

31.5.5.4.5 shall not be deemed to modify the treatment of such rates as nonjurisdictional pursuant to Section 201(f) of the FPA.

31.5.6 Cost Recovery for Regulated Projects

31.5.6.1 Cost Recovery for Regulated Transmission Project to Address a   
 Reliability Need

31.5.6.1.1 A Responsible Transmission Owner, a Transmission Owner, or an Other

Developer may recover in accordance with Rate Schedule 10 of the ISO OATT   
the costs incurred with respect to the implementation of: (i) a regulated backstop   
transmission solution proposed by a Responsible Transmission Owner pursuant to

Section 31.2.4.3.1 of this Attachment Y and the ISO/TO Reliability Agreement or   
an Operating Agreement; (ii) an alternative regulated transmission solution that   
the ISO has selected pursuant to Section 31.2.6.5.2 of this Attachment Y as the

more efficient or cost-effective solution to a Reliability Need; (iii) a regulated   
transmission Gap Solution proposed by a Responsible Transmission Owner   
pursuant to Section 31.2.11.4 of this Attachment Y; or (iv) an alternative

regulated transmission Gap Solution that has been determined by the appropriate state regulatory agency(ies) as the preferred solution(s) to a Reliability Need pursuant to Section 31.2.11.5 of Attachment Y of the ISO OATT.

31.5.6.1.2 If a regulated solution: (i) is eligible for cost recovery as described in

Section 31.5.6.1.1 and (ii) is not triggered or is halted pursuant to Sections 31.2.8   
or 31.2.10.1.2 of this Attachment Y, the Responsible Transmission Owner,   
Transmission Owner or Other Developer of that solution may recover the costs

that it eligible to recover pursuant to Sections 31.2.8 or 31.2.10.1.2 in accordance with Rate Schedule 10 of the ISO OATT.

31.5.6.1.3 Costs related to non-transmission regulated solutions to Reliability Needs

will be recovered by a Responsible Transmission Owner, Transmission Owner, or   
Other Developer in accordance with the provisions of New York Public Service   
Law, New York Public Authorities Law, or other applicable state law. A   
Responsible Transmission Owner, a Transmission Owner, or Other Developer   
may propose and undertake a regulated non-transmission solution, provided that   
the appropriate state agency(ies) has established cost recovery procedures   
comparable to those provided in this tariff for regulated transmission solutions to   
ensure the full and prompt recovery of all reasonably-incurred costs related to   
such non-transmission solutions. Nothing in this section shall affect the   
Commission’s jurisdiction over the sale and transmission of electric energy   
subject to the jurisdiction of the Commission.

31.5.6.2 Cost Recovery for Regulated Economic Transmission Project

A Transmission Owner or an Other Developer may recover in accordance with Rate Schedule 10 of the ISO OATT the costs incurred with respect to the implementation a regulated economic transmission project that has been   
approved pursuant to Section 31.5.4.6 of this Attachment Y.

31.5.6.3 Cost Recovery for Regulated Transmission Project to Address a Public   
 Policy Transmission Need

31.5.6.3.1 A Transmission Owner or an Other Developer may recover in accordance

with Rate Schedule 10 of the ISO OATT the costs incurred with respect to the

implementation of: (i) a Public Policy Transmission Project that the ISO has   
selected as the more efficient or cost-effective solution to a Public Policy   
Transmission Need, or (ii) a Public Policy Transmission Project proposed by a   
Developer in response to a request by the NYPSC or Long Island Power   
Authority in accordance with Section 31.4.3.2 of Attachment Y of the ISO OATT. Such cost recovery will also include reasonable costs incurred by the Developer to provide a more detailed study or cost estimate for such project at the request of   
the NYPSC, and to prepare the application required to comply with New York   
Public Service Law Article VII, or any successor statute or any other applicable permits, and to seek other necessary authorizations.

31.5.6.3.2 If a regulated solution that: (i) is eligible for cost recovery as described in

Section 31.5.6.3.1 and (ii) is halted as described in Section 31.4.12.1 of this

Attachment Y, the Transmission Owner or Other Developer of that solution may recover the costs that it is eligible to recover pursuant to Section 31.4.12.1 in accordance with Rate Schedule 10 of the ISO OATT.

31.5.6.4 Cost Recovery for Interregional Transmission Project

A Responsible Transmission Owner, a Transmission Owner, or an Other Developer may   
recover in accordance with Rate Schedule 10 of the ISO OATT the costs incurred with respect to   
the implementation of the portion of an Interregional Transmission Project selected by the ISO in   
the CSPP that is allocated to the NYISO region pursuant to Section 31.5.7 of Attachment Y of   
the ISO OATT.

31.5.7 Cost Allocation for Eligible Interregional Transmission Projects

31.5.7.1 Costs of Approved Interregional Transmission Projects

The cost allocation methodology reflected in this Section 31.5.7.1 shall be referred to as the “Northeastern Interregional Cost Allocation Methodology” (or “NICAM”), and shall not be modified without the mutual consent of the Section 205 rights holders in each region.

The costs of Interregional Transmission Projects, as defined in the Interregional Planning   
Protocol, evaluated under the Interregional Planning Protocol and selected by ISO-NE, PJM and   
the ISO in their regional transmission plans for purposes of cost allocation under their respective   
tariffs shall, when applicable, be allocated to the ISO-NE region, PJM region and the ISO region   
in accordance with the cost allocation principles of FERC Order No. 1000, as follows:

(a) To be eligible for interregional cost allocation, an Interregional Transmission

Project must be selected in the regional transmission plan for purposes of cost allocation in each of the transmission planning regions in which the transmission project is proposed to be located, pursuant to agreements and tariffs on file at FERC for each region. With respect to Interregional Transmission Projects and other transmission projects involving the ISO and PJM, the cost   
allocation of such projects shall be in accordance with the Joint Operating Agreement (“JOA”) among and between the ISO and PJM. With respect to Interregional Transmission Projects and other transmission projects involving the ISO and ISO-NE, the cost allocation for such projects shall be in accordance with this Section 31.5.7 of Attachment Y of the NYISO Open Access   
Transmission Tariff and with the respective tariffs of ISO-NE.

(b) The share of the costs of an Interregional Transmission Project allocated to a

region will be determined by the ratio of the present value of the estimated costs of such region’s   
displaced regional transmission project to the total of the present values of the estimated costs of

the displaced regional transmission projects in all regions that have selected the Interregional Transmission Project in their regional transmission plans.

(i) The present values of the estimated costs of each region’s displaced regional

transmission project shall be based on a common base date that will be the

beginning of the calendar month of the cost allocation analysis for the subject Interregional Transmission Project (the “Base Date”).

(ii) In order to perform the analysis in this Section 31.5.7.1(b), the estimated cost of

the displaced regional transmission projects shall specify the year’s dollars in which those estimates are provided.

(iii) The present value analysis for all displaced regional transmission projects shall

use a common discount rate. The regions having displaced projects will mutually   
agree, in consultation with their respective transmission owners, and for purposes   
of the ISO, its other stakeholders, on the discount rate to be used for the present   
value analysis.

(iv) For the purpose of this allocation, cost estimates shall use comparable cost

estimating procedures. In the Interregional Planning Stakeholder Advisory

Committee review process, the regions having displaced projects will review and   
determine, in consultation with their respective transmission owners, and for   
purposes of the NYISO, its other stakeholders, that reasonably comparable   
estimating procedures have been used prior to applying this cost allocation.

(c) No cost shall be allocated to a region that has not selected the Interregional Transmission Project in its regional transmission plan.

(d) When a portion of an Interregional Transmission Project evaluated under the

Interregional Planning Protocol is included by a region (Region 1) in its regional transmission

plan but there is no regional need or displaced regional transmission project in Region 1, and the neighboring region (Region 2) has a regional need or displaced regional project for the   
Interregional Transmission Project and selects the Interregional Transmission Project in its   
regional transmission plan, all of the costs of the Interregional Transmission Project shall be   
allocated to Region 2 in accordance with the NICAM and none of the costs shall be allocated to Region 1. However, Region 1 may voluntarily agree, with the mutual consent of the Section 205 rights holders in the other affected region(s) (including the Long Island Power Authority and the New York Power Authority in the NYISO region) to use an alternative cost allocation method filed with and accepted by the Commission.

(e) The portion of the costs allocated to a region pursuant to the NICAM shall be

further allocated to that region’s transmission customers pursuant to the applicable provisions of   
the region’s FERC-filed documents and agreements, for the ISO in accordance with Section

31.5.1.7 of Attachment Y of the ISO OATT.

(f) The following example illustrates the cost allocation for such an Interregional

Transmission Project:

• A cost allocation analysis of the costs of Interregional Transmission Project Z is to be   
 performed during a given month establishing the beginning of that month as the Base   
 Date.

• Region A has identified a reliability need in its region and has selected a transmission   
 project (Project X) as the preferred solution in its regional plan. The estimated cost of

Project X is: Cost (X), provided in a given year’s dollars. The number of years from   
 the Base Date to the year associated with the cost estimate of Project (X) is: N(X). • Region B has identified a reliability need in its region and has selected a transmission   
 project (Project Y) as the preferred solution in its Regional Plan. The estimated cost   
 of Project Y is: Cost (Y), provided in a given year’s dollars. The number of years   
 from the Base Date to the year associated with the cost estimate of Project (Y) is:   
 N(Y).

• Regions A and B, through the interregional planning process have determined that an

Interregional Transmission Project (Project Z) will address the reliability needs in

both regions more efficiently and cost-effectively than the separate regional projects. The estimated cost of Project Z is: Cost (Z). Regions A and B have each determined that Interregional Transmission Project Z is the preferred solution to their reliability needs and have adopted that Interregional Transmission Project in their respective regional plans in lieu of Projects X and Y respectively. If Regions A and B have   
agreed to bear the costs of upgrades in other affected transmission planning regions, these costs will be considered part of Cost (Z).

• The discount rate used for all displaced regional transmission projects is: D

• Based on the foregoing assumptions, the following formulas will be used:

▪ Present Value of Cost (X) = PV Cost (X) = Cost (X) / (1+D)N(X)

▪ Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / (1+D)N(Y)

▪ Cost Allocation to Region A = Cost (Z) x PV Cost (X)/[PV Cost (X) + PV   
 Cost (Y)]

▪ Cost Allocation to Region B = Cost (Z) x PV Cost (Y)/[PV Cost (X) + PV   
 Cost (Y)]

• Applying those formulas, if:

Cost (X) = $60 Million and N(X) = 8.25 years Cost (Y) = $40 Million and N(Y) = 4.50 years Cost (Z) = $80 Million

D = 7.5% per year   
Then:

PV Cost (X) = 60/(1+0.075) 8.25 = 33.039 Million   
PV Cost (Y) = 40/(1+0.075)4.50 = 28.888 Million

Cost Allocation to Region A = $80 x 33.039/(33.039 + 28.888) = $42,681 Million   
Cost Allocation to Region B = $80 x 28.888/(33.039+28.888) = $37.319 Million

31.5.7.2 Other Cost Allocation Arrangements

(a) Except as provided in Section 31.5.7.2(b), the NICAM is the exclusive means by which any costs of an Interregional Transmission Project may be allocated between or among PJM, the ISO, and ISO-NE.

(b) Nothing in the FERC-filed documents of ISO-NE, the ISO or PJM shall preclude   
agreement by entities with cost allocation rights under Section 205 of the Federal Power Act for   
their respective regions (including the Long Island Power Authority and the New York Power   
Authority in the ISO region) to enter into separate agreements to allocate the cost-of   
Interregional Transmission Projects proposed to be located in their regions as an alternative to   
the NICAM, or other transmission projects identified pursuant to assessments and studies   
conducted pursuant to Section 6 of the Interregional Planning Protocol. Such other cost-

allocation methodologies must be approved in each region pursuant to the Commission-approved rules in each region, filed with and accepted by the Commission, and shall apply only to the   
region's share of the costs of an Interregional Transmission Project or other transmission projects pursuant to Section 6 of the Interregional Planning Protocol, as applicable.

31.5.7.3 Filing Rights

Nothing in this Section 31.5.7 will convey, expand, limit or otherwise alter any rights of ISO-NE, the ISO, PJM, each region’s transmission owners, market participants, or other entities to submit filings under Section 205 of the Federal Power Act regarding interregional cost   
allocation or any other matter.

Where applicable, the regions have been authorized by entities that have cost allocation rights for their respective regions to implement the provisions of this Section 31.5.7.

31.5.7.4. Merchant Transmission and Individual Transmission Owner Projects

Nothing in this Section 31.5.7 shall preclude the development of Interregional Transmission Projects that are funded solely by merchant transmission developers or by individual transmission owners.

31.5.7.5 Consequences to Other Regions from Regional or Interregional   
 Transmission Projects

Except as provided herein in Sections 31.5.7.1 and 31.5.7.2, or where cost responsibility   
is expressly assumed by ISO-NE, the ISO or PJM in other documents, agreements or tariffs on   
file with FERC, neither the ISO-NE region, the ISO region nor the PJM region shall be   
responsible for compensating another region or each other for required upgrades or for any other   
consequences in another planning region associated with regional or interregional transmission   
facilities, including but not limited to, transmission projects identified pursuant to Section 6 of

the Interregional Planning Protocol and Interregional Transmission Projects identified pursuant to Section 7 of the Interregional Planning Protocol.