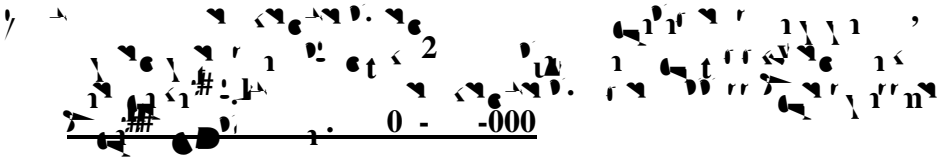
December 29, 2006

Honorable Magalie Roman Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426



Dear Secretary Salas:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] ISO New England Inc. (the "ISO") and New England Power Pool ("NEPOOL") Participants Committee[2] hereby jointly submit an original and six (6) copies of this transmittal letter and revised

and modify the application of the CC Rate to recognize leading as well as lagging VAR capability. Section V also addresses the proposed phased-in implementation schedule for the Schedule 2 Amendments, which provides that commencing:

- March 1, 2007 – Cross Sound Cable will be accepted into the program as a Qualified Non-Generator Reactive Resource eligible for the CC Rate payment provided that it has satisfied all criteria specified in Section II.B, including a requirement that operating protocols for provision of reactive power voltage support from such equipment have been agreed to, in writing, between the ISO and the Cross Sound Cable operator.

- June 1, 2007 – The Base CC Rate will increase from $1.05/kVAR-year to $2.32/kVAR-year for the lagging capabilities of all dynamic reactive resources that have been accepted into the program. At this time, the ISO also will initiate the testing for the leading capabilities; that is, all Qualified Generator and Non-Generator Reactive Resource seeking to be compensated under Schedule 2 will be required to provide the appropriate data necessary to test for leading capability and the first set of these resources will perform leading capability tests during the 2007 leading capability test period.

- January 1, 2008 – The Adjusted Base CC Rate will be applied to reflect leading and lagging capability. Also, on this date, all other non-generator dynamic reactive resources that have demonstrated their compliance with the eligibility criteria established in Section II.B will be eligible to receive the CC payment under Schedule 2.

The proposed Amendments have been incorporated in Schedule 2 of the OATT in the following manner:

Section I – This Section has been added to Schedule 2 to provide definitions of the new terms used throughout the rate schedule.

Section II – This Section has been added to provide the specific criteria that "Qualified Generator Reactive Resources" and "Qualified Non-Generator Reactive Resources" must meet to be eligible for CC Rate payments under Schedule 2. Section II also includes a provision addressing the treatment of Non-Dynamic Reactive Resources for purposes of compensation.

Section III – This Section provides the formula applied to determine the payments to be made by Transmission Customers for VAR Service provided under Schedule 2. The provisions set forth in Section III are provided in Section I of the currently effective Schedule 2. The revisions reflected in this section clarify the provision of VAR Service, and add consistency in the terminology used.

Section IV – This Section has been added to define the cost allocation for VAR Service costs. Section IV does not change the existing cost allocation approach provided under the current rate schedule.

Section V – This Section sets forth the elements of the Schedule 2 rate design, as provided in Section II of the currently effective Schedule 2. As Section V reflects, while the existing Schedule 2 rate design remains unchanged, each element has been modified to recognize the addition of Qualified Non-Generator Reactive Resources. The provisions regarding the CC Rate have also been revised to provide for the update of the amount paid for the CC component, and to provide payment to resources based on their leading as well as their lagging capability.

Section VI – This Section has been added to provide alternative methods of payment for Qualified Non-Generator Reactive Resources that cannot recover their costs under Schedule 2.

Specifically, the Schedule 2 Amendments incorporate a new term – "Qualified Non-Generator Reactive Resource" – defined in Section I (Definitions) as "any non-generator source of dynamic reactive power that meets the criteria specified in Section II of the revised Schedule 2." Additionally, proposed Section II.B sets forth the criteria that

Section 205 of the Federal Power Act, at the time the particular category of equipment is approved for compensation under Schedule 2.

Since Schedule 2 may not appropriately compensate (a) a non-operating, non-dispatchable generator that functions as a synchronous condenser and (b) an operating generator that utilizes a clutch device to operate as both a real power generator and a synchronous condenser, Section VI of Schedule 2 permits a separate schedule and filing for compensation of the first type of resource. Schedule 2 does not provide separate treatment for operating generators that utilize a clutch device to operate as both a real power generator and a synchronous condenser because of potential market rule and operational impacts. If alternative treatment is warranted, changes will be examined by the ISO and NEPOOL through the stakeholder process. Until the time that alternative treatment is determined and filed, operating generators that have the ability to utilize a clutch device to operate as both a real power generator and a synchronous condenser will receive Schedule 2 compensation based on its generator reactive capability only.

2. [illegible]

Schedule 2 is amended to memorialize and clarify the criteria for new generator eligibility for CC Rate payments. Currently, Section II.1.1 of Schedule 2 defines a "Qualified Generator" as "any generator that is in the Market System and provides measurable voltage support, as determined from time to time by the ISO to the New England Control Area." As with Qualified Non-Generator Reactive Resources, the proposed amendments to Schedule 2 provide specific criteria that new generators must satisfy to be eligible for CC Rate payments under Schedule 2.

The Schedule 2 Amendments include a new Section II.A, which sets forth the criteria that new generators that elect to join the Schedule 2 program after June 1, 2007 (***i.e.***, "Qualified Generator Reactive Resources" also defined in Section I, Definitions) must meet in order to qualify for CC Rate payments under Schedule 2. The criteria are as follows:

1. the entity owning or controlling the reactive power capability of the generator reactive resource is a Market Participant;

2. the generator is: (a) interconnected to the New England Transmission System or (b) interconnected to the distribution system but participating in the New England Markets and (c) is metered and dispatchable by the ISO or otherwise subject to operational control by the ISO;

3. the generator provides measurable reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO, and has its automatic voltage regulator status and control mode (including

power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the generator shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;

4. the generator meets the reactive power testing requirements applicable to generators, as determined from time-to-time by the ISO and specified in the

2. [illegible]

With regard to the CC component, the VWG played an important role in updating the rate paid under this component to account for changes in the cost-basis or mix of reactive resources in the New England since 1998. As provided in Section II.1.4 of Schedule 2, the current CC Rate is $1.05/kVAR-year, which is based upon pre-1998 cost data, and further resulted from a negotiated settlement. The VWG considered a number of different means of updating the CC component, including developing unit-specific revenue requirements as well as using the so-called "AEP methodology"[19] applied to a proxy unit. Ultimately, the VWG recommended updating the CC Rate through a negotiated rate based on a weighted-average blend of the costs of older generators in New

because: (1) the generators are a similar vintage and technology (*i.e.*, post-1998 combined cycle gas-fired generators), and in most cases have the same manufacturer as the majority of the post-market generators in New England; and (2) the revenue requirement numbers had undergone scrutiny through the FERC approval process. The rate calculated for the average revenue requirement for those generators is $4.20/kVAR-year. Using a blend of the pre- and post-market generation resulted in a blended revenue requirement of $2.32/kVAR-year or ((2 * $1.38) + $4.20) /3 = $2.32.

Assuming that the current qualified generator reactive resource mix stays constant and Cross Sound Cable receives CC payments in 2007, it is estimated that the impact of increasing the CC Rate from $1.05 kVAR-year to $2.32 kVAR-year will increase the total Schedule 2 fixed payments in the second half of 2007 from roughly $1.015 million/month (which equates to $12.2 million/year) to roughly $2.3 million/month (which equates $27.3 million/year).[23]

The Schedule 2 Amendments incorporate the blended rate of $2.32/kVAR-year in new Section V.4 of Schedule 2, which provides the cost components for Qualified Reactive Resource's Payments, previously provided in Section II of Schedule 2. This blended rate of $2.32/kVAR-year on a net lagging basis is reasonable when compared to the numbers from the pre-market generation in New England and the post-2000 combined cycle, gas-fired generators from PJM. Further, the use of this approach provides the same benefits of simplicity and avoidance of administrative burden or regulatory litigation as would the use of a proxy unit, while at the same time being grounded in reasonable cost data for the reactive power equipment.[24] In addition, new Section V.4 provides for the updated CC Rate to remain in effect for five years and to be revisited near the end of the five years to determine whether another adjustment to the rate is appropriate then in light of any changes to the mix of reactive resources in New England, especially, as new generators are added or older generators are retired.

One issue that surfaced during the development of the updated CC Rate was how payment of the CC Rate should be reconciled with payments to generators under the Forward Capacity Market ("FCM") when it is fully implemented at the end of the transition period (*i.e.*, 2010) such that there would not be any double payment. ISO and NEPOOL have agreed that any measures needed to ensure that there will not be such double payment will be addressed in the development of the final FCM rules rather than through new provisions in Schedule 2 of the OATT.

[23] A spreadsheet containing the historical Schedule 2 VAR costs over a twelve-month period used to calculate the impact of increasing the CC Rate from $1.05/kVAR-year to $2.32/kVAR-year is included here2.71431( )-3.5012(3(o)-0.TJ /R11 9.96-2.53658(r)2.3678(e)3.d58(o)-0.956239(/)0.35p956417(e)35727(C)3.06797(C)3.070)-0l

3. Applying the testing criteria results in payment for what the dynamic reactive resources can actually produce or absorb, rather than what the dynamic reactive resources might be able to perform as provided on paper.

4. As a result of testing, the ISO and the Local Control Centers have more accurate data to support planning and real-time operations.

To properly implement VAR compensation for leading and lagging capability and tie the VAR compensation mechanism to the VAR testing requirement, there needs to be a conversion of the Base CC Rate, which is calculated based upon lagging values, into an Adjusted CC Rate that recognizes both leading and lagging VAR capability within the

(the Base CC Rate ($CCRate_{base}$) * Current Total Aggregate lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs). The Total Aggregate Leading and Lagging VAR values reflect the untested and tested values of all dynamic reactive resources that are in the program at the beginning of each calendar year. During the first three years of the program, the dynamic reactive resources that are currently in the program will be required to have completed leading and lagging VAR tests. As dynamic reactive resources that are added to the program will have one calendar year to perform both leading and lagging VAR tests, by the end of the transition period in year three, almost every dynamic reactive resource will have performed both leading and lagging VAR tests. At that point the only dynamic reactive resources that would not have tested would be those resources that joined the VAR program in year three of the transition period.

There is a concern that the addition or removal of too many dynamic reactive resources into or out of the VAR program in any one year would cause a dramatic change in the Adjusted CC Rate calculation. In addition, if all dynamic reactive resources were to fail to test in one direction (***e.g.***, the leading direction) then the resulting Adjusted CC Rate would be based solely on lagging capability and result in a value of $2.32/kVAR-year. This would result in a number of things, particularly: (a) only compensating dynamic reactive resources for their one side of their VAR capability (in the example, lagging capability); (b) providing a disincentive of resources in the program to fully test their VAR capability in the other direction (in the example, in the leading direction); and (c) providing a disincentive to new dynamic reactive resources to join the program (in the example, new resources that have primarily leading VAR capability). To restrict this from occurring and to maintain payment incentives if there were to be a withdrawal of VAR capability primarily in one direction, increase and decrease limiters are applied to the Adjusted CC Rate calculation. These limiters mitigate the potential impact of major increases or decreases of VAR capability within the program during the three-year transition period and afterwards. The extent by which these limiters can impact the Adjusted CC Rate calculation is more restrictive during the transition period as compared to how they are applied afterwards.

Currently, Section II.1.3 of Schedule 2 provides a megawatt-based CC Rate Payment Cap that is applied to the annual CC Rate at the beginning of the year on a prospective basis for that calendar year. The CC Rate Payment Cap formula does not need to be revi0.5177(d)-31.0138(y)-0.956417(n)-20.9947(a)- a

(2) revisions to the associated business processes within ISO Settlements and System Operations; (3) modification of the ISO-developed stand-alone software that supports the administration and billing of VAR Services under Schedule 2; (4) inclusion of AVR telemetered data within the ISO control room; and (5) development and administration of the expanded VAR testing program. These changes also will require the availability of new data and likely require revisions or replacement of the current ISO-developed stand-

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Transmission Owners and recovered through regional transmission rates. In its review, the VWG considered two alternatives for the allocation of Schedule 2 costs: (1) to keep the current Commission-approved method of allocating Schedule 2 costs to all regional transmission customers; or (2) to change the cost allocation so that the CC component costs would be allocated under the current method to all transmission customers but the variable costs under Schedule 2 (***i.e.***, the lost opportunity cost, cost of energy produced and cost of energy consumed) would be allocated on a localized basis to transmission customers within the Reliability Region(s) where voltage support is required – the "Reliability Region Cost Allocation Proposal."[33] The latter alternative to localize some costs was considered by the Transmission Committee at the September 19 meeting, but only obtained support of 45% in a straw poll,[34] whereas the former alternative to maintain the status quo for cost allocation received supermajority support.[35]

The ISO and NEPOOL request that the Commission accept the Schedule 2 Amendments as reflected in the appended tariff sheets to become effective March 1, 2007.

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates.[36] However, the changes included in the Schedule 2 Amendments are not traditional "rates" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the ISO requests waiver of Section 35.13 of the Commission's regulations. Notwithstanding its request for waiver, the ISO submits the following

[33] To put in context, the costs of the fixed component (i.e., the CC costs) over the last 12 calendar months total $12,183,512.83. The variable costs (i.e., the PC, LOC and SCL costs) over the last 12 calendar months total $23,255,938.71.

[34] The Reliability Region Cost Allocation Proposal was also presented to tona98(C)3.07091( )-5ostthe ostthsuhe fixe

additional information in substantial compliance with relevant provisions of Section 35.13.

35.13(b)(1) - Materials included herewith are as follows:

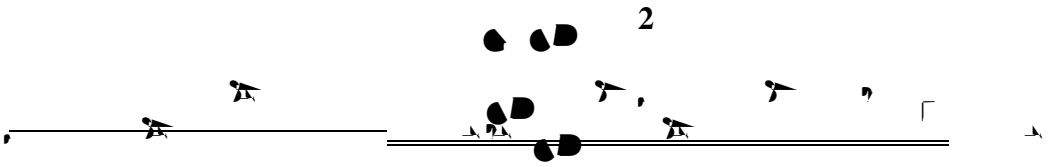
- This transmittal letter;
- Attachment 1: Redlined Tariff sheets reflecting the changes proposed by this filing;[37]
- Attachment 2: Clean revised Tariff sheets reflecting the changes proposed by this filing;

35.13(b)(4) - A description of the materials submitted pursuant to this filing is contained in Section IV of this transmittal letter.

35.13(b)(5) - The reasons for this filing are discussed in Sections I and IV of this transmittal letter.

35.13(b)(6) - The ISO's approval of these changes is evidenced by this filing. These changes reflect the results of the Participant Processes required by the Participants Agreement and reflect the support of Participants Committee.

35.13(b)(7) – Neither the ISO nor NEPOOL has knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

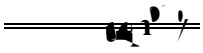


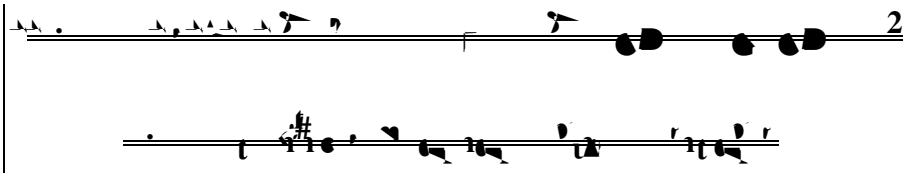
In order to maintain transmission voltages on the New England Transmission System (for voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO~~'s operating procedures~~ New England Operating Procedures) within acceptable limits, ~~generation facilities~~Qualified Reactive Resources (as defined below) are operated to produce (or absorb) reactive power. ~~Thus, Reactive Supply and Voltage Control from Generation Sources Service~~Thus, VAR Service (as defined below) must be provided ~~for each transaction~~to support Regional Network Service and Through or Out Service on the New England Transmission System (~~for~~both of which services have a direct impact on voltage constraints that are reflected in the ISO's systems for operating the New England Transmission

(r): means any generator source of dynamic reactive power that meets the criteria specified in Section II of this Schedule 2.

(r): means any non-generator source of dynamic reactive power that meets the criteria specified in Section II of this Schedule 2.

(r): means any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource.





Qualified Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. In addition, any generator that is dispatched by ISO-NE for the purpose of providing voltage support to the New England Transmission System shall be eligible to recover its Lost Opportunity Costs ("LOC"), Cost of Energy Consumed ("CEC"), and Cost of Energy Produced ("CEP") pursuant to Sections V.B-D of this Schedule 2.

A generator shall be deemed a P517 oe-DefP517 (0 8.33333 -2.5366.6

3. the generator provides measurable reactive power voltage support to the

ISO New England Inc.

A non-generator shall be deemed a Qualified Non-Generator Reactive Resource if it meets the following criteria:

1. the entity owning or controlling the reactive power capability of the non-generator reactive power resource is a Market Participant;

2. the non-generator reactive power equipment provides measurable dynamic

CC = the capacity costs for the hour shall be the VAR Revenue Requirement determined as set forth herein divided by the number of hours in the month;

LOC = the lost opportunity costs for the hour to be paid ~~to Market Participants who provide VAR support~~for a dynamic reactive power resource that provides VAR Service to meet reliability criteria within one or more Reliability Regions;

CEP~~PC~~ = the cost of energy produced which is the portion of the amount paid ~~to Market Participants~~ for the hour for Energy produced by a ~~generating unit that is considered under this Schedule 2 to be paid for VAR support~~dynamic reactive power resource for VAR Service to meet reliability criteria within one or more Reliability Regions;

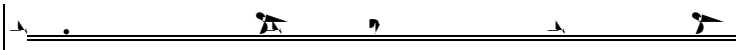
CEC~~SCL~~ = the cost of energy consumed which is the cost of energy used in the hour by ~~generating facilities, synchronous condensers or static controlled VAR regulators~~a dynamic reactive power resource in order to

ISO New England Inc.

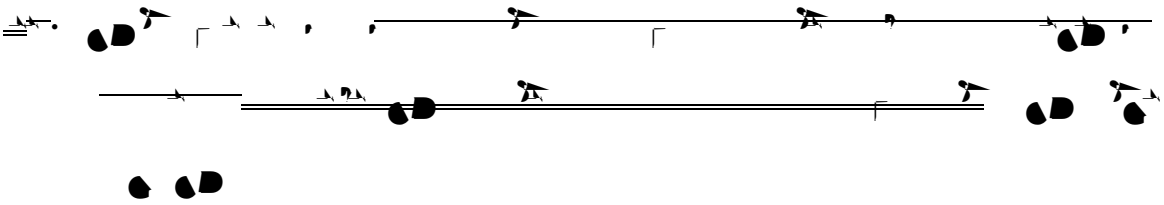
HL = the aggregate of the Regional Network Loads of all Transmission Customer for the hour;

RC_1 = the Reserved Capacity for Through or Out Service of the Transmission Customers for the hour; and

RC = the aggregate Reserved Capacity for Through or Out Service of all Transmission Customers for the hour.



The charge for VAR Service shall be paid by each Transmission Customer that receives either Regional Network Service or Through or Out Service.



The compensation to be paid to ~~generators~~resources providing ~~Schedule 2~~VAR ~~s~~Service shall be ~~based on the four components~~as set forth below.

~~1.~~ ( )

~~1.~~1. A Qualified ~~Generator~~Reactive Resource shall be eligible to receive ~~compensation for the capability to deliver VARs to the system (a "~~VAR Payments~~")~~ under the Capacity Cost component of this Schedule 2

~~1.~~2. ~~The VAR~~ Payment for VAR Service associated with lagging capability is not intended to compensate a Qualified Generator ~~for losses associated with station use and energizing the generator leads and~~Reactive Resource for reactive power absorbed by the generator step-up transformer. Payment for VAR Service associated with leading capability is intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer.

~~1.~~3. The "VAR CC Rate" will be established each year as of January 1 on a prospective basis for that calendar year and shall be the ~~Base VAR~~Adjusted CC Rate * Min (1, (1.2*Forecast Peak Adjusted Reference Load for the year/(SUM of all (Qualified ~~Generator's~~Reactive Resources' Summer Seasonal Claimed Capability))).

~~1.~~4. ~~The "Base VAR Rate" shall be $0.90/kVAR-yr in 2001; $0.95/kVAR-yr in 2002; $1.00/kVAR-yr in 2003 and $1.05/kVAR-yr in 2004 and thereafter.~~The "Base CC Rate" shall be $1.05/kVAR-yr before June 1, 2007 and shall be $2.32/kVAR-yr commencing June 1, 2007 and shall not be changed pursuant to Section 205 of the Federal Power Act until January 1, 2012. An examination of the Base CC Rate shall be completed no later than July 1, 2011; such examination shall determine whether the Base CC

b. A "Qualified Non-Generator Reactive Resource's Seasonal Claimed Capability" shall be 2.5 times the maximum dynamic reactive power capability on a lagging basis demonstrated by the Qualified Non-Generator Reactive Resource during the testing of its VAR Service capability consistent with ISO Procedures for measurement of such capability.

~~1.~~7. The "VAR Revenue Requirement" shall be the sum over a month of all Qualified Reactive Resources' VAR Payments~~SUM (Qualified Generator's VAR Payment)~~.

~~1.~~8. A Qualified ~~Generator~~Reactive Resource's VAR Payment shall equal ~~the~~

capability at the Summer Seasonal Claimed Capability as indicated on the Qualified Generator Reactive Resource's

~~3.~~ [illegible]

~~3.~~1. ~~Motoring Hydro or Pumped Storage Generating Units.~~ The CEC~~SCL~~ associated with hydro and pumped storage generating units that are motoring at the request of the ISO~~,~~ or a ~~PTO's~~ Local Control Center~~, or PTO dispatch center~~ for the purpose of providing ~~reactive supply and voltage control~~VAR Service will equal the cost of energy to motor and will be calculated in each hour as follows: CEC~~SCL~~ = (MWhUnit * (~~ECP or~~ LMP or ~~A~~actual energy cost), where the MWh Unit are calculated pursuant to the Ancillary Service Schedul17(e)3.15789(f2.53536(o)-0.9.0819( )*-10.4973

Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within written operating protocols developed under Section II.B.4). The CEC of such Qualified Non-Generator Reactive Resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within

b. the Current Net Aggregate Non-Tested lagging VARs shall equal the total of net lagging kVARs for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful lagging VAR test, as reflected in the most current monthly ***VAR Status Report*** that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html); this value will reflect the lagging kVARs of Schedule 2 Qualified Reactive Resources as taken from its NX-12D (and NX-9B, where needed to calculate generator step-up transformer losses) data at EcoMin adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross lagging VARs NX-12D data at SCC adjusted down for losses).

c. Increase and ed sen

- Current Total Aggregate Lagging VARs Decrease Limiter for Year 4 and beyond, the calculated Current Total Aggregate Lagging VARs will be limited to no less than 70% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for Year 3.

2. Calculate the Current Total Aggregate Leading VARs which shall equal the Current Net Aggregate Tested Leading VARs plus the Current Net Aggregate Non-Tested Leading VARs;

   Where:

   a. the Current Net Aggregate Tested Leading VARs shall equal the total of Net Leading kVARs for all Schedule 2 Qualified Reactive Resources that have completed a successful Leading VAR Test, as reflected in the most current monthly ***VAR Status Report*** that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html); this value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its leading VAR test results adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross leading VARs test results adjusted up for losses);

   b. the Current Net Aggregate Non-Tested Leading VARs: shall equal the total of Net Leading kVARs for all Schedule 2 Qualia Leading VARs:

ii. Current Total Aggregate Leading VARs Limiters for Year 2 (2009) :

- Current Total Aggregate Leading VARs Increase Limiter for Year 2: the calculated Current Total Aggregate Leading VARs will be limited to no greater than 110% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1); and
- Current Total Aggregate Leading VARs Decrease Limiter for Year 2: the calculated Current Total Aggregate Leading VARs will be limited to no less than 90% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1).

iii. Current Total Aggregate Leading VARs Limiters for Year 4 and beyond:

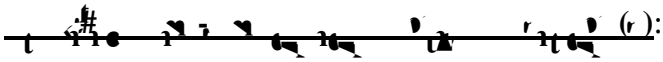
- Current Total Aggregate Leading VARs Increase Limiter for Year 4 (2011) and beyond: the calculated Current Total Aggregate Leading VARs Increase Limiter

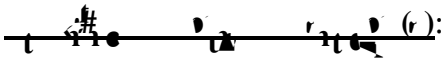
Where:

a. the "Forecast Peak Adjusted Reference Load" for the year shall equal the amount specified as "Adjusted Reference Load" for the applicable year in *Section I.1 - Summaries – Summer* from the most current

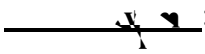
b. Monthly Net Leading VARs: a Qualified Reactive Resource's Monthly Net Leading VARs value shall equal its VAR value based on (a) its most recent successful Leading VAR test or (b) if it has not yet completed such a test, its VAR value at EcoMin based on its submitted and ISO accepted NX-12D and NX-9B data. The Qualified Reactive Resource's Monthly Net Leading VARs value shall be reflected in the applicable monthly ***VAR Status Report*** that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html).

 : means any generator source of dynamic reactive power that meets the criteria specified in Section II of this Schedule 2.

 : means any non-generator source of dynamic reactive power that meets the criteria specified in Section II of this Schedule 2.

 : means any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource.

 means the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power.

 : means the payment made to Qualified Reactive Res

Reactive Resources as of June 1, 2007 but that do not submit an updated NX-12 form with leading VAR data prior to June 1, 2007 will not receive VAR Payments until the beginning of the year following the submittal of their update

A non-generator shall be deemed a Qualified Non-Generator Reactive Resource if it meets the following criteria:

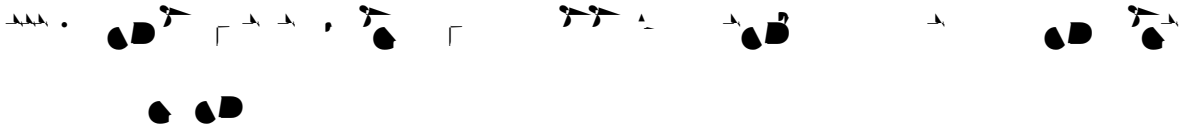
1. the entity owning or controlling the reactive power capability of the non-generator reactive power resource is a Market Participant;

2. the non-generator reactive power equipment provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO;

3. the type of dynamic reactive power equipment is within a category of equipment that has been approved by the ISO, with advisory input from the Reliability Committee;

4. the dynamic reactive power equipment is subject to the operating authority of the ISO and all necessary operating protocols for provision of reactive power voltage support from such equipment have been agreed to, in writing, between the

ISO New England Inc.



VAR Service under this Schedule 2 shall be provided through the ISO. Transmission Customers must purchase VAR Service through the ISO for the support of transmission voltages on the New England Transmission System. The charge for VAR Service shall be determined in accordance with the following formula:

CC = the capacity costs for the hour shall be the VAR Revenue Requirement determined as set forth herein divided by the number of hours in the month;

LOC = the lost opportunity costs for the hour to be paid for a dynamic reactive power resource that provides VAR

ISO New England Inc.

b. A "Qualified Non-Generator Reactive Resource's Seasonal Claimed Capability" shall be 2.5 times the maximum dynamic reactive power capability on a lagging basis demonstrated by the Qualified Non-Generator Reactive Resource during the testing of its VAR Service capability consistent with ISO Procedures for measurement of such capability.

7. The "VAR Revenue Requirement" shall be the sum over a month of all Qualified Reactive Resources' VAR Payments.

8. A Qualified Reactive Resource's VAR Payment shall equal (1/12) * (VAR CC Rate*Qualified VARs).

9. Qualified Reactive Resources will be paid their VAR Rate under this Section for each month of a calendar year starting with the month in which the resource is approved as a Qualified Reactive Resource.

10. "Qualified VARs" shall be determined as follows:

(a) In accordance with the ISO New England Operating Procedures, the Qualified VARs of a Qualified Reactive Resource initially

NX-12D form that is then in effect adjusted (downward for lagging capability) for reactive power absorbed by the generator step-up transformer.

- The Qualified VARs of an untested Qualified Non Generator Reactive Resource shall be equal to the lagging VAR capability at the corresponding Summer Seasonal Claimed Capability or an equivalent point as indicated on the Qualified Non-Generator Reactive Resource's NX-12D form that is then in effect adjusted for reactive power absorbed by its step-up transformer.

(c) On and after January 1, 2008:

- the Qualified VARs of an untested Qualified Generator Reactive Resource shall be equal to the sum of the absolute values of the lagging VAR capability at the Summer Seasonal Claimed Capability and the leading VAR capability at the EcoMin point as indicated on the Qualified Generator Reactive Resource's NX-12D form that is then in effect

adjusted (downward for lagging capability and upward for leading capability) for reactive power absorbed by the generator step-up transformer.

- The Qualified VARs of an untested Qualified Non-Generator Reactive Resource shall be equal to the sum of the absolute values of the lagging VAR capability at the corresponding

[illegible] ( )

1. The CEC associated with hydro and pumped storage generating units that are motoring at the request of the ISO or a Local Control Center for the purpose of providing VAR Service will equal the cost of energy to motor and will be calculated in each hour as follows: CEC = (MWhUnit * (LMP or actual energy cost), where the MWh Unit are calculated pursuant to the Ancillary Service Schedule 2 Business Procedure. The actual energy cost applies only if motoring energy is purchased through a bilateral contract.

2. For the Chester SCV, the CEC will be set to zero ($0), and the cost of energy to supply reactive supply and voltage control from the Chester SCV will be treated as losses on the New England Transmission System.

b. the Current Net Aggregate Non-Tested lagging VARs shall equal the total of net lagging kVARs for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful lagging VAR test, as reflected in the most current monthly ***VAR Status Report*** that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html); this value will reflect the lagging kVARs of Schedule 2 Qualified Reactive Resources as taken from its NX-12D (and NX-9B, where needed to calculate generator step-up transformer losses) data at EcoMin adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross lagging VARs NX-12D data at SCC adjusted down for losses).

c. Increase and decrease limiters shall be applied to potential increases or decreases in the Current Total Aggregate Lagging VARs as follows:

i. Current Total Aggregate Lagging VARs Limiters for Year 1 (2008) and Year 3 (2010):

- The Current Total Aggregate Lagging VARs value shall not be limited for Year 1 and Year 3.

ii. Current Total Aggregate Lagging VARs Limiters for Year 2 (2009):

- Current Total Aggregate Lagging VARs Increase Limiter for Year 2: the calculated Current Total Aggregate Lagging VARs will be limited to no greater than 110% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1); and

- Current Total Aggregate Lagging VARs Decrease Limiter for Year 2: the calculated Current Total Aggregate Lagging VARs will be limited to no less than 90% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1).

iii. Current Total Aggregate Lagging VARs Limiters for Year 4 (2011) and beyond:

- Current Total Aggregate Lagging VARs Increase Limiter for Year 4 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no greater than 130% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for Year 3; and

- Current Total Aggregate Lagging VARs Decrease Limiter for Year 4 and beyond, the calculated Current Total Aggregate Lagging VARs will be limited to no less than 70% of the Cur

ii. Current Total Aggregate Leading VARs Limiters for Year 2 (2009) :

- Current Total Aggregate Leading VARs Increase Limiter for Year 2: the calculated Current Total Aggregate Leading VARs will be limited to no greater than 110% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1); and
- Current Total Aggregate Leading VARs Decrease Limiter for Year 2: the calculated Current Total Aggregate Leading VARs will be limited to no less than 90% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for the prior year (Year 1).

iii. Current Total Aggregate Leading VARs Limiters for Year 4 and beyond:

- Current Total Aggregate Leading VARs Increase Limiter for Year 4 (2011) and beyond:

Where:

a. the "Forecast Peak Adjusted Reference Load" for the year shall equal the amount specified as "Adjusted Reference Load" for the applicable year in ***Section I.1 - Summaries – Summer*** from the most current ***Forecast Report of Capability, Energy, Loads and Transmission (CELT Report)*** ***(***http://www.iso-ne.com/trans/celt/report/index.html***)***;

b. The sum of the "Qualified Reactive Resources' Seasonal Claimed Capability" shall equal the Qualified Generator Reactive Resources' Seasonal Claimed Capability plus the Qualified Non-Generator Reactive Resources' Adjusted Seasonal Claimed Capability;

Where:

i. the Qualified Generator Reactive Resources' Seasonal Claimed Capability: shall equal the total of the ***"Summer Seasonal Claimed Capability"*** column of all Qualified Generator VAR Resources from the most current ***VAR Status Report*** (http://www.iso-

b. Monthly Net Leading VARs: a Qualified Reactive Resource's Monthly Net Leading VARs value shall equal its VAR value based on (a) its most recent successful Leading VAR test or (b) if it has not yet completed such a test, its VAR value at EcoMin based on its submitted and ISO accepted NX-12D and NX-9B data. The Qualified Reactive Resource's Monthly Net Leading VARs value shall be reflected in the applicable monthly ***VAR Status Report*** that is posted on the ISO website (http://www.iso-ne.com/stlmnts/iso_rto_tariff/schd2/var_status/index.html).

Zone	Generator	Annual Reactive Power Service Revenue Requirement	Monthly Reactive Power Service Revenue Requirement	Ferc Docket	Fuel/Turbine	Claimed Real Power Capability (MW)	Net MVAR @ 0.9pf	Effective Net Voltage Support Rate ($/MVAR-yr)	Online Year	Fixed Capability Component	Heating Losses Component	Fixed Capability Component in $/MVAR-yr
AE	Atlantic City Electric Company	$ 3,712,750	$ 309,396									
	Conectiv Energy Supply, Inc.	$ 1,140,535	$ 95,045									
	TXU Pedricktown Cogeneration Company	$ 263,515	$ 21,960									
APS	Allegheny Energy Supply Company, LLC	$ 11,704,576	$ 975,381									
	Armstrong Energy Limited Partnership	$ 1,435,113	$ 119,593	ER03-229	Gas Peaker	600	291	$ 4,939				
	Pleasants Energy, LLC	$ 722,906	$ 60,242	ER03-451	Gas Peaker	300	145	$ 4,975				
	Duke Energy Fayette, LLC	$ 2,312,572	$ 192,714	ER03-794-002	Gas Peaker	620	300	$ 7,701				
	Monongahela Power Company	$ 3,193,690	$ 266,141									
	Allegheny Energy Supply Company, LLC	$ 1,354,022	$ 112,835									
	Monongahela Power Company	$ 403,763	$ 33,647									
BGE	Constellation Power Source, Inc.	$ 8,344,846	$ 695,404									
	ISG Sparrows Point, Inc.	$ 319,464	$ 26,622	ER03-852	Gas Peaker	152	74	$ 4,340				
DPL	Conectiv Energy Supply, Inc.	$ 3,756,981	$ 313,082									
	NRG Power Marketing, Inc.	$ 1,957,059	$ 163,088									
	Commonwealth Chesapeake Company	$ 1,270,890	$ 105,908	ER02-2520	Gas Peaker	342	166	$ 7,673				
JCPL	Jersey Central Power & Light Company	$ 3,009,853	$ 250,821									
	Calpine Energy Services, LP (Parlin)	$ 693,132	$ 57,761	ER04-889	Gas CC	114	55	$ 12,554	1991			
	Ocean Peaking Power, L.L.C.	$ 952,555	$ 79,380	ER05-289	Gas Peaker	330	160	$ 5,960				
	FPL Energy Power Marketing, Inc. NJEA	$ 515,329	$ 42,944	ER05-845	Gas Cogen	300	145	$ 3,547				
METED	Metropolitan Edison Company	$ 2,038,623	$ 169,885									
	Reliant Energy Hunterstown, LLC	$ 2,027,683	$ 168,974	ER03-1164-000	Gas CC	830	402	$ 5,044	2003	$ 1,749,489	$ 278,193	$ 4,352
	Calpine Energy Services, (Ontelaunee)	$ 1,176,052	$ 98,004	ER03-624-000	Gas CC	573	278	$ 4,238	2002	$ 1,105,962	$ 70,089	$ 3,985
PENELEC	Pennsylvania Electric Company	$ 2,061,826	$ 171,819									
	First Energy Solutions Corp.	$ 47,432	$ 3,953									
	Allegheny Electric Cooperative Inc.	$ 21,416	$ 1,785									
	Handsome Lake Energy, LLC	$ 370,304	$ 30,859	ER03-269-000	Gas Peaker	250	121	$ 3,058				
	Reliant Energy Seward, LLC	$ 1,142,356	$ **95,196**	ER04-1164	Coal	521	252	$ 4,527				
PECO	Exelon Generation Company, LLC	$ 8,695,200	$ 724,600									
	FPL Energy Power Marketing, Inc.				Gas Peaker	317	154	$ 4,264				
PPL	PPL EnergyPlus, LLC	$ 9,040,000	$ 753,333									
	Allegheny Electric Cooperative, Inc.	$ 898,115	$ 74,843									
	Sunbury Generation, L.L.C.	$ 450,000	$ 37,500	ER02-2362	Coal	389	188	$ 2,389				
	WPS Westwood Generation, LLC	$ 103,950	$ 8,663	ER02-2361	Coal	30	15	$ 7,154				
	Safe Harbor Water Power Corporation	$ 2,149,747	$ 179,146	ER03-423	Hydro	400	194	$ 11,097				
	Conectiv Bethlehem, LLC	$ 2,699,389	$ 224,949	ER04-231-002	Gas CC	885	429	$ 6,298	2003	$ 1,783,970	$ 310,282	$ 4,162
	Lower Mount Bethel Energy, LLC	$ 1,086,303	$ 90,525	ER04-1142	Gas CC	600	291	$ 3,738	2004	$ 849,298	$ 237,005	$ 2,923
PEPCO	Mirant Potomac River, LLC	$ 4,733,477	$ 394,456									
	Potomac Power Resources, Inc.	$ 721,723	$ 60,144									
PSEG	PSEG Energy Resources & Trade, LLC	$ 8,587,290	$ 715,608									
	Calpine Energy Services, LP (Newark)	$ 478,818	$ 39,901	ER04-978	Gas CC	56	27	$ 17,654	1991			
	Newmarket Power Company, LLC	$ 1,778,283	$ 148,190	ER05-1058	Gas Peaker	149	72	$ 8,784				
	(Bayonne, Camden & Newark)			ER05-1059	Gas Peaker	146	71	$ 8,784				
				ER05-1060	Gas Peaker	123	60	$ 8,784				
ComEd	Exelon Generation	$ 10,227,259	$ 852,272									
	Midwest Generation, LLC	$ 2,295,784	$ 191,315	ER04-190	Coal	9,287	4,290	$ 535				
	University Park Energy, LLC	$ 543,304	$ 45,275	ER04-765	Gas Peaker	300	145	$ 3,739				
	Duke Energy Lee, LLC	$ 1,500,000	$ 125,000	ER04-641	Gas Peaker	640	310	$ 4,839				
	PPL University Park, LLC	$ 1,504,414	$ 125,368	ER04-911	Gas Peaker	540	262	$ 5,752				
	Reliant Energy Aurora, LP	$ 1,490,000	$ 124,167	ER04-1066	Gas Peaker	873	423	$ 3,524				
AEP	AEP East Operating Cos.	$ 26,091,131	$ 2,174,261									
	Big Sandy Peaker Plant, LLC	$ 525,904	$ 43,825	ER04-1103	Gas Peaker	300	145	$ 3,620				
	Wolf Hills Energy, LLC	$ 442,023	$ 36,835	ER04-1102	Gas Peaker	250	121	$ 3,651				
	Rolling Hills Generating, L.L.C.	$ 1,100,000	$ 91,667	ER04-1098	Gas Peaker	800	387	$ 2,839				
	Riverside Generating Company, L.L.C.	$ 1,702,765	$ 141,897	ER05-328	Gas Peaker	820	397	$ 4,288				
	Buckeye Power, Inc.	$ 1,215,129	$ 101,261	EL05-20	Coal	1,066	516	$ 2,354				
	Duke Energy Hanging Rock, LLC	$ 3,429,356	$ 285,780	ER05-567	Gas CC	1,240	601	$ 5,710	2003	$ 3,328,957	$ 100,398	$ 5,543
	Duke Energy Washington LLC	$ 1,569,806	$ 130,817	ER05-623	Gas CC	620	300	$ 5,228	2002	$ 1,519,992	$ 49,813	$ 5,062
	Indiana Municipal Power Agency	$ 489,001	$ 40,750	ER05-971	Gas Peaker	251	122	$ 4,023				
	Twelvepole Creek LLC	$ 1,457,832	$ 121,486	ER04-1166	Gas Peaker	458	222	$ 6,572				
Dayton	The Dayton Power and Light Company	$ 6,692,774	$ 557,731									
Dominion												

Schedule 2 Costs from 05/05 through 10/06

- Corrected after Settlements review

(18 months)

	Variable	Fixed
May-05	15,903,321.65	1,034,788.43
Jun-05	6,040,456.72	1,048,417.05
Jul-05	2,925,783.61	1,044,618.74
Aug-05	1,159,770.96	1,029,508.10
Sep-05	3,600,306.98	1,016,535.31
Oct-05	1,931,910.18	1,016,535.31

(12 months)

Denotes numbers used in Schedule 2 Filing

	2nd half of 2007 calc			
	Fixed			CSC
Fixed=X*2.32	2,260,558.97	1	CSC=75*2.32	14,500
/1.05+CSC	2,260,558.97	2	*1000/12	14,500
	2,260,558.97	3		14,500
	2,260,558.97	4		14,500
	2,277,995.47	5		14,500
	2,277,995.47	6		14,500
	2,277,995.47	7		14,500
	2,277,995.47	8		14,500
	2,272,881.62	9		14,500
	2,272,881.62	10		14,500
	2,272,881.62	11		14,500
estimated	*2,274,500.00*	12		14,500
12 mo Total	**27,247,362.62**		12 mo Total	174,000
Mo Avg	**2,270,613.55**			

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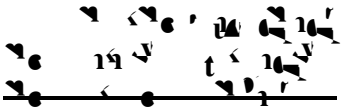

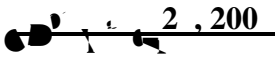

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