24 Attachment R – Cost Allocation and Measurement and Verification Methodologies for Demand Reductions by ~~Incentivized Day-Ahead Economic Load Curtailment~~Demand Side Resources in a DER Aggregation ~~Program~~

~~Under the Incentivized Day-Ahead Economic Load Curtailment Program – also referred to in the ISO Tariffs and ISO Procedures as the Day-Ahead Demand Response Program – ("Program" or "DADRP"), c~~Costs incurred by the ISO in covering ~~Demand Reduction Providers' Curtailment Initiation Costs and making~~ Load ~~Reduction Incentive Payments for scheduled and verified Demand Reductions by the dispatchable DER Aggregations are to be recovered under Schedule 1. Measurement and verification of actual Demand Reductions by Demand Side Resources scheduled under the Program dispatchable DER Aggregations shall be conducted in accordance with subsections 24.2, 24.3, and 24.4.~~

24.1 Cost Allocation Methodology for ~~Payments~~ Demand Reductions ~~to Demand Reduction Providers~~Aggregators ~~under the Program~~ Recovered Pursuant to Schedule 1

The "Schedule 1 Program Costs" for verified Actual Demand Reductions by DER Aggregations participating in the Energy and Ancillary Serivces Markets shall be equal to the Supplier payments for Demand Reductions calculated in accordance with ISO Services Tariff Section 4.5.2.

The "Schedule 1 Program Costs" for ~~scheduled and~~ verified Demand Reductions by ~~dispatchable~~ DER Aggregations participating in the Energy and Ancillary Serivces Markets shall be allocated to Transmission Customers, pursuant to the methodology set forth below, on the basis of their Load Ratio Shares and in proportion to the probability, given historical transmission congestion patterns, that a particular Demand Reduction will benefit them by reducing Energy costs in their Load Zones or "Composite Load Zones" (see below).

More specifically, Schedule 1 Program Costs shall be allocated to Transmission Customers each Billing Period as follows:

a) Schedule 1 Program Costs shall initially be attributed to the Load Zone where the ~~Generator Bus~~Transmission Node ~~that was~~ used to ~~b~~Bid the associated Demand Reduction ~~associated with them,~~ is located.

b) In determining whether and how Transmission Customers located in particular Load Zones, or Composite Load Zones, have benefited from the Energy provided by Demand Reduction, and how much they shall be required to pay a share of the associated Schedule 1 Program Costs, the ISO shall account for the effects of congestion at the most frequently constrained NYCA interfaces. When none of these interfaces are constrained Transmission Customers in all Load Zones shall be deemed to have benefited from the Energy provided by Demand Reduction and shall pay a share of the associated Schedule 1 Program Costs. When one or more of the most frequently constrained NYCA interfaces is constrained, then Transmission Customers located in a Load Zone, or Composite Load Zone, that is upstream of the constrained interface, shall be deemed to have benefited from ~~an~~ the upstream Energy provided by Demand Reduction and shall be required to pay a share of the associated Schedule 1 Program Costs. Similarly, when one or more of the interfaces is congested, Transmission Customers located in a Load Zone, or Composite Load Zone, that is downstream of a constrained interface, shall be deemed to have benefited from ~~a~~ the downstream Energy provided by Demand Reduction and shall be required to pay a share of the associated Schedule 1 Program Costs. By contrast, Transmission Customers that are “separated” from ~~a~~

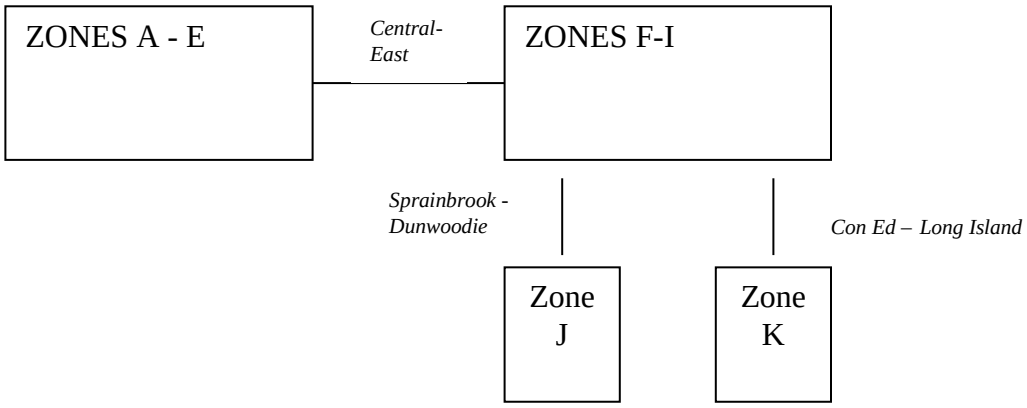
the Energy provided by Demand Reduction by a constrained interface shall be deemed not to have benefited from it and shall not be required to pay a share of the associated Schedule 1 Program Costs.

c) The ISO shall determine the extent of congestion at the most frequently constrained interfaces using a series of equations that calculate the static probability that: (i) no constraints existed in the transmission system serving the Load Zone or Composite Load Zone; (ii) the Composite Load Zone was upstream of a constraint and curtailment pursuant to the Program occurred upstream; and (iii) the Composite Load Zone was downstream of a constraint and curtailment pursuant to the Program occurred downstream.

Costs shall be allocated to each Transmission Customer that is deemed to have benefited from the ~~scheduled and~~ verified Demand Reduction on a Load Ratio Share basis, using Real-Time metered hourly Load data.

d) The three most frequently constrained interfaces are currently the "Central-East" interface, which divides western from eastern New York State, the Sprainbrook-Dunwoodie interface, which divides New York City and Long Island from the rest of New York State, and the Consolidated Edison Company ("ConEd") - Long Island interface (including the Y49/Y50 lines), which divides New York City from Long Island. Given these limiting interfaces, four Composite Load Zones currently exist, *i.e.*, West of Central-East (Load Zones A, B, C, D, E,), East Upstate Excluding New York City and Long Island (Load Zones F, G, H, I), New York City (Load Zone J), and Long Island (Load Zone K). The geographic configuration of these Composite Load Zones is depicted in the illustration below.

Relationship Between Frequently Constrained Interfaces and Composite Load Zones



Based on these factors, Schedule 1 Program Costs shall be allocated to Transmission Customers as follows:

For Transmission Customer m in Load Zones A-E:

$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K)$ + **'no constraints**
$a_2 * (cost_A+\ldots+cost_E) * load_m / (load_A+\ldots+load_E)$ + **'Central East const**
$a_3 * (cost_A+\ldots+cost_I+cost_K) * load_m / (load_A+\ldots+load_I+load_K)$ + **'NYC constraint**
$a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)$ + **'LI constraint**
$a_5 * (cost_A+\ldots+cost_E) * load_m / (load_A+\ldots+load_E)$ + **'Cent East + NYC**
$a_6 * (cost_A+\ldots+cost_E) * load_m / (load_A+\ldots+load_E)$ + **'Cent East + LI**
$a_7 * (cost_A+\ldots+cost_I) * load_m / (load_A+\ldots+load_I)$ + **'NYC + LI**
$a_8 * (cost_A+\ldots+cost_E) * load_m / (load_A+\ldots+load_E)$ **'Cent East + NYC + LI**

For Transmission Customer m in Load Zones F-I:

$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K)$ + **'no constraints**
$a_2 * (cost_F+\ldots+cost_K) * load_m / (load_F+\ldots+load_K)$ + **'Central East const**
$a_3 * (cost_A+\ldots+cost_I+cost_K) * load_m / (load_A+\ldots+load_I+load_K)$ + **'NYC constraint**
$a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)$ + **'LI constraint**
$a_5 * (cost_F+\ldots+cost_I+cost_K) * load_m / (load_F+\ldots+load_I+load_K)$ + **'Cent East + NYC**
$a_6 * (cost_F+\ldots+cost_J) * load_m / (load_F+\ldots+load_J)$ + **'Cent East + LI**

a_7 * ($cost_A$+…+$cost_I$) * $load_m$ / ($load_A$+…+$load_I$) + 'NYC + LI
a_8 * ($cost_F$+…+$cost_I$) * $load_m$ / ($load_F$+…+$load_I$) 'Cent East + NYC + LI

For Transmission Customer m in Load Zone J:

a_1 * ($cost_A$+…+$cost_K$) * $load_m$ / ($load_A$+…+$load_K$) + 'no constraints
a_2 * ($cost_F$+…+$cost_K$) * $load_m$ / ($load_F$+…+$load_K$) + 'Central East const
a_3 * $cost_J$ * $load_m$ / $load_J$ + 'NYC constraint
a_4 * ($cost_A$+…+$cost_J$) * $load_m$ / ($load_A$+…+$load_J$) + 'LI constraint
a_5 * $cost_J$* $load_m$ / $load_J$ + 'Cent East + NYC
a_6 * ($cost_F$+…+$cost_J$) * $load_m$ / ($load_F$+…+$load_J$) + 'Cent East + LI
a_7 * $cost_J$ * $load_m$ / $load_J$ + 'NYC + LI
a_8 * $cost_J$ * $load_m$ / $load_J$ 'Cent East + NYC + LI

For Transmission Customer m in Load Zone K:

a_1 * ($cost_A$+…+$cost_K$) * $load_m$ / ($load_A$+…+$load_K$) + 'no constraints
a_2 * ($cost_F$+…+$cost_K$) * $load_m$ / ($load_F$+…+$load_K$) + 'Central East const
a_3 * ($cost_A$+…+$cost_I$+$cost_K$) * $load_m$ / ($load_A$+…+$load_I$+$load_K$) + 'NYC constraint
a_4 * $cost_K$ * $load_m$ / $load_K$ + 'LI constraint
a_5 * ($cost_F$+…+$cost_I$+$cost_K$) * $load_m$ / ($load_F$+…+$load_I$+$load_K$) + 'Cent East + NYC
a_6 * $cost_K$ * $load_m$ / $load_K$ + 'Cent East + LI
a_7 * $cost_K$ * $load_m$ / $load_K$ + 'NYC + LI
a_8 * $cost_K$ * $load_m$ / $load_K$ 'Cent East + LI + NYC

In all cases, the variables are:

a_1 = fraction of time when no constraints exist
a_2 = fraction of time when Central East interface alone is constraining
a_3 = fraction of time when Sprainbrook-Dunwoodie interface alone is constraining
a_4 = fraction of time when Con Ed-Long Island (including the Y49/Y50 lines) interfaces are constraining, but Central East and Sprainbrook-Dunwoodie interfaces are not constraining
a_5 = fraction of time when Central East and Sprainbrook-Dunwoodie interfaces are constraining
a_6 = fraction of time when Central East, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining
a_7 = fraction of time when Sprainbrook-Dunwoodie, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining
a_8 = fraction of time when Central East, Sprainbrook-Dunwoodie, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining

$cost_{A…K}$ = revenue deficiencies due to ~~DADRP scheduled~~ DER Aggregation Demand Reductions in Load Zones A…K, calculated on an hourly basis
$load_m$ = real-time Load for Transmission Customer m, calculated on a hourly basis
$load_{A…K}$ = real-time Loads for all Transmission Customers in Load Zones A…K, calculated on an hourly basis

~~24.1.1 Cost Allocation Value for Demand Reductions Recovered Pursuant to Schedule 1~~

~~The "Schedule 1 Program Costs" for verified Demand Reductions by DER Aggregations shall be , pursuant to the methodology set forth below, eal ime LBMP. If the Demand Side Resource is not eligible for Energy payments, pursuant to Services Tariff Section 4.5.7, this value will be zero.~~

~~he Schedule 1 Program Costs shall be calculated each Billing Period as follows:~~

~~Demand Reduction Cost Value = MIN(ADR_{iu}, MAX(RTS_{iu} - AE_{iu}, 0)) * $LBMP_{iu}^{RT}$) * $\frac{S_t}{3600}$~~

~~Where:~~

AE_{iu}	=	~~(1) average Actual Energy Injection by Supplier *u* in interval *i* expressed in terms of MW; or (2) average Actual Energy Withdrawal by an Energy Storage Resource or DER Aggregation that include an Energy Storage Resource *u* in interval *i* expressed in terms of MW;~~
ADR_{iu}	=	~~average Actual Demand Reductions that are eligible for Energy payments pursuant to Services Tariff Section 4.5.7 by Supplier *u* in interval *i*, this term will be set to zero if the Actual Demand Reduction is not eligibile for Energy payments pursuant to Services Tariff Section 4.5.7;~~
RTS_{iu}	=	~~(1) real-time Energy scheduled by Supplier *u* in interval *i* plus Compensable Overgeneration; or (2) real-time Energy scheduled for withdrawal by Energy Storage Resource or Aggregation that includes Withdrawal Eligible Generator(s) *u* in interval *i* plus 3% of the absolute value of the Energy Storage Resource's or Aggregation's Lower Operating Limit; or (3) average Actual Energy Withdrawal by an Energy Storage Resource or Aggregation that includes Withdrawal Eligible Generator(s) *u* in interval *i* when it has been designated as operating Out-of-Merit to withdraw at the request of a Transmission Owner or the ISO;~~
$LBMP_{iu}^{RT}$	=	~~real-time price of Energy at the location of Supplier *u* in interval *i*;~~
S_t	=	~~number of seconds in RTD interval *i*;~~

24.2 Measurement of Actual Demand Reduction of Individual DER within a DER Aggregation~~in the Program~~

The measured amount of Demand Reduction ~~supplied~~ by an ~~Demand Reduction Provider of~~ individual Demand Side Resource within a DER Aggregation which is dispatched for Energy only shall be the greater of: (i) difference between the ~~Demand Reduction Provider~~ Demand Side Resource's Resource's ~~baseline load~~adjusted Economic Customer Baseline Load ("ECBL") for each ~~scheduled hour~~interval, which shall be calculated in accordance with section 24.2.1 and ISO Procedures, and the actual metered ~~hourly~~ load for each ~~scheduled hour~~interval and (ii) zero.

The measured amount of Demand Reduction by an individual Demand Side Resource within a dispatachable DER Aggregation which is dispatched for Regulation Service shall be the greater of: (i) difference between the Demand Side Resource's Baseline Load for each ~~scheduled~~ interval of Regulation Service, which shall be calculated in accordance with section 24.2.2 and ISO Procedures, and the ~~Distributed Energy~~Demand Side Resource's 6--second telemetered load values for each ~~scheduled~~ interval and (ii) zero.

The amount of Demand Reduction supplied by a DER Aggregation shall be the sum of Demand Reductions from each individual Demand Side Resource within the DER Aggregation. Aggregators shall provide these DER Aggregation Demand Reductions to the ISO for each interval using real-time telemetry in accordance with Services Tariff section 13 and the ISO Procedures. These calculated interval Demand Reductions should be time-weighted into an hourly MWh value when submitting to the NYISO as a meter data for settlements.

24.2.1 Methodology for the Calculating the Economic Customer Baseline Load for a Resource ~~Scheduled~~ to Reduce Load Under the ~~Dispatchable~~ DER Participation Model during Intervals with No Regulation Service Dispatch~~Program~~

The ISO shall employ two different calculation methodologies of the Economic Customer Baseline Load ("ECBL") for ~~scheduled~~ Demand Reductions ~~Reductions scheduled to provide Energy~~, depending on whether the Demand Reduction is ~~scheduled~~ on a weekend or a weekday, during the intervals with no Regulation Service dispatch for the ~~Dispatchable~~ DER Aggregation.

24.2.1.1 Definitions

Adjusted Weekday ECBL: For each five-minute interval ~~of the scheduled Demand Reduction~~, the Adjusted Weekday ECBL shall be equal to the sum of the ECBL ~~added to~~ and the ECBL In-Day Adjustment ~~Factor~~ calculated for the ~~scheduled~~ Demand Reduction ~~period~~interval.

ECBL In-Day Adjustment ~~Factor~~: The ECBL In-Day Adjustment shall be an adjustment ~~factor~~ that is applied to the ECBL for each five-minute interval ~~hour~~ of the ~~scheduled~~ Demand Reduction ~~period~~interval.

a) Calculate the ECBL In-Day Adjustment by ~~dividing~~ subtracting the average of the ~~unadjusted~~ ECBL over the three five-minute intervals of the ECBL In-Day Adjustment Period from the average of the metered load for the same period~~two hours of the ECBL In-Day Adjustment Period on the day of the scheduled Demand Reduction~~, provided that the ~~Resource~~ ~~Dispatchable~~ DER Aggregation ~~did not respond to the NYISO's dispatch instructions,~~ was not ~~scheduled to~~ provideing ~~for e~~ Energy and/or ~~ancillary services~~Regulation Service~~,~~ in any of the three five-minute intervals of the ECBL In-Day Adjustment Period.

~~a)~~b) If the ~~Dispatchable~~ DER Aggregation was ~~scheduled to provide~~providing Energy and/or Regulation Service during one or more of the three five-minute intervals of the ECBL In-Day Adjustment Period, calculate the ECBL In-Day Adjustment by replacing the metered loads by the Proxy Load values for the intervals in which the ~~Dispatchable~~ DER Aggregation was ~~scheduled to~~ provideing Energy and/or Regulation Service.

~~b)~~c) ~~b)~~ The ECBL In-Day Adjustment ~~Factor~~ shall be limited to ± 20% of the ~~unadjusted~~ ECBL value for the interval it is applied to. ~~a minimum of 0.8 and a maximum of 1.2.~~

ECBL In-Day Adjustment Period: The ECBL Adjustment Period is the time prior to the ~~scheduled~~ Demand Reduction period that is used to determine the ECBL In-Day Adjustment. The intervals ~~hours~~ to be used in the ECBL Adjustment Period shall be the ~~two~~ three consecutive intervals starting 60 minutes prior to the first operating interval of dispatch and ending 45 minutes prior to the operating interval of dispatch. All the subsequent intervals of uninterrupted dispatch following the first interval of dispatch shall use the same ECBL In-Day Adjustment Period. The ECBL In-Day Adjusment Period shall be be relcalculated for every interval of dispatch which is preceeded by an interval of non-dispatch. ~~hours that occur four hours prior to the first hour of the scheduled Demand Reduction period, provided that the hours are part of the same calendar day.~~

~~To determine the two hours of the ECBL In-Day Adjustment Period:~~

~~a) The fourth hour before the first hour of the scheduled Demand Reduction period shall be the first hour of the ECBL In-Day Adjustment Period, except when the fourth hour before first hour of the scheduled Demand Reduction period occurs on the previous day.~~

~~b) The third hour before the first hour of the scheduled Demand Reduction period shall be the second hour of the ECBL In-Day Adjustment Period, except when the third hour before the first hour of the scheduled Demand Reduction period occurs on the previous day.~~

~~c) When the third and/or fourth hour of the ECBL In-Day Adjustment Period occurs on the previous day, the ISO shall use as a substitute the hour beginning midnight on the day of the scheduled Demand Reduction. Both hours of the ECBL In-Day Adjustment Period may equal the hour beginning midnight on the day of the scheduled Demand Reduction.~~

Proxy Load: The Proxy Load for a five-minute interval is the adjusted ECBL for that interval calculated as per the instructions in section 24.2.1.2.

ECBL Weekday Window: The ECBL Weekday Window is the time period reviewed in determining the ECBL for any ~~hour~~ five--minute interval ~~of scheduled Demand Reduction~~ that takes place on a weekday. It shall consist of the ~~hours~~ like-kind five-minute intervals from the previous ten weekdays that correspond to each ~~hourly~~ five-minute interval that is being calculated.~~of the scheduled Demand Reduction period.~~ Treatment of NERC holidays that occur on weekdays shall be equivalent to all ~~hours~~ intervals that take place ~~scheduled~~ on the ~~NERC holiday~~weekend.

ECBL Weekend Window: The ECBL Weekend Window is the time period reviewed in determining the ECBL for any ~~hour~~ five-minute interval ~~of scheduled Demand Reduction~~ that takes place on a weekend. It shall consist of the ~~hours~~ like-kind intervals from the previous three weekend days of the same type (Saturday or Sunday) that correspond to each ~~hourly~~ five-minute interval ~~of the scheduled Demand Reduction period~~.

~~**Weekday Proxy**: The Weekday Proxy is a value that is substituted for the metered load for any hour in any ECBL Weekday Window in which a Demand Reduction was scheduled. It shall be determined by (1) establishing a new ECBL Weekday Window for that hour consisting of the corresponding hours in the ten weekdays preceding the day the Demand Reduction occurred, and (2) repeating the steps described at section 24.2.1.2 b, c, d, and e.~~

~~**Weekend Proxy:** The Weekend Proxy is a value that is substituted for the metered load for any hour in any ECBL Weekend Window in which a Demand Reduction was scheduled. It shall be determined by (1) establishing a new ECBL Weekend Window for that hour consisting of the corresponding hours in the three weekends preceding the day the Demand Reduction occurred, and (2) repeating the steps described at section 24.2.1.2 b, c, d, and e.~~

24.2.1.2 Methodology for the Calculating the Economic Customer Baseline Load for Demand Reductions ~~Scheduled~~ on a Weekday

To determine the ECBL for a five-minute interval~~n hour of scheduled Demand Reduction~~ (a "Target ~~Hour~~Interval") that occurs on a weekday:

a) Select the ~~hours~~ five-minute intervals that comprise the ECBL Weekday Window for that Target ~~Hour~~Interval.

b) Select the metered load value for each ~~hour~~ five-minute interval in the ECBL Weekday Window where no ~~scheduled~~ Demand Reduction occurred pursuant to this Program.

c) For each ~~hour~~ five-minute interval of the ECBL Weekday Window ~~where a scheduled~~ Demand Reduction occured~~where a scheduled Demand Reduction occurred~~, select the Proxy Load values ~~Weekday Proxy~~ for that ~~hour~~ five-minute interval and day in place of the actual metered load for that ~~hour~~interval.

d) Rank in descending order the metered load and ~~Weekday Proxy~~Proxy Load values determined in steps b and c.

e) Calculate the average of the fifth and sixth ranked values. The value as so calculated shall be the ECBL for the Target ~~Hour~~Interval.

f) Apply the ECBL In-Day Adjustment ~~Factor~~ to the ECBL to determine the Adjusted Weekday ECBL for the Target ~~Hour~~Interval.

24.2.1.3 Methodology for the Calculating the Economic Customer Baseline Load for a Resource's Demand Reduction ~~Scheduled Under the Program~~ on a Weekend

To determine the ECBL for a Target ~~Hour~~ Interval that occurs on a weekend:

a) Select the ~~hours~~ five-minute intervals that comprise the ECBL Weekend Window for the Target ~~Hour~~Interval.

b) Select the metered load value for each ~~hour~~ interval in the ECBL Weekend Window. where no ~~scheduled~~ Demand Reduction occurred pursuant to this Program.

c) For each ~~hour~~ five minute interval of the ECBL Weekend Window where a ~~Scheduled~~ Demand Reduction occurred, select the ~~ECBL Weekend Proxy~~Proxy Load Value for that hour and day in place of the actual metered load for the ~~hour~~interval.

d) Rank in descending order the metered load and ~~ECBL Weekend~~ Proxy Load values determined in steps b and c.

e) Calculate the average of the metered load and ~~ECBL~~ Proxy Load values. The value so calculated is the ECBL for the Target ~~Hour~~Interval.

f) Apply the ECBL In-Day Adjustment Factor to the ECBL to calculate the Adjusted Weekend ECBL for the Target ~~Hour~~Interval.

24.2.2 Methodology for the Calculating the Baseline Load for a Resource ~~Scheduled~~ to Reduce Load Under the ~~Dispatchable~~ DER Participation Model during Intervals with Regulation Service Dispatch

For Demand Reductions ~~in~~by a ~~Dispatchable~~ DER Aggregation that is dispatched to provide Regulation Service, the Aggregator shall calculate the Demand Side Resource's Baseline Load as the ~~-~~Demand Side Resource's 6-second telemetered Load prior to the start of dispatch for Regulation Service. If the Aggregation was dispatched to provide only Energy in the interval prior to being dispatched for Regulation Service, the Aggregator shall use the Proxy Load value corresponding to the five-minute interval immediately preceding the dispatch instruction as the Demand Side Resource's Baseline Load.

24.3 Verification of Actual Demand Reduction ~~Scheduled~~ in the ~~Program~~~~Dispatchable~~ DER Participation Model

Demand Reduction calculated using the Economic Customer Baseline Load methodology is subject to verification by the ISO. ~~Demand Reduction Providers~~Aggregators shall report the data at the time and in the format required by the ISO pursuant to Section 24.4. If a~~ Demand Reduction Provider~~n Aggregator fails to report the required data to the ISO in accordance with Section 24.4, the ~~Demand Reduction Provider~~Aggregator will be subject to penalties associated with a failure to supply the ~~scheduled~~ Demand Reductions and may lose its eligibility to participate in the ~~Dispatchable~~ DER Participation Model~~Program~~. All Demand Reduction data are subject to audit by the ISO. If the ISO determines that it has made an erroneous payment to a ~~Demand Reduction Provider~~n Aggregator, it shall have the right to recover it either by reducing other payments to that ~~Demand Reduction Provider~~ Aggregator or by any other lawful means.

24.4 Data Reporting Requirements for ~~Demand Reduction Providers~~Aggregators

Upon request, t~~Demand Reduction Provide~~Aggregator must submit to the ISO the information specified in this Section 24.4 for each Demand Side ~~Demand Side~~ Resource ~~that it has enrolled either as~~in a ~~n individual DADRP~~ DER Aggregation ~~resource or with other Demand Side Resources as part of a single, aggregated DADRP resource~~. The ~~Demand Reduction Provider~~ Aggregator must submit this information for the purpose of enrolling, registering, making settlements, and verifying the participation of each ~~Demand Side~~ Demand Side Resource in the ISO's Energy market. ~~To enroll and participate in the DADRP~~Dispatchable DER ~~Participation Model, a Demand Side Resource must have NYPSC-approved, revenue-quality, hourly-interval meters~~ and real-time telemetry-quality meters or devices, compliant with ISO ~~standards and procedures, sufficient to calculate its net Load and/or Supply.~~ If the ~~Demand Side~~ Demand Side Resource has a Local Generator at its site, it must also have a~~n hourly-interval~~ meter, compliant with ISO standards and procedures, that measures the total output of the Local Generator ~~within a 2% accuracy threshold~~, regardless of whether at initial enrollment the Local Generator is intended to be used to provide Demand Reduction in the ~~Dispatchable~~ DER Participation Model~~DADRP~~.

24.4.1 Data Reporting Requirements for Enrollment of Demand Side Resources Participating as ~~DADRP~~ DER~~Resources~~

The ~~Demand Reduction Provider~~Aggregator shall provide to the ISO the following information for each Demand Side Resource that is seeking to enroll, either individually or collectively with other Demand Side Resources, as a ~~DADRP resource~~DER participating in the ISO's Energy market, which shall include providing information regarding each of the Demand Side Resource's interval meters required under Section 24.4:

a. ~~As left m~~Meter test criteria, ~~as prescribed in the New York Department of Public Service 16 NYCRR Part 92 Operating Procedure~~compliant ~~as~~ as described in the Services Tariff Sec. 13 and the ~~with~~ ISO ~~standards and p~~Procedures;

b. Documentation to validate installation of ~~interval~~ interval meter equipment;

c. ~~Interval m~~Interval metering installation individual, company, and professional engineering license information;

d. Make and model of installed ~~interval~~ interval metering device(s);

e. Accuracy of installed ~~interval~~ interval metering device(s);

f. ~~Interval m~~Interval meter Current Transformer (CT) and Potential Transformer (PT) type designation, if applicable;

g. CT Ratio, if applicable;

h. Use of pulse data recorder as an interval ~~interval~~ metering device, if applicable;

i. Pulse data recorder multiplier, if applicable;

j. Any other type of meter multiplier used in the translation of data collected by the device for measuring demand, kWh, and/or MWh, if applicable;

k. Its service address;

l. Its Load Serving Entity;

m. Its Transmission Owner;

n. Its meter authority/~~Meter Data Service Provider~~Meter Services Entity;

o. Demand Side Resource's maximum Winter and Summer reduction MW;

p. Business classification of the Demand Side Resource (based on ISO-defined categories or national standards for business classification); and

q. A description of any Local Generator at its site, including the Local Generator's system, its primary fuel type, the year in which it was built, the year of any retrofit, its nameplate capacity, and its horsepower, if applicable.

24.4.2 Data Reporting Requirements for Verification of Energy Reductions of ~~DADRP~~ DER ~~Resources Scheduled~~ in the ISO's Energy Market

The ~~meter authority/~~Meter Service Entity~~ or Meter Data Service Provider of the Demand Reduction Provider~~Aggregator ~~of DER Aggregations~~ shall retain for purposes of an audit, and provide the ISO with the following required data from each interval meter required under Section 24.4 for each Demand Side Resource that is registered, either individually or collectively with other Demand Side Resources, as a ~~DADRP~~ DER Aggregation~~resource~~, to verify the ~~scheduled~~ calculated ~~Load reduction~~Demand Reduction of a ~~DADRP~~ ~~DER~~Demand Side Resource ~~resource~~ in the ISO's Energy market:

a) Totalized net ~~hourly~~ interval ~~Load reduction~~Demand Reduction data of the ~~DADRP~~ ~~DER~~Demand Side Resource ~~resource~~ (*i.e.*, the net ~~hourly~~ interval ~~Load reduction~~Demand Reduction data totalized across all Demand Side Resources that are registered, either individually or collectively with other Demand Side Resources, as a ~~DADRP~~ ~~DER~~Demand Side Resource ~~resource~~) for the period of the ~~scheduled Load reduction~~Demand Reduction of the ~~DER~~Demand Side Resource ~~DADRP~~ ~~resource~~ in the format required for reporting to the ISO's Settlement Data Exchange application;

b) ~~Hourly~~Five-minute-interval metered Load data for each of the individual Demand Side Resources that is registered as part of a single ~~DADRP~~ DER~~resource~~ Aggregation, for all ~~hours~~ intervals of ~~the day on the days of the scheduled Load~~

~~reduction~~Demand Reduction ~~of the DADRP resource~~the period for which it was enrolled; and

c) ~~Hourly~~Five-minute-interval metered Load data for each of the individual Demand Side Resources that is registered as part of a single ~~DADRP~~ DER Aggregation~~resource~~, for all ~~hours~~ intervals of ~~each of the thirty days preceding the day in which the DADRP resource is scheduled~~the period for which it was enrolled.

The ~~meter authority or Meter Data Service Provider~~Meter Service Entity ~~of the Demand Reduction Provider~~ Aggregator shall comply with the following when~~ reporting Demand Reduction~~ providing metering data to verify energy reductions of ~~DER~~Demand Side Resources ~~the ISO~~:

a) Section 7.4.1 of the ISO Services Tariff;

b) Section 13 of the ISO Services Tariff; and

c) The ISO's Meter Data Management Protocols as provided on the ISO's website.

24.4.3 Additional Data Required Upon Request

To verify the participation of each Demand Side Resource that is enrolled, either individually or collectively with other ~~Demand Side Resources~~DER, as a ~~DADRP~~ DER Aggregation~~resource~~ in the ISO's Energy market, ~~Demand Reduction Providers~~Aggregators and/or their meter authority/~~Meter Data Service Provider~~Meter Service Entity shall provide the ISO upon the ISO's request such additional information that may be required, including, but not limited, to the following:

a) Any data reporting requirements of Attachments H and O to the ISO Services Tariff;

b) Any data reporting requirements of Section 3.4 of the ISO Services Tariff;

c) Historical Load documentation;

d) Load data history for Pre- and Post-Validation, Edit and Estimation (VEE);

e) Up to three months of historical Load data when enrolling a Demand Side Resource to participate in the ISO's Energy market;

f) New and existing metering documentation, including, but not limited to:

1. Calibration records;
2. Time check;
3. Sum check;
4. High/Low check; and
5. Zero value check.