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Exhibit No. J

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 14-238

2015 PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE RESTRUCTURING AND RATE STABILIZATION AGREEMENT

REBUTTAL TESTIMONY OF JAMES R. SHUCKEROW

November 19, 2015

INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, position, employer and address.

A. My name is James R. Shuckerow. I am the Director, Electric Supply for Eversource Energy Service Company. My business address is 107 Selden Street, Berlin, Connecticut.

Q. Please provide a brief summary of your background.

A. I received a B.S. in Mechanical Engineering from Purdue University and an MBA from University of Connecticut. I joined Northeast Utilities, now Eversource Energy, in 1979.

Q. Have you ever testified before the New Hampshire Public Utilities Commission (NHPUC or Commission) or any other regulatory agency?

A. Yes. I have provided testimony before the Connecticut Department of Public Utility Control, the Connecticut Public Utility Regulatory Agency, the Connecticut Siting Council, the Massachusetts Department of Public Utilities and the Federal Energy Regulatory Commission, as well as before this Commission.

Q. Please describe your responsibilities as Director, Electric Supply.

A. In my present position as Director, Electric Supply, my responsibilities include procurement of wholesale power supply contracts for Eversource customers in Connecticut and Massachusetts who have not selected retail power supply, contracting for renewable power, and dispatch and scheduling of PSNH's generation resources.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut the recommendations made in the September 18, 2015, prefiled direct testimony of Richard A. Norman on behalf of the Granite State Hydropower Association ("GSHA") concerning the establishment of the proper avoided cost under the Public Utility Regulatory Policies Act ("PURPA") which PSNH would have to pay qualifying facilities ("QFs") that put their generating output to PSNH. My testimony also rebuts Mr. Norman's supplemental prefiled testimony dated November 12, 2015.

Q. Please provide an overview of your testimony in this proceeding.

A. My testimony will demonstrate that for both the "hybrid" (near-term until divestiture) and "generic" (post-divestiture) periods as set forth in Mr. Norman's testimony, the proper avoided cost that QFs are entitled to receive under PURPA is the price that PSNH presently pays, which is the ISO-NE real time energy market price; i.e., the locational marginal price as the term is used in ISO-NE which has three components: energy, loss and congestion.

Q. What is PURPA?

A. PURPA is the Public Utility Regulatory Policies Act of 1978, as amended. For purposes of this docket, I will only be discussing the portions of PURPA that relate to the requirement that utilities must purchase the output from QFs at avoided cost rates established by the appropriate state regulatory agency. Section 210 of PURPA is captioned "Cogeneration and Small Power Production." Section 210 required the Federal Energy Regulatory Commission ("FERC") to establish rules regarding QFs which in relevant part would "require electric utilities to offer to – (2) purchase electric energy from such facilities." PURPA §210(a)(2). PURPA further required that the rates established for purchase of QF output by utilities had to be "just and reasonable to the electric consumers of the electric utility and in the public interest." PURPA §210(b). PURPA also requires that the purchase price established by the state regulator shall not exceed "the incremental cost" to the utility. *Id.*

Q. Did FERC ever promulgate the rules required by PURPA Section 210?

A. Yes. FERC's QF regulations are found at 18 CFR, Part 292, "Regulations Under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 With Regard to Small Power Production and Cogeneration."

Q. Are there portions of the FERC PURPA rules relevant to your testimony?

A. Yes.

18 CFR 292.101(b)(1) defines "qualifying facility." For purposes of this proceeding, I do not think there is any dispute over which generators are QFs under PURPA.

18 CFR 292.101(b)(6) defines "avoided cost" – "Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

18 CFR 292.301(b)(1) allows "any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart." It is this authority that allows power purchase agreements such as those PSNH has with the Lempster Wind and the Burgess Biopower facilities.

18 CFR 292.303(a) requires electric utilities to purchase the output from QFs, regardless of whether a QF is directly interconnected with that utility or whether the output is transmitted to that utility.

18 CFR 292.304 regulates the rates that utilities must pay QFs. That regulation begins by stating:

> § 292.304 Rates for purchases.
>
> (a) Rates for purchases.
>
> (1) Rates for purchases shall:
>
> (i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and
>
> (ii) Not discriminate against qualifying cogeneration and small power production facilities.
>
> (2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

Subparagraph (c) of §292.304 requires state regulatory agencies to establish standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. Section 292.304 sets forth other details concerning the establishment of an avoided cost rate.

Finally, at 18 CFR 292.309, FERC implements the process whereby a utility may seek a waiver of the obligation to purchase the output from QFs when a QF has nondiscriminatory access to markets, such as that in ISO-New England. I will note that PSNH applied for a waiver from the PURPA "must buy" requirement, and FERC granted PSNH's request, but only relating to QFs with a net capacity in excess of 20 MW. *Public Service Co. of New Hampshire,* 131 FERC ¶ 61,027 (April 15, 2010).

Q. Has the New Hampshire Public Utilities Commission ("NHPUC") ever considered the proper avoided cost that utilities must pay QFs?

A. Yes. The NHPUC dealt with the PURPA avoided cost issue in myriad proceedings beginning in the late 1970s. In those proceedings, the NHPUC has, *inter alia,*

- found that the term avoided cost is another way of expressing the concept of incremental cost. For purposes of uniformity with the FERC rules, the commission said it would use the term "avoided costs" with the understanding that the use of the term equates to the concept of "incremental costs." *Re Small Energy Producers and Cogenerators*, 65 NHPUC 291 (1980).

- held that the avoided cost for a utility that does not generate its own power would be based on that utility's supplier's avoided cost, and that a full avoided cost rate equaling the price set by the competitive market brings on line the optimal amount of power at an optimal price. *Re Purchases for Nongenerating Utilities*, 67 NHPUC 825 (1982)

- found that calculation of the proper avoided cost rate is dependent upon the identification of the generating units operating on the margin. *Re Industrial Cognerators Group,* 72 NHPUC 8 (1987)

- specifically recognized that QFs are not bound by state franchise boundaries, but have the right to compel purchases of their output from distant utilities. *Re New Hampshire Electric Cooperative,* 80 NHPUC 489 (1995).

Q. Has the NHPUC implemented any regulations setting an avoided cost rate under PURPA?

A. Yes. In 2011 the NHPUC implemented a PURPA avoided cost rate in its Net Metering Rules in Puc 903. In this regulation, the Commission specifically states that the ISO-NE hourly real time locational marginal price is intended to set "the rates for utility avoided costs for energy and capacity consistent with the requirements of the Public Utilities Regulatory Policy Act of 1978 (PURPA) (16 USC § 824a-3 and 18 CFR § 292.304)." Puc 903.02(i). (Attachment JRS-R-1).

Q. Is the avoided cost standard contained in Puc 903.02(i)(2) consistent with PURPA avoided cost determinations made in other New England states?

A. In general, yes. As part of my job responsibilities for Eversource Energy, I am directly involved in transactions in the ISO-New England energy market and have specific duties relating to electricity supply in New Hampshire, Connecticut and Massachusetts. In both Connecticut and Massachusetts, the avoided cost rate established for the purchase of power from QFs under PURPA with respect to energy is set in the same manner as the avoided cost rate in Puc 903.02(i)(2); i.e., using the ISO-NE real-time energy market price.

In Massachusetts, avoided costs are set by regulation at 220 CMR 8.00, "Sale of Electricity by Qualifying Facilities and On-Site Generating Facilities to Distribution Companies, and Sales of Electricity by Distribution Companies to Qualifying Facilities and On-Site Generating Facilities." (Attachment JRS-R-2). The purpose of this Massachusetts regulation includes implementation of PURPA avoided cost requirements. 220 CMR 8.01(1)(c). The Massachusetts avoided cost rate is called the "Short-run Rate" and "means the hourly market clearing price for energy and the monthly market clearing price for capacity, as determined by the ISO and its successors." 220 CMR 8.02. Massachusetts utilities "must offer a Standard Contract providing for payment at the Short-run Rate to any Qualifying Facility making a request for such a contract." 220 CMR 8.05(4).

In Connecticut, avoided cost rates are set by tariff. Eversource Energy's Connecticut operating company, The Connecticut Light and Power Co., offers Rate 980, Non-Firm Power Purchase, to electric generators. (Attachment JRS-R-3). The rate paid under Rate 980 is "the appropriate hourly Connecticut ISO-NE Wholesale Electric Market Real-Time Locational Marginal Price ("RT-LMP") clearing price for such hour" for generators with time differentiated meters; without such metering, generators receive "the appropriate RT-LMP average clearing price over the billing period." Under Rate 980 QFs do not receive capacity payments, rather any capacity revenues received as a result of the resources being in the wholesale market flow to distribution customers through a non-bypassable bill line item.

In Maine, the Maine Public Utilities Commission has also established "the ISO-NE real-time nodal clearing price for the node on which the generator is located" as the avoided cost rate to be paid. 65-407 Code of Maine Rules, ch. 315, §3(B). (Attachment JRS-R-4).

Similarly, in Rhode Island, Narragansett Electric pays QFs "the hourly clearing prices at the ISO-NE for the hours in which the qualifying facility generated electricity in excess of its requirements." Narragansett Electric Tariff RIPUC No. 2098, para. III.2. (Attachment JRS-R-5).

It is my understanding that the practice of using real time locational marginal prices to determine avoided costs is followed fairly uniformly throughout New England. A recent survey of the various PURPA compliance methods used in the New England states conducted by La Capra Associates shows that with the exception of Vermont, a state that has not embraced retail competition, all the New England states use ISO-NE prices to set the avoided cost for energy for QF purchases under PURPA. I have attached a copy of the La Capra study as Attachment JRS-R-6.

Q. Have avoided cost rates been set for other PURPA-jurisdictional utilities in New Hampshire?

A. Yes. The NHPUC has approved tariff provisions for Liberty Utilities ("Liberty"), Unitil Energy Systems, Inc. ("Unitil"), and the New Hampshire Electric Cooperative, Inc. ("NHEC") which set avoided costs for their QF purchases based on the hourly prices these utilities receive for sales of IPP output into the ISO-NE real-time energy market. See N.H.P.U.C. No. 19 Electricity, Liberty Utilities (Granite State Electric) Corp. D/B/A/ Liberty Utilities, Original Page 9 Attachment JRS-R-7); N.H.P.U.C. No. 3 Electricity Delivery, Unitil Energy Systems, Inc., Original Page 76 (Attachment JRS-R-8); N.H.P.U.C. No. 21 Electricity, New Hampshire Electric Cooperative, Inc., Original Page 18 (Attachment JRS-R-9).

Q. Are you aware of any jurisdiction that sets avoided costs for PURPA "based upon the lowest default service bid rate accepted by [a utility] for the period when the IPP purchases are made"?

A. No. I am not. And, Mr. Norman has not provided any evidence that his suggested avoided cost standard has been implemented by any regulatory agency.

Q. What is the avoided cost standard in effect for PSNH at this time?

A. The avoided cost standard in effect for PSNH was approved by the Commission as part of its approval of the 1999 PSNH Restructuring Settlement Agreement. That 1999 Agreement as approved by the Commission states at Article V,G:

> G. Avoided Costs for IPPs
>
> PSNH's responsibilities and avoided cost rates on and after Competition Day for short-term purchases of IPP power pursuant to the federal Public Utility Regulatory Policies Act and the New Hampshire Limited Electrical Energy Producers Act shall be equal to the market price for sales into the ISO-New England power exchange, adjusted for line losses, wheeling

> costs, and administrative costs. This Agreement is not intended to impair existing rate orders or contracts.

Q. How has that 1999 Agreement standard been implemented?

A. Since that standard has been in effect, PSNH has paid the real-time energy market price for energy as the applicable PURPA avoided cost. Notably, although having authority to do so, PSNH has not imposed any administrative fee for dealing with the dozens of small generators that have put their output to PSNH pursuant to PURPA.

Q. How does the 2015 PSNH Restructuring Settlement change the current avoided cost standard?

A. The 2015 PSNH Settlement makes no changes to the existing avoided cost methodology. The 2015 PSNH Settlement at Article III,C reads:

> C. Avoided Costs for IPPs
>
> Unless otherwise found by the Commission or other appropriate authority, PSNH's responsibilities and avoided cost rates for purchases of IPP power pursuant to PURPA and LEEPA shall be equal to the market price for sales into the ISO-NE power exchange, adjusted for line losses, wheeling costs, and administrative costs. This Agreement is not intended to impair existing rate orders or contracts. Nothing in this Agreement shall be construed as limiting the Commission's authority with respect to calculating avoided costs. The Settling Parties agree not to oppose the opening of a generic docket or rulemaking upon petition by any Settling Party to consider the proper calculation of Avoided Costs under PURPA and LEEPA for all electric distribution companies in New Hampshire.

This standard is exactly the same as the avoided cost standard that has been authorized for PSNH for the past 15 years, is identical to the avoided cost standard for Unitil, Liberty Utilities, and the N.H. Electric Cooperative, and is similar to the avoided cost standard in place throughout New England (other than Vermont).

Q. What could happen if the Commission were to approve an avoided cost standard for PSNH that was higher than for other utilities in the region?

A. As noted earlier, 18 CFR 292.303(a) states and the NHPUC has acknowledged that QFs are not bound by state electric franchise boundaries, but instead, have the right to sell their output to any utility they can transmit their output to. Hence, if PSNH had to pay QFs an avoided cost rate higher than other utilities in the region, QFs throughout the region would be incented to put their output to PSNH, and PSNH's customers would ultimately pay the resulting higher costs. This is similar to what one sees when there is an intersection with four gasoline stations, and one of the stations has prices less than the others. Customers line up and wait at the low-cost station.

Q. In your opinion is the real-time energy market price the appropriate measure of avoided cost for a supplier, such as PSNH, that must provide all-requirements, load following service?

A. Yes. An entity providing full requirements, load following service, whether it is PSNH, another utility, or a merchant supplier responding to an RFP, is always in the ISO-New England real-time energy market at the margin. No supplier has exactly the precise amount of energy through owned generation and energy purchases to meet demand at every instant. At the margin, load following suppliers must rely upon the real-time energy market to take up the slack or surplus. Recall that in *Re Industrial Cogenerators Group*, 72 NHPUC 8 (1987), this Commission found that calculation of the proper avoided cost rate is dependent upon the identification of the generating units operating on the margin. Thus, the value of an additional kilowatt-hour of generation has a value equal to the real-time energy market price. Any other price would be disparate.

Q. In his supplemental testimony at page 4, Mr. Norman suggests that an appropriate avoided cost rate should be weighted based upon a utility's relative participation in the real-time and day-ahead markets. Do you agree with that suggestion?

A. No. The suggestion ignores the Commission's *Re Industrial Cogenerators Group* decision finding that the proper avoided cost rate is based upon the marginal price of the utility. In today's ISO-NE market, that marginal price is always set by the real-time market because all load imbalances are resolved in the real-time energy market. Furthermore as GSHA's resources only participate in the real-time energy market; they do not and cannot allow PSNH to avoid day-ahead energy market purchases. His suggestion that some type of weighted average of day-ahead energy market and real-time energy market prices is an appropriate price is unprecedented and given how the resources operate in the current wholesale energy market would create a valuation mismatch. In organized wholesale markets the value of resources to customers is straightforward. Wholesale energy transactions to which GSHA member facilities are a party occur in the real-time market. That defines their worth to customers and the remainder of PSNH's wholesale transactions (in whatever market) are irrelevant to the value GSHA resources provide. Unless and until that changes that is how they should be compensated, for the straightforward value which they provide. Any other outcome is illogical and would not conform with the structure of the ISO-NE wholesale energy market.

Q. In the near term period until a generic avoided cost for all New Hampshire utilities is established, Mr. Norman testifies that the appropriate avoided cost for QF purchases by PSNH should be set at the "Day Ahead ISO-NE New Hampshire Locational Marginal Price" in lieu of the real-time energy market price. Do you agree with Mr. Norman?

A. No, I do not, for several reasons. First, an avoided cost standard for all QFs based on day-ahead energy market prices is inappropriate for many types of QFs. Not all generators can or want to participate in the day-ahead energy market. Small QFs, such as all of Granite State Hydropower Association member plants, would likely find participating in the day-ahead energy market very burdensome. Every individual generator must offer its generation into the day-ahead energy market every day – 7 days per week, 365 day per year. If a plant is not timely offered into the day-ahead energy market, it is not entitled to receive day-ahead energy market prices from ISO-NE.

Indeed, GSHA has admitted that its members do not have the capability to provide the information necessary to participate in the day-ahead market. In GSHA's "Opening Scoping Memorandum" filed in this docket on December 5, 2014, at page 1, GSHA admitted:

> PURPA serves to provide small generators with non-discriminatory access to the market; "Qualified Facilities" ("QFs"), such as GSHA's members, often do not have the resources to bid production hourly and bear all the administrative burdens associated with ISO-NE market rules.

GSHA also told FERC the same thing:

> Granite State states that developers of small hydroelectric plants do not have the software, computer and monitoring equipment to integrate to RTO/ISO operations and, in many regions, would not even be eligible to bid their energy into these markets because they are too small for the applicable minimum block.

FERC Order No. 688, "Final Rule, New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities," October 20, 2006, p. 40.

If a utility had the obligation to pay day-ahead energy market prices to a generator, in order to protect customers from paying too much, that utility would have to ensure that each QF receiving day-ahead energy market prices is timely offered into and cleared in the day-ahead energy market every day, necessitating daily timely input from each QF's owner. But the information necessary to participate in the day-ahead market is the very information GSHA has admitted earlier in this docket, as well as to FERC, that its members do not have the resources to provide.

Furthermore, even if a QF timely offers into the day-ahead market, that QF must satisfy its daily cleared offers or be subject to monetary penalties from ISO-NE by replacing what it failed to provide at real-time energy market prices plus an allocation of real-time net commitment period compensation costs. These bidding requirements would be administratively burdensome and time consuming for a utility to handle, potentially requiring the hiring of additional personnel to deal with the daily offering, recordkeeping, accounting, and general administration of the day-ahead energy market process.

Q. If a QF wanted to participate in the day-ahead energy market, could it do so on its own?

A. Yes. There is nothing stopping any QF from joining ISO-NE and directly participating in the day-ahead energy market if it felt such pricing was desirable. That way, all administrative costs and requirements would be borne by the generator, and not subsidized by electric distribution company customers. But, as GSHA has admitted in its "Opening Scoping Memorandum," retail electric customers are bearing the administrative costs of QF generators today, and those QFs are not desirous of losing that subsidy.

Q. Initially, in the future "generic" period described by Mr. Norman, he testified that the appropriate avoided cost for QF purchases by PSNH should be "based upon the lowest default service bid rate accepted by PSNH for the period when the IPP purchases are made." In his supplemental testimony, he disregards his "generic" period and now testifies that post-divestiture PSNH should continue to use day-ahead prices as the appropriate avoided cost until such time as the Commission establishes a new avoided cost methodology for all utilities. Do you agree with Mr. Norman?

A. Yes and no. First of all I would like to point out that divestiture has zero impact on the value to customers provided by GSHA members' QF resources. Their interaction in wholesale markets is unaffected by divestiture. However, I agree that post-divestiture, if and when the Commission establishes an appropriate avoided cost methodology for all PURPA-jurisdictional utilities in New Hampshire, that would be the applicable avoided cost rate under PURPA.

But, until such a generic Commission determination applicable to all of the state's PURPA-jurisdictional utilities is rendered, my answer is "no" – I do not agree with Mr. Norman. Recall that the original purpose of PURPA's small generator provisions was to allow QFs to interconnect with the grid and to create a market for their output, i.e., energy and capacity. As previously noted above 18 CFR 292.101(b)(6) defines "avoided cost" to mean "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.". Today, with open access transmission and vibrant competitive organized day-ahead and real-time energy markets, the need for PURPA's QF provisions have waned.

Congress signaled this when it added section 210(m) to PURPA in the Energy Policy Act of 2005 (EPAct 2005). On October 20, 2006, FERC issued Order No. 688, revising its regulations governing utilities' obligations to purchase electric energy produced by QFs by implementing §292.310 of its regulations.. Order No. 688 implements PURPA §210(m) which provides for termination of the requirement that an electric utility must purchase the electric energy from QFs if FERC finds that the QFs have nondiscriminatory access to markets.

FERC specifically found in Order No. 688 that the market administered by ISO-NE was one of four markets nationwide that satisfy the criteria of PURPA §210(m)(1)(A). In Order No. 688, FERC noted that it was the intent of Congress in section 210(m) to have QF development "stimulated by market forces," much like the New Hampshire Legislature has determined that this state's retail electricity market should "harness[ ] the power of competitive markets" in the Restructuring Law at RSA 374-F:1. In Order No. 688, FERC stated, "These RTOs [including ISO-NE] are independently administered and offer auction based day ahead and real time wholesale markets for the sale of electric energy; and within the regions represented by these RTOs there is nondiscriminatory access to wholesale markets for long-term sales of capacity and electric energy."

In light of the Congressional intent for enacting section 210(m) of PURPA and FERC's finding that the ISO-NE market meets the criteria set forth in that statute by offering markets for the sale of electric energy, it is clear that the prices set by the ISO-NE market are what FERC would find to be the "fair and reasonable" prices required by both statute (PURPA Section 210(b)) and by FERC regulation (§ 292.304). A full-requirements, load-following retail RFP price is not what PURPA intends that utilities, and ultimately its customers, must pay a QF.

FERC has expressly agreed with my understanding that competitive market rates are the fair and reasonable rates required by PURPA in *Southern California Edison*, 70 FERC ¶ 61,215 (1995) at 61,676 & n.14. In that decision, FERC agreed that "Congress did not intend QFs to have any rate benefit above a market rate level." FERC went on to say that setting avoided costs above market levels "will … give QFs an unfair advantage over other market participants (non QFs)," and this, in turn, "will hinder the development of competitive markets and hurt ratepayers, a result clearly at odds with ensuring the just and reasonable rates required by PURPA section 210(b)." FERC has also expressed "concern that the mandatory QF purchase obligation under PURPA in conjunction with administratively avoided cost rates may be inconsistent with the operation of an effective competitive market." *Cogen Lyondell, Inc.*, 95 FERC ¶ 61,243 (2001) at 61,838.

Q. Does the energy output from a QF have the same value as the energy obtained via an RFP process to serve retail consumers?

A. No. The default service bid rate described by Mr. Norman is a load-following, full-requirements rate which is not the appropriate payment rate to a generator that provides specific electricity products such as energy and capacity.

GSHA has admitted that its members participate in the *wholesale*, not retail, market. In paragraph 3 of GSHA's August 12 Motion to Compel, GSHA stated, "In its order granting GSHA's petition to intervene in this docket, *the Commission recognized that GSHA's members primarily sell power at wholesale* to distribution utilities, including some sales under the 1999 Settlement Agreement. Order No. 25,733 (Nov. 16, 2014), p. 6." (Emphasis added). In the Petition to Intervene of GSHA, September 29, 2014, at paragraphs 5 and 7, GSHA stated

> *Most GSHA member projects sell power at wholesale* to one or another of New Hampshire's electric distribution companies under rate orders, via negotiated power purchase agreements, or in

> PSNH's case, in accordance with the 1999 restructuring settlement agreement with PSNH in docket DE 99-099; GSHA members operate in a competitive marketplace in which they must net meter, undertake contracts with distribution utilities, or sell power into the market to deliver their produced electricity to consumers. This circumstance puts them in the same position *(offering to sell power at wholesale)* as PSNH's hydroelectric power projects if those projects are divested."

(Emphases added.)

The distinction between the wholesale products produced by a QF and the retail product supplied under a default service RFP was recently discussed in Docket No. IR 14-338, "Review of Default Service Procurement Processes for Electric Distribution Utilities." During the hearing in that proceeding on May 27, 2015, Mr. Allegretti (who is also a witness in this proceeding) provided a detailed explanation of that distinction. His explanation from pages 61-63 of the Transcript of that hearing is appended hereto as Attachment JRS-R-10.

GSHA's member QF generators do not provide full-requirements, load-following service. Even GSHA's President and witness, Mr. Norman, has admitted that he "is unaware of QFs providing ancillary services." (Response to data request Q-PSNH-18, Attachment JRS-R-11). The table below identifies: a) the composition of full requirements load following service, b) how each component's cost is determined, and c) what QFs provide. As can be seen, QFs do not fully avoid the costs of a full requirements load following power supply, but rather offset the need to purchase a portion of some discreet components of full requirements load following power supply. Thus the expression "market price for sale into the ISO-NE power exchange" used in both the 1999 Restructuring Settlement and the current 2015 Settlement refers to the costs avoided by purchasing discrete power supply products from the QF rather than buying the discrete power supply product in the ISO-NE power exchange. Since GSHA's clients' resources are presently

ISO-NE registered assets they provide discrete wholesale power supply products and are not capable of providing anything more.

Whether Eversource NH self-supplies or procures a full requirements load following power supply it does not change the fact that the QFs provide only discrete power supply components.

Full Requirements Load Following Service Components	Cost Basis	What Hydro QF Provides
Energy	Purchase exact amount customers require on an hourly basis. Some may be bought day ahead based on forecast customer demand, but ultimately actual amount bought is refined in real time. In addition, load serving entities have Marginal Loss Revenue allocations, Net Commitment Period Cost allocations, Inadvertent Energy Flow cost allocations, and Emergency Energy Purchase allocations.	Energy amounts tied to hourly water flows. Do not participate in the day-ahead energy market.
Capacity	Current customers' share of prior year's annual system peak, times total amount of capacity required to cover peak load plus a required reserve margin for load uncertainty and supply unavailability.	Its capacity supply obligation, no greater than its seasonal MW capabilities.
Forward Reserves	Hourly load share times payments to resources providing the service.	None.
Real-time Operating Reserves	Hourly load share times payments to resources providing the service.	None.
Regulation	Hourly load share times payments to resources providing the service.	None.
ISO & NEPOOL Expenses	Allocated to load serving entities under various metrics tied to load and/or transactions.	None.
Renewable Portfolio Standards	Must purchase RECs equal to percentages of sales for each renewable class bilaterally, and pay alternative compliance rate for any deficiency.	If qualified, based on generation amounts. RECs are retained by owner and not part of QF avoided cost.

Q. In the "generic" time period, PSNH will no longer have generating assets, and instead would rely upon a competitive RFP solicitation to obtain the full requirements, load following power supply needed to meet its default energy service needs. Has the NHPUC ruled on what the appropriate avoided cost standard is for such a non-generating utility?

A. Yes. This Commission has already considered and decided what the appropriate avoided cost standard is for utilities that do not generate their own power, but instead rely upon full requirements supply contracts. As I noted earlier, in *Re Purchases for Nongenerating Utilities*, 67 NHPUC 825 (1982), the Commission held that the avoided cost for a utility that does not generate its own power would be based on that utility's supplier's avoided cost, and that a full avoided cost rate equaling the energy and capacity prices set by what the competitive market brings on line is the optimal amount of power at an optimal price. I also testified earlier that any entity providing full requirements, load following service, whether it is PSNH, another utility, or a merchant supplier responding to an RFP, is always in the ISO-New England real-time energy market at the margin, and that therefore, the real-time energy market price is the appropriate avoided energy cost for purposes of PURPA.

Q. Has the FERC made any similar rulings concerning the appropriate avoided cost standard for a non-generating utility?

A. Yes. In *Western Farmers Electric Cooperative,* 115 FERC ¶ 61,323 (2006), FERC stated, "The Commission has consistently held that the avoided costs of an all-requirements customer to be those of its all-requirements supplier." FERC also noted in this decision:

> The Commission first made this determination in Order No. 69 which implemented section 210 of PURPA. *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 at

> 30,871, *order on reh'g*, Order No. 69-A, FERC Stats. & Regs. ¶30,160 (1980), *aff'd in part aad vacated in part, American Electric Power Service Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part, American Paper Institute, Inc. v. American Electric Power Service Corp.*, 461 U.S. 402 (1983). The Commission has consistently followed this determination in case law. *See, e.g., Carolina Power & Light Co.*, 48 FERC ¶ 61,101 at 61,390 (1989) (citing *City of Longmont*, 39 FERC ¶ 61,301 (1987)) (in the case of a QF selling to a full requirements customer instead of selling to that customer's supplying utility, the Commission will measure "the avoided cost of the full requirements customer as the avoided cost of the full requirements supplier since it is the supplier that avoids generation when the full requirements customer purchases from a QF"). To the extent protesters argue that the avoided cost should be the purchase price, they have not offered any compelling reason to change our policy. *See North Little Rock Cogeneration, L.P. and Power Systems, Ltd. v. Entergy Services, Inc.* and *Arkansas Power & Light Company, Entergy Services, Inc.*, 72 FERC ¶ 61,263 at 62,172 (1995).

It is clear from these FERC decisions that the proper avoided cost for a non-generating utility is <u>not</u> the power cost of the requirements contract, but instead is the avoided cost of the supplier. Mr. Norman's suggestion that the retail price established by a default energy service RFP is the proper standard for establishing a PURPA avoided cost is contrary to FERC's decisions

Q. Has FERC ever ruled on whether use of market-based prices is an appropriate means of determining the proper avoided cost under PURPA?

A. Not that I am aware of. The issue was brought to FERC in its Docket No. EL13-43 that arose from a petition filed by the Mississippi Public Service Commission, the Arkansas Public Service Commission, and the City of New Orleans, all three of which exercise regulatory authority over Entergy. In its decision at 145 FERC ¶ 61,057 issued in October, 2013, the FERC said it would not determine in that case whether use of market-based locational marginal prices ("LMPs") to establish an avoided cost would comply with PURPA because none of the petitioning regulators had adjudicated that issue and, "It is the state's responsibility in the first instance to determine an avoided cost rate consistent with the Commission's regulations." However, the FERC noted, "It appears that various states have opted to use LMPs in calculating avoided costs. *See* Entergy February 21, 2013 Answer at 19-20. The record in this proceeding does not contain extensive evidence on the particular methodologies that are being used by these states, and these methodologies have not otherwise been the subject of Commission proceedings."

So, FERC is aware that various states have opted to use LMPs to determine the proper avoided cost under PURPA, as New Hampshire has done since industry restructuring, and to date has not interfered with those states' determinations.

Q. Has GSHA discussed the PURPA avoided cost issue at FERC?

A. Yes. On November 8, 2005, GSHA filed, "Comments of Granite State Hydropower Association, Inc. Regarding Proposal to Eliminate FPA Exemption for Small Power Production Facilities," in FERC Docket RM05-36-000. In that filing (at page 6), GSHA stated:

> [W]hat constitutes an "avoided cost" rate has changed considerably over the years, especially in states with operating regional transmission organizations. When contracts were executed in the 1980s and 1990s, each utility calculated its avoided costs periodically and these rates were posted and available to QFs. That is no longer the case. In New Hampshire and Vermont, for example, the public utility commissions have not formally calculated avoided cost rates for years. Today, QFs typically sell their power to the utility at the locational marginal price ("LMP") rate- a market-based rate. Yet, the rate is an avoided cost rate that is sanctioned by the state for purposes of the sale of power from the QF to the utility. Thus, the Commission should expand its proposal to exempt projects purchasing under avoided cost rate schemes to take into account the evolution and expanded definition of what constitutes an avoided cost rate.

GSHA expressly told FERC that ins states with operating RTOs, and specifically in New Hampshire, the LMP rate is an avoided cost rate sanctioned by the state for purposes of the sale of power from the QF to the utility.

Q. Unitil and Liberty Utilities have relied upon full requirements RFP solicitations for many years to obtain their default energy service needs. Has GSHA sought to change the avoided costs prices they pay QFs in order to benefit its members?

A. The only attempt I am aware of is discussed in Docket No. IR 14-338, where Messrs. Locke and Norman of GSHA testified on behalf of Briar Hydro Associates. In his filing dated "February 11, 2105" (sic), Mr. Locke stated that Briar Hydro Associates "approached Unitil representatives twice in 2014 to discuss the possibility of selling ... power to Unitil at a rate discounted off of Unitil's default service rate," but Unitil declined to do so.

New Hampshire's other utilities have been restructured for many years. Unitil and Liberty Utilities have relied upon RFP solicitations since restructuring to procure default service supply for their customers. If Mr. Norman's suggestion that their RFP results establish the appropriate standard for setting their avoided cost rates for purchases from QFs, I cannot understand why the Granite State Hydropower Association or its members have taken no action to enforce their PURPA rights and obtain significantly higher prices for their generating output. They cannot say that electric franchise boundaries preclude their members from selling to Unitil or Liberty – this Commission (and 18 CFR 292.303(a)) has ruled that they do not. I discussed earlier where the Commission specifically recognized that QFs are not bound by state franchise boundaries, but have the right to compel purchases of their output from distant utilities. See *Re New Hampshire Electric Cooperative,* 80 NHPUC 489 (1995).

Q. Did GSHA just ignore tens of millions of dollars of additional revenues?

A. That prospect is unlikely – the more believable answer is that GSHA never really felt that a full requirements RFP price was an appropriate avoided cost for purposes of PURPA. Their involvement in this Settlement proceeding appears to me to be opportunistic. Otherwise, GSHA would be protecting its members' economic interests by asserting their rights under PURPA to receive what they deem to be the proper avoided cost rate for the output from its members from the state's other utilities that already rely upon RFPs for their default energy service.

Q. Do you have a recommendation for the proper PURPA avoided cost rate for QFs that put their output to PSNH?

A. Yes. Both during the near-term "hybrid" period and post-divestiture until a uniform avoided cost methodology is adopted for all of New Hampshire's PURPA-jurisdictional utilities, the proper avoided cost rate that QFs are entitled to remains what this Commission decided in *Re Industrial Cogenerators Group*, 72 NHPUC 8 (1987), the price at the margin, i.e., the real-time ISO-NE energy market nodal price for energy and whatever the capacity market provides them. At the margin, the supplier's price (whether the supplier is PSNH itself during the hybrid period, or a competitive supplier in the generic period) is that real-time energy market price.

As FERC has ruled, any other energy price would be inconsistent with a competitive marketplace and would hurt customers – outcomes that are contrary to the express findings of the Legislature in the Restructuring Law when it stated, "Restructuring of electric utilities to provide greater competition and more efficient regulation is a nationwide phenomenon and New Hampshire must aggressively pursue restructuring and increased customer choice in order to provide electric service at lower and more competitive rates." 1996 N.H. Laws, 129:1, III. A properly established avoided cost rate set by the competitive market at the real-time energy market price is consistent with the competitive marketplace and would not hurt customers.

In conclusion, it is important to note, Commission Staff recently agreed that "the current situation where [QFs are] eligible for short-term avoided costs is appropriate." Transcript, IR 14-338, May 27, 2015, p. 57, line 18.

N.H. Code of Admin. Rules, Puc 903.02 (i)

Puc 903.02 Statutory and Other Requirements

(i) Unless an electric distribution utility elects otherwise as provided in paragraph (k) below, and except as may be provided otherwise pursuant to paragraph (p) below, the commission shall annually determine the rates for utility avoided costs for energy and capacity consistent with the requirements of the Public Utilities Regulatory Policy Act of 1978 (PURPA) (16 USC § 824a-3 and 18 CFR § 292.304) and as set forth below:

(1) On or before April 15 of each year, the commission shall publish on its website its calculation of the rates for avoided costs of energy and capacity for the previous year ending March 31 to be used by utilities to calculate the economic value of surplus net metered generation for the previous year which may be paid or credited starting in the May billing cycle, along with supporting calculations, an explanation of assumptions and data sources, and estimated portions of annual surplus generated during the hour or hours used to calculate avoided capacity costs pursuant to (6) and (7) below (capacity factors) if actual hourly surplus generation data is not used for such calculation pursuant to (5) below;

(2) The rates for avoided energy costs shall be based on the short-term avoided energy costs for the New Hampshire load zone in the wholesale electricity market administered by ISO New England, Inc., consisting of the hourly real time locational marginal price (LMP) of electricity plus generation related ancillary service charges, all adjusted for the average line loss in New Hampshire between the wholesale metering point and the retail metering point;

(3) The rate for the avoided generation related capacity costs shall be based on the applicable ISO New England, Inc. Forward Capacity Market (FCM) price for the power year most closely matching the 12 months ending in the March billing cycle. The avoided FCM price shall be adjusted to account for any peak energy rent payments made from the energy market that reduce direct capacity

costs charged to load and for average line loss in New Hampshire between the wholesale metering point and the retail metering point. Such adjusted price shall be used to determine the rate for avoided capacity costs in dollars per kW to be used by utilities to calculate the value of generation capacity associated with surplus generation on a customer by customer basis. If there is more than one hour in each power year on which ISO New England, Inc. allocates FCM costs to load, the commission shall structure the rate proportionally to ISO New England, Inc.'s allocation of such costs;

(4) In determining the customer specific value of avoided capacity costs each utility shall multiply the quantity (in kW) of each customer-generator's surplus generation fed into the distribution grid at the hour or hours of capacity peak on which the FCM costs are allocated to load, whether actual, pursuant to (5) below, or estimated, pursuant to (6) or (7) below, as applicable, by the rate or rates determined by the commission pursuant to (1) and (3) above;

(5) If hourly meter data is available for a customer-generator's net meter and the utility has the technical capability to utilize that data for avoided cost calculations, the utility, at its election by written notice to the commission on or before May 1 of each year, shall calculate the value of avoided capacity costs or avoided energy costs, or both, for each such customer-generator using actual hourly surplus generation data. The value of avoided energy costs shall be individually calculated by weighting the actual avoided energy costs for each hour of the 12 months ending the immediately preceding March 31, as determined by the commission pursuant to (1) and (2) above, by the actual hourly surplus electricity fed into the distribution system in each hour for the same period to determine a customer-specific average rate for the energy value of net surplus generation;

(6) For all types of net metered systems other than solar photovoltaic (PV) systems, and for which actual hourly data is not utilized pursuant to (5) above:

a. The rate for avoided energy costs shall be calculated by using a simple average of hourly cost data from ISO New England, Inc. for the 12 months ending the immediately preceding March 31, assuming that surplus generation is, on average, equally distributed over all hours of the year; and

b. The portion of surplus generation estimated to be produced during the hour or hours of capacity peak on which FCM costs are allocated to load shall be equal to the number of such hours divided by 8760;

(7) For net metered PV systems for which actual hourly data is not utilized pursuant to (5) above, the rate for avoided energy costs shall be calculated as a weighted average annual rate by weighting the actual avoided costs for each hour of the 12 months ending the immediately preceding March 31 by the hourly generation output profile for PV systems in New Hampshire determined as follows:

a. If verifiable hourly generation output data is available and on file at the commission by April 5 for the applicable year from at least 25 kW of PV system capacity operating within New Hampshire, then the output profile for PV systems shall be the hourly average of all such data; or

b. If such data is not available the hourly generation output profile shall be the modeled hourly PV performance data output produced by the U.S. Department of Energy, National Renewable Energy Laboratory, PVWatts software, version 1, (available at http://www.nrel.gov/rredc/pvwatts/site_specific.html) with the default settings for Concord, New Hampshire; and

c. The portion of surplus generation estimated to be produced during the hour or hours of capacity peak on which FCM costs are allocated to load shall be in the same proportion as the output profile utilized pursuant to (7) a. or b. above.

220 CMR 8.00: SALE OF ELECTRICITY BY QUALIFYING FACILITIES AND ON-SITE GENERATING FACILITIES TO DISTRIBUTION COMPANIES, AND SALES OF ELECTRICITY BY DISTRIBUTION COMPANIES TO QUALIFYING FACILITIES AND ON-SITE GENERATING FACILITIES

Section

8.01: Purpose and Scope

(1) Purpose: 220 CMR 8.00 establishes regulations governing the rates, terms, and conditions of sales of electricity by qualifying facilities and on-site generating facilities to distribution companies. Similarly, 220 CMR 8.00 establishes regulations governing the rates, terms, and conditions of sales of electricity by distribution companies to qualifying facilities and on-site generating facilities. 220 CMR 8.00 also establishes regulations:

(a) for the interconnection of qualifying facilities and on-site generating facilities to distribution company systems;
(b) for the metering of qualifying facilities and on-site generating facilities; and
(c) regarding payment to qualifying facilities and on-site generating facilities.
220 CMR 8.00 implements the provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA), Title II, Sections 201 and 210, and regulations promulgated by the Federal Energy Regulatory Commission (FERC) in 18 C.F.R. 292 (Section 292).

(2) Scope.

(a) 220 CMR 8.00 applies to sales and purchases between qualifying facilities, on-site generating facilities, and distribution companies. Nothing in 220 CMR 8.00 limits the ability of any party to agree to rates, terms, or conditions of purchase which differ from the rates, terms, or conditions which would otherwise be required by 220 CMR 8.00.
(b) 220 CMR 8.00 addresses the distribution company's obligation to interconnect qualifying facilities and on-site generating facilities. 220 CMR 8.00 prescribes interconnection standards and assign cost responsibilities.
(c) 220 CMR 8.00 addresses metering requirements for qualifying facilities and on-site generating facilities.
(d) 220 CMR 8.00 addresses the payment method for qualifying facilities.
(e) 220 CMR 8.00 prescribes reporting requirements for distribution companies with respect to interconnected qualifying facilities and on-site generating facilities.

8.02: Definitions

Distribution Company means an electric utility company engaging in the distribution of electricity owning, operating, or controlling distribution facilities and subject to the ratemaking authority of the Department of Public Utilities (Department); provided, however, a distribution company shall not include any entity that owns or operates plant or equipment used to produce electricity, steam, and chilled water, or any affiliate engaged solely in the provision of such electricity, steam, and chilled water, where the electricity produced by such entity or its affiliate is primarily for the benefit of hospitals and non-profit educational institutions, and where such plant and equipment was in operation prior to January 1, 1986.

Distribution means the delivery of electricity over lines which operate at a voltage level typically equal to or greater than 110 volts and less than 69,000 volts to an end-use customer within the commonwealth.

8.02: continued

Distribution Facility means plant or equipment used for the distribution of electricity and which is not a transmission facility, a cogeneration facility, or a small power production facility.

Independent System Operator or ISO means ISO New England, Inc., authorized by the Federal Energy Regulatory Commission to operate the New England bulk power system and administer New England's organized wholesale electricity market pursuant to the ISO Tariff and operation agreements with transmission owners.

NEPOOL means the New England Power Pool, and its successors.

On-site Generating Facility means any plant or equipment that is used to produce, manufacture, or otherwise generate electricity and that is not a transmission facility and that has a design capacity of 60 KW or less.

Qualifying Facility means small power producers and cogenerators that meet the criteria specified by FERC in 18 C.F.R. §§ 292.203(a) and (b).

Short-run Rate means the hourly market clearing price for energy and the monthly market clearing price for capacity, as determined by the ISO and its successors.

Transmission means the delivery of power over lines that operate at a voltage level typically equal to or greater than 69,000 volts from generating facilities across interconnected high voltage lines to where it enters a distribution system.

Transmission Facility means plant or equipment used for the transmission of electricity, as determined by the FERC pursuant to federal law and regulation.

8.03: General Terms and Conditions

(1) Power Purchase Contracts.

(a) Nothing in 220 CMR 8.00 shall be construed to affect, modify or amend terms and conditions of any existing Qualifying Facility's contract.

(b) A Qualifying Facility may sell its generation output to a Distribution Company under one of the following arrangements:

1. A standard contract available to all Qualifying Facilities for sales at the Short-run Rate only; or

2. A negotiated contract executed by a Qualifying Facility and a Distribution Company.

(c) When a Qualifying Facility submits an offer to sell generation output to a Distribution Company, the Distribution Company must respond to the offer within 30 days of receipt of the offer. If, within 90 days of a Qualifying Facility submitting an offer to a Distribution Company, there is a failure to agree to terms, the Qualifying Facility may petition the Department to investigate the reasonableness of the Distribution Company's actions.

(2) Other General Terms and Conditions.

(a) Information, Rules, and Requirements. A Qualifying Facility shall comply with any and all applicable NEPOOL and ISO information requests, rules, and requirements that are necessary for a Qualifying Facility's generation output to be sold to the ISO power exchange by a Distribution Company. The Qualifying Facility shall provide such information to the Distribution Company in a timely manner.

(b) Fines, Penalties, Sanctions. In the event that a fine, penalty, or sanction is levied on a Distribution Company by NEPOOL or the ISO as a result of a Qualifying Facility's failure to comply with a NEPOOL or ISO information request, rule, or requirement, then the Qualifying Facility shall be responsible for the costs of such fines, penalties, or sanctions imposed by NEPOOL or the ISO on the Distribution Company.

8.04: Interconnection, Metering, and Payment

(1) Distribution Company Procedures for Interconnection, Metering, and Payment. Each Distribution Company shall file with the Department written procedures addressing provisions 220 CMR 8.04(2) through (9), within 60 days of the effective date of 220 CMR 8.00.

8.04: continued

(2) Inspection. At the request of a Qualifying Facility or an On-site Generating Facility, a Distribution Company shall conduct an initial site inspection of the proposed Qualifying Facility or On-site Generating Facility to determine the equipment necessary for protecting the Distribution Company's system, and, where necessary to estimate the cost of additional engineering studies that will be used to provide a more accurate assessment of interconnection costs. Such initial inspection shall be made within 45 days of the request by the Qualifying Facility or On-site Generating Facility at the Distribution Company's expense.

(3) Interconnection Cost Estimate. If a thorough estimate of interconnection costs cannot be determined after the initial site inspection, the Distribution Company shall provide a complete estimate of interconnection costs upon request by the Qualifying Facility or On-site Generating Facility. The cost of providing this estimate, including engineering studies where necessary, shall be paid by the Qualifying Facility or On-site Generating Facility to the Distribution Company. Each Distribution Company shall develop, for public review, written procedures for estimating interconnection costs. If the parties cannot reach an agreement on interconnection costs within 90 days of the Qualifying Facility's or the On-site Generating Facility's request for an estimate, the parties may petition the Department to review the reasonableness of the Distribution Company's interconnection cost estimate.

(4) Standards for Interconnection.

(a) All Qualifying Facility and On-site Generating Facility interconnections shall provide protection against the following:

1. Inadvertent and unwanted reenergization of a Distribution Company dead line or bus;
2. Interconnection while out of synchronization;
3. Ground faults and phase fault;
4. Frequency outside permissible limits; and
5. Voltage generated outside permissible limits.

(b) Protections proposed for implementation, in addition to those listed in 220 CMR 8.04(4)(a), require a thorough explanation, particularly if applicable to On-site Generating Facilities.
(c) The Qualifying Facility or On-site Generating Facility equipment must be compatible with the character of service supplied by the Distribution Company at the location of the Qualifying Facility or On-site Generating Facility.
(d) Prior to delivering power to a Distribution Company, the Qualifying Facility or On-site Generating Facility shall provide the Distribution Company with written certification by qualified personnel or from a qualified testing agency that protective devices and related equipment are installed and have been successfully tested.

(5) Distribution Company Right to Inspect. The Distribution Company has the right to periodically inspect, test, and certify in writing the accuracy of any metering equipment owned by the Qualifying Facility or the On-site Generating Facility. The Distribution Company has the right to periodically inspect, test, and certify in writing the Qualifying Facility's or the On-site Generating Facility's compliance with the protection standards described in 220 CMR 8.04(4)(a). The Distribution Company has the right to inspect and test the electrical interface at any time to certify its proper operation. There will be no charge to the Qualifying Facility or On-site Generating Facility for such inspections, tests, or certifications by the Distribution Company.

(6) Conditions for Interconnection.

(a) Distribution Company's Obligation to Interconnect. A Distribution Company is not required to interconnect with a Qualifying Facility or On-site Generating Facility until 90 days after the Qualifying Facility or On-Site Generating Facility has notified the Distribution Company in writing that it intends to interconnect with the Distribution Company's system. Upon notice to the Qualifying Facility or On-site Generating Facility and the Department, the Distribution Company may petition the Department for additional time when extensive modifications or additions to the Distribution Company transmission or distribution system are required to accommodate an interconnection. Additional time may also be granted by the Department if a petition under 220 CMR 8.03(1)(c) or 220 CMR 8.04(3) is before the Department. The Department, upon a petition by a Qualifying Facility or On-site Generating Facility, or on its own motion, may, after notice and public hearing, order a Distribution Company to interconnect with a Qualifying Facility or On-site Generating Facility in a timely manner.

8.04: continued

(b) Notice of Intent to Interconnect. A Qualifying Facility or On-site Generating Facility shall provide the following information, in writing, to the Distribution Company at the time it files its notice of intent to interconnect:

1. The name and address of the applicant and location of the Qualifying Facility or On-site Generating Facility;
2. A brief description of the type of Qualifying Facility or On-site Generating Facility, including a statement indicating whether such Qualifying Facility or On-site Generating Facility is a small power production facility or a cogeneration facility;
3. The primary energy source used or to be used by the Qualifying Facility or On-site Generating Facility;
4. The power production capacity of the Qualifying Facility or On-site Generating Facility and the maximum net energy that may be delivered to the Distribution Company's system;
5. The owners of the Qualifying Facility or On-site Generating Facility, including the percentage ownership by any electric utility or by any public utility holding company, or by any entity owned by either;
6. The expected date of installation and the anticipated on-line date;
7. The anticipated purchase and sale of power to the Distribution Company (simultaneous purchase and sale, net purchase and sale, net metering, or other method);
8. A description of any power conditioning equipment to be located between the Qualifying Facility or On-site Generating Facility and the Distribution Company's system; and
9. A description of the type of generator used in the Qualifying Facility or On-site Generating Facility installation (synchronous, induction, photovoltaic, or other).

(7) Interconnection Costs. The Qualifying Facility or On-site Generating Facility shall reimburse the Distribution Company for the incremental cost, i.e., the costs resulting solely from interconnecting the power production equipment with the Distribution Company's system, including meter installation where applicable. Such costs are to be calculated as follows:

(a) The incremental cost of interconnection shall be the sum of all costs incurred by the Distribution Company that are a direct result of connecting the Qualifying Facility or On-site Generating Facility power production equipment to the Distribution Company's system. This sum includes the costs of installation, the operations and maintenance expense, property taxes, and all incremental modifications to the distribution and transmission system to the extent that such incremental modifications are for the sole benefit of the Qualifying Facility or On-site Generating Facility and are necessary to incorporate its generation into the Distribution Company's system. Costs of system improvements and equipment installed to provide retail service to the Qualifying Facility or On-site Generating Facility consistent with each Distribution Company's. Terms and Conditions for Distribution Service shall be excluded from the incremental cost of interconnection.
(b) In the case where, during the term of a contract, a Qualifying Facility or On-site Generating Facility will purchase electricity from the interconnecting Distribution Company under a standard rate tariff or special contract that includes interconnection costs, the incremental costs of interconnection shall be the difference between the interconnection cost of the Qualifying Facility or On-site Generating Facility and the customer interconnection costs recovered through the tariff or special contract.
(c) For Qualifying Facilities selling electricity to the Distribution Company under Short-run Rates pursuant to 220 CMR 8.05, interconnection costs may be amortized over a period of up to three years, with the period of amortization chosen by the Qualifying Facility. If the charges are amortized, the Qualifying Facility will pay a monthly charge designed to recover the interconnection costs plus interest computed at the Distribution Company's average weighted cost of capital. The Qualifying Facility may instead elect to pay all interconnection costs at the time of interconnection.

(8) Metering. The Qualifying Facility or On-site Generating Facility shall furnish and install the necessary meter socket and wiring in accordance with accepted electrical standards. The Distribution Company shall furnish, read, and maintain the metering equipment.

8.04 continued

(a) Qualifying Facilities with a design capacity of one megawatt (MW) or greater shall use bidirectional, interval recording metering with remote access capability. Such remote access capability may include telemetering to the extent required by NEPOOL standards. Such meter shall be in compliance with NEPOOL standards and requirements for meters on generation resources. The interval recording metering will be controlled, tested, maintained, and read by the Distribution Company.
(b) Qualifying Facilities with a design capacity greater than 60 KW but less than one MW shall use a metering system that can record sales to the Distribution Company.
(c) Qualifying Facilities with a design capacity of 60 KW or less shall use a metering system that can record sales to the Distribution Company.
(d) On-site Generating Facilities with a design capacity of 60 KW or less that net meter shall use a standard service meter capable of running backwards.
(e) Where the. Qualifying Facility or On-site Generating Facility chooses to own the meter, the Qualifying Facility or On-site Generating Facility shall pay to the Distribution Company a monthly charge to cover meter maintenance and incremental reading and billing costs.
(f) Where the Qualifying Facility or On-site Generating Facility chooses to have the Distribution Company own the meter, the Qualifying Facility or On-site Generating Facility shall pay to the Distribution Company a monthly charge which covers taxes, meter maintenance, incremental reading and billing costs, the allowable return on the invoice cost of the meter, and the depreciation of the meter.

(9) Payment.
(a) A Qualifying Facility or On-site Generating Facility selling power to a Distribution Company may choose to receive a check from the Distribution Company as payment for power supplied or may have payment credited towards its bill from the Distribution Company.
(b) Costs charged to a Qualifying Facility or On-site Generating Facility for interconnection equipment, meters, and meter reading shall be the standard charges approved by the Department in a tariff filed by the Distribution Company. Where standard charges are not applicable, the Distribution Company shall charge the Qualifying Facility or On-site Generating Facility the Distribution Company's invoice cost of such equipment. Interconnection costs which are not standardized or invoiced shall be estimated on a case-by-case basis.

8.05: Terms and Conditions for Sales of Electricity by Qualifying Facilities and On-site Generating Facilities to Distribution Companies

(1) Eligibility. All Qualifying Facilities, regardless of size, are eligible to receive Short-run Rates.

(2) Standard Terms of Purchase.
(a) Qualifying Facilities that have a design capacity of one MW or greater shall have their output metered and purchased at rates equal to the payments received by the Distribution Company from the ISO power exchange for' such output for the hours in which the Qualifying Facility generated electricity in excess of its requirements.
(b) Qualifying Facilities with a design capacity greater than 60 KW but less than one MW shall have their output metered and purchased at rates equal to the arithmetic average of the Short-run Energy rate in the prior calendar month for the KWH which the Qualifying Facility generated electricity in excess of its requirements
(c) Qualifying Facilities with a design capacity of 60 KW or less shall have the option to have their output metered and purchased at rates equal to the arithmetic average of the Short-run Energy rate in the prior calendar month for the KWH which the Qualifying Facility generated electricity in excess of its requirements. Qualifying Facilities with a design capacity of 60 KW or less shall have the option to run their meters backward and may choose to receive a credit from the Distribution Company equal to the arithmetic average of the Short-run Energy rte in the prior calendar month for any month during which there was a positive net difference between KWH generated and consumed. Such credit shall appear on the following month's bill. Distribution Companies shall be prohibited from imposing special fees on these customers, such as backup charges and demand charges, or

8.05: continued

additional controls, or liability insurance, as long as the facility meets the Interconnection Standard and all relevant safety and power quality standards. These customers must still pay the minimum charge for Distribution Service (as shown in an appropriate rate schedule on file with the Department) and all other charges for each net KWH delivered by the Distribution Company in each billing period.

(3) Net Metering. Certain On-site Generating Facilities may elect net metering consistent with 220 CMR 18.00.

(4) Standard Contracts. Each Distribution Company must offer a Standard Contract providing for payment at the Short-run Rate to any Qualifying Facility making a request for such a contract.

(5) Effective Date for Short-run Energy and Capacity Rates. Payment of ISO power exchange Short-run energy and capacity rates shall take effect on the first day of the month immediately following the effective date of 220 CMR 8.00. For the period prior to such effective date, Distribution Companies shall pay Qualifying Facility rates currently approved by the Department.

(6) Line Loss Factors. Energy for purchases shall be adjusted to reflect the costs or savings in line losses that result from purchases from the Qualifying Facility. Each Distribution Company shall file with the Department its line loss factors. Line loss factors shall be in accordance with the NEPOOL Market Rules and Procedures.

(7) Short-run Capacity or Reserves Payments. A Distribution Company shall make payments to a Qualifying Facility for capacity and/or reserves-related products if the sale is recognized by NEPOOL as a capacity and/or reserves-related product sale. The Distribution Company shall pay rates equal to the payments received for the sale of any capacity and/or reserves-related products associated with such Qualifying Facility output to the ISO power exchange.

8.06: Terms and Conditions for Sales of Electricity by Distribution Companies to Qualifying Facilities and On-site Generating Facilities

(1) Each Distribution Company shall, upon request by a Qualifying Facility or On-site Generating Facility, supply to a Qualifying Facility or On-site Generating Facility supplementary, back-up, maintenance, and interruptible power pursuant to 18 C.F.R. 292.305(b) under rate schedules applicable to all customers, regardless of whether they generate their own power.

(2) Where it is possible for a Qualifying Facility or On-site Generating Facility to receive power under the applicability clauses of more than one rate schedule, the Qualifying Facility or On-site Generating Facility may choose the rate schedule under which it will be served.

8.07: Reporting Requirements

(1) Each Distribution Company shall file with the Department a report of new Qualifying Facility and On-site Generating Facility activity in a calendar year, by April 1st of the subsequent year. Such filing shall include:

(a) The name and address of the owner, and the address where the Qualifying Facility or On-site Generating Facility is located;
(b) A brief description of the type of Qualifying Facility or On-site Generating Facility;
(c) The primary energy source used by the Qualifying Facility or On-site Generating Facility;
(d) The date of installation and the on-line date;
(e) The method of delivering power to the Distribution Company (contract or net metering);
(f) The design capacity of the Qualifying Facility or On-site Generating Facility;
(g) A brief discussion identifying any Qualifying Facility or On-site Generating Facility that was denied interconnection by the Distribution Company, including a statement of reasons for such denial.

8.07: continued

(2) Each Distribution Company shall file with the Department a report describing the incremental reductions in the purchases of electricity during a calendar year due to customer operations of, or purchases from, on-site renewable energy technologies; fuel cells; cogeneration equipment; On-site Generating Facilities eligible for net metering; or cogeneration facilities eligible for net metering. Such filing shall be submitted to the Department by April 1st of the subsequent year, and it shall include:

(a) A brief discussion of the incremental reductions in purchases of electricity during the calendar year due to customer operations of, or purchases from:

1. on-site renewable energy technologies;
2. fuel cells;
3. cogeneration equipment with a combined heat and power system efficiency of at least 50% based upon the higher heating value of the fuel used in the system;
4. On-site Generation Facilities eligible for net metering; or
5. cogeneration facilities eligible for net metering;

(b) A brief discussion of the effect of 220 CMR 8.07(2)(a) on the Distribution Company's transition charge, including a quantitative estimate of the lost dollar contribution to the Distribution Company's transition charge during the calendar year;
(c) A brief discussion of the effect of 220 CMR 8.07(2)(a) on the Distribution Company's kilowatt hour sales during the calendar year;
(d) An estimate of the percent of the Distribution Company's gross annual revenues that have been lost during the calendar year due to 220 CMR 8.07(2)(a);
(e) A brief narrative identifying all customers that have given notice to the Distribution Company of their plans to reduce electricity purchases due to operations of, or purchases from a facility described in 220 CMR 8.07(2)(a).

8.08: Miscellaneous

(1) Each Distribution Company shall file with the Department and maintain on file for inspection at its place of business the current rates, prices, charges, and terms and conditions established pursuant to 220 CMR 8.00 et seq.

(2) If, at any time, a Qualifying Facility or On-site Generating Facility is aggrieved by an action of a Distribution Company pursuant to 220 CMR 8.00, the Qualifying Facility or On-site Generating Facility may petition the Department to investigate such action. The Department may, at its discretion, open an investigation and, if it deems necessary, hold public hearings regarding any such petition.

(3) The Department may, where appropriate, grant an exception from any provision of 220 CMR 8.00.

REGULATORY AUTHORITY

220 CMR 8.00: M.G.L. c. 25, § 5; c. 164, § 76C.

THE CONNECTICUT LIGHT AND POWER COMPANY, DBA EVERSOURCE ENERGY

NON-FIRM POWER PURCHASE

AVAILABILITY: This purchase arrangement is available to any self generation facility.

CUSTOMER CHARGES: The Company shall install, maintain and read the metering equipment necessary to measure the flow of energy from the facility to the Company. If the facility owns the necessary metering equipment and relieves the Company of all investment, the charge for installation and maintenance shall be the actual cost, and the monthly customer charge for reading and handling shall be $3.00. If the Company owns the metering equipment, the monthly customer charge shall be the capitalized cost of the metering equipment times 2.5% plus the reading and handling charge of $3.00.

PURCHASE OF CUSTOMER GENERATION: The Company will purchase electric energy supplied by the facility in accordance with either of the following two alternatives.

<u>Alternative A</u>: If a time differentiated meter is installed, the Company will determine the energy payment as the sum of delivered energy for each hour in the billing period times the appropriate hourly Connecticut ISO-NE Wholesale Electric Market Real-Time Locational Marginal Price ("RT-LMP") clearing price for such hour. The hourly prices shall be appropriately adjusted to reflect line loss savings. Under this alternative the Customer shall install and maintain communication technology that provides remote access for the Company to read the meter(s) at all times. The location of such facilities shall be at the sole discretion of the Company; however, the Company shall consult with the customer regarding the location of these facilities. The Customer will choose to either provide a dedicated direct dial analog phone line(s), or other mutually agreed communication technology that is compatible with the Company's meter data collection systems. The interconnection of communications equipment that provides for remote meter reading shall be within reasonable proximity of the electric meter as determined by the Company's specifications and is the sole responsibility of the Customer. The Customer shall be the owner of all telephone lines or the remote communications technology and shall maintain them in operable condition at all times. The Company will be responsible for the installation and maintenance of the connection between the Company meter(s) and the Customer's communication system.

<u>Alternative B</u>: If no time differentiated meter is installed, all electric energy will be purchased at the appropriate RT-LMP average clearing price over the billing period. The average price for the billing period shall be appropriately adjusted to reflect line loss savings.

MARKET-CLEARING PRICES: In accordance with Standard Market Design, the RT-LMP for Connecticut is the basis for the market-clearing price. The market-clearing price for Generation recognized in the ISO-NE settlement system is the appropriate Node. The market-clearing price for all other generation is the Connecticut Zone. In the future, LMP may be replaced with another market mechanism. If this occurs, Rate 980 will make payments based on the subsequent market mechanism for calculating the market-clearing price.

Supersedes Rate 980
Effective January 1, 2000
By Supplemental Decision dated December 15, 1999
Docket No. 99-03-36

Effective March 27, 2006
by Decision dated March 27, 2006
Docket No. 05-07-17
Revised to Reflect New Trade Name October 1, 2015
Docket No. 14-05-06

THE CONNECTICUT LIGHT AND POWER COMPANY, DBA EVERSOURCE ENERGY

ADJUSTMENT IN MARKET CLEARING PRICE FOR LINE LOSS SAVINGS: The purchase voltage shall be determined in accordance with the voltage level at which interconnection is made with the Company's system. The voltage level at which purchases are made shall be the level at which sales are made by the Company to the customer, unless otherwise agreed by the Company. Purchases at Transmission voltage levels of 69 kV or higher are paid at the appropriate RT-LMP market-clearing price. For purchases at voltage levels less than 69 kV the appropriate RT-LMP market-clearing prices will be increased by the percentage shown below:

	Alternative A (hourly metering)		Alternative B
Purchase Voltage	On-Peak Hrs.	Off-Peak Hrs.	No time differential meter
Bulk Substation	0.50%	0.34%	0.42%
Primary Distribution	4.38%	2.89%	3.60%
Secondary Distribution	7.13%	4.59%	5.80%

On-Peak Hours: 7 a.m. to 11 p.m. Eastern Standard Time, weekdays.
Off-Peak Hours: All other hours.

Secondary Distribution is defined as purchase voltages below 2.4 kV. All other connections to the distribution system will be Primary Distribution. Customers connected through a bulk substation or at voltages of 69 kV or higher are not considered Distribution.

OWNERSHIP OF CAPACITY RIGHTS: There shall be no capacity payment under any alternative. The Company shall retain the capacity rights for generating units up to the capacity that has been subsidized by ratepayers through the monetary grant process approved in the Decision dated March 27, 2006, in Docket No. 05-07-16. All base load customer-side Distributed Generation ("DG") projects including combined heat and power projects that receive a monetary grant are required to transfer the capacity rights to the Company for fifteen (15) years from the date the facility begins operation.

The Customer shall retain capacity rights if one of the following conditions exists:

1.) The project is an emergency generator; or

2.) All of the following three criteria are met: (1) the generating unit is not under a long-term power purchase contract whose original term is or was one year or longer; (2) the generating unit has a settlement account with ISO-NE; and (3) the generating unit is entitled to the capacity in excess of that subsidized by ratepayers through the monetary grant process. In the unique and limited situations where the generating unit is entitled to the capacity in excess of that subsidized by the ratepayers through the monetary grant process, the Company will work with the generating facility to ensure that any capacity value retained by the generating unit is properly calculated, claimed and allocated.

THE CONNECTICUT LIGHT AND POWER COMPANY, DBA EVERSOURCE ENERGY

NON-FIRM POWER PURCHASE

RATE 980

RENEWABLE ENERGY CERTIFICATES ("RECs") OWNERSHIP: The Company shall retain ownership of RECs for power purchases made pursuant to a long-term purchase power contract which uses Rate 980 as a pricing mechanism for some or all of the output to be purchased under the contract, or if the contract provides for the Company to retain ownership of RECs. A long-term contract is any contract for power purchase whose original term is or was one year or longer. DG projects that are not under a long-term contract, including those that receive monetary grants, will retain the RECs associated with their generation unit.

DETERMINATION OF THE COMPANY'S PURCHASE: Where the metering facilities are on the facility's side of the transformer, the metered energy shall be reduced by 0.35% to determine the Company's purchase.

TERM OF CONTRACT: All base load customer-side DG capacity that receives a monetary grant through the monetary grant process approved in the Decision dated March 27, 2006, in Docket No. 05-07-16 must take service under Rate 980 for a minimum period of fifteen (15) years. For a generating unit that does not receive a monetary grant and where the Customer owns the metering equipment, there will be no term of contract; otherwise, the term of contract shall be for one year and thereafter until the Company shall have received not less than one month's written notice of termination from the facility.

INTERRUPTION OF PURCHASES: The Company reserves the right, upon 48 hours prior notice where practicable, to interrupt purchases and to refuse to purchase energy at times of system emergency or severe operational circumstances in accordance with any applicable New England Power Pool (NEPOOL), Independent System Operator New England (ISO-NE) and Northeast Power Coordinating Council (NPCC) operating procedures.

65-407 PUBLIC UTILITIES COMMISSION

Chapter 315: SMALL GENERATOR AGGREGATION

SUMMARY - This rule establishes the requirements for standard offer providers to purchase the electricity from small generators.

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§ 1 PURPOSE

The purpose of this Chapter is to ensure that small generators have reasonable access to the regional wholesale market.

§ 2 DEFINITIONS

A. **Eligible Generator**. "Eligible generator" means a generator with a nameplate capacity of 5 megawatts or less.

B. **GIS Certificates**. "GIS certificates" means certificates created pursuant to the NEPOOL Generation Information System that represent attributes of electric power and that may be traded separately from the energy commodity.

C. **ISO-NE**. "ISO-NE" means the Independent System Operator of the New England bulk power system or successor organization.

D. **Northern Maine**. "Northern Maine" means the area of Maine that is part of the Maritimes control area.

E. **Real-Time Nodel Clearing Price**. "Real-time nodal clearing price" means the wholesale price for electric energy received or furnished at the applicable nodal location, as determined by ISO-NE for settlement in the New England real-time energy market.

F. **Standard Offer Provider**. "Standard offer provider" means a provider of standard offer service chosen pursuant to Chapter 301 of the Commission's rules.

§ 3 PURCHASE OBLIGATION

A. **Purchase Requirement**. The standard offer provider designated pursuant to Chapter 301 of the Commission's rules to serve residential customers within the ISO-NE control area shall purchase any electricity available from any eligible generator located in the transmission and distribution service territory in which the standard offer provider is obligated to provide service, if requested to do so by the entity who own or controls the eligible generator. Requests for a standard offer provider to purchase electricity pursuant to this subsection shall be made through the transmission and distribution utility charged with administering the transaction between the eligible generator and the standard offer provider.

B. **Purchase Price**. The standard offer provider shall purchase the energy from an eligible generator at the ISO-NE real-time nodal clearing price for the node on which the generator is located. The purchase price under this subsection shall be reduced for any incremental ISO-NE system administrative costs charged to the purchasing standard offer provider as a result of the requirements of this Chapter. The Commission by order may change the applicable purchase price upon a finding that another price would result in the transaction being financially neutral to the standard offer provider consistent with the purposes of this Chapter.

C. **Multiple Providers**. If there are multiple standard offer providers serving residential customers within a transmission and distribution utility service territory, the purchase obligation shall be apportioned according to each provider's share of the standard offer load obligation.

D. **Northern Maine**. The purchase requirements of this Chapter shall become applicable to entities in northern Maine upon a finding by the Commission that the market design in northern Maine will accommodate the purchase of electricity from eligible generators by a standard offer provider in a manner that is financially neutral to the standard offer provider. In the event the Commission makes the requisite finding, it shall determine the appropriate means of establishing the purchase price.

§ 4 ADMINISTRATION

Transmission and distribution utilities shall administer the purchase and sale of electricity required by this Chapter for eligible generators located within their service territories. Eligible generators shall pay the utility's administrative costs pursuant to a rate schedule approved by the Commission. Each transmission and distribution utility within the ISO-NE control area shall file a proposed rate schedule within 30 days of the effective date of this Chapter.

§ 5 FINANCIAL NEUTRALITY

The Commission shall issue an order suspending the operation of this Chapter if it finds that the purchase and sale of electricity from eligible generators cannot be accomplished in a manner that is financially neutral to the standard offer provider.

§ 6 NET ENERGY BILLING

A customer that has elected net energy billing pursuant to Chapter 313 of the Commission's rules may opt to sell its monthly excess generation to the standard offer provider pursuant to this Chapter rather than applying excess kilowatt-hour credits against future kilowatt-hour usage pursuant to section 3(D) of Chapter 313. A customer that opts to sell generation pursuant to this section must affirmatively elect the option through the execution of a contract with the transmission and distribution utility. Net energy billing customers may not change between the sale of excess generation option and the application of excess kilowatt-hour credits against future usage option more than once in a calendar year.

§ 7 STANDARD CONTRACTS

Each transmission and distribution utility within the ISO-NE control area shall develop a standard contract to govern interactions with eligible generators that is consistent with the provisions of this Chapter. Any interested person may request that the Commission order a modification to the standard contract. Nothing in this Chapter exempts eligible generators from other legal requirements regarding the execution of contracts.

§ 8 GIS CERTIFICATES

An eligible generator that sells electricity pursuant to this Chapter is not required to transfer GIS certificates to the purchasing standard offer provider.

§ 9 TECHNICAL SPECIFICATIONS

The Director of Technical Analysis may adopt technical specifications that are necessary or useful in implementing the requirements of this Chapter. All technical specifications adopted pursuant to this section shall be consistent with applicable ISO-NE requirements. Any interested person may request that the Director of Technical Analysis adopt technical specifications pursuant to this section.

§ 10 WAIVER OR EXEMPTION

Upon the request of any person subject to this Chapter or upon its own motion, the Commission may, for good cause, waive any requirement of this Chapter that is not required by statute. The waiver may not be inconsistent with the purposes of this Chapter or Title 35-A. The Commission, the Director of Technical Analysis, or the Presiding Officer assigned to a proceeding related to this Chapter may grant the waiver.

STATUTORY AUTHORITY: 35-A M.R.S.A. §§ 104, 111, 1301 and 3210-A.

EFFECTIVE DATE: This rule, filing 2004-397, was approved as to form and legality by the Attorney General on September 10, 2004. It was filed with the Secretary of State on September 13, 2004 and will be effective on September 18, 2004.

THE NARRAGANSETT ELECTRIC COMPANY
QUALIFYING FACILITIES POWER PURCHASE RATE

I. <u>Applicability</u>

The Company will purchase the electrical output from any qualifying facility as defined under the Public Utility Regulatory Policies Act of 1978 and constructed after November 9, 1978, under the following terms and conditions. Qualifying facilities include the following:

a. Small power production facilities of 20 megawatts or less which use biomass, waste, renewable resources, or any combination thereof for at least 75 percent of their total energy input in the aggregate during any calendar year period.

b. Cogeneration facilities of 20 megawatts or less which first generate electricity and then use at least five percent of the total energy output for thermal production, provided that the useful power output of the facility plus one-half the useful thermal energy output must be:

   1) no less than 42.5 percent of the total energy input of natural gas and oil to the facility in any calendar year; or

   2) if the useful thermal energy output is less than 15 percent of the total energy output of the facility, no less than 45 percent of the total energy input of natural gas and oil to the facility in any calendar year.

c. Cogeneration facilities of 20 megawatts or less which first provide useful thermal energy and then use reject heat to generate electricity, provided that the useful power output must be no less than 45 percent of the total energy input of natural gas and oil during any calendar year period.

II. Terms and Conditions

1. Any qualifying facility that desires to sell electricity to the Company must provide the Company with sufficient prior written notice. At the time of notification, the qualifying facility shall provide the Company with the following information:

a. The name and address of the applicant and location of the qualifying facility.
b. A brief description of the qualifying facility, including a statement indicating whether such facility is a small power production facility or a cogeneration facility.
c. The primary energy source used or to be used by the qualifying facility.
d. The power production capacity of the qualifying facility and the maximum net energy to be delivered to the Company's facilities at any clock hour.
e. The owners of the qualifying facility including the percentage of ownership by any electric utility or by any public utility holding company, or by any entity owned by either.
f. The expected date of installation and the anticipated on-line date.
g. The anticipated method of delivering power to the Company.
h. A copy of the qualifying facility's Federal Energy Regulatory Commission certification as a qualifying facility.

Such notice shall be sent to:

Director, Wholesale Electric Supply
Energy Procurement
National Grid USA Service Company, Inc.
100 East Old Country Rd.
Hicksville, NY 11801

Following such notification, the qualifying facility and the Company shall execute the standard purchase power agreement setting forth the terms of the sale, a form of which is attached in Schedule A, which shall be executed no later than thirty (30) days prior to the desired commencement date of the sale. The actual commencement date of the sale shall be the first day of the calendar month following the acceptance by ISO-New England, Inc. ("ISO-NE") of the registration of the qualifying facility in the ISO-NE settlement system.

2. The qualifying facility shall furnish and install the necessary meter socket and wiring in accordance with the Company's Standards for Connecting Distributed Generation.

3. The qualifying facility shall install equipment approved by the Company which prevents the flow of electricity into the Company's system when the Company's supply is out of service, unless the qualifying facility's generation equipment can be controlled by the Company's supply.

4. The qualifying facility's equipment must be compatible with the character of service supplied by the Company at the qualifying facility's location.

5. The qualifying facility shall be required to install metering pursuant to the requirements contained in the Company's Standards for Connecting Distributed Generation.

6. The qualifying facility shall enter into an interconnection agreement and follow all other procedures outlined in the Company's Standards for Connecting Distributed Generation, as amended and superseded from time to time.

7. The qualifying facility shall reimburse the Company for any equipment and the estimated total cost of construction (excluding costs which are required for system improvements or for sales to the qualifying facility, such as the cost of a standard metering installation, in accordance with the Company's Terms and Conditions) which are necessary to meter purchases under this rate and to interconnect the qualifying facility to the Company's distribution or transmission

system in accordance with the Company's Standards for Connecting Distributed Generation. The Company will install, own, and maintain the equipment.

8. The qualifying facility shall save and hold harmless the Company from all claims for damage to the qualifying facility's equipment or injury to any person arising out of the qualifying facility's use of generating equipment in parallel with the Company's system; provided that nothing in this paragraph shall relieve the Company from liability for damage or injury caused by its own fault or neglect.

9. As a condition to receiving any payments required by this rate, the qualifying facility must comply with any and all applicable New England Power Pool ("NEPOOL") and ISO-NE rules, requirements, or information requests that are necessary for the qualifying facilities' output to be sold into the ISO-NE administered markets (whether the Company or the qualifying facility is actually submitting information to ISO-NE). The Company is not obligated to seek to obtain capacity market payments from ISO-NE for qualifying facilities. If the Company must provide to NEPOOL or ISO-NE any information regarding the operation, output, or any other data in order to sell the output of the qualifying facility into the ISO-NE administered markets, the qualifying facility must provide such information to the Company in a timely manner. The Company will not be liable to pay the qualifying facility for the output of the qualifying facility if the Company is unable to sell the output into the ISO-NE administered markets because of a failure of the qualifying facility to provide to the Company, NEPOOL or ISO-NE any information on a timely basis that was required for sale

of the facility output into the ISO-NE administered markets. For any perceived errors or omissions in the data reported to NEPOOL or ISO-NE or the transactions from ISO-NE to the Company or qualifying facility, the qualifying facility must notify the Company within 30 days of such error or omission occurring.

10. NEPOOL and ISO-NE have the authority to impose fines, penalties, and/or sanctions on participants if it is determined that a participant is violating established rules in certain instances. Accordingly, to the extent that a fine, penalty, or sanction is levied by NEPOOL or the ISO-NE as a result of the qualifying facility's failure to comply with a NEPOOL or ISO-NE rule or information request, the qualifying facility will be responsible for the costs incurred by the Company, if any, associated with such fine, penalty or sanction.

III. <u>Rates for Purchases</u>

<u>Rates for Qualifying Facilities</u>

For qualifying facilities not eligible for net metering under the Company's Net Metering Provision, R.I.P.U.C. No. 2075, as amended and superseded from time to time, the Company will pay the following rates:

1. For facilities meeting the definition of renewable energy resources as defined in R.I.G.L. Section 39-26-5, the Company will pay the Standard Offer Service rate for the applicable retail delivery rate as determined in

Section IV for each kilowatt-hour generated in excess of the facility requirements.

2. For all other qualifying facilities, the Company will pay the hourly clearing prices at the ISO-NE for the hours in which the qualifying facility generated electricity in excess of its requirements. Additionally, the Company shall make payments to a qualifying facility for capacity and/or reserves-related products if the sale is recognized by NEPOOL or ISO-NE as a capacity and/or reserves-related product sale. The Company shall pay rates equal to the payments received for the sale of any capacity and/or reserves-related products associated with such qualifying facility output to ISO power exchange.

IV. <u>Rates for Distribution Service to Qualifying Facilities</u>

Retail distribution delivery service by the Company to the qualifying facility shall be governed by the tariffs, rates, terms, conditions, and policies for retail delivery service which are on file with the Public Utilities Commission. The selection of the appropriate retail rate will be determined as follows:

1) for qualifying facilities with generating capacity of less than 10kW, the appropriate residential or small general service rate will apply unless the customer's load necessitates use of G-02, G-32, or G-62 rate;
2) for qualifying facilities serving non-profit affordable housing, Residential Rate A-16 will apply;

3) for qualifying facilities with generating capacity of at least 10kW but not more than 200 kW, Rate G-02 will apply, unless the customer's load necessitates the use of the G-32 or G-62 rate;

4) for qualifying facilities with generating capacity of at least 200kW but not more than 3,000 kW, Rate G-32 will apply unless the customer's load necessitate the use of the G-62 rate;

5) for qualifying facilities with generating capacity of 3,000 kW or more, Rate G-62 will apply.

V. Cost Recovery

The Company shall be entitled to recover the difference between the payments made to qualifying facilities for purchases pursuant to Section III. and the actual energy market payments received by ISO-NE for the electricity generated by those qualifying facilities from all customers through a uniform per kilowatt hour (kWh) surcharge embedded in the distribution component of the rates reflected on customer bills.

Effective: April 1, 2012