PASCOAG
UTILITY DISTRICT
Pascoag Electric • Pascoag Water

253 Pascoag Main Street
P.O. Box 107
Pascoag, RI 02859
Phone: 401-568-6222
Fax: 401-568-0066
www.pud-ri.org

Pascoag Utility District

Electric Department

In Re: Pascoag Utility District

Year-End Status Report

(Standard Offer Service, Transition, and Transmission

RIPUC Docket No. 4664

Table of Contents

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November 4. 2016

Rhode Island Public Utilities Commission
Ms. Luly Massaro
Commission Clerk
89 Jefferson Blvd.
Warwick, RI 02888

Re: Year-End Status Report
RIPUC Docket No.: 4664

Dear Ms. Massaro;

On Behalf of Pascoag Utility District (Pascoag or PUD), we herewith submit an original and nine copies of Pascoag's Year-End Status Report as ordered in the above docket. This Submittal consists of three books:

Book 1	Testimony and Testimony Exhibits
Book 2	Supporting Schedules
Book 3	Purchase Power Invoices

In this filing, Pascoag is requesting the following changes to its Standard Offer, Transition and Transmission Charges, as well as a Purchase Power Restricted Fund Credit:

Factor	**Current (2016)**	**Proposed (2017)**	**Difference**
Standard Offer	$0.05401	$0.05887	(.00486)
Transition	$0.00957	$0.01024	(.00670)
Transmission	$0.03081	$0.03211	(.00130)
PPRFC	($0.00222)	($0.00445)	(0.00223)
Total	$0.09217	$0.09677	$0.0046

Under the current Rate, a residential customer using 500 kilowatt-hours of electricity per month pays $72.85. Under the proposed rate, that customer will see his bill decrease to $75.14, an increase of $2.30.

The requested date for the new rate is January 1, 2017. If you have any questions, please do not hesitate to contact me.

Very truly yours,

Harle J. Round

Harle J. Round
Manager, Finance and Customer Service

Cc: Service List

Pascoag Utility District – Docket No. 4664 – Annual Reconciliation of the Standard Offer Service Rate, Transmission Charge and Transition Charge
Service List as of 1/19/16

Name/Address	E-mail	Phone
Michael R. Kirkwood, General Mgr./CEO Pascoag Utility District 253 Pascoag Main St. PO Box 107 Pascoag, RI 02859	mkirkwood@pud-ri.org;	401-568-6222
Harle Round Pascoag Utility District	Hround@pud-ri.org;	401-568-6222
William L. Bernstein, Esq. 627 Putnam Pike Greenville, RI 02828	wlblaw@verizon.net;	401-949-2228
Leo Wold, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Lwold@riag.ri.gov; Al.contente@dpuc.ri.gov; Steve.scialabba@dpuc.ri.gov; Al.Mancini@dpuc.ri.gov; Pat.smith@dpuc.ri.gov; dmacrae@riag.ri.gov; Jmunoz@riag.ri.gov;	401-222-2424
Original & nine copies file w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Todd.bianco@puc.ri.gov; Patricia.lucarelli@puc.ri.gov; Sharon.ColbyCamara@puc.ri.gov;	401-780-2107
Nick Ucci, OER	Nicholas.Ucci@energy.ri.gov;	

CERTIFICATE OF SERVICE
I hereby certify that copy/copies of this Year-End Status Report, RIPUC Docket No.: 4664 were served electronically on the individuals named in the above List of Recipients of Filing, this 4th Day of November 2016.

Harle J. Round

Harle J. Round, Notary Public
My Commission expires July 10, 2017

HARLE J ROUND
MY COMMISSION EXPIRES
NOTARY PUBLIC
07-10-2017
STATE OF RHODE ISLAND

State of Rhode Island and Providence Plantations
PUBLIC UTILITIES COMMISSION

RE: PASCOAG UTILITY DISTRICT
RIPUC DOCKET NO.: 4664

NOTICE OF CHANGE IN RATE

Pursuant to Rhode Island General Laws (R.I.G.L.), Section 39-3-11, and in accordance with Section 2.4 of the Rules of Practice and Procedure of the Rhode Island Public Utilities Commission (RIPUC), the Pascoag Utility District hereby gives notice of a proposed change in rates filed and published in compliance with R.I.G.L. 39-3-10.

The proposed changes are contained in the exhibits accompanying the filing. The new rates, as proposed, are to become effective January 1, 2017.

Standard Offer	Current	$0.05401	Proposed	$0.05887
Transition Charge	Current	$0.00957	Proposed	$0.01024
Transmission Charge	Current	$0.03081	Proposed	$0.03211
Purchase Power Restricted Fund Credit		($0.00222)	Proposed	($0.00445)
		$0.09217		$0.09677

A residential customer using 500 kilowatt-hours is currently paying $72.85. Under the proposed rates, this customer's bill would increase to $75.14, an increase of $2.30

Be advised as follows:

1) Pascoag Utility District, incorporated by a special act of the General Assembly, is a quasi-municipal utility within the Village of Pascoag with offices located at 253 Pascoag Main Street, Pascoag, Rhode Island.
2) The Electric Department of the Pascoag Utility District operates an electric distribution system providing retail electric service to customers in the Villages of Pascoag and Harrisville, both in the Town of Burrillville, Rhode Island.
3) Correspondence for Pascoag Utility District in this case should be addressed to Michael R. Kirkwood, General Manager, Pascoag Utility District Electric Department, 253 Pascoag Main Street, P O Box 107, Pascoag, Rhode Island, 02859.
4) In accordance with the RIPUC Rules and Regulations, the documents accompanying this filing contain data and information in support of Pascoag Utility District's application. A copy of this filing is at our offices and may be examined by the public during business hours.

Michael R. Kirkwood
Michael R. Kirkwood, General Manager
Pascoag Utility District

STATE OF RHODE ISLAND
COUNTY OF PROVIDENCE
Subscribed and sworn to before me on the 4th day of November, 2016.

Harle J Round
Notary Public

HARLE J ROUND
MY COMMISSION EXPIRES
NOTARY PUBLIC
07-10-2017
STATE OF RHODE ISLAND

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Pascoag Utility District – Electric Department

Year-End Status Report for Standard Offer Service, Transmission and Transition Reconciliation

RIPUC Docket No.___________

Book 1 Testimony and Testimony Exhibits

Michael R. Kirkwood, General Manager

Harle J. Round, Manager of Finance & Customer Service

Q. Can you detail Pascoag's power portfolio for 2017?

A. M. Kirkwood Pascoag's power portfolio for 2017, used in developing the Standard Offer, Transition and Transmission rate reconciliation request, is detailed in *Table 1-MRK*, below:

Table 1-MRK

Pascoag Utility District 2017 Power Entitlements

NYPA	20%	(Hydro)
Miller (Brown Bear)	3%	(Hydro)
Spruce Mountain	3%	(Wind)
Seabrook	18%	(Nuclear)
NextEra RISE	10%	(virtual gas-fired)
TransCanada	46%	(mostly Fossil Fuel)
	100%	

The total renewable/sustainable power in this portfolio is 26%. This represents mostly hydro power (NYPA and Brown Bear Hydro) at 23%, with one wind entitlement, Spruce Mountain, estimated to contribute 3% of the District's total annual purchased energy in 2017.

Pascoag's total non-carbon based energy is 44% of its requirements and includes a mix of the previously mentioned hydro and wind power, together with nuclear power from Pascoag's Seabrook entitlement. The remaining 56% of Pascoag's requirement is mainly fossil fuel based energy through a 3-year contract entered into with TransCanada Power Marketing LTD. ("TransCanada") which commenced in January 2015 and ends at the end of 2017, and a virtual gas-fired unit transaction reached with NextEra Energy Power Marketing ("NextEra RISE") that began in June of 2013. *Testimony Exhibit 1-MRK* highlights this mix or resources in graphic form.

Q. Please provide an update on Pascoag's power purchase agreement entered into in order to hedge the rest of Pascoag's requirements in 2015 through 2017.

A. M. Kirkwood Based on the extreme spot market pricing experienced in New England during the winter 2013/14 Polar Vortex, Pascoag was concerned that the main driver of volatile pricing, especially in the winter months for several more years, will be the lack of adequate natural gas pipeline capacity. This inadequate gas infrastructure has not only lead to volatile prices in the natural gas spot market, especially in winter, but also in the electricity spot markets in New England (Day Ahead and Real Time) which are driven by natural gas-fired generating units. Since major improvements in pipeline capacity are not projected to be in place until late 2017 at the earliest, Pascoag and its power supply advisor, Energy New England (ENE), thought it would be best to protect Pascoag's remaining open power supply position through that period. Since Pascoag's unhedged position was approximately 42-46% of its energy requirements in 2015-2017, as illustrated for the year 2017 in *Table 1-MRK* above and

Exhibit 1-MRK attached, Pascoag secured the TransCanada agreement at 7.03 cents/kWh throughout the period in order to protect Pascoag's customers from volatility in the energy markets.

Q. Was Pascoag successful in obtaining a competitive supply to hedge its remaining open position?

A. Yes, Pascoag and ENE ran a solicitation for the 2015-17 time period by seeking a load following deal. A load following deal has the structure similar to our expired 2012-2014 agreements with Exelon, except that this time we sought a 100% load-following hedge for the whole 2015-2017 term of the agreement due to the volatility in future spot-market pricing expected for the years 2015, 2016 and 2017.

Q. Please describe the solicitation and resulting deal that was confirmed for 2015-17.

A. Pascoag and ENE queried several power suppliers in early April 2014 to provide fixed pricing for load following energy. Load following energy is calculated by taking Pascoag's actual day-to-day load requirement and subtracting the estimate of our other entitlements (Seabrook, NYPA, RISE, Miller/Brown Bear Hydro, and Spruce Mountain Wind) to determine what our additional need is. We then asked for pricing that would fill 100% of this hour-by-hour need (load – existing supply). We received quotes from three of the supplier entities that were very competitive with the prices that ENE estimated for that period. After several rounds of negotiations and price improvement, Pascoag selected TransCanada Power Marketing Ltd. (TransCanada) as the supplier, at a fixed price of 7.03 cents/kWh for the 3-year period. This contract has been protecting Pascoag from the volatility we saw in the 2013/2014 winter for the un-hedged portion or our portfolio, which oftentimes exceeded 25 cents/kWh on the spot market and at times hit 50 cents/kWh. Please see *Exhibit 2-MRK*, which is a copy of the contract (called a Confirmation) with TransCanada.

Q. Has Pascoag done anything else that would improve its fiscal position and rate stability?

A. M. Kirkwood The District has over the past few years negotiated a number of EEI Master Power Purchase and Sales Agreements. In 2014, Pascoag added EEI Master Agreements with PSEG Energy Resources and Trade LLC and Shell Energy North America (US) L.P. to supplement those it had with TransCanada, NextEra Energy, Exelon/Constellation Energy and Macquarie Energy. These documents improved Pascoag's position in contract negotiations by streamlining the negotiation process with those it has signed EEI Master Agreements with and by ensuring Pascoag's credit worthiness to potential new EEI Master partners. In fact, it was the use of EEI Master Agreements which allowed the competitive solicitations that resulted in the previously beneficial Load Following Energy deals with Exelon/Constellation and Shell Energy, and the 2015-17 Load Following deal with TransCanada. These EEI Masters allow the parties to transact quickly based on market conditions at the time the transactions are priced.

Finally by way of important information regarding Pascoag's fiscal health, Standard and Poor's re-affirmed the District's "A-"credit rating in 2015 based on the results of their annual review and rating of our company. Pascoag has now maintained an A- rating with S&P from 2008 to the present.

Q. The Pascoag entitlement with Miller Hydro was set to expire in May of 2016. Was Pascoag able to replace this beneficial renewable energy entitlement?

A. M. Kirkwood Yes, Pascoag' energy advisor ENE, on behalf of Pascoag and sixteen of the public power project participants, was able to negotiate an extension to the Miller Hydro agreement. The Second Amendment to the Miller Hydro PPA (now known as Brown Bear II Hydro) is included as *Exhibit 3-MRK*.

The key terms of the extended contract are as follows:

Price for Facility Energy and Ancillary Services:

06/01/2016 - 12/31/2016 @ $46.00/MWh

01/01/2017 - 05/31/2017 @ $48.00/MWh

06/01/2017 - 05/31/2018 @ $48.96/MWh

06/01/2018 - 05/31/2019 @ $49.94/MWh

06/01/2019 - 05/31/2020 @ $50.94/MWh

06/01/2020 - 05/31/2021 @ $51.96/MWh

Pascoag was extremely pleased to be able to extend the contract from this excellent facility at these low prices, especially since the project is a renewable energy project which helps Pascoag to retain a high percentage of its portfolio mix in clean energy.

Q. Has Pascoag looked at other opportunities for its power portfolio?

A. M. Kirkwood Yes, Pascoag has been in discussion with several solar energy farm developers during 2016, and in fact reached a preliminary understanding with a project developer for a project proposed on the border of our service territory. Negotiations continue for the output of this project.

In addition, ENE brought another very good wind development opportunity to its public power participants that was similar in nature and structure to our existing Spruce Mountain wind entitlement. ENE informed its public power clients in early 2016 about the possibility of purchasing the output of the *Canton Mountain Wind Project*. Canton Mountain is an 8 turbine, 22.8 MW commercial scale wind project located in Canton, Maine developed by Patriot Renewables, LLC. Patriot Renewables has extensive experience developing, constructing, and operating wind projects in New England. Patriot built and operates the Beaver Ridge, Spruce Mountain and Saddleback Ridge projects in Maine. To date, these existing projects have met or exceeded all operational expectations. ENE in past years established public power groups to buy the output from the Spruce Mountain project and the Saddleback Ridge project and continued this group buying power philosophy for the Canton Mountain project. In addition to doing the due diligence on the viability and the potential value of such projects on behalf of the public power community, ENE assists the buyers such as Pascoag with PPA negotiations as well as REC marketing and administration. ENE also provides lead market participant services to ensure the projects are in compliance with all ISO NE market rules. Based on ENE's ongoing review of the renewable energy market in New England, the Canton Mountain Project has significant advantages:

- Supportive town, permitting is complete and all appeals are exhausted;
- 2016-17 construction, one of the few projects that can take full advantage of the Production Tax Credit (PTC) which is slated to phase out through 2019, the PTC in 2014 was $0.023 KWH, adjusted annually;
- The PTC falls by 20% each year for wind facilities that don't commence construction in 2016. That equates to an additional $4.60/MWH in PPA requirements in 2017, which compounds in 2018 and again in 2019.
- Lower energy prices have kept pressure on turbine manufacturers to keep pricing low
- REC prices remain competitive
- Debt rates remain low
- No significant transmission upgrades are required by ISO-NE for the Canton Mountain Wind Project
- Canton Wind project applied to the ISO-NE generation queue in 2010

The Canton Mountain project presents an opportunity for buyers to layer in a green project without overextending their power portfolio. The Canton Mountain transaction is for 20 years beginning with anticipated commercial operations in late 2017. The Spruce Mountain transaction would overlap with the Canton Mountain project for only nine years, affording a layering effect of renewable resources for Pascoag and other project participants.

The baseline PPA price is $99.97/MWH for year one escalating at 1% until year four where a 2.22% adjustment is necessary (this increase was actually warranted at the start of the project, but Patriot agreed to absorb additional costs for the first three years) and from year five through fifteen the escalation remains 1%. The pricing for the last five years drops substantially to $80.37/MWH reflecting project debt rolling off. This yields a 20 year average price of $101.32/MWH. The price for Canton Mountain is slightly higher than our past wind PPA's due to lower projected wind, however, ENE determined the economics for this project compelling on a relative basis and especially compelling because no material transmission upgrades are required. It is very likely that future wind projects located in Maine will pay substantial transmission upgrade costs. The Canton Mountain project is a competitively priced wind PPA with a developer that has an excellent track record with ENE and its members.

Capacity - ENE considered the known capacity prices through May 2020, the likely low capacity prices for an additional auction or two thereafter, and modest estimates of capacity thereafter and arrived at a level price for the term of $7.00/kW-mo., which is below the carrying cost of new-build, fossil fueled generation and is in line with the results of the recently completed FCA 10. In the end, this is part of arriving at a price that "works" for the project's economics, as it is bundled with energy and RECs.

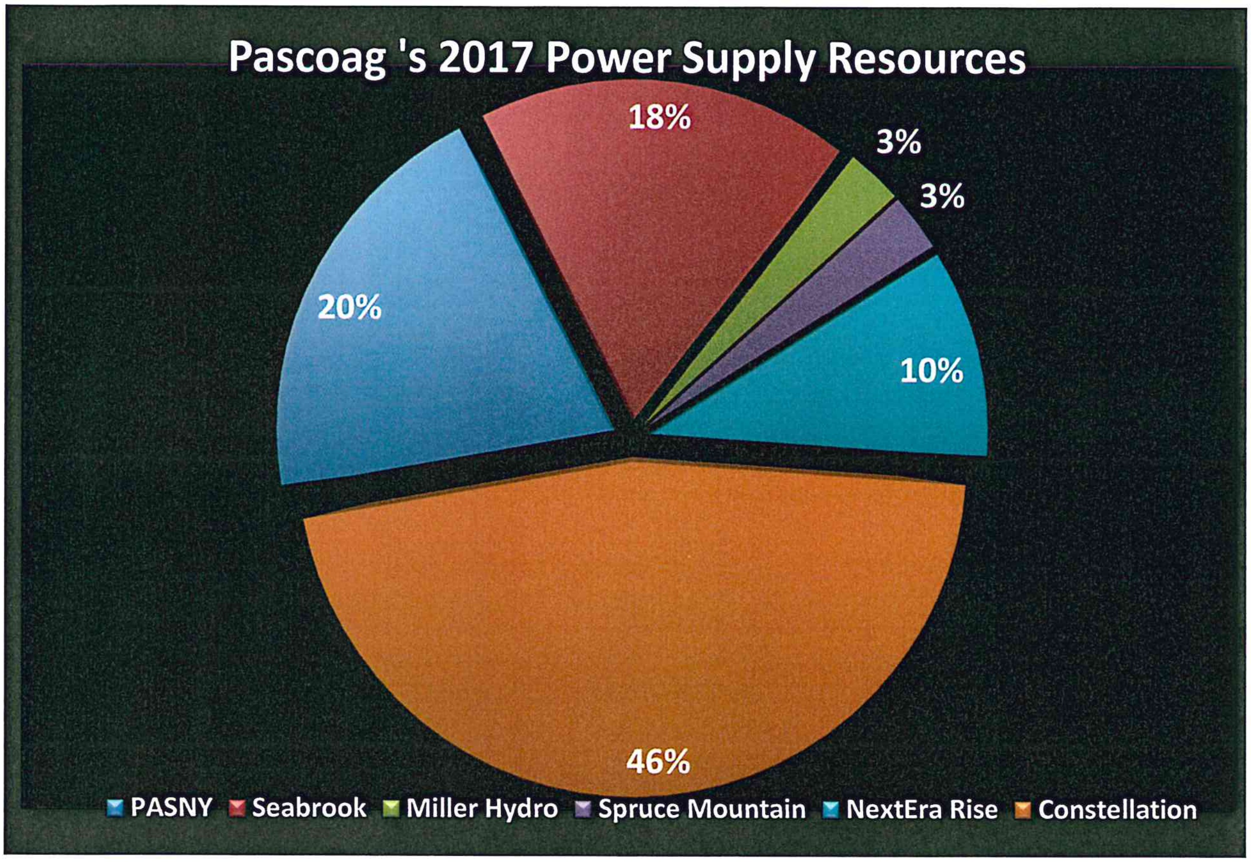
Renewable Energy Credits (RECs) - ENE looked at where RECs are trading in the market – currently prices are quoted out through 2019: 2017 at $44.00, 2018 at $44.00 and 2019 at $40.00/MWH. We kept the $40.00 price estimate through the year 2032 because there is a recognition by policy makers that a stable REC market is necessary for continued renewable energy development. ENE then discounted the price of RECs to $35.00/MWH for the longer dated vintages beyond 2032.

ENE's expectation is that RECs will retain some degree of value over the term of the transaction as state renewable portfolio standard requirements increase and given the difficulty with permitting and building renewable projects in Southern New England. As a new wind resource, this project will qualify for Class I equivalent RECs in all New England states with RPS programs. With regional push for offshore wind at much higher PPA requirements, this would also be supportive of higher, longer term REC values. Please see *Exhibit 4-MRK*, which is a copy of the contract for the Canton Mountain Wind project.

Q. Does this conclude your portion of the testimony?

A. M. Kirkwood Yes it does.

Testimony Exhibit 1-MRK



Testimony Exhibit 2-MRK

Confirmation Letter for:

TransCanada Power Marketing, LTD.

Confirmation Letter

This Confirmation (the "Confirmation") shall confirm the agreement reached on April 23, 2014 (the "Trade Date") between TransCanada Power Marketing Ltd. ("Seller") and Pascoag Utility District ("Pascoag") (each individually a "Party" and collectively the "Parties") regarding the purchase and sale of Load Following Energy, as more fully set forth herein. This Confirmation is being provided pursuant to and in accordance with the EEI Master Power Purchase and Sale Agreement dated December 7, 2010 (the "Master Agreement") between Seller and Pascoag and constitutes part of and is subject to the terms and provisions of such Master Agreement.

1. Definitions. Except as otherwise provided herein or in the Master Agreement, all product or market-related terms capitalized but not defined herein shall have the meaning given such terms (or any successor thereto) in the Applicable Market Rules as amended from time to time. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement. In the event of a conflict between the terms of the Master Agreement and this Confirmation, the terms contained in this Confirmation shall control. In addition to the foregoing, the following terms shall have the meanings set forth herein.

1.1 "2x16 Energy" shall be Energy scheduled during 2x16 Hours.

1.2 "2x16 Hours" shall mean the hours beginning on HE 0800 through and including HE 2300 EPT on Saturday, Sunday and NERC Holidays.

1.3 "Applicable Market Rules" means Market Rule 1, the ISO-NE Information Policy, the ISO-NE Administrative Procedures, the ISO-NE Manuals and any other system rules, procedures or criteria for the operation and administration of the ISO-NE Market System and the ISO-NE Tariff.

1.4 "Confirmation" shall have the meaning given such term in the first paragraph of this Confirmation.

1.5 "DR Program" means any load interruption or demand-side management program imposed by applicable law or ISO-NE in accordance with Applicable Market Rules that affects the Pascoag Load Asset.

1.6 "Delivery Point" shall have the meaning set forth in Section 4 hereof.

1.7 "EPT" shall mean Eastern Prevailing Time, which shall be the local time in New York City on the date of determination.

1.8 "HE" shall mean hour ending.

1.9 "Hedged Percentage" shall mean one hundred percent (100%) of the gross hourly Energy requirements of Pascoag's ratepayers located in Pascoag's service territory as of the Trade Date.

1.10 "ISO-NE" means ISO-New England Inc. and its successors and assigns.

1.11 "IBT Container" shall mean the form of electronic contract submittal, as implemented by the ISO-NE Market System effective March 1, 2003, that only requires Pascoag to confirm the general parameters of the IBT and not the hourly schedules of Energy delivery.

1.12 "Load" means the RTLO of the Pascoag Load Asset, as measured at the interconnection point of Pascoag's system with National Grid, less the Pascoag Fixed Volumes. Load shall not include any capacity, ancillary services obligations, or renewable portfolio standards. In addition, and notwithstanding anything to the contrary in the Confirmation, Load shall not include any Load Following Energy requirements related to (i) any wholesale or aggregation transaction to which Pascoag is a Party; (ii) any change in customers as a result of any acquisition, divestiture, annexation, merger, joint venture, partnership, or other similar transaction that Pascoag may undertake on or after the Trade Date; or (iii) the addition of any single customer of Pascoag whose peak load in any single hour is greater than 1 MW. To the extent that Pascoag does incur such an additional load obligation because of the occurrence of one or more of the events contemplated in the prior sentence, such additional load obligation shall not be included in the Load and Seller shall have no responsibility to provide Load Following Energy for such load.

1.13 "Load Cap" shall mean 14 MW.

1.14 "Load Following Energy" shall mean the quantity of Energy required to serve the Hedged Percentage of the Pascoag Load Asset during each ISO-NE settlement interval including the Day-Ahead and the Real-Time Load Obligation associated with the Pascoag Load Asset.

1.15 "Master Agreement" shall have the meaning given such term in the first paragraph of this Confirmation.

1.16 "MW" shall mean megawatts.

1.17 "NERC" shall mean the North American Electric Reliability Corporation, including with any successors thereto.

1.18 "Operating Day" means the calendar day period beginning at HE 0100 EPT for which transactions in the New England Markets are scheduled.

1.19 "On-Peak Energy" shall be Energy scheduled during On-Peak Hours.

1.20 "On-Peak Hours" shall mean the hours beginning on HE 0800 EPT through and including HE 2300 EPT each day during the Supply Term except Saturday, Sunday and any holiday designated by NERC.

1.21 "Off-Peak Energy" shall be Energy scheduled during Off-Peak Hours.

1.22 "Off-Peak Hours" shall be those hours beginning on HE 2400 EPT through and including HE 0700 EPT each day during the Supply Term and shall include Saturday, Sunday and any holiday designated be NERC.

1.23 "Pascoag Estimated Load" shall have the meaning set forth in Section 3.3.

1.24 "Pascoag Fixed Volumes" shall mean the volumes, in megawatts, set forth on Schedule 1 hereto for On-Peak Energy, Off-Peak Energy and 2x16 Energy.

1.25 "Pascoag Load Quantity" shall have the meaning set forth in Section 3.2 hereof.

1.26 "Purchase Price" shall have the meaning set forth in Section 5 hereof.

1.27 "RTLO" shall mean the Real Time Load Obligation, as defined by the ISO-NE Rules.

1.28 "Supply Term" shall have the meaning set forth in Section 2 hereof.

2. Supply Term. Seller's obligation to sell Load Following Energy, as defined in this Confirmation, and Pascoag's obligation to purchase Load Following Energy is effective as of the Trade Date. The period during which Seller shall sell and Buyer shall purchase Load Following Energy shall commence on HE 0100 EPT, on January 1, 2015 and shall terminate at the end of HE 2400, EPT, on December 31, 2017 (the "Supply Term") unless earlier terminated pursuant to the Master Agreement; provided that the applicable provisions of this Confirmation shall continue in effect after termination or expiration hereof to the extent necessary to provide for accountings, final billing, billing adjustments, resolution of any billing dispute, resolution of any court or administrative proceeding and payments

3. Purchase and Sale of Load Following Energy.

3.1 Load Following Energy. During the Supply Term, Pascoag shall schedule and purchase and TransCanada shall confirm and sell Load Following Energy at the Delivery Point at the price set forth on Exhibit A for On-Peak Hours, Off-Peak Hours and 2x16 Hours in accordance with ISO-NE Rules, all as more fully set forth in this Confirmation.

3.2 Load Asset. Pascoag has established a Load Asset in the ISO-NE Market System, with such Load Asset being designated as Load Asset #159 (the "Pascoag Load Asset"). The Pascoag Load Asset includes transmission and distribution losses from the ISO-NE Pool Transmission Facilities (as defined in the ISO-NE Rules) to the retail meters for Pascoag's retail customers and shall be used to determine the Load. Pascoag shall report, or cause to be reported, the quantity of Load to ISO-NE (the "Pascoag Load Quantity") and to Seller in accordance with ISO-NE Rules..

3.3 Scheduling of Energy. Pascoag shall schedule Load Following Energy in accordance with Section 3.3.1. If Pascoag does not know the actual amount of the RTLO in time to schedule the Load Following Energy on the day after the Operating Day, Pascoag shall schedule an estimated amount of Energy that reasonably approximates Pascoag's RTLO based upon information available to it at the time of scheduling (the "Pascoag Estimated Load"). If Pascoag's actual Load differs from the Pascoag Estimated Load, Seller and Pascoag shall settle such difference in accordance with Section 3.3.2. All Energy scheduled on the day after the Operating Day shall be scheduled at the Day-Ahead Locational Marginal Price for the Delivery

Point for the hour that the Energy was consumed. Unless the Parties agree otherwise, Pascoag shall schedule Energy by submitting one IBT Container for each month during the Supply Term.

3.3.1 Load Calculation. Pascoag shall calculate the amount of Load for each hour of each Operating Day according to the following formula; provided, however, if during any hour, the result of subtracting the Pascoag Fixed Volumes from the product of the Pascoag Load Quantity and the Hedged Percentage is negative then Seller shall sell 0.0 MW to Pascoag and Pascoag shall purchase 0.0 MW from Seller during such hour(s):

Load = (Pascoag Load Quantity * (Hedged Percentage) – Pascoag Fixed Volumes

3.3.2 Settlement of Pascoag Estimated Load. In the event that Pascoag schedules an amount of Energy that is different than the amount of Load in any hour on an Operating Day, Seller shall credit or charge Pascoag an amount equal to the product of (i) the hourly difference obtained by subtracting the amount of Energy scheduled and confirmed, if any, from the Load in such hour, and (ii) the Day Ahead Locational Marginal Price at the Delivery Point for such hour, as determined by ISO-NE in accordance with the Applicable Market Rules for the hours when Pascoag over-scheduled or under-scheduled the Load hereunder. If the foregoing product is negative, such amounts shall be a charge to Pascoag and if such amount is positive, such amount shall be a credit to Pascoag.

3.4 Sales for Resale. Notwithstanding anything to the contrary in this Confirmation, all sales of Load Following Energy hereunder shall be sales for resale and Pascoag shall continue to be responsible for furnishing retail service to its retail customers in accordance with applicable laws and requirements, at its sole cost and expense. For the avoidance of doubt, Pascoag shall bear all administrative costs associated with retail service, including, but not limited to billing, customer service, and meter reading.

4. Delivery Point. Pascoag shall schedule all deliveries of Load Following Energy to the Massachusetts Trading Hub (ISO-NE Node #4000) (the "Delivery Point"). Seller shall bear all costs and losses of supplying Load Following Energy hereunder to the Delivery Point and Pascoag shall bear all costs and losses at and after the Delivery Point. Title to all Load Following Energy shall pass at the Delivery Point.

5. Purchase Price. Pascoag shall pay Seller, each month during the Supply Term, an amount equal to the product of the Load delivered pursuant to the calculation in Section 3.3.1 and the price set forth on Exhibit A for such month (the "Purchase Price").

6. Load Growth.

6.1 Changes in Service Territory; Additional Customers; Load Cap. Notwithstanding anything to the contrary in this Confirmation, Seller shall not be obligated to sell and deliver Load Following Energy for any changes to the Load resulting from any Load in excess of the Load Cap. To the extent that Pascoag does incur such an additional load obligation in excess of the Load Cap, such additional load obligation shall not be included in the Load and Seller shall have no responsibility to provide Load Following Energy for such load.

6.2 Warranty and Representation Regarding DR Program. Pascoag represents and warrants to Seller as of the Trade Date that to the best of its knowledge and belief there are no DR Programs being considered by Pascoag or that may be imposed on Pascoag during the Supply Term. If Pascoag becomes involuntarily subject to any DR Program then Pascoag shall provide Seller with the earlier of (i) sixty (60) days or (ii), in the event that such DR Programs are implemented in less than 60 days, as soon as practicable, advance written notice of such requirements and provide a description of such DR Program in reasonable detail.

6.3 Voluntary Demand Response. Prior to Pascoag instituting any DR Program, Pascoag will provide at least 60 days advance written notice to Seller of such DR Program and a description of such DR Program in reasonable detail. In addition, (i) if such DR Program would reduce Load by more than 1 MWs in any hour, whether alone or aggregated with other DR Programs, or (ii) Pascoag implements DR Programs such that the total curtailment associated therewith is greater than 100 hours per calendar year, then Seller and Pascoag agree to meet to discuss whether changes should be made to the prices set forth in Exhibit A and if so the actual changes. If the Parties are unable to agree then Seller may terminate this Confirmation upon 30 days' prior written notice. For clarity, the foregoing shall not apply to any DR Program implemented directly by any of Pascoag's customers.

[Signature page contained on next page]

Agreed to as of the date set forth above.

TRANSCANADA POWER MARKETING LTD.

By:
Its:

By:
Its:

PASCOAG UTILITY DISTRICT, RHODE ISLAND

Michael R. Kirkwood

By: Michael R. Kirkwood
Its: General Manager / CEO

Agreed to as of the date set forth above.

TRANSCANADA POWER MARKETING LTD.	PASCOAG UTILITY DISTRICT, RHODE ISLAND
By: Geoff Murray	By:
Its: Vice President Western Power Growth	Its:
By: Richard Schuler	
Its: As Agent and Attorney-In-Fact	

Business	
Legal	GAS

SCHEDULE 1

Fixed Volumes

Pascoag's "FIXED" Supply Volumes for 2015			
	PEAK	7x8	2x16
Jan	3.641	3.295	3.292
Feb	3.673	3.317	3.286
Mar	4.971	3.356	4.292
Apr	5.084	3.494	4.492
May	4.844	3.222	4.219
Jun	5.044	3.299	4.270
Jul	4.937	3.363	4.326
Aug	4.842	3.432	4.405
Sep	4.816	3.429	4.405
Oct	3.437	2.077	3.034
Nov	4.673	3.293	4.278
Dec	3.386	3.129	3.111

Pascoag's "FIXED" Supply Volumes for 2016			
	PEAK	7x8	2x16
Jan	3.641	3.295	3.292
Feb	3.673	3.317	3.286
Mar	4.971	3.356	4.292
Apr	5.084	3.494	4.492
May	4.844	3.222	4.219
Jun	4.825	3.076	4.039
Jul	4.790	3.211	4.169
Aug	4.728	3.308	4.260
Sep	4.668	3.280	4.263
Oct	4.468	3.104	4.057
Nov	4.510	3.129	4.113
Dec	3.201	2.940	2.922

Pascoag's "FIXED" Supply Volumes for 2017			
	PEAK	7x8	2x16
Jan	3.446	3.102	3.094
Feb	3.507	3.153	3.123
Mar	4.734	3.119	4.051
Apr	3.638	2.053	3.054
May	4.591	2.973	3.979
Jun	4.825	3.076	4.039
Jul	4.790	3.211	4.169
Aug	4.728	3.308	4.260
Sep	4.668	3.280	4.263
Oct	4.468	3.104	4.057
Nov	4.510	3.129	4.113
Dec	3.201	2.940	2.922

EXHIBIT A

Pricing

Fixed price of $70.30/MWh for all months in the Supply Term.

Testimony Exhibit 3-MRK

Second Amendment of Power Purchase Agreement: Brown Bear II Hydro, Inc. (formerly Miller Hydro)

SECOND AMENDMENT

POWER PURCHASE AGREEMENT

FOR

UNIT CONTINGENT ENERGY AND ANCILLARY SERVICES

Between

PASCOAG UTILITY DISTRICT

And

BROWN BEAR II HYDRO, INC.

This SECOND AMENDMENT (this "Amendment") to the Power Purchase Agreement for Unit Contingent Energy and Ancillary Services, dated September 15, 2009 (the "Agreement") by and between Pascoag Utility District, having a business address at 253 Pascoag Main Street, Pascoag, Rhode Island 02859, hereinafter referred to as "Buyer" and Brown Bear II Hydro, Inc. (formerly known as Miller Hydro Group, Inc.), a Maine corporation, having its principal place of business at 148 Middle Street, Suite 506, Portland, Maine 04101, hereinafter referred to as "Seller" (Buyer and Seller are referred to herein individually as a "Party" and collectively as the "Parties") is made and entered into as of May 31, 2016. Capitalized terms used herein and not defined herein shall have the meanings set forth in the Agreement.

WHEREAS, the Parties desire to make certain amendments to the Agreement that will be effective as of the date hereof; and

WHEREAS, the Parties desire to make certain amendments to the Agreement that will become effective on 12:01 a.m. on June 1, 2016, including extending the term, changing the Contract Energy Price, adding Renewable Energy Certificates or Environmental Attributes as a Contract Product and removing Installed Capacity as a Contract Product;

NOW, THEREFORE, in accordance with the foregoing and in consideration of the mutual promises, covenants and agreements set forth herein, and for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree to amend the Agreement pursuant to Article 21.11 thereof as follows:

A. Amendments To The Agreement That Are Effective Upon Execution Of This Amendment.

Effective upon execution of this Amendment, the following changes shall take effect:

1. Article 5 is amended by deleting (a) the fourth, fifth and sixth sentences of the first paragraph and (b) the entire second paragraph.

2. Article 18.1(a) is amended and restated in its entirety and replaced with the following: "Seller shall provide to such Person with, which Person shall be identified in writing by Buyer and the other Persons named in this sentence not less than five (5) Business Days prior to issuance of, a Letter of Credit issued by a Qualified Institution, substantially in the form attached hereto as Appendix A for the benefit of Belmont Municipal Light Department, the Braintree Electric Light Department, the Concord Municipal Light Plant, the Danvers Electric Division, the Hingham Municipal Light Plant, the Georgetown Municipal Light Department, the Groveland Electric Light Department, the Middleton Electric Light Department, the Merrimac Municipal Light Department, the North Attleborough Electric Department, the Norwood Municipal Light Department, the Pascoag Utility District, the Rowley Municipal Light Plant, the Taunton Municipal Lighting Plant, the Town of Stowe Electric Department, the Wellesley Municipal Light Plant as buyers of the output from the Unit under the same terms and conditions as set forth in this Agreement. The Letter of Credit or a replacement Letter of Credit shall be maintained in at least the following amounts: "$500,000 from the issue date of the Letter of Credit, through May 31, 2017, $400,000 from June 1, 2017 through May 31, 2018, $300,000 from June 1, 2018 through May 31, 2019, $200,000 from June 1, 2019 through May 31, 2020, and $100,000 from June 1, 2020 through May 31, 2021." The amount maintained for the benefit of the Buyer shall be equal to the Contract Products percent multiplied by the applicable amount set forth in the prior sentence for the relevant period of time ("Seller's Credit Support Amount"). If at any time, (a) the Credit Rating of Seller is lowered by S&P below BBB- and/or by Moody's below Baa3, as applicable, or (b) Seller fails to maintain a Credit Rating with at least one of S&P or Moody's and such failure is continuing, then Seller shall be required to provide the Seller's Credit Support Amount to Buyer within five (5) Business Days of a request by Buyer to be held as security for Seller's obligations under this Agreement.".

3. Article 18.2(a) is amended and restated in its entirety and replaced with the following: "Within ninety (90) days of the Effective Date, Buyer shall provide Seller with evidence of an Investment Grade Credit Rating pertaining to it of S&P BBB- and/or Moody's Baa3 or better. If this is not provided, then within ninety (90) days after the Effective Date, Buyer shall provide Seller with cash. The cash shall be maintained in the same amount as the Seller's Credit Support Amount ("Buyer's Credit Support Amount"). The Buyer shall be required to maintain the Buyer's Credit Support Amount until such time as the Buyer obtains an Investment Grade Credit Rating at which time the Buyer's Credit Support Amount shall be returned to the Buyer. However, if at any time after the Buyer obtains an Investment Grade Credit Rating, (a) the Credit Rating of Buyer is lowered by S&P below BBB- and/or by Moody's below Baa3, as applicable, or (b) Buyer fails to maintain a Credit Rating with at least one of S&P or Moody's and such failure is continuing, then Buyer shall be required to provide the Buyer's Credit Support Amount to Seller within five (5) Business Days of a request by Seller to be held as security for Buyer's obligations under this Agreement."

4. Article 18.2(b) is hereby deleted in all respects.

5. Article 20.1 is amended and restated in its entirety and replaced with the following: "This Agreement for the purchase and sale of Contract Products (as herein defined) is one of sixteen (16) identical or substantially identical such Agreements that are simultaneously

made and entered into on or about the Effective Date between Seller and sixteen (16) separate "Buyers" (as defined). Each of the Buyers has a principal place of business in the Commonwealth of Massachusetts or in the State of Rhode Island or the State of Vermont. Seller and Buyer each seek to assure that all disputes arising out of these sixteen (16) agreements are resolved in Boston, Massachusetts subject to the terms of this Article 20."

6. Article 20.5 is hereby deleted in all respects.

7. Appendix A attached to the Agreement is hereby deleted and Appendix A attached hereto is replaced in lieu thereof.

B. Amendments To The Agreement That Are Effective On June 1, 2016.

Effective on 12.01 a.m. June 1, 2016, the following changes shall take effect:

1. Wherever the phrase "Unit Contingent Energy, Installed Capacity and Ancillary Services" appears in the Agreement, it is deleted and replaced with "Unit Contingent Energy, Ancillary Services and Renewable Energy Certificates or Environmental Attributes".

2. Article 1.07 is deleted in its entirety and replaced with the following: "'Contract Price'" shall mean $46.00 per MWh during June 1, 2016 through December 31, 2016, $48.00 per MWh during January 1, 2017 through May 31, 2017, $48.96 per MWh during June 1, 2017 through May 31, 2018, $49.94 per MWh during June 1, 2018 through May 31, 2019, $50.94 per MWh during June 1, 2019 through May 31, 2020, and $51.96 during June 1, 2020 through May 31, 2021."

3. Article 1.08 is deleted in its entirety and replaced with the following: "'Contract Products'" shall mean 1.683% of the Energy, Renewable Energy Certificates or Environmental Attributes, Ancillary Services and all other products produced by or otherwise attributable to the Unit, which shall be unit contingent, except that Contract Products shall not include Installed Capacity."

4. Article 2.1 is amended by deleting "March 1, 2013" and replacing it with "June 1, 2016" and by deleting "May 31, 2016" and replacing it with "May 31, 2021".

5. Article 4.2 is amended by inserting the phrase "plus the Capacity Credit or minus the Capacity Charge, as applicable".

6. Any disputes between the Parties regarding the interpretation and performance of this Amendment shall be resolved in accordance with Article 20 of the Agreement.

7. Except as expressly amended or waived by this Amendment, the terms, conditions, covenants, agreements, warranties and representations contained in the Agreement are in all respects ratified, confirmed and remade as of the date hereof (except to the extent any such representation or warranty speaks solely as of an earlier date, in which case such

representation or warranty is made only as of such earlier date) and, except as amended or waived hereby, shall continue in full force and effect.

8. This Amendment represents the entire agreement of the Parties hereto with respect to the subject matter hereof, and there are no promises, undertakings, covenants, representations or warranties by the Parties hereto relative to the subject matter hereof not expressly set forth or referred to herein.

9. This Amendment may be executed in any number of counterparts, each of which shall be an original, but all of which together shall constitute one instrument.

Agreed to as of the date set forth above.

Seller: BROWN BEAR II HYDRO, INC.

By: RRR
Name: Daniel R. Revers
Title: President

Buyer: PASCOAG UTILITY DISTRICT

By:______________________________
Name: ____________________________
Title: _____________________________

Agreed to as of the date set forth above.

Seller: BROWN BEAR II HYDRO, INC.

By:______________________________
Name: ____________________________
Title: _____________________________

Buyer: PASCOAG UTILITY DISTRICT

By: Michael R. Kirkwood
Name: Michael R. Kirkwood
Title: General Manager

APPENDIX A

FORM OF LETTER OF CREDIT

[See attached Letter of Credit]

Testimony Exhibit 4-MRK

Power Purchase Agreement:
Canton Mountain Wind, LLC

POWER PURCHASE AGREEMENT

FOR

UNIT CONTINGENT CONTRACT PRODUCTS

BETWEEN

PASCOAG UTILITY DISTRICT

AND

CANTON MOUNTAIN WIND, LLC

TABLE OF CONTENTS

This POWER PURCHASE AGREEMENT FOR UNIT CONTINGENT CONTRACT PRODUCTS ("Agreement") is made and entered into as of September 19, 2016 (the "Effective Date") by and between the Pascoag Utility District its principal place of business at 253 Pascoag Main Street. P.O. Box 107, Pascoag, Rhode Island, 02859 hereinafter referred to as "Buyer", and Canton Mountain Wind, LLC, a Massachusetts limited liability company having its principal place of business at 549 South Street, Building 19, Quincy, Massachusetts 02169, hereinafter referred to as "Seller" (Buyer and Seller are referred to herein individually as a "Party" and collectively the "Parties").

WHEREAS, Seller plans to permit, construct, install, own, operate and maintain the Unit (as defined below) and wishes to sell to Buyer a certain percent of the output of the Unit and all Contract Products (as defined below) related to such percentage of the output; and

WHEREAS, Buyer serves load and wishes to purchase a certain percent of the output of the Unit and all Contract Products related to such percentage of the output,

Now, therefore, in accordance with the foregoing and in consideration of the mutual promises and agreements set forth herein, Buyer agrees to purchase from Seller, and Seller agrees to provide to Buyer, Contract Products in accordance with the following provisions.

ARTICLE 1.
DEFINITIONS

Any term that is capitalized herein but not defined below shall be defined in accordance with the definitions contained in the ISO-New England, Inc. Transmission, Markets and Services Tariff as it may hereafter be amended from time to time, or a successor set of market rules taking effect within the term of this Agreement ("ISO-NE Rules"). As of the Effective Date, the ISO-NE Rules can be found at http://iso-ne.com/participate/rules-procedures/tariff.

1.01 "Annual Termination Rate" means Contract Product Price I less the Annual Replacement Price for each remaining year, or portion thereof, of the Intended Term should the Buyer be the Defaulting Party. Should the Seller be the Defaulting Party, the Annual Termination Rate means the Annual Replacement Price less Contract Product Price I for each remaining year, or portion thereof, of the Intended Term.

1.02 "Annual Replacement Price" means the weighted average rate in dollars per megawatt hour that represents the price that the Seller would expect to be able to sell its Contract Products in the market or the price at which the Buyer would expect to be able to purchase replacement for the Contract Products in the market, which shall be calculated as set forth in Article 13.2.

1.03 "Applicable Laws" means, with respect to any Party, any constitutional provision, law, statute, rule, regulation, ordinance, treaty, order, decree, judgment, decision, certificate, holding, injunction, registration, license, franchise, permit, authorization, guideline, Governmental Approval, consent or requirement of any Governmental Authority having jurisdiction over such Person or its property, enforceable at law or in equity, including the interpretation and administration thereof by such Governmental Authority.

1.04 "Buyer's Credit Support Amount" has the meaning set forth in Article 19.2.

1.05 "Buyer's Zonal LMP" is, with respect to a Settlement Interval, the Zonal Price for the Load Zone in which the Buyer's load is located, for the Day-Ahead Energy Market or Real-Time Energy Market as applicable, for such Settlement Interval. The Buyer's Zonal LMP is the final, ex-post price as published by ISO-NE.

1.06 "Business Day" shall mean any day except a Saturday, Sunday, a Federal Reserve Bank holiday, a State of Maine holiday or a Commonwealth of Massachusetts holiday. A Business Day shall open at 8:00 a.m. and close at 4:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance, shall be the Party from whom the notice, payment or delivery is being sent.

1.07 "Closing Date" shall have the meaning set forth in Article 19.1.

1.08 "Commercial Operation" shall be achieved when the Unit is in compliance with all requirements of the Interconnecting Utility, the Seller has received notice of final interconnection authorization, and the Seller is able to confirm the date of commencement of commercial operation of the Unit by letter to the Transmission Owner and ISO-NE in conformance with Appendix E of the ISO-NE Large Generator Interconnection Agreement.

1.09 "Commercial Operation Date" means the date upon which Commercial Operation of the Unit is achieved.

1.10 "Commercial Operation Deadline" means December 31, 2017, which date shall be extended on a day-for-day basis, or such longer period as may be appropriate under the circumstances, for any delay in the Commercial Operation of the Unit, but in no event shall such period be extended beyond June 30, 2018.

1.11 "Commercially Reasonable Efforts" shall mean a level of effort which in the exercise of prudent judgment in the light of facts or circumstances known, or which should reasonably be known, at the time a decision is made, can be expected by a reasonable person to accomplish the desired result in a manner consistent with Good Industry Practice and which takes the performing Party's interests into consideration. "Commercially Reasonable Efforts" will not be deemed to require a Party to undertake unreasonable measures or measures that have an adverse economic effect on such Party, including the payment of sums in excess of amounts that would be expended in accordance with Good Industry Practice.

1.12 "Contract Percentage" means the percentage share of the Contract Products to be purchased by Buyer, as set forth in Appendix D. Buyer's Contract Percentage plus

Other Buyers' (as defined herein) percentages of the Contract Product shall equal 100% of the Contract Products attributable to the Unit.

1.13 "Contract Product Price" shall have the meaning set forth in Appendix A.

1.14 "Contract Products" shall mean 100% percent of the products produced by the Unit and any other attribute associated with the output of the Unit, including, but not limited to Energy, capacity, and any other market product now or later produced by, or attributable to the Unit, which shall be Unit Contingent, Renewable Energy Certificates ("RECs") and Environmental Attributes.

1.15 "Contract Product Year" shall mean the 12-month period commencing on the first day of the month following the Commercial Operations Date and ending on the 12-month anniversary of such day and each consecutive 12-month period thereafter.

1.16 "Costs" shall mean, with respect to the Non-Defaulting Party, brokerage fees, commissions and other similar third party transaction costs and expenses, including, but not limited to, attorneys' fees reasonably incurred by such Party in entering into new arrangements which replace the terminated transaction but only as the same relates specifically to this Agreement; and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of the transaction but only as the same relates specifically to this Agreement.

1.17 "Credit Rating" means the rating assigned to a Party by Moody's or S&P for a Party's long term unsecured debt not supported by third party credit enhancement (other than by repayment of its debt) or, if such Party does not issue long term debt, then the rating then assigned to such entity as a long-term issuer rating by Moody's or S&P.

1.18 "Defaulting Party" has the meaning set forth in Article 13.1.

1.19 "Delivery Point" has the meaning set forth in Article 5.

1.20 "Due Date" has the meaning set forth in Article 9.2.

1.21 "Early Termination Date" has the meaning set forth in Article 13.2.

1.22 "Energy" shall mean the amount of electricity generated by the Unit as metered in kilowatt hours (kWh) at the Metering Equipment and delivered to Buyer and the Other Buyers in accordance with this Agreement to the Delivery Point.

1.23 "Effective Date" means the date of execution of this Agreement.

1.24 "Environmental Attributes" means those attributes that are aspects, claims, characteristics or benefits associated with the generation of a quantity of Energy by the Unit, other than the electric energy produced and that are capable of being measured, verified or calculated and are documented or classified in the NEPOOL GIS during the Term of Service. An Environmental Attribute may include, but is not limited to, one or more of the following identified with a particular megawatt hour of generation: the Unit's use of a particular renewable energy source, avoided NOx, SOx, CO_2, greenhouse gas emissions or avoided water use (but not water rights or other rights or credits obtained pursuant to requirements of applicable law in order to site and develop the Unit itself). Environmental Attributes may or may not be included in the definition or valuation of Renewable Energy Certificates by various certification authorities for use in meeting requirements of renewable portfolio standards under their jurisdictions. Environmental Attributes do not include (i) any capacity of the Unit, or (ii) any Tax Benefits.

1.25 "Event of Default" shall have the meaning set forth in Article 13.1.

1.26 "Force Majeure" shall mean any cause beyond the reasonable control of, and not the result of negligence, or the lack of due diligence of, the Party claiming suspension of performance as a result thereof. Neither economic harm to a Party nor the financial condition of a Party shall constitute Force Majeure hereunder. Force Majeure shall include, without limitation, strike, stoppage in labor, riot, fire, flood, ice, invasion, civil war, commotion, insurrection, blockades, embargoes, sabotage, epidemics, explosions, acts of terrorism, military or usurped power, order of any court granted in any bona fide adverse legal proceeding or action (not brought by either Party), order of any civil, military or governmental authority (either de facto or de jure and including, without limitation, orders of governmental and administrative agencies which conflict with the terms of this Agreement), failure of any governmental authority to act, or material delay in any such action, including material delay attributable to the appeal of any governmental action (provided that such action has been timely requested and diligently pursued), and acts of God or public enemies. Seller shall be deemed to have suffered an event of Force Majeure due to the failure of equipment for which it is responsible for operating or maintaining if the equipment has been operated and maintained in accordance with manufacturer's warranties and Good Industry Practice.

1.27 "Forced Outage" means that term as defined in the Scheduling Procedure.

1.28 "Generator Asset" has the meaning set forth in the ISO-NE Rules.

1.29 "Good Industry Practice" shall mean the practices, methods and acts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electric generation industry in the operation and maintenance of generating equipment similar in size and technology to the Unit) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with law, regulation, reliability, safety, environmental protection, economy and expedition.

1.30 "Information" shall mean all records, reports, communications, papers, maps, photographs, financial statements, statistical tabulations, or other documentary materials or data, regardless of physical or electronic form or characteristics, made, received or otherwise possessed by Seller pertaining to the Unit, any portion thereof, the Interconnection, or this Agreement.

1.31 "Intended Term" has the meaning set forth in Article 2.2.

1.32 "Interest Rate" has the meaning set forth in Article 9.2.

1.33 "Interconnecting Utility" shall mean the electric utility to which Energy and other Contract Products are transferred through the Interconnection Facilities.

1.34 "Interconnection Facilities" shall mean generator step-up transformers, primary switchgear, system protection and Metering Equipment owned by Seller or the Interconnecting Utility, and agreements between Seller and the Interconnecting Utility, that effect the physical transfer of Energy and other Contract Products from the Unit to the Interconnecting Utility for delivery to the Delivery Point.

1.35 "Intermittent Power Resource" shall have the meaning given in the ISO-NE Rules.

1.36 "Investment Grade Credit Rating" shall mean a Credit Rating of at least BBB- from S&P and/or a Credit Rating of at least Baa3 from Moody's.

1.37 "ISO-NE" means ISO-New England.

1.38 "Liabilities" means any and all liabilities, losses, fines, obligations, penalties, costs or other expenses of any kind or nature, including reasonable attorneys', experts' and accountants' fees, court costs and other costs of any proceeding, incurred by a Person, whether arising from claims, demands, causes of action, litigation, lawsuits, proceedings, investigations, judgments, settlements or from any similar type of occurrence whether actual, threatened or filed and regardless of whether groundless, false or fraudulent.

1.39 "Lead Market Participant" shall have the meaning set forth in the ISO-NE Rules.

1.40 "Letter of Credit" means one or more irrevocable, transferable standby letters of credit issued by a Qualified Institution, and otherwise being in a form reasonably acceptable to the Party in whose favor the Letter of Credit is issued. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit. A Letter of Credit shall be valued at zero unless it expires more than thirty (30) days after the date of valuation or contains terms allowing for a drawing of the full then-available amount during such thirty (30) day period if not renewed (including automatic renewable mechanisms) or otherwise replaced.

1.41 "Letter of Credit Default" has the meaning set forth in Articles 19.1(b).

1.42 "Maintenance Outage" means that term as defined in the Scheduling Procedure.

1.43 "Massachusetts Hub or Mass Hub" means the reporting location for the forward price of Day Ahead electricity as reported by energy brokerage firms, such as ICAP Energy LLC or Amerex Brokers, LLC, that is based on trades taking place at the location formally referred to by the ISO New England as Location ID 4000:_.H.INTERNAL_HUB.

1.44 "Material Contract" shall, as of the Commercial Operation Date, mean any written contract, agreement, license, sublease, lease, easement, sublease, mortgage, instrument, guarantee, commitment, undertaking or other similar arrangement, whether expressed or implied, which either:

(i) creates a right to lease, use or occupy real estate which is necessary for the operation of the Unit according to Good Industry Practice; or

(ii) provides rights or benefits for the Seller such that the consequences of a default under or termination of such an arrangement would reasonably be expected to have a material adverse effect upon Seller's ability to operate the Unit according to Good Industry Practice.

1.45 "Metering Equipment" shall mean the revenue metering equipment installed at the Unit pursuant to the Unit's Large Generator Interconnection Agreement, owned by the Interconnecting Transmission Owner.

1.46 "Monthly Contract Products Charge" has the meaning set forth in Article 4.2.

1.47 "Moody's" shall mean Moody's Investors Service, Inc.

1.48 "Non-Defaulting Party" has the meaning set forth in Article 13.1.

1.49 "Off-Peak" shall mean weekends, NERC holidays, and hours ending 01:00 through 07:00 and hour ending 24:00 local time on weekdays that are not NERC holidays.

1.50 "On-Peak" shall mean hours ending 08:00 through 23:00 local time on weekdays, excluding NERC holidays.

1.51 "Other Buyers" means the Braintree Electric Light Department, the Concord Municipal Light Plant, the Danvers Electric Division, the Groveland Municipal Light Department, the Hingham Municipal Lighting Plant, the Littleton Electric Light & Water Department, the Merrimac Municipal Light Department, the Middleton Electric Light Department, the New Hampshire Electric Cooperative, the North Attleborough Electric Department, the Norwood Municipal Light Department, the Pascoag Utility District and the Wellesley Municipal Light Plant.

1.52 "Person" means an individual, partnership, corporation, business trust, joint stock company, trust, unincorporated association, joint venture, governmental entity, limited liability company, or any other entity of whatever nature.

1.53 "Planned Outage" means that term as defined in the Scheduling Procedure.

1.54 "Planned Maintenance" means maintenance of the Unit that is planned in advance and is scheduled in accordance with ISO-NE Operating Procedures as a Planned Outage or a Maintenance Outage.

1.55 "Qualified Capacity" shall mean the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

1.56 "Qualified Institution" shall mean a U.S. commercial bank or a U.S. branch of a foreign bank (which is not an affiliate of either Party) with such bank having a credit rating of at least A- from Standard & Poor's Rating Group ("S&P") and A3 from Moody's Investor Service ("Moody's"), having $10,000,000,000 in assets.

1.57 "Received" has the meaning set forth in Article 9.2.

1.58 "Renewable Energy Certificates" means the certificates, which relate to each megawatt hour ("MWh") of generation from the Unit that are produced, documented or classified in the NEPOOL GIS according to their ability to meet renewable portfolio standards requirements in any New England State or under any applicable federal program.

1.59 "Replacement Capacity Price" means the weighted average rate in dollars per megawatt hour that represents the price that the Seller would expect to be able to sell its Capacity in the market or the price at which the Buyer would expect to be able to purchase replacement Capacity in the market, which shall be calculated as set forth in Article 13.2.

1.60 "Replacement Energy Price" means the weighted average rate in dollars per megawatt hour that represents the price that the Seller would expect to be able to sell its energy in the market or the price at which the Buyer would expect to be able to purchase replacement energy in the market, which shall be calculated as set forth in Article 13.2.

1.61 "Replacement REC Price" means the rate in dollars per megawatt hour that represents the price that the Seller would expect to be able to sell its RECs in the market or the price at which the Buyer would expect to be able to purchase replacement RECs in the market, which shall be calculated as set forth in Article 13.2.

1.62 "S&P" shall mean Standard and Poor's Rating Group.

1.63 "Scheduling Procedure" means ISO-NE Operating Procedure No. 5 - Generator and Dispatchable Asset Related Demand Maintenance and Outage Scheduling Effective Date: January 11, 2016. Revision No. 16, as in effect on the date of this Agreement and as may be amended from time to time.

1.64 "Seller's Credit Support Amount" has the meaning set forth in Article 19.1. "Settlement Interval" shall be the shortest duration period for which ISO-NE calculates LMPs used directly in its Energy Market settlement process for the Unit, as set forth in Section III.3.2.1 of the ISO-NE Rules. As of the Effective Date, the Settlement Interval in the Energy Market is one hour, but may be changed from time to time by ISO-NE.

1.65 "Tax Benefits" means any tax benefits associated with ownership or operation of the Unit including without limitation production tax credits, investment tax credits, depreciation or any similar benefit, and any grant in lieu of any of the foregoing.

1.66 "Term of Agreement" has the meaning set forth in Article 2.3.

1.67 "Term of Service" has the meaning set forth in Article 2.2.

1.68 "Termination Amount" shall have the meaning set forth in Article 13.2.

1.69 "Termination Payment" shall have the meaning set forth in Article 13.2.

1.70 "Transferred Generator Asset" has the meaning set forth in Article 4.1.

1.71 "Unit" means the Seller's wind-powered electric generating facility consisting of at least six, but no more than eight, wind turbines, each having a nameplate rating of 2.85 megawatts ("MW"), to be constructed by Seller in the Town of Canton, Maine. The nameplate rating of each turbine may be upgraded by Seller, in its sole discretion, to 3.2 MW at any time.

1.72 "Unit Contingent" means that Seller's obligation to deliver Contract Products to Buyer is expressly subject to, and contingent on, the availability of one or more wind turbines at the Unit which availability is subject to Seller's obligations described in Sections 3.2 and 3.4 below.

1.73 "Unit Nodal LMP" is, with respect to a Settlement Interval, the specific Locational Marginal Price calculated by ISO-NE for the Delivery Point for the Day-Ahead Energy Market or the Real-Time Energy Market, as applicable, for such Settlement Interval. The Unit Nodal LMP is the final ex-post price at the Delivery Point, as published by ISO-NE.

1.74 "Unplanned Maintenance" means all maintenance on the Unit during a Forced Outage.

ARTICLE 2.
TERM OF SERVICE

2.1. Commercial Operation. Seller shall achieve Commercial Operation on or before the Commercial Operation Deadline. Seller shall provide notice of Commercial Operation to Buyer within three (3) Business Days of achievement thereof. If Seller fails to achieve Commercial Operation by the Commercial Operation Deadline (as may be extended in accordance with the terms of the definition thereof), then Buyer shall have the right to terminate this Agreement without any liability whatsoever on the part of either Party, and if so terminated this Agreement shall then become null and void and of no effect whatsoever. Buyer shall notify Seller of its exercise of the foregoing right in writing within fifteen (15) calendar days after the Commercial Operation Deadline. If Seller achieves Commercial Operation and notifies Buyer thereof before Buyer notifies Seller of the termination of this Agreement, then Buyer shall have no right to terminate this Agreement pursuant to this Section.

2.2. Term of Service. Subject to Article 2.1 above, Seller shall commence selling the Contract Products, and Buyer shall commence purchasing its Contract Percentage of the Contract Products on the latter of the Initial Synchronization Date or the date upon which the Contract Percentage of the Generator Asset has been transferred to Buyer pursuant to Article 4.1, and Seller shall continue selling the Contract Products, and Buyer shall continue purchasing its Contract Percentage of the Contract Products, from each wind turbine at the Unit, as provided herein, through the earlier of (i) Hour Ending 2400 on the day twenty (20) years following the first day of the month following the Commercial Operation Date ("Intended Term"), or (ii) such earlier date of termination in accordance with the provisions of this Agreement (collectively the "Term of Service").

2.3. Termination. The applicable provisions of this Agreement shall commence on the Effective Date and shall continue in effect after termination or expiration hereof to the extent necessary to provide for accountings, final billing, billing adjustments, resolution of any billing dispute, resolution of any court or administrative proceeding and payments ("Term of Agreement"). Notwithstanding anything in the Agreement to the contrary, expiration or termination of the Agreement for any reason shall not relieve either Party of any right or obligation accrued or accruing hereunder prior to such expiration or termination, and no expiration or termination of this Agreement shall affect or excuse the performance of either Party under any provision of this Agreement that by its terms survives any expiration or termination.

ARTICLE 3.
TRANSACTION TYPE AND SELLER OBLIGATIONS

3.1. Transaction Type. This Agreement is for the purchase and sale of the Contract Products produced by the Unit or attributable to the Unit in the Contract Percentage set forth in Appendix D. The Unit will consist of a minimum of six but no more than eight wind turbines. Seller will notify Buyer on or before October 15, 2017, how many and the size(s) of the wind turbines will be included in the Unit.

3.2. Maximize Contract Products. The Parties understand and agree that Seller shall use Commercially Reasonable Efforts consistent with Good Industry Practice to maximize the availability and, subject to Seller's right to determine the Unit's energy market offer price, operation of the Unit in order to maximize the amount of Contract Products that Buyer will receive hereunder. The Parties understand and agree that this is a Unit Contingent Agreement. Notwithstanding the foregoing and subject to the terms and conditions of Section 4.2 hereunder, Seller shall have the sole discretion to determine the price at which the Unit's energy will be offered into the energy market within the bounds described in this Section 3.2, recognizing that such offer price may impact the amount of Contract Products produced and sold to Buyer. Seller shall not cause the Unit's energy to be offered at a price below zero dollars per megawatt hour in the Day Ahead Energy Market, or at a price below the negative of the Contract Product Price in the Real Time Energy Market unless the Parties and the Other Buyers agree, in writing, to an alternate offer price. The Contract Product Price used as the basis for the Real Time Energy Market offer price in this Section 3.2 shall be the Contract Product Price in effect as of 9:00 am local time on the Business Day prior to the Operating Day at issue.

As and when required by the ISO-NE market rules, and as may be directed unanimously in writing by Buyer and the Other Buyers, Seller shall offer the Unit's energy into the Day Ahead Energy Market in a quantity unanimously directed by Buyer and the Other Buyers. All Day Ahead Energy Market offers shall be in accordance with ISO-NE Day Ahead Energy Market offer requirements then in effect.

3.3. Construction. Seller shall be solely responsible for all costs of furnishing all design, materials, supplies, tools, equipment, labor and other services and obtaining all permits, licenses and other approvals required by Applicable Laws necessary for the installation and operation of the Unit.

3.4. Maintenance Obligation. Seller, at its sole cost and expense, shall use Commercially Reasonable Efforts to provide operation, repair, monitoring and maintenance services to the Unit in accordance with the schedule below as well as in accordance with equipment manufacturer requirements, Applicable Laws and Good Industry Practice:

a. At all times perform basic monitoring of the Unit to verify Unit is fully functional and recording all meter data.

b. At all times maintain equipment warranty records

c. At all times, respond to all alarms, alerts and service requests pertaining to the Unit within two Business Days of such alarm, alert and/or service request.

3.5. Planned Maintenance. Seller shall schedule and perform all Planned Maintenance in accordance with the Scheduling Procedure. Prior to performing or causing the performance of any Planned Maintenance, Seller shall notify Buyer upon the earlier of: (a) notification to ISO-NE and (ii) May 1st of each year of Planned Maintenance Seller intends to schedule for the First Future Year, and upon notification to, or from, ISO-NE of any additions or changes to the Planned Maintenance Schedule. All Planned Maintenance will be done in accordance with ISO-NE procedures for Intermittent Power Resources.

3.6. Forced Outage. Seller shall use Commercially Reasonable Efforts consistent with Good Industry Practice to fully resolve any Unplanned Maintenance as quickly as possible. Seller shall notify Buyer of any Unplanned Maintenance activities as soon as reasonably possible after Seller learns of the need for such activities, but in no event later than twenty-four hours after learning of such need. Seller shall comply with the Scheduling Procedure regarding Forced Outages when performing Maintenance.

3.7. Regulatory Status. Seller shall obtain and maintain such authorizations, certificates and approvals as may be required from the Federal Energy Regulatory Commission ("FERC") as may be required for Seller to make wholesale electricity sales to Buyer at the rates and on the terms set forth under this Agreement, which Seller acknowledges is a market based rate.

3.8. Obligation to Provide Information. Seller shall provide to Buyer copies of all Information within a reasonable period of time, but in no event later than fifteen (15) days, of making or receiving Information pertaining to: (i) communications between the Seller and ISO-NE and/or the Interconnecting Utility pertaining to the Unit, any portion thereof, the Interconnection, or this Agreement; and, (ii) maintenance and/or repair pertaining to the Unit or any portion thereof or the Interconnection.

If Buyer is required to provide any Information to ISO-NE as a result of the transfer of the Generator Asset ownership to Buyer, then upon written request by Buyer, Seller shall provide such Information to Buyer within fifteen (15) days of such request unless a shorter time is needed to meet an ISO-NE deadline, in which case, Seller shall provide such information to Buyer two calendar days (one of which must be a Business Day) before said ISO-NE deadline. If Seller does not possess or have reasonable access to such information and/or documentation then Seller shall so notify Buyer as soon as reasonably practicable, but in no event later than fifteen (15) days after such request is made.

3.9. Capacity Qualification. At its sole expense, beginning with the eleventh Forward Capacity Auction ("FCA") which shall be held to establish Forward Capacity Market prices for the June 2020 through May 2021 period, the Seller shall use its Commercially Reasonable Efforts to qualify the Unit for the Forward Capacity Market as a New Generating Capacity Resource that is an Intermittent Power Resource. Seller shall use its Commercially Reasonable Efforts to maintain qualification as a New Generating Capacity Resource or an Existing Generating Capacity Resource throughout the Term of Service. If a capacity self-supply option becomes available to Buyer under ISO-NE Rules and Buyer elects, in its sole discretion, to designate its Contract Products percentage of the Installed Capacity as self-supply for the Buyer's benefit then Seller shall use Commercially Reasonable Efforts to comply with Buyer's election or any other Buyer elections pertaining to participation in the Forward Capacity Market. Seller's failure to succeed in its Commercially Reasonable Efforts pursuant to this provision shall not be considered an Event of Default hereunder or result, except as expressly provided in Section 4.4 hereof, in any reduction in payments otherwise due and owing to Seller hereunder.

3.10. Adjustment for FCM Settlement. The Parties agree to work cooperatively to take all reasonable actions and to file all documents reasonably required by ISO-NE, from time to time during the term of this Agreement, so that ISO-NE pays to or charges the Buyer directly, as applicable, with respect to any and all FCM settlements, including any FCM performance incentive payments, pertaining to the Unit. However, in the event that Seller and not Buyer receives payments from ISO-NE for Forward Capacity, the Monthly Contract Products Charge shall be reduced by an amount equal to percentage of Contract Products purchased by Buyer, as set forth in the definition of Contract Products, multiplied by any such payments received by Seller. In the event that Seller and not Buyer incurs charges from ISO-NE for Forward Capacity, Seller is hereby authorized to provide ISO-NE with standing instructions to pay all such charges through the use of cash investments posted with ISO-NE (further described in Section 4.7 hereof). Seller shall invoice Buyer for such charges pursuant to Article 9 and Buyer shall pay such invoice pursuant to Article 9. Any such invoiced amounts shall be used by Seller to replenish the cash investments posted with ISO-NE.

3.11. NERC Compliance. The Parties understand and agree that the Seller, and not the Buyer, shall be responsible for compliance with the North American Electric Reliability Corporation (NERC) Compliance Monitoring and Enforcement Program as such compliance relates to the Seller's obligations under this Agreement and/or ownership and/or operation of the Unit.

3.12. Lead Market Participant. The Parties understand and agree that the Seller, and not the Buyer, shall be responsible for all Lead Market Participant obligations and responsibilities.

ARTICLE 4. PURCHASE AND SALE OF CONTRACT PRODUCTS

4.1. Sale of Contract Products. Seller shall transfer or otherwise cause a transfer to Buyer of a portion of the Generator Asset representing the Unit in an amount equal to Buyer's Contract Percentage on or prior to the Initial Synchronization Date using the ISO-NE's Asset Registration Process ("Transferred Generator Asset"). Buyer will accept such Transferred Generator Asset including all associated rights and obligations related to ISO-NE market settlements. Any such transfer of the Transferred Generator Asset to Buyer shall be solely for purposes of ISO-NE's settlement procedures, and shall not in any way affect the Seller's exclusive legal ownership of the Unit for all other purposes or affect any security interest granted therein (and all rights related thereto) by Seller to its financing parties (or any representative thereof) from time to time. At the end of the Term of Service, Buyer covenants to transfer and return the Transferred Generator Asset to the Seller and shall execute and deliver all documentation reasonably requested by Seller or its financing parties to effectuate such transfer.

4.2. Price of Contract Products. Buyer will pay Seller each month an amount equal to the number of megawatt-hours of Energy received by Buyer in its ISO-NE settlement account multiplied by the Contract Product Price ("Monthly Contract Products Charge"); however, this amount may be reduced as provided in this Section 4.2. For any Settlement Interval in which a) the Unit's energy market settlement reflects a net sale in the Real Time Energy Market, (*i.e.*, the Real-Time Generation Obligation Deviation is positive), b) the Real Time Unit Nodal LMP is less than zero dollars per megawatt-hour and c) the Real Time Unit Nodal LMP is less than the Real Time Buyer's Zonal LMP, the Monthly Contract Products Charge otherwise payable hereunder with respect to such Settlement Interval shall then be reduced by an amount equal to the product of a) the number of megawatt-hours received by Buyer in its ISO-NE settlement account as a Real-Time Generation Obligation Deviation during such Settlement Interval and b) the lesser of x) the absolute value of the Real Time generation offer price and y) the difference resulting from the subtraction of the Unit Nodal LMP from the lesser of i) the Buyer's Zonal LMP or ii) zero. The Parties agree that the examples set forth in Appendix E accurately demonstrate the application of the foregoing price reduction mechanism.

4.3. Capacity Supply Obligation. Seller shall use Commercially Reasonable Efforts to obtain a Capacity Supply Obligation by submitting offers at a price of $0.00 in reconfiguration auctions beginning with the first reconfiguration auction for which it is qualified for a Capacity Commitment Period following the Commercial Operation Date until such time as the Unit is assigned an initial Capacity Supply Obligation from an FCA or is issued different direction that is unanimous among Buyer and all Other Buyers. Supply offers in such reconfiguration auctions shall be in an amount (in MWs) equal to the maximum supply offer designated by the ISO-NE for the applicable reconfiguration auction. Seller's failure to succeed in its Commercially Reasonable Efforts pursuant to this provision shall not be considered an Event of Default hereunder or result in any reduction in payments otherwise due and owing to Seller hereunder.

4.4. Adjustment for Failure to Qualify Capacity. Beginning with the eleventh FCA which shall be held to establish Forward Capacity Market ("FCM") prices for the June 2020 through May 2021 period and subject to Article 4.5, in the event that Seller fails to qualify the Unit for the FCM in accordance with Article 3.9 of this Agreement, then until such time as the Unit becomes qualified for the FCM the Monthly Contract Products Charge will, subject to the proviso below, be reduced by an amount equal to the product of (a) twenty-five percent (25%) of the nameplate rating of the Unit, in MW and (b) the Capacity Clearing Price from the Forward Capacity Auction in effect for the month for the capacity zone in which the Unit is located, provided, however, any such reduction shall not exceed Buyer's Contract Percentage of $200,000 during any Contract Products Year (which amount shall be pro-rated for any time period less than one year), provided, further, the amount, if any, that Seller shall be required to pay to Buyer during any Contract Products Year pursuant to this Section 4.4 shall be further reduced (but not below zero) by an amount equal to Buyer's Contract Percentage of all FCM performance incentive payments which are paid by ISO-NE to the Seller, Buyer and/or the Other Buyers in respect of the Unit for such Contract Products Year.

4.5. Buyer's Right to Determine FCM Participation. Notwithstanding any provision in this Agreement to the contrary, Buyer shall have the right to direct Seller, from time to time, (a) to submit a full or partial delist bid, as applicable, in any FCA for which Seller does not already have a Capacity Supply Obligation, (b) to submit a demand bid in any reconfiguration auction in order to shed all or part of a Capacity Supply Obligation, (c) to challenge an existing Qualified Capacity value, (d) to take action in response to an ISO-NE determination of a significant decrease in capacity, (e) or take any other measure as is allowed by the ISO-NE Rules to adjust the Capacity Supply Obligations of the Unit; provided, however, that Buyer shall only have this right if (i) Buyer and all Other Buyers that are then permitted to give Seller directions under comparable provisions of their respective power purchase agreements unanimously agree and unanimously direct Seller in writing to undertake the action specified in such writing and (ii) Buyer is then in compliance with its obligations under Sections 4.6 and 4.7 hereof. During such periods that Seller has been directed by Buyer to take action under this Section 4.5 that alter Seller's obligations under Sections 3.9, 4.3 and 4.4, Seller's obligations under Sections 3.9, 4.3 and 4.4 shall be suspended.

4.6. Capacity Supply Obligation Payments and Penalties. Buyer is entitled to a percentage of all payments related to the Unit's Capacity Supply Obligations in an amount equal to the Buyer's Contract Percentage of all such payments. Buyer assumes responsibility for financial penalties related to the Unit's Capacity Supply Obligations in an amount equal to the Buyer's Contract Percentage of all such penalties, and Buyer agrees to indemnify Seller for such amount, provided that Seller has not breached its obligations under Section 3.2 and/or Section 3.4. In the event that Buyer owes any amount to Seller under this Section 4.6 or under Section 4.7

below, Seller shall be permitted to off-set such amount owed by Buyer to Seller against amounts owed by Seller to Buyer under the first sentence of this Section 4.6.

4.7. Buyer's Cash Collateral Requirement. Buyer assumes financial responsibility for (a) Buyer's Contract Percentage of all Financial Assurance Obligations arising pursuant to ISO-NE Rules related to the Unit's Capacity Supply Obligations with the exception of the Non-Commercial Capacity Financial Assurance Amount and (b) Buyer's Contract Percentage of all incremental amounts which may become payable to ISO-NE related to the Unit's Capacity Supply Obligations. To the extent that Seller and not Buyer is listed as the Resource Lead Market Participant (*i.e.*, the party responsible to ISO-NE for the facility's capacity), Buyer agrees to pay to Seller, or cause to be paid by its agent, cash collateral equal to Buyer's Contract Percentage of Seller's total financial obligations as security in respect of the foregoing financial obligations. The amount of such cash collateral owed by Buyer shall be determined on an annual basis in the reasonable discretion of Seller ("Buyer's Cash Collateral Requirement") by calculating the maximum Financial Assurance Obligation the Unit could reasonably be expected to incur in any given month for the upcoming Capacity Commitment Period and multiplying such amount by Buyer's Contract Percentage. No later than thirty (30) calendar days prior to the final Annual Reconfiguration Auction for each annual Capacity Commitment Period following the Effective Date, Seller shall determine the amount of Buyer's Cash Collateral Requirement to be established under this Agreement with respect to such Capacity Commitment Period. An amount equal to the Buyer's Cash Collateral Requirement for such Capacity Commitment Period, less the amount on deposit with Seller from the then-current Capacity Commitment Period from Buyer, shall be paid by Buyer or by Buyer's agent to Seller, at least 5 Business Days prior to the Annual Reconfiguration Auction. To the extent this amount is negative, Seller shall return this amount to Buyer within 5 Business Days of the start of the Capacity Commitment Period. To the extent that Buyer instructs Seller to take (or not take) actions pursuant to Section 4.5 that would result in an additional Financial Assurance Obligation, Buyer shall pay, or cause to be paid this additional amount prior to Seller being required to take (or not take) such action. Buyer and Seller agree that (a) all cash constituting the Buyer's Cash Collateral Requirement paid by Buyer hereunder shall be deposited (the "Deposit") into an account established by Seller, with BlackRock Institutional Management Corporation or any successor institution acting in such capacity under the ISO-NE Rules ("BlackRock") which account shall be used to meet the Financial Assurance Obligations relating solely to the Unit and shall be the subject of both a Security Agreement between Seller and the ISO-NE and a Control Agreement among the Seller, the ISO-NE, and BlackRock (the "Control Agreement"), (b) the Deposit will be invested in the investment option selected by Seller (pursuant to Buyer's or Buyer's agent's instructions), unless Buyer has not selected such an investment option in which case the Deposit shall be invested in the "Default Investment" option identified from time to time by the ISO-NE and approved by the New England Power Pool ("NEPOOL") Budget and Finance Subcommittee, pursuant to the ISO New England Financial Assurance Policy for Market Participants (the "Financial Assurance Policy"), (c) all income generated by the Deposit will be added to the amount of the Deposit and will be reinvested in the applicable investment described above, (d) all losses to the Deposit as a result of it being so invested or any liquidation of such Deposit in connection with a draw on the Deposit will be deducted from such deposit, (e) Seller shall issue a "Standing Instruction Form Letter" to ISO-NE authorizing the application of such cash investments to all invoices due in respect of the Unit's Capacity Supply Obligations, (f) the Deposit is intended to constitute Financial Assurance under the ISO-NE Tariff and (g) Seller shall be authorized to apply all or any portion of the Deposit in satisfaction of Buyer's obligations under Section 4.6 and/or 4.7 hereunder. Seller shall provide a monthly statement with respect to the Deposit, which shall describe all credits and debits thereto during such period.

ARTICLE 5.
DELIVERY POINT

The Delivery Point for the Contract Products consisting of Energy and capacity will be the Unit's Node as determined by ISO-NE, which shall be a PTF point. Seller shall be responsible for all losses up to the Delivery Point.

ARTICLE 6.
TRANSMISSION

Seller shall be responsible for all transmission arrangements and all costs associated therewith, necessary to deliver and transmit the Energy sold hereunder up to the Delivery Point. Buyer shall be responsible for all transmission arrangements, and all costs associated therewith, necessary to receive and transmit the Energy purchased hereunder from the Delivery Point to the consumption point meters registering Buyer's load including, without limitation, all costs for any Regional Network Service ("RNS") and Local Network Service ("LNS") associated with the Buyer's load.

ARTICLE 7.
METERING

Seller shall cause the electricity provided by Seller from the Unit to be metered at the Delivery Point. Seller shall cause the Metering Equipment to be calibrated and maintained in accordance with its Large Generator Interconnection Agreement. If at any time Metering Equipment associated with the Unit is found to be inaccurate or defective by those standards, Seller shall cause it to be made accurate by adjustment, repair, or replacement. The meter readings for the period of inaccuracy shall be adjusted in accordance with the terms of the Large Generator Interconnection Agreement. Following Seller receipt of notice from Interconnecting Transmission Owner, Seller shall provide Buyer with notice of the time when any inspection or test of the Metering Equipment shall take place, and the Buyer may have representatives present at the test or inspection.

ARTICLE 8.
RENEWABLE ENERGY CERTIFICATES

8.1. <u>Seller's Registration Obligations</u>. The Seller shall register the Unit, as necessary, and to the extent the Unit qualifies, so that the Unit is compliant with reporting requirements related to Renewable Energy Certificates, Environmental Attributes, certification in the New England States, including but not limited to the Commonwealth of Massachusetts, or under any applicable federal program and under the Green-E certification program. Such registration shall include, but not be limited to, registering the Unit so that it is compliant with NEPOOL GIS reporting requirements relative to renewable portfolio standards. The Seller shall be obligated to maintain such registrations throughout the Term of Service. The Seller shall be responsible for all initial and ongoing costs to establish and maintain such registrations pertaining to the New England States, any applicable federal program and the Green-E certification program including, but not limited to, consultant, legal or other fees or expenses incurred, but shall not be obligated to incur any cost to modify the Unit so that it complies with the requirements of such programs to the extent that such requirements change from those in existence as of the date of this Agreement. Buyer shall assist, cooperate and consult with Seller to the extent reasonably requested by Seller in all such processes at Buyer's sole expense.

8.2. Seller's Obligations with respect to Green-E Certification. Notwithstanding anything to the contrary in this Article 8, Seller's obligations hereunder with respect to registration or qualification of the Unit under the Green-E certification program shall consist solely of providing information required for such registration or qualification and shall in no event impose any certification fee obligations or any further obligations or conditions on Seller in addition to those imposed under applicable state and federal programs.

8.3. Delivery of RECs. Seller shall deliver RECs associated with the Buyer's Contract Percentage of Energy delivered to the Delivery Point to Buyer by depositing such RECs into Buyer's NEPOOL GIS Account (or such other NEPOOL GIS account(s) designated by Buyer to Seller in writing) no later than five (5) Business Days following the opening of the Trading Period (as that term is defined in the NEPOOL GIS Operating Rules), which, as of the Effective Date, is quarterly on the 15th day of the calendar quarter that is the second calendar quarter following the calendar quarter in which the Energy associated with a REC was generated (*i.e.,* RECs associated with Energy generated in January, February and March of a year may be traded beginning on July 15 of that same year). At the time of each REC delivery under this Section 8.3, Seller shall (a) convey title to RECs associated with Buyer's Contract Percentage of Energy generated by the Unit and required to be delivered to Buyer hereunder for each Creation Date to Buyer free and clear of any liens, taxes, claims, security interests or other encumbrances or title defects therein or thereto, (b) have the sole and exclusive legal right to sell such RECs to Buyer, (c) have sold and transferred such RECs hereunder once and only once exclusively to Buyer, and (d) have made no representation, in writing or otherwise, that any third party has received or obtained any right to such RECs that are inconsistent with the rights being acquired by Buyer hereunder. Seller shall provide such documentation to Buyer as Buyer may reasonably request to qualify the RECs under any applicable renewable energy portfolio standard.

8.4. Failure to Deposit RECs. To the extent that the acts or omissions of Seller or its agent, as applicable, cause failure to deposit Renewable Energy Certificates (or Environmental Attributes, as applicable) in Buyer's NEPOOL GIS Account (or such other NEPOOL GIS account(s) designated by Buyer to Seller in writing) in an amount equal to Buyer's Contract Percentage of the Energy delivered to the Delivery Point during the applicable deposit period specified in Section 8.3 ("Deficient REC Amount"), then Seller shall, within thirty (30) days after written notification from Buyer deposit in Buyer's NEPOOL GIS Account substitute Renewable Energy Credits (or Environmental Attributes, as applicable) equal in quality (*e.g.*, Class and vintage) and amount to the Deficient REC Amount. Should such 30th day not fall within a GIS Trading Period, Seller shall make the required deposit within the first seven days of the next available GIS Trading Period. Buyer shall specify to Seller the REC Type that shall be deposited into Buyer's NEPOOL GIS Account and Seller shall deposit such RECs (and/or Environmental Attributes, as applicable) in the Deficient REC Amount.

8.5. Title and Risk of Loss. Title to and risk of loss associated with the RECs shall transfer from Seller to Buyer when such RECs are successfully credited to Buyer's NEPOOL GIS account(s) or the GIS account(s) designated by Buyer to Seller in writing.

ARTICLE 9.
BILLING AND PAYMENT

9.1. Calculation of Monthly Invoice. For each month or portion thereof during the Term of Service, and, except as otherwise expressly provided herein, Buyer shall pay to Seller an amount equal to the Monthly Contract Products Charge. Pending the availability of actual data, computations by Seller of charges for the purposes of billings hereunder may be based upon estimates made by Seller. Any charges that are based upon estimates shall be trued-up as soon as practicable once actual data becomes available. Errors in arithmetic, computation, meter readings, estimating, or otherwise that affect the accuracy of a bill shall be promptly corrected in a subsequent corrected bill so long as such correction is made during the period of up to twenty-four (24) months from the date of rendering of the original billing.

9.2. Presentation and Payment. Unless otherwise agreed to in writing by the Parties: (i) Seller shall submit an invoice to Buyer for the Monthly Contract Product Charge and the respective amounts due under the terms of this Agreement as soon as practicable after the end of each calendar month during the Term of Service; (ii) the invoice shall identify each input on the bill which is based upon an estimate, in whole or in part; (iii) invoices shall be delivered to Buyer by facsimile or by mutually agreed upon electronic means, followed up by an original invoice delivered by regular mail; (iv) all such invoices shall be due and payable in immediately available funds via wire transfer no later than the Due Date, defined as twenty (20) Business Days after the date on which such invoice is Received; and (v) any amounts not paid by the Due Date shall be deemed delinquent and shall accrue interest from the Due Date to the date of payment at a per annum rate of interest equal to the prime lending rate as may from time to time be published in The Wall Street Journal under "Money Rates" as the same may change from to time (or if not published on such day on the most recent preceding day on which published), or any other periodical that may be agreed upon in writing from time to time, plus two percent (2%) ("Interest Rate"). For purposes of this Article 9.2, "Received" shall mean the date that the invoice is confirmed successfully delivered by telecopy, express mail or electronic communication.

9.3. Challenge of Invoices. Unless otherwise agreed, in the event of a good faith dispute relating to the amounts set forth on any invoice, and provided that the undisputed portion of the invoice at issue is paid, then: (i) either Party may challenge, in writing, the accuracy of any original or adjusted invoice, provided that no adjustment for any invoice or payment will be made unless the challenge to the accuracy thereof was made prior to the lapse of twenty four (24) months from the receipt thereof; (ii) if a Party does not challenge the accuracy of an original or adjusted invoice within such twenty four (24) month period, such invoice shall be binding upon that Party and shall not be subject to challenge.

9.4. Disputed Invoice. Within the limitation of Article 9.3, each invoice shall be subject to adjustment for true-up from estimated costs to actual costs, errors in arithmetic, computation or estimating, or adjustments related to ISO-NE settlement, or as otherwise applicable. Seller may make adjustments to any billing for a period of up to twenty-four (24) months from the date of rendering of such original billing in order to reflect differences in Seller's receipt of more current data. The Parties shall use good faith efforts to resolve any billing and payment disputes promptly. Unless otherwise agreed, in case of a dispute to any portion of any invoice, only the non-disputed amount shall be paid in accordance with Article 9.2. Unless otherwise agreed, upon final determination of the invoice amount, any necessary adjustments in such invoice and the payments thereof shall be made in the invoice submitted in the month following such determination, with interest at the Interest Rate from the original Due Date of the invoice until the date of payment. Buyer's payment of an invoice (whether or not under protest) shall not affect any legal or equitable rights a Party may have to challenge the invoice within the time limitations established in Article 9.3 above.

9.5. Monthly Payment Netting. Except for amounts that one Party may owe to the other under Articles 13 and 19, which amounts shall not be included in any netting calculation, if Seller and Buyer are each required to pay an amount in the same month to the other, such amounts shall be netted, and the Party owing the greater aggregate amount shall pay to the other Party any difference between the amounts owed. Each Party reserves all rights, setoffs, counterclaims and other remedies and defenses (to the extent not expressly herein waived or denied) to which such Party has or may be entitled arising from or out of this Agreement.

ARTICLE 10.
TRANSFER OF TITLE FOR CONTRACT PRODUCTS OTHER THAN RECS

Title to, and risk of loss related to, Buyer's Contract Percentage of the Contract Products (other than RECs) delivered or received hereunder shall transfer from Seller to Buyer at the Delivery Point. Except as provided elsewhere in this Agreement, Seller shall be responsible and liable for any costs or charges imposed with respect to and shall bear the risk of loss and damage associated with the possession, ownership, transmission, transfer and delivery of the Contract Products (other than RECs) up to the Delivery Point and Buyer shall be responsible and liable for Buyer's Contract Percentage of any costs or charges imposed with respect to and shall bear the risk of loss and damage associated with the possession, ownership, transmission, transfer and delivery of the Buyer's Contract Percentage of Contract Products (other than RECs) from and after the Delivery Point. Seller warrants and represents to Buyer that it will deliver the Contract Products (other than RECs) free and clear of all liens, security interests, claims and encumbrances and of all interests of any person arising prior to the Delivery Point.

ARTICLE 11.
TAXES

Seller shall pay or cause to be paid all taxes on or with respect to the sale of the Contract Products prior to the Delivery Point. Buyer shall pay or cause to be paid all taxes on or with respect to the purchase of the Contract Products at and after the Delivery Point. Payment of all other taxes which are enacted or become effective or are assessed with respect to the Contract Products after the Effective Date shall be governed by the terms of this Article 11. Nothing contained herein shall obligate or cause a Party to pay or be liable to pay any tax for which it is exempt under Applicable Laws.

Each Party shall use reasonable efforts to administer this Agreement and implement its provisions in accordance with Applicable Laws and it is the intent of the Parties to minimize the imposition of taxes. Buyer agrees to furnish Seller with all applicable tax exemption certificates and documentation where exemption from applicable taxes is claimed.

ARTICLE 12.
FORCE MAJEURE

If Force Majeure prevents a Party from fulfilling any obligations under this Agreement, the Party affected by Force Majeure ("Affected Party") shall promptly notify the other Party, either in writing or via the telephone, followed as soon as practicable by written notice, of the existence of such Force Majeure. The notification must specify in reasonable detail, to the extent then known, the circumstances of the Force Majeure, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure until such Force Majeure ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure cannot be mitigated by the use of Commercially Reasonable Efforts. The Affected Party will use Commercially Reasonable Efforts to resume its performance as soon as possible. If a Party claims a Force Majeure for a consecutive period of twelve (12) calendar months or longer and such Force Majeure excuses performance under a material provision of this Agreement, then, for so long as such Force Majeure is continuing, the Party not claiming a Force Majeure may terminate this Agreement and neither Party shall have any liability to the other as a result of such termination; provided, however, that if: (i) four (4) or more wind turbines continue to be available for energy generation and (ii) the Force Majeure affects some, but not all, of the wind turbines at the Unit, such termination shall only apply to the affected wind turbines, and this Agreement shall remain in effect with respect to the available four (4) or more wind turbines.

ARTICLE 13.
EVENTS OF DEFAULT

13.1. Events of Default. For purposes of this Agreement, each of the following shall constitute an event of default ("Event of Default") with respect to a Party (the "Defaulting Party").

(a) Failure by the Defaulting Party to make, when due, any payment required under this Agreement if such failure is not remedied within ten (10) Business Days after written notice of such failure is given by the other Party ("Non-Defaulting Party") and provided the payment is not the subject of a good faith dispute as described in Article 9.4.

(b) The Defaulting Party:

(i) makes a general assignment for the benefit of creditors;

(ii) files a petition or otherwise commences, authorizes or consents to the commencement of a proceeding, or cause of action, under any bankruptcy or similar law for the protection of creditors, or has any such petition filed or commenced against it that is not discharged within forty five (45) days or otherwise becomes bankrupt or insolvent (however evidenced);

(iii) is found by a court of competent jurisdiction to not be generally paying its debts as such debts become due; or

(iv) admits in writing its inability to pay its debts generally as they become due.

(c) Failure by the Defaulting Party to perform any material covenant set forth in this Agreement (other than the events that are otherwise specifically covered in this Article 13.1 as a separate Event of Default), including compliance with Article 8, and such failure is not excused by Force Majeure or such failure continues uncured for more than thirty (30) calendar days after written notice to such Party specifying the nature of such failure; provided, however, that in the event of an Event of Default that is not reasonably capable of cure within thirty (30) days, the Defaulting Party commences to cure such Event of Default within thirty (30) calendar days and uses Commercially Reasonable Efforts to cure such Event of Default; provided, however, that such cure period shall not exceed one hundred eighty (180) days.

(d) Any representation or warranty made by the Defaulting Party in this Agreement is not true and complete in any material respect when made unless (i) the fact, circumstance or condition that is the subject of such representation or warranty is made true within thirty (30) calendar days after written notice to such Party specifying the nature of such misrepresentation, and (ii) such cure removes any adverse effect on the other Party of such fact, circumstance or condition being otherwise than as first represented.

(e) Failure of either Party to provide or maintain credit support provided as required by Article 19.

(f) The Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee's creditworthiness and/or ability to perform is materially inferior to the Party as reasonably determined by the other Party or the resulting, surviving or transferee entity fails to assume all the obligations of such Party under this Agreement to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the Non-Defaulting Party.

(g) The occurrence of an uncured Letter of Credit Default.

13.2. Termination Amount. If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the Non-Defaulting Party shall have the right to: (i) designate a day, no earlier than the day such notice is effective and no later than forty-five 45

Business Days after such notice is effective, as an early termination date ("Early Termination Date") to accelerate all amounts owing from the Defaulting Party to the Non-Defaulting Party, if any, and to liquidate and terminate this Agreement and (ii) withhold any payments due to the Defaulting Party under this Agreement. If the Non-Defaulting Party establishes an Early Termination Date, the Non-Defaulting Party shall calculate a Termination Amount as follows:.

(a) The Termination Amount shall be calculated as the sum of (a) the Non-Defaulting Party's Costs plus (b) the product of (i) the Contract Percentage and (ii) the net present value of the product of (A) the Annual Termination Rate and (B) the P90 annual production threshold set forth in Appendix A for each remaining year, or pro rata portion thereof, of the Intended Term. The discount rate for the present value calculation shall be 3.5%. For the avoidance of doubt, if the above calculation results in a negative number, the Termination Amount shall be set at zero dollars ($0.00).

(b) In calculating the Annual Termination Rate, the Annual Replacement Price for the first twelve (12) months following the Early Termination Date shall be the sum of the Replacement Energy Price, the Replacement Capacity Price, and the Replacement REC Price. Following the first twelve (12) months, the Annual Replacement Price shall be escalated on each anniversary of the Early Termination Date for the remainder of the Intended Term at 2% annually.

(c) The Replacement Energy Price shall be calculated as (I) the sum, for each of the twelve (12) months following the month in which the Termination Amount is calculated, of a) the product of i) the forward On-Peak Massachusetts Hub Energy Price, reduced by 6%, and ii) the corresponding monthly P50 expected On-Peak energy production set forth in Appendix C, and b) the product of i) the forward Off-Peak Massachusetts Hub Energy Price, reduced by 6%, and ii) the corresponding monthly P50 expected Off-Peak energy production set forth in Appendix C, which sum shall be divided by (II) the total P50 expected annual energy production as set forth in Appendix C. The monthly forward energy market prices to be used in calculating the Replacement Energy Price will be obtained from brokers of forward energy trades such as ICAP Energy LLC or Amerex Brokers LLC.

(d) The Replacement Capacity Price shall be calculated as the sum of the product, for each future month in which Forward Capacity Auction results are available at the time the Termination Amount is calculated, of a) the Capacity Clearing Price in dollars per kilowatt-month for the Capacity Zone which includes the Delivery Point and b) the Capacity Supply Obligation held by the Unit in kilowatts, which sum shall be multiplied by 12 months and divided by the product of (a) the number of months included in the calculation and (b) the total expected P90 annual production as set forth in Appendix A.

(e) The Replacement REC Price shall be defined as the highest forward Class I REC price for a State in the New England region as reported by a REC brokerage firm for the calendar year following the year in which the Termination Amount is calculated. The forward REC market prices to be used in calculating the Replacement REC Price will be obtained from brokers of forward REC trades such as ICAP Energy LLC or Evolution Markets.

(f) The Non-Defaulting Party shall determine a single liquidated amount (the "Termination Payment") payable by the Defaulting Party to the Non-Defaulting Party by netting out from the Termination Amount (i) any cash or other form of security then available to the Non-Defaulting Party pursuant to Article 19 and (ii) at the option of the Non-Defaulting Party (a) any amounts due to the Defaulting Party under this Agreement against (b) any amounts due to the Non-Defaulting Party under this Agreement. Notwithstanding the foregoing, all payments due and owing for the Contract Products prior to the Early Termination Date shall be made except to the extent such amounts are setoff as forth in this Article.

(g) As soon as practicable after a liquidation, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment. In no event shall a Termination Payment be due from the Non-Defaulting Party to the Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. The Termination Payment shall be made by the Defaulting Party within three (3) Business Days after such notice is effective. In connection with such payment, the Non-Defaulting Party shall have the right to draw on any cash or other form of security then available to the Non-Defaulting Party pursuant to Article 19, or otherwise account therefor in a manner consistent with the calculation of the Termination Payment.

If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, nevertheless immediately pay the total Termination Payment within three (3) Business Days after receipt of the Non-Defaulting Party's notice of such amount plus any unpaid amounts owing to the Non-Defaulting Party, and, within seven (7) Business Days of receipt of such notice, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute. The Non-Defaulting Party shall answer any questions, within two (2) Business Days of receiving such questions, from the Defaulting Party regarding the calculation of the Termination Payment. If the dispute is resolved in favor of the Defaulting Party, the disputed amount shall be refunded within seven (7) Business Days, with interest upon such amount, calculated at the Interest Rate from the date the Termination Payment was paid to the Non-Defaulting Party until the date upon which the refund is made.

ARTICLE 14.
LIMITATION OF LIABILITY

EXCEPT AS SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, TO THE FULLEST EXTENT PERMITTED BY LAW, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. TO THE FULLEST EXTENT PERMITTED BY LAW, IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION,

THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE 15.
INDEMNIFICATION

15.1. Seller's Indemnity. Seller shall, to the fullest extent permitted by law, defend, indemnify and hold harmless Buyer and its directors, officers, board members, managers, agents, employees, and contractors (the "Buyer Indemnitees") from, against and with respect to, any and all Liabilities arising out of or relating to any third party claim or action against any Buyer Indemnitees arising of the following, except to the extent caused by the negligence or willful misconduct of a Buyer Indemnitee:

(a) any inaccuracy in any representation or breach of warranty of Seller contained in this Agreement;

(b) any failure by Seller to perform or observe, or to have performed or observed, in full, any covenant, agreement or condition to be performed or observed by it under this Agreement;

(c) the design, construction, ownership, operation and maintenance of the Unit;

(d) any actual or alleged injury or death of persons or damage to property arising in connection with Seller's operation of the Unit;

(e) any payments owing by Seller to counterparties of Seller, including any expense reimbursement or other payment obligations that Seller may have in connection with the Unit; and

(f) any liabilities arising from or relating to the Unit and the Unit site, under any Applicable Laws including those addressing health, safety and the protection of the environment.

15.2. Buyer's Indemnity. Buyer shall, to the fullest extent permitted by law, defend, indemnify and hold harmless Seller and its directors, officers, managers, agents, employees, and shareholders (the "Seller Indemnitees") from, against and with respect to, any and all Liabilities arising out of or relating to any third party claim or action against any Seller Indemnitees arising out of the following, except to the extent caused by the negligence or willful misconduct of a Seller Indemnitee:

(a) any inaccuracy in any representation or breach of warranty of Buyer contained in this Agreement; and

(b) any failure by Buyer to perform or observe, or to have performed or observed, in full, any covenant, agreement or condition to be performed or observed by Buyer under this Agreement.

ARTICLE 16.
ASSIGNMENT

This Agreement shall inure to the benefit of, and shall be binding upon, the Parties hereto and their respective permitted successors and assigns. Neither Party shall assign or transfer, in whole or in part, this Agreement without the prior written consent of the other Party, which consent may not be unreasonably withheld. Absent such written consent, any such attempted assignment shall be null and void. Notwithstanding the foregoing, either Party may assign the Agreement without the other Party's consent as a transfer, pledge or assignment of its rights to receive performance under a transaction as security for any financing with financial institutions provided however, that any ultimate assignee who is charged with operation of the Unit is competent to perform the assignor's obligations under the Agreement; provided, however, that in any such case, the assignor or transferor shall remain liable for all of its obligations under the Agreement.

ARTICLE 17.
CONFIDENTIALITY

The Parties consider the terms of this Agreement to be sensitive commercial information. Accordingly, the Parties shall not disclose the terms of this Agreement to any third party unless and to the extent required to make such disclosure by action of a court or other government authority or applicable law, provided, however, each Party shall provide the other Party with prompt notice of the requirement to disclose confidential information in order to allow the other Party to seek an appropriate protective order or other remedy. The Parties shall only disclose this Agreement and other confidential information received from the other Party to (i) those of its employees, consultants, authorized representatives, and attorneys having a "need to know" in order to carry out their functions in connection with the Agreement and (ii) to prospective lenders and investors and other prospective purchasers of energy or other products of the Unit, or Renewable Energy Certificates, which agree to maintain the confidentiality of the information disclosed, or as otherwise required by Applicable Laws. Notwithstanding the foregoing, at any time after thirty (30) days after the Effective Date, either Party may make a public announcement, or otherwise disclose the existence and term of this Agreement, the Parties to this Agreement, and the name, location and size of the Unit.

ARTICLE 18.
REPRESENTATIONS AND WARRANTIES

As a material inducement to entering into this Agreement, each Party (or the Party specified, as applicable), with respect to itself, represents and warrants to the other Party as of the Effective Date:

18.1. Duly Organized and Validly Existing. It is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation and is qualified to conduct its business in those jurisdictions necessary to perform this Agreement. Specifically, with respect to the Seller, Seller represents that is a limited liability company duly organized, validly existing and in good standing under the laws of the Commonwealth of Massachusetts and has the corporate power and authority to carry on its business as now conducted. Seller also represents that it is in good standing duly qualified to do business in the Commonwealth of Massachusetts.

18.2. No Consents or Authorizations. It has or will obtain when required all regulatory authorizations necessary for it to legally perform its obligations under this Agreement and no consents of any other Party and no act of any other governmental authority is required in connection with the execution, delivery and performance of this Agreement other than those which it has or will obtain. In addition, Buyer warrants, with respect to this Agreement, that all acts necessary to the valid execution, delivery and performance of this Agreement have or will be taken and performed as required under all Applicable Laws with which Buyer is obligated to comply.

18.3. Due Authorization. The execution, delivery and performance of this Agreement are within its powers, have been duly authorized by all necessary action and do not violate any of the terms or conditions in its governing documents or any contract to which it is a party or any Applicable Laws.

18.4. Enforceability. This Agreement constitutes a legal, valid and binding obligation of such Party enforceable against it in accordance with its terms, subject to bankruptcy, insolvency, reorganization and other laws affecting creditors' rights generally, and with regard to equitable remedies, to the discretion of the court before which proceedings to obtain same may be pending.

18.5. No Bankruptcy. There are no bankruptcy, insolvency, reorganization, receivership or other proceedings pending or being contemplated by it or to its knowledge threatened against it.

18.6. Seller's Power. Seller represents and warrants to Buyer that it has the right to sell Contract Products hereunder.

18.7. Market Participant. It is party to a Market Participant Service Agreement with ISO-NE, or otherwise has all rights with respect to the markets operated by ISO-NE required for it to fulfill its obligations under this Agreement.

18.8. Due Diligence. It is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other

Party hereto in so doing, and is capable of assessing the merits of, and understands and accepts, the terms, conditions and risks of this Agreement

18.9. Material Contracts. Seller represents to Buyer that, as of the Commercial Operation Date, Seller will own the Unit and will have secured all necessary rights to or in any Material Contract.

18.10. Sovereign Immunity. Buyer warrants to Seller that it has the capacity to be sued by Seller for disputes arising under this Agreement. Buyer further warrants to Seller that in any contract action brought by Seller, whether in law or equity, to enforce Buyer's obligations under this Agreement, Buyer shall not raise sovereign immunity as a defense to such contract action.

ARTICLE 19.
CREDIT SUPPORT

19.1. Seller Credit Support

(a) Within five (5) Business Days after the date on which the construction financing for the Unit is closed and all conditions to disbursement of funds have been satisfied ("Closing Date"), Seller shall provide Energy New England, LLC ("Energy New England") as beneficiary with an irrevocable standby Letter of Credit issued by a Qualified Institution, substantially in the form attached hereto as Appendix B for the collective benefit of Buyer and the Other Buyers under the same terms and conditions as set forth in this Agreement, which shall be subject to an administration agreement among Energy New England, Buyer and the Other Buyers executed prior to the date that the Seller's Letter of Credit is delivered to Energy New England under this Section 19.1 (the "Administration Agreement"). The Letter of Credit or a replacement Letter of Credit shall be maintained in the following amounts: $2,472,000 from up to five Business Days after the Closing Date until December 31, 2018; $2348,400 from January 1, 2019 until December 31, 2019; $2,224,800 from January 1, 2020 until December 31, 2020; $2,101,200 from January 1, 2021 until December 31, 2021; $1,977,600 from January 1, 2022 until December 31, 2022; $1,854,000 from January 1, 2023 until December 31, 2023; $1,730,400 from January 1, 2024 until December 31, 2024; $1,606,800 from January 1, 2025 until December 31, 2025; $1,483,200 from January 1, 2026 until December 31, 2026; $1,359,600 from January 1, 2027 until December 31, 2027; $1,236,000 from January 1, 2028 until December 31, 2028; $1,112,400 from January 1, 2029 until December 31, 2029; $988,800 from January 1, 2030 until December 31, 2030; $865,200 from January 1, 2031 until December 31, 2031; $741,600 from January 1, 2032 until December 31, 2032; $618,000 from January 1, 2033 until December 31, 2033; $494,400 from January 1, 2034 until December 31, 2034; $370,800 from January 1, 2035 until December 31, 2035; $247,200 from January 1, 2036 until December 31, 2036; $123,600 from January 1, 2037 until the day twenty years following the Commercial Operation Date. The amount to be maintained for the benefit of the Buyer shall be equal to its Contract Products percent multiplied by the applicable amount of the Letter of Credit set forth in the prior sentence ("Seller's Credit Support Amount"). The Seller shall be required to maintain the Seller's Credit Support Amount until such time as the Seller obtains an Investment Grade Credit Rating, at which time the Seller's Credit Support Amount shall be cancelled and returned to the Seller. However, if at any time after the Seller obtains an Investment Grade Credit Rating, (a) the Credit Rating of Seller is lowered by S&P below BBB- and/or by Moody's below Baa3, as applicable, or (b) Seller fails to maintain a Credit Rating with at least one of S&P or Moody's and such failure is continuing, then Seller shall be required to provide the Seller's Credit Support Amount to Buyer within five (5) Business Days of a request by Buyer to be held as security for Seller's obligations under this Agreement. In the event of a continuing Event of Default by Seller, Buyer may avail itself of the credit support provided by Seller under this Section 19.1 by directing Energy New England to draw on the Letter of Credit in an amount up to the Buyer's Contract Percentage of the Stated Amount in the Letter of Credit..

(b) For purposes hereof, it shall be a "Letter of Credit Default" with respect to any Letter of Credit, upon the occurrence of any of the following events: (i) the Qualified Institution shall fail to maintain a Credit Rating of at least ("A-") by S&P and ("A3") by Moody's, (ii) the Qualified Institution shall fail to comply with or perform its obligations under such Letter of Credit if such failure shall be continuing after the lapse of any applicable grace period; (iii) the Qualified Institution shall disaffirm, disclaim, repudiate or reject, in whole or in part, or challenge the validity of such Letter of Credit; (iv) such Letter of Credit shall fail or cease to be in full force and effect at any time during the Term of Agreement; (v) any event analogous to an event specified in Articles 13.1(b) or 13.1(c) of this Agreement shall occur with respect to the Qualified Institution; or (vi) the Seller or the Qualified Institution shall fail to cause the renewal or replacement of the Letter of Credit to the Buyer at least thirty (30) days prior to the expiration of such Letter of Credit; provided, however, that no Letter of Credit Default shall occur in any event with respect to a Letter of Credit after the time such Letter of Credit is required to be canceled or returned to the Seller in accordance with the terms of this Agreement. If a Letter of Credit Default occurs, then the Party which has applied for such Letter of Credit shall have five Business Days to: (i) cure the event(s) causing the Letter of Credit Default; (ii) replace the Letter of Credit with a substitute Letter of Credit in the same amount as the Letter of Credit that is subject to the Letter of Credit Default and in a form reasonably acceptable to ENE; or (iii) post cash collateral in the same amount as the Letter of Credit that is subject to the Letter of Credit Default (which cash collateral may be obtained through a permitted drawing by ENE under a Letter of Credit which has not been renewed or where the issuer thereof fails to continue to be a Qualified Institution) to be held by ENE as beneficiary in an escrow account on terms reasonably acceptable to the Seller and ENE and at the sole cost and expense of Seller. Seller's failure to deliver any replacement Letter of Credit within the timeframe set forth in this Article 19.1 shall entitle ENE as beneficiary of the Letter of Credit to draw on the Letter of Credit and to place the cash proceeds of such Letter of Credit in an escrow account, on terms reasonably acceptable to Seller and ENE and at Seller's sole cost and expense, as security for the Seller's obligations under this Agreement. If the Buyer's beneficiary draws on a Letter of Credit pursuant to the previous sentence, it shall promptly return all such cash collateral in the event that Seller cures the Letter of Credit Default; provided that in no event shall such beneficiary be required to return such cash collateral if it is applied to amounts owing to Buyer or an Other Buyer. Any failure to cure the event(s) causing the Letter of Credit Default or to provide a Substitute Letter of Credit or cash collateral within five Business Days after the event(s) leading to the Letter of Credit Default shall be an Event of Default under Article 13.1(g).

19.2. Buyer Credit Support.

(a) Within five (5) Business Days after the Closing Date, Buyer shall provide Seller with evidence of an Investment Grade Credit Rating pertaining to it of S&P BBB- and/or Moody's Baa3 or better. If this is not provided, then within five (5) days after the Closing Date, Buyer shall provide Seller with cash collateral to be held by Seller in an escrow account on terms reasonably acceptable to Buyer and at the sole cost and expense of Buyer. The cash shall be maintained in an amount equal to the Seller's Credit Support Amount multiplied by the Buyer's Contract Percentage ("Buyer's Credit Support Amount"). The Buyer shall be required to maintain the Buyer's Credit Support Amount until such time as the Buyer obtains an Investment Grade Credit Rating at which time the Buyer's Credit Support Amount shall be returned to the Buyer. However, if at any time after the Buyer obtains an Investment Grade Credit Rating, (a) the Credit Rating of Buyer is lowered by S&P below BBB- and/or by Moody's below Baa3, as applicable, or (b) Buyer fails to maintain a Credit Rating with at least one of S&P or Moody's and such failure is continuing, then Buyer shall be required to provide the Buyer's Credit Support Amount to Seller within five (5) Business Days of a request by Seller to be held in escrow as described above as security for Buyer's obligations under this Agreement.

ARTICLE 20.
OPERATIONS COMMUNICATION

Commencing on the Effective Date, the Seller shall provide to Buyer inputs, as requested, concerning the quarterly performance reports, and notification of major incidents affecting the Unit, including scheduled and unscheduled outages, and operating limitations. The Seller shall meet with the Buyer at a time and place that is mutually agreed to between the Buyer and the Seller and shall not be required to meet with the Buyer more often than once every six (6) months. The Buyer shall be notified regarding any decision or issue having a material impact on the capacity, availability or dispatch of the Unit. Seller shall retain final decision authority on all matters relating to the Unit. Seller shall use commercially reasonable efforts to provide the Buyer with a non-binding day ahead forecast of hourly production on each Business Day by 9:00 a.m. local time.

ARTICLE 21.
DISPUTE RESOLUTION

21.1. Formal Dispute Resolution. Disputes arising under this Agreement shall be resolved according to the following procedures. In the event that there is any controversy, claim or dispute between the Parties arising out of this Agreement, or the breach hereof, that has not been resolved by informal discussions and negotiations, then either Party may, by written notice to the other, invoke the formal dispute resolution procedures set forth herein. The written notice invoking these procedures shall set forth in reasonable detail the nature, background and circumstances of the controversy, claim or dispute. During the twenty (20) Business Day period following a Party's receipt of said written notice, the Parties shall meet, confer and negotiate in good faith to resolve the dispute.

21.2. Mediation. If the Parties are unable to resolve any controversy, claim or dispute cannot be settled or resolved amicably by the Parties during the twenty (20) day period provided for above, then either Party may commence mediation by providing to JAMS and the other Party a written request for mediation, setting forth the subject of the dispute and the relief requested. The Parties will cooperate with JAMS and with one another in selecting a mediator from JAMS panel of neutrals, and in scheduling the mediation proceedings. The venue for the mediation shall be in Boston, Massachusetts. In the event the Parties are unable to agree upon a mediator within ten (10) days from the date of the initial written request for mediation, either Party may request that JAMS appoint a mediator who is knowledgeable about renewable energy power purchase agreements and disputes. The Parties covenant that they will participate in the mediation in good faith and that they will share equally in its costs. All offers, promises, conduct and statements, whether oral or written, made in the course of the mediation by either of the Parties, their agents, employees, experts and attorneys, and by the mediator and any JAMS employees, are confidential, privileged and inadmissible for any purpose, including impeachment, in any litigation or other proceeding involving the Parties, provided that evidence that is otherwise admissible or discoverable shall not be rendered inadmissible or non-discoverable as a result of its use in the mediation. Either Party may seek equitable relief prior to the mediation to preserve the status quo pending the completion of that process. Except for such an action to obtain equitable relief, neither Party may commence a civil action with respect to the matters submitted to mediation until after the completion of the initial mediation session, or 45 days after the date of filing the written request for mediation, whichever occurs first. Mediation may continue after the commencement of a civil action, if the Parties so desire. The provisions of this Section 21.2 may be enforced by any court of competent jurisdiction, and the Party seeking enforcement shall be entitled to an award of all costs, fees and expenses, including attorneys' fees, to be paid by the Party against whom enforcement is ordered.

21.3. Legal and Equitable Remedies. In the event that any such controversy, claim or dispute cannot be settled or resolved amicably by the Parties as set forth in Section 21.1 or by mediation as set forth in Section 21.2, then either Party may pursue all available legal and equitable remedies.

ARTICLE 22.
MISCELLANEOUS

22.1. Waivers. Any waiver at any time by any Party of its rights with respect to the other Party or with respect to any matter arising in connection with this Agreement shall not be considered a waiver with respect to any other prior or subsequent default or matter.

22.2. Notices. Any notice, demand, request, consent, approval, confirmation, communication, or statement which is required or permitted under this Agreement, shall be in writing, except as otherwise provided, and shall be given or delivered by Federal Express or comparable overnight delivery service, postage prepaid, addressed to the Party at the address set forth below. Notwithstanding the foregoing, bills, invoices, credit memos, reports and other communications in the ordinary performance of the respective duties and obligations of the Parties hereunder, may be sent by e-mail, telefax, first class mail or any other method, whether herein specifically provided or as the parties may hereafter adopt. Changes in such address shall be made by notice similarly given.

Notices to Buyer shall be sent to:

Pascoag Utility District
Attn. General Manager: Michael Kirkwood
Phone: (401) 568-6222
Fax: (401) 568-0066
Email: mkirkwood@pud-ri.org

With a copy to:

Energy New England LLC
100 Foxborough Boulevard, Suite 110
Foxborough, MA 02035
Attn. Timothy Hebert
Phone: (508) 698-1219
Fax: (508) 698-0222
Email: Thebert@energynewengland.com; accounting@energynewengland.com

Notices to Seller shall be sent to:

Canton Mountain Wind, LLC
549 South Street, Building 19
Quincy, MA 02169
Attn: Andrew Goldberg
Phone: 617-503-5640
Fax: 617-890-0606
Email: agoldberg@patriotrenewables.com

With a copy to:

Canton Mountain Wind, LLC
549 South Street, Building 19
Quincy, MA 02169
Attn: Todd Presson
Phone: 617-503-5435
Fax: 617-890-0606
Email: tpresson@patriotrenewables.com

Notices shall be deemed to have been received, and shall be effective, upon receipt. Notices of changes of address by either Party shall be made in writing no later than ten (10) days prior to the effective date of such change; provided, however, that any failure hereof shall not be deemed an event of default or other grounds for termination of the Agreement.

22.3. Governing Law and Waiver of Jury Trial, Venue. All disputes arising out of the performance or non-performance under this Agreement shall be construed in accordance with the laws of the Commonwealth of Massachusetts, notwithstanding any laws requiring the application of the laws of another state. The Parties agree that the sole and exclusive venue for any action or litigation arising from or relating to this Agreement shall be in the court of appropriate jurisdiction located in the Commonwealth of Massachusetts. Each Party agrees to waive all rights to a trial by jury in the event of litigation to resolve any disputes hereunder.

22.4. Headings Not to Affect Meaning. The descriptive headings used for the various Articles and sections herein have been inserted for convenience and reference only and shall in no way affect the meaning or interpretation, or modify or restrict any of the terms and provisions hereof.

22.5. No Consent to Violation of Law. Nothing contained herein shall be construed to constitute consent or acquiescence by either Party to any action of the other Party which violates the laws of the United States as those provisions may be amended, supplemented or superseded, or which violates any other law or regulation, or any order, judgment or decree of any court or governmental authority of competent jurisdiction.

22.6. No Dedication of Facilities. Any undertakings or commitments by one Party to the other Party under this Agreement shall not constitute the dedication of the Unit or any portion thereof of any Party to the public or to the other Party.

22.7. Relationship of the Parties. Nothing contained in this Agreement shall be construed to create an association, joint venture, partnership or any other type of entity or relationship between Seller and Buyer, or between either or both of them and any other Party.

22.8. Third-Party Beneficiaries. This Agreement is intended solely for the benefit of the Parties hereto, and nothing therein will be construed to create any duty to, or standard of care with reference to, or any liability to, any person not a Party hereto.

22.9. Entire Agreement. This Agreement and the attached appendices constitute the entire agreement between the Parties and parol or extrinsic evidence shall not be used to vary or contradict the express terms of this Agreement.

22.10. Records. The Parties shall keep (or as necessary cause to be kept by their respective agents) for a period of six (6) years such records as may be needed to afford a clear history of all deliveries of the Contract Products pursuant to this Agreement. For any matters in dispute, the Parties shall keep the records related to such matters until the dispute is ended. In maintaining or causing to be maintained such records, the Parties shall effect such segregation and allocation as may be needed to properly bill delivery of Energy pursuant to this Agreement.

22.11. Audit. Not more than once each calendar quarter, each Party or any third party representative of a Party shall have the right, at its sole expense, to examine the records of the other Party relating to this Agreement during normal business hours upon reasonable notice to the extent necessary to verify any invoice or amounts due and payable pursuant to this Agreement or to verify compliance with the terms of this Agreement.

22.12. Amendment. This Agreement shall be amended or modified only by the mutual written agreement of both Seller and Buyer.

22.13. Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be an original, but all of which together shall constitute one instrument.

22.14. Forward Contract. The Parties acknowledge and agree that this Agreement is a "forward contract" within the meaning of the Bankruptcy Code, and that the Parties are acting as "forward contract merchants" by entering into the Agreement.

22.15. Material Adverse Change. If the federal government, the State of Maine, Commonwealth of Massachusetts or ISO-NE adopts, enacts, or otherwise imposes a new law, rule or regulation which either makes a Party's performance under this Agreement unlawful, or makes this Agreement unenforceable and such governmental action does not constitute a Force Majeure event under Article 12 of this Agreement, the Parties shall negotiate in good faith to amend the terms of this Agreement and to determine the appropriate changes, if any, so that the Party affected by such change in law or regulation is able to lawfully perform its obligations without materially adversely affecting the financial benefit hereunder to the other Party. If the Parties are unable to reach agreement on such an amendment, then either Party shall have the right to terminate this Agreement, and neither Party shall have any further liability to the other Party, except for the payment of amounts owing prior to the date of termination.

22.16. Severability. In the event that any provision of this Agreement is deemed unlawful or unenforceable, the remaining provisions shall remain in full force and effect; provided that (1) the material purpose thereof can be lawfully effectuated; and (2) the economics underlying this Agreement remain substantially the same.

22.17. Further Assurances. In furtherance of the terms and provisions hereof, the Parties agree to collaborate in good faith in order to achieve the performance by each other of their respective obligations hereunder, including by executing and delivering such documents and instruments as reasonably requested by either Party. Buyer acknowledges that Seller intends to finance the acquisition and construction of the Unit, and may in the future refinance such financing, with funds to be provided, in whole or in part, by lenders and equity investors, some or all of which are yet to be identified. As reasonably necessary to accommodate such financing or refinancing, Buyer shall provide such information and documentation as may be reasonably requested by any actual or prospective lender or equity investor, including a consent to the collateral assignment of this Agreement to any such actual or prospective lender or equity investor containing such customary terms and provisions as may be reasonably requested by such actual or prospective lender or equity investor, provided, however, that the foregoing shall not obligate Buyer to materially change any rights or benefits or materially increase any burdens, liabilities or obligations of Buyer, under this Agreement. Seller shall reimburse Buyer for its reasonable legal fees resulting from compliance with this Section 22.17 in connection with financing for the Unit.

22.18. Bankruptcy Code References. The payment of the Termination Amount constitutes a "margin payment", and the Termination Payment constitutes a "settlement payment" and/or a "transfer" under the Bankruptcy Code and for purposes of determining the Termination Payment by the Non-Defaulting Party, the netting out from the Termination Amount of the Buyer's or Seller's Letter of Credit, as applicable, held by the Non-Defaulting Party under Article 19 herein shall constitute a "setoff or net out of termination values or payment amounts" under the Bankruptcy Code. "Bankruptcy Code" shall mean the U.S. Bankruptcy Code, 11 U.S.C. Sec. 101 et. seq., as such may be amended from time to time.

ARTICLE 23.
REGULATORY REVIEW

23.1. Neither Party shall seek to change or amend this Agreement in any way through making application to the Maine Public Utilities Commission or the Federal Energy Regulatory Commission (or to any other government agency or authority), and this Agreement shall not be subject to change through unilateral application by either Party under Sections 205 and 206 of the Federal Power Act (or pursuant to any other provision of law). Each Party hereby irrevocably waives the right to seek any change or to support any application or complaint or other legislative, judicial or regulatory action made seeking a change in the rates or a change in the terms and conditions of this Agreement, absent the mutual agreement of the Parties.

23.2. Absent the agreement of both Parties to the proposed change, the standard of review for changes to this Agreement proposed by either Party, a non-party or the Federal Energy Regulatory Commission acting *sua sponte* shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Services Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (the "Mobile-Sierra" doctrine).

Agreed to as of the date set forth above.

SELLER	BUYER
Canton Mountain Wind, LLC	Pascoag Utility District
By:	By: Michael R. Kirkwood
Name: SAM CASHMAN	Name: Michael R. Kirkwood
Title: Managing Member	Title: General Manager

APPENDIX A
CONTRACT PRODUCT PRICE

The Contract Product Price shall be calculated per the following rate schedule.

RATE SCHEDULE			
Contract Product Year	**<u>Contract Product Price I</u>** **Contract Product Price per MWh for Aggregate Annual Unit Production up to and including 50,900 MWh per Contract Product Year** **(See Note following table)**	**<u>Contract Product Price II</u>** **Contract Product Price per MWh for Aggregate Annual Unit Production greater than 50,900 MWh up to and including 61,800 MWh per Contract Product Year** **(See Note following table)**	**<u>Contract Product Price III</u>** **Contract Product Price per MWh for Aggregate Annual Unit Production greater than 61,800 MWh per Contract Product Year** **(See Note following table)**
1	$100.50	$97.50	$65.00
2	$101.50	$98.50	$65.00
3	$102.50	$99.40	$65.00
4	$104.80	$101.70	$65.00
5	$105.80	$102.70	$65.00
6	$106.90	$103.70	$65.00
7	$107.90	$104.80	$65.00
8	$109.00	$105.80	$65.00
9	$110.10	$106.90	$65.00
10	$111.20	$107.90	$65.00
11	$112.30	$109.00	$65.00
12	$113.40	$110.10	$65.00
13	$114.50	$111.20	$65.00
14	$115.70	$112.30	$65.00
15	$116.80	$113.40	$65.00
16	$81.30	$76.30	$65.00
17	$81.30	$76.30	$65.00
18	$81.30	$76.30	$65.00
19	$81.30	$76.30	$65.00
20	$81.30	$76.30	$65.00

NOTE: The 50,900 MWh production threshold is equal to the 90% probability (P90) of exceeding such average annual production level (the "1-yr P90") utilizing eight 2.85 MW turbines. The 61,800 MWh production threshold is equal to the 50% probability (P50) of exceeding such average annual production level (the "1-yr P50") utilizing eight 2.85 MW turbines. The P90 and P50 values are based on that certain energy assessment prepared by GL Garrad Hassan on February 26, 2016 entitled, "Preliminary Assessment of the Energy Production of the Proposed Canton Mountain Wind Farm, Document number 10016455-HOU-R-01. If the Unit consists of less than eight turbines, then in each such case, the Parties agree to adjust the P(90) and P(50) figures to account for such differences in accordance with the information set forth in the table below.

	P(90) MWh	P(50) MWh
6 turbines 2.85 MW (17.1 MW)	38,175	46,350
7 turbines 2.85 MW (19.95 MW)	44,538	54,075
8 turbines 2.85 MW (22.8MW)	50,900	61,800

Prior to the Commercial Operation Date the Contract Product Price shall mean $85.50 per MWh. On the first day of a Contract Product Year , the Contract Product Price shall mean: (1) the value set forth in the column labeled Contract Product Price I for the amount of Energy delivered to the Delivery Point up to and including 50,900 MWhs (or as adjusted as noted above) for the applicable Contract Product Year; and (2) the value set forth in the column labeled Contract Product Price II for the amount of Energy delivered to the Delivery Point in excess of 50,900 MWhs and up to and including 61,800 MWhs (or as adjusted as noted in above) for the applicable Contract Product Year; and (3) the value set forth in the column labeled Contract Product Price III for the amount of Energy delivered to the Delivery Point in excess of 61,800 MWhs for the applicable Contract Product Year.

Contract Product Price shall be the total price for all Contract Products hereunder.

APPENDIX B
SELLER'S FORM OF LETTER OF CREDIT

Dated:

Irrevocable Standby Letter of Credit No. 231

Confirming Bank:
U.S. Bank, National Association
777 East Wisconsin Avenue
Milwaukee, WI 53202
Attention: Global Documentary Services, MK-WI-J6NI

Issuing Bank:
Customers Bank ("Lender")
99 Bridge Street
Phoenixville, PA 19460

Beneficiary: Energy New England
100 Foxborough Blvd. #110
Foxborough, MA 02035

Applicant: Canton Mountain Wind, LLC
549 South Street,
Quincy, MA 02269

Term: August 21, 2016 through August 21, 2017

Stated Amount: Two Million Four Hundred Seventy-Two Thousand Dollars and No Cents
($2,472,000.00)

Expiration Date: December 31, 20__, or any automatically extended date, however not later than November ______, 2036, which is the Final Expiration Date.

Ladies and Gentlemen:

We hereby establish our Irrevocable Standby Letter of Credit No. 231 in your favor for the account of Canton Mountain Wind, LLC, (the "Applicant") available for drawings for up to an aggregate amount of Two Million Four Hundred Seventy-Two Thousand Dollars and No Cents (USD $2,472,000.00). Sight Drafts must be drawn on the Confirming Bank. Any documents must be presented at the Confirming Bank's counters.

Funds under this Letter of Credit, in an amount not to exceed that amount stated above, will be made available to you in accordance with the terms and conditions herein against presentation at the above address of your sight draft drawn on the Confirming Bank (as per Exhibit A) bearing the clause "Drawn under Irrevocable Standby Letter of Credit No. 231", dated ________________, 2016 and Advice of Confirmation No. ____________________, and accompanied by one of the following documents:

(a) A dated certificate submitted on letterhead executed by a duly authorized officer of the Beneficiary reading as follows: "The amount of ___________(_____) ("Draw Amount") is claimed under your Irrevocable Letter of Credit No. 231 is due and payable because (i) payment is due to Buyer(s) (under the Power Purchase Agreement as defined herein) from Applicant (as defined in such Letter of Credit) pursuant to that certain Power Purchase Agreement for Unit Contingent Contract Products made and entered into as of ____________20__, by and among, inter alios, the Applicant and Buyer(s) ("Power Purchase Agreement"); (ii) Applicant has not made such payment in accordance with the Power Purchase Agreement; and (iii) Buyer(s) have made written demand upon Applicant for payment. Wherefore, demand is hereby made under your Irrevocable Standby Letter of Credit No 231 for payment of the Draw Amount. Payment should be remitted to the Beneficiary by wire transfer to the following account __________."

Or

(b) A dated certificate submitted on letterhead executed by a duly authorized officer of the Beneficiary reading as follows: "An Event of Default, (as defined in the Power Purchase Agreement for Unit Contingent Contract Products made and entered into as of ___________, 20__ by and among, inter alios, the Applicant (as defined in the Letter of Credit referenced below) has occurred and is continuing with respect to the Applicant.

Or

(c) The Irrevocable Standby Letter of Credit has not been extended or replaced within thirty (30) days prior to the expiration of the Irrevocable Standby Letter of Credit and five (5) Business Days have passed after written notice from the Beneficiary without Canton Mountain Wind LLC replacing such Irrevocable Standby Letter of Credit with a letter of credit issued by a Qualified Institution (as defined in the Power Purchase Agreement for Unit Contingent Contract Products.)

THIS IRREVOCABLE STANDBY LETTER OF CREDIT SHALL BE DEEMED AUTOMATICALLY EXTENDED WITHOUT AMENDMENT FOR ONE YEAR FROM THE EXPIRATION DATE HEREOF OR ANY FUTURE EXPIRATION DATE UNLESS AT LEAST THIRTY (30) DAYS PRIOR TO ANY EXPIRATION DATE, WE NOTIFY YOU BY CERTIFIED MAIL OR OVERNIGHT COURIER SERVICE THAT WE ELECT NOT TO EXTEND THIS LETTER OF CREDIT FOR SUCH ADDITIONAL PERIOD. NOTWITHSTANDING THIS AUTOMATIC EXTENSION CLAUSE, THIS LETTER OF CREDIT HAS A FINAL EXPIRY DATE OF NOVEMBER __, 2036, UPON WHICH DATE IT BECOMES NULL AND VOID WITHOUT OUR REQUISITE NOTICE TO YOU.

Wherefore, demand is hereby made under your Irrevocable Standby Letter of Credit No. 231 for payment of _______________ ($_______). Payment should be remitted to the Beneficiary by wire transfer to the following account _______________."

We hereby agree with you that amounts drawn under this Irrevocable Standby Letter of Credit will be honored in accordance with the terms and conditions stated herein provided the required documents are presented to the Confirming Bank at the above address on or before the Letter of Credit Expiration Date stated above. The amount of each draft presented hereunder will automatically decrease the total amount of this Irrevocable Standby Letter of Credit. Multiple and partial drawings are expressly permitted under this Irrevocable Standby Letter of Credit.

We give our undertaking to the Beneficiary that sums drawn under and in compliance with the terms of this Irrevocable Standby Letter of Credit will be duly honored by us on presentation of drawings in accordance with the terms of this Irrevocable Standby Letter of Credit.

If cancellation of this Irrevocable Standby Letter of Credit is required by the Beneficiary before the current expiration date, the Original of this Irrevocable Standby Letter of Credit and any amendment(s), must be returned to us accompanied by a letter signed by the Beneficiary requesting its cancellation.

This Irrevocable Standby Letter of Credit will decrease in accordance with the Schedule on Appendix B.

This Irrevocable Standby Letter of Credit sets forth in full the terms of our undertaking and such undertaking shall not be in any way be modified, amended, or amplified by reference to any document, instrument or agreement referred to herein or in which this

Irrevocable Standby Letter of Credit is referred to or to which this Irrevocable Standby Letter of Credit relates, and any such reference shall not be deemed to incorporate herein by reference any document, instrument or agreement.

Except to the extent otherwise expressly agreed to this Irrevocable Standby Letter of Credit is subject to the Uniform Customs and Practice for Documentary Credits (2007 Revision) ICC Publication No. 600, to the extent not inconsistent therewith, the law of the State of New York, including Article 5 of the New York Uniform Commercial Code, as applicable, and engages us to the terms herein.

All communications to us with respect to this Irrevocable Standby Letter of Credit must be addressed to **Loan Operations Dept., (Attn: Letter of Credit Unit) Customers Bank, 99 Bridge Street, Phoenixville, PA 19460-3411**.

Very truly yours,

____

Joseph M. Swarr
Senior Vice President

Exhibit A to Appendix B

SIGHT DRAFT

Drawn under Irrevocable Letter of Credit No. 231, dated _______________________, 20____
and Advice of Confirmation No. SLCMIL000XXX
US$ (amount in figures) (Date)

At Sight, pay to the order of __________________.

(amount in words)

TO: U.S. BANK NATIONAL ASSOCIATION

777 EAST WISCONSIN AVENUE
MILWAUKEE, WI 53202
ATTN: GLOBAL DOCUMENTARY SERVICES, MK-WI-J6NI

(Name of Beneficiary)

____

Signature

____

Printed Name

____

Title

WIRES TRANFER INSTRUCTIONS

Bank: _____________________________________

Bank Address: _____________________________________

____

____

ABA No. ____________________________________

Account Number: ____________________________________

For Account of: ____________________________________

(Name of Beneficiary)

By: _________________________ ____________________________

Title: _______________________ Authorized Signature

Address:__________________________

Exhibit B to Appendix B

Dates	Amount
From Five Days after Closing to December 31, 2018	$2,472,000.00
January 1, 2019 to December 31, 2019	$2,348,400.00
January 1, 2020 to December 31, 2020	$2,224,800.00
January 1, 2021 to December 31, 2021	$2,101,200.00
January 1, 2022 to December 31, 2022	$1,977,600.00
January 1, 2023 to December 31, 2023	$1,854,000.00
January 1, 2024 to December 31, 2024	$1,730,400.00
January 1, 2025 to December 31, 2025	$1,606,800.00
January 1, 2026 to December 31, 2026	$1,483,200.00
January 1, 2027 to December 31, 2027	$1,359,600.000
January 1, 2028 to December 31, 2028	$1,236,000.00
January 1, 2029 to December 31, 2029	$1,112,400.00
January 1, 2030 to December 31, 2030	$988,800.00
January 1, 2031 to December 31, 2031	$865,200.00
January 1, 2032 to December 31, 2032	$741,600.00
January 1, 2033 to December 31, 2033	$618,000.00
January 1, 2034 to December 31, 2034	$494,400.00
January 1, 2035 to December 31, 2035	$370,800.00
January 1, 2036 to December 31, 2036	$247,200.00

January 1, 2037 to the Day Twenty Years Following the Commercial Operating Date	$123,600.00

APPENDIX C
P50 EXPECTED ANNUAL ENERGY PRODUCTION

	On Peak	Off Peak	Total
January	3,097	3,818	6,915
February	2,971	3,284	6,255
March	2,869	3,255	6,124
April	2,587	2,728	5,315
May	1,995	2,387	4,382
June	1,735	2,128	3,863
July	1,512	1,930	3,442
August	1,541	1,877	3,418
September	1,818	2,199	4,017
October	2,662	2,907	5,569
November	2,539	3,196	5,735
December	3,029	3,739	6,768
Total	**28,355**	**33,448**	**61,803**

Note: The parties agree to adjust the figures set forth above in the event that the Unit consists of fewer than eight turbines based upon the energy assessments prepared by GL Garrad Hassan on February 26, 2016 entitled, "Preliminary Assessment of the Energy Production of the Proposed Canton Mountain Wind Farm," Document number 10016455-HOU-R-01.

APPENDIX D

CONTRACT PERCENTAGE

	Buyer	Contract Percentage
1	Braintree Electric Light Department	13.026
2	Concord Municipal Light Plant	6.241
3	Town of Danvers Electric Division	11.136
4	Groveland Municipal Light Department	1.329
5	Hingham Municipal Light Plant	7.253
6	Littleton Electric Light & Water Department	13.158
7	Merrimac Municipal Light Department	1.062
8	Middleton Municipal Electric Department	3.511
9	New Hampshire Electric Cooperative	13.158
10	North Attleboro Electric Department	8.220
11	Norwood Municipal Light Department	11.207
12	Pascoag Utility District	2.193
13	Wellesley Municipal Light Plant	8.506

APPENDIX E

SECTION 4.2 EXAMPLE CALCULATIONS

Row\Column	B	C	D	E	F	G	H	I	J	K
	Canton PPA Section 4.2 Reduction Mechanism Numerical Examples									
	August 1, 2016									
5	**Assumptions used in below examples:**									
6	Canton Net RTM Sale in Settlement Period (MW)	15								
7	Settlement Period Duration (hours)	1								
8	PPA Contract Products Price in Effect ($/MWh)	100.5								
9										
10	**Example No.**	**Buyer's Zonal LMP* ($/MWh)**	**Facility Nodal LMP ($/MWh)**	**PPA Contract Products Price ($/MWh)**	**Energy Offer Price**	**Energy Offer Accepted?**	**Gross Contract Products Charge For Settlement Period ($)**	**Reduction in Contract Products Charge for Settlement Period ($)**	**Net Contract Products Charge for Settlement Period ($)**	**Net Contract Products Charge for Settlement Period ($/MWh)**
11	Scenario Set 1: Facility Nodal LMP and Buyer's Zonal LMP are both positive									
12	1	45	42	100.5	-100.5	yes	1507.5	0	1507.5	100.5
13	2	100	0	100.5	-100.5	yes	1507.5	0	1507.5	100.5
14	3	150	1	100.5	-100.5	yes	1507.5	0	1507.5	100.5
15	4	50	100	100.5	-100.5	yes	1507.5	0	1507.5	100.5
16	Scenario Set 2: Facility Nodal LMP is slightly less than Buyer's Zonal LMP									
17	5	45	42	100.5	-100.5	yes	1507.5	0	1507.5	100.5
18	6	0	-1	100.5	-100.5	yes	1507.5	15	1492.5	99.5
19	7	-30	-33	100.5	-100.5	yes	1507.5	45	1462.5	97.5
20	8	-50	-50	100.5	-100.5	yes	1507.5	0	1507.5	100.5
21	9	-90	-94	100.5	-100.5	yes	1507.5	60	1447.5	96.5
22	10	-130	-125	100.5	-100.5	no	0	0	0	0
23	Scenario Set 3: Facility Nodal LMP is significantly less than Buyer's Zonal LMP									
24	11	50	-50	100.5	-100.5	yes	1507.5	750	757.5	50.5
25	12	150	-150	100.5	-100.5	no	0	0	0	0
26	13	-40	-50	100.5	-100.5	yes	1507.5	150	1357.5	90.5
27	14	0	-94	100.5	-100.5	yes	1507.5	1410	97.5	6.5
28	15	0	-25	100.5	-100.5	yes	1507.5	375	1132.5	75.5
29	16	60	45	100.5	-100.5	yes	1507.5	0	1507.5	100.5
30	17	100	0	100.5	-100.5	yes	1507.5	0	1507.5	100.5
31	Scenario Set 4: Facility Nodal LMP is greater than Buyer's Zonal LMP									
32	18	75	120	100.5	-100.5	yes	1507.5	0	1507.5	100.5
33	19	-10	5	100.5	-100.5	yes	1507.5	0	1507.5	100.5
34	20	-75	-15	100.5	-100.5	yes	1507.5	0	1507.5	100.5
35	21	-150	-50	100.5	-100.5	yes	1507.5	0	1507.5	100.5

Formulas, as entered for Example No. 1, by column (where a column is not listed below, no formula is used):

Column E =C8
Column F =-E12
Column G =IF(D12>F12,"yes","no")
Column H =IF(G12="yes",E12*C6*C7,0)
Column I =IF(G12="yes",IF(D12<0,IF(D12<C12,(C6*C7)*(MIN(C12,0)-D12),0),0),0
Column J =H12-I12
Column K =J12/(C6*C7)

* As of the date of this document, the load for each Buyer is located within the following Load Zones

Load Zone	Buyer
SEMA	Braintree Electric Light Department
SEMA	Hingham Municipal Lighting Plant
SEMA	North Attleborough Electric Department
SEMA	Norwood Municipal Light Department
NEMA	Concord Municipal Light Department
NEMA	Danvers Electric Division
NEMA	Groveland Municipal Light Department
NEMA	Merrimac Municipal Light Department
NEMA	Middleton Municipal Electric Department
NEMA	Wellesley Municipal Light Plant
WCMA	Littleton Electric Light & Water Departments
NH	New Hampshire Electric Cooperative
RI	Pascoag Utility District

Testimony & Testimony Exhibits

Harle J. Round, Manager, Finance & Customer Service

- **Q1. Please provide and update of the status of the Pascoag's fuel reconciliation for the period ending December 31, 2016.**

  A1. As of this filing dated (November 4, 2016), this submittal contains actual expenses and revenues through September 2016. The fourth quarter (October through December) is based on estimates provided by Energy New England ('ENE"). The projected reconciliation at December 31, 2016 is estimated to be an over collection of $185,609.

- **Q2. Before you get into the details of the over collection, could you please provide an update on Pascoag's Purchase Power Restricted Fund and Restricted Fund for Capital and Debt Services, as well as a status on the Districts Cash flow position.**

  A2. The District cash flow was more than adequate to meet all the purchase power obligations this year. As a result the District did not have to use money from the **Purchase Power Restricted Fund ("PPRF")**. We continue to transfer a monthly amount to the Purchase Power Restricted Fund equal to the base rate revenue (customer charge and demand charge) from Daniele Prosciutto International (DPI) and we withdraw the Purchase Power Restricted Fund Credit (PPRFC). The monthly transfer of base rate revenue is required from Pascoag's Cost of Service Filing in 2013 (RIPUC Docket #4341) and the withdraws were approved in RIPUC Docket 4584 which is the $125,000 reimbursement of the PPRFC that is being issued back to the customers through a credit on the electric bills. The balance in this account is now at $ 834,273.24 as of the October transfer. A summary of the PPRF for 2016 can be seen below in **Table #1**.

  The kW Demand charges for DPI have increased by 686.40 kW on their combined electric accounts. The District compared the data from November of 2015 through October of 2016 to November of 2014 through October of 2015. Please see **Testimony Exhibit HJR-1**. All three accounts remain active and the District, even after repeated attempts, has not been informed of the status of DPI's continuing operations. We were told by an inside source that they upgraded some of their equipment in the Pascoag facility and do not intend to shut down within the near future.

  The District received permission to increase the PPRF funding level to $550,000 in RIPUC Docket No. 4584 which gives us a safety net equal to one month of the District's highest month of power bills on average. The District expects to have a balance of $844,226.80 by year end 2016 in this account. If we back out the PPRF approved level of $550,000 this would leave a balance of $294,226.80. As of October, the District has flowed back $108,160.36 through a billing credit. What is happening is the DPI Base Rate addition to the PPRFC minus the PPRFC reimbursements are resulting in a net increase each month which resulted in a cumulative increase of $46,618.34 through October of 2016. The PPRF account is an 18-month CD and it matured in April, yielding $8,312.14 in interest that was applied to the account resulting in a total increase of $54,931.18. The District would like to increase the flow back to customers to $250,000 in 2017 through the Purchase Power Restricted

Fund Credit and re-evaluate the excess balance with next year's rate filing. The credit would result in a 4.45 mills ($0.00445) per kilowatt hour reduction in the proposed rates for 2017, please see **Testimony Exhibit HJR-2** which is included in this filing. The proposed reduction in the PPRF is also out lined in **Testimony Exhibit HJR-3.**

	Table # 1	PURCHASE POWER RESTRICTED FUND			
MONTH/YEAR	**DEPOSIT**	**WITHDRAWAL**	**Net Increase**	**INTERST**	**BALANCE**
START BALANCE					**$779,342.06**
Jan 2016	$14,999.85	($10,416.63)	$4,583.22		$783,925.28
Feb 2016	$12,129.85	($10,416.67)	$1,713.18		$785,638.46
March 2016	$17,869.85	($10,416.67)	$7453.18		$793,091.64
April 2016	$14,999.85	($10,416.67)	$4,583.18	$8,312.14	$805,986.96
May 2016	$14,999.85	($10,416.67)	$4,583.18		$810,570.14
June 2016	$14,999.85	($10,416.67)	$4,583.18		$815,153.32
July 2016	$14,999.85	($10,416.67)	$4,583.18		$819,736.50
Aug 2016	$15,221.25	($10,416.67)	$4804.58		$824,541.08
Sept 2016	$15,172.05	($10,416.67)	$4,755.38		$829,296.46
Oct 2016	$15,393.45	($10,416.67)	$4,976.78		$834,273.24
Nov 2016					
Dec 2016					

The **Restricted for Capital and Debt Services balance** is on deposit with Freedom National Bank as a repurchase agreement that allows Pascoag to make deposits and withdrawals as needed for capital purchases and debt services. As of October, the District has fully funded the account to the $306,000 level for 2016. The Balance in this account is $636,553 as of this filing. The District uses this money to fund all capital projects and capital purchases, including vehicles. The District has plans to purchase a $190,000 bucket truck and a $45,000 pickup truck in 2017 along with several smaller capital purchases. The activity in this account is listed in **Table #2**

Table# 2	**Summary Of The Restricted Fund for Capital and Debt Activity**				
Month/YR	**Contribution**	**Deductions**		**Dividends**	**Balance**
		CAPITAL	**DEBT**		**$544,988 Start Bal**
JAN 2016	$25,500	($43,276)			$527,212
FEB 2016	$25,500	($34,609)			$518,103
MAR 2016	$25,500	($31,406)			$512,197
APRIL 2016	$25,000	($1,050)			$536,647
MAY 2016	$25,500	($48,914)		$7,045	$520,278
JUNE 2016	$25,500	($978)			$544,799
JULY 2016	$25,500	($17,075)			$553,224
AUG 2016	$25,500	($23,256)			$555,468
SEPT 2016	$25,500	($15,886)			$565,083

Table #2 Continued	Summary of The Restricted Fund for Capital and Debt Activity				
Month/YR	**Contribution**	**Deductions**		**Dividends**	**Balance**
		CAPITAL	**DEBT**		
OCT 2016	$76,500	($5,030)			$636,553
NOV 2016					
DEC 2016					
Total	**$306,000**	**($217,451)**		**$7,045**	**$636,553**

The **Storm Fund** was created as a result of the Cost of Service Study and rate filing approved for 2013 and allows for funding of $20,000 per year up to $100,000. The District has funded the $20,000 annual requirement to 100% as of this filing and was allowed to make one withdrawal due to a major storm in February of 2016. Please see **Table #3** for the activity.

Table #3 Storm Fund Goal for 2016 is $20,000 ($5,000 per quarter)			
Start Balance (Dec 2015)	$59,173		
Date	Deposit	Withdrawal	Balance
3-2016	$5,000	($13,679)	$50,494
6-2016	$5,000		$55,494
9-2016	$5,000		$60,494
10-2016	$5,000		$65,494

As of this filing, Pascoag has met all of our financial obligations. The Cash Flow Summaries for fiscal year 2016 are attached as **Testimony Exhibit HJR-4.** The Accounts Payable balances are all within the thirty-day window and Standard and Poor reaffirmed Pascoag's A- Rating in 2015. A Summary of the Accounts Payable/Accounts Receivable balances is attached as **Testimony Exhibit HJR-5**.

- **Q3. Please provide the details of the cumulative over collection and then break it out by factor.**

  A3. The cumulative over collection of the combined Standard Offer, Transition Charge and Transmission charge is expected to be $185,609 as shown in **Table #4 and Table #5**. Actual expenses exceeded revenue in all months January through September except for the months of January, April and September, and by using Energy New England's forecast, the expenses will exceed revenue for October - December. Please note that the 2016 Bulk Power Projection from ENE did not include the Surplus funds. I have included the $6,197.96 deduction from the ENE estimates for October through December of 2016. Please see **Testimony Exhibit HJR-9.**

TABLE #4 Combined Standard Offer, Transition Charge, and Transmission Charge

	Start Bal	Revenue	Expense	Monthly	Cumulative
Jan-16	$486,652	$574,653	$538,592	$36,061	$522,713
Feb-16	$522,713	$460,125	$493,850	($33,725)	$488,988
Mar-16	$488,988	$391,702	$441,455	($49,753)	$439,235
Apr-16	$439,235	$449,199	$378,193	$71,006	$510,242
May-16	$510,242	$366,325	$412,346	($46,022)	$464,220
Jun-16	$464,220	$385,902	$448,751	($62,849)	$401,371
Jul-16	$401,371	$463,263	$514,431	($51,168)	$350,203
Aug-16	$350,203	$541,695	$560,906	($19,211)	$330,992
Sep-16	$330,992	$543,820	$445,026	$98,793	$429,785
Oct-16 EST	$429,785	$418,148	$447,086	($28,938)	$400,847
Nov-16 EST	$400,847	$415,788	$444,001	($28,213)	$372,635
Dec-16 EST	$372,635	$391,247	$578,272	($187,025)	$185,609
	Period Cumulative Over/(Under) collection			($301,043)	
Forecast Cumulative Over/(Under) Collection at 12/31/2016					$185,609

Table #5	Summary of Year-End Cumulative Over/ (Under) Collection as of 12/31/2016[1]
Standard Offer	$ 59,377
Transition	$ 2,052
Transmission	$124,180
Total	$185,609

- **Q4. Please provide reasons for the over collection in 2016.**

A4. The District started the year with a cumulative over collection for the combined standard offer, transition charge, and transmission charge of $486,652 from 2015. The District deposited the money to a Year-End over Collection ("YEOC") account which is an account on deposit with Freedom National Bank. The money in this account was used to make up the gap in revenue when the rate reduction began flowing the over collection back to the District's customers in 2016. The Balance in this account is $429,785 which is reconciled to the September Schedule C-1, Line 136 G in Book 2. The District had under collections for six of the nine months January - September which helped to bring down the cumulative over collection. In January we had an over collection because of the fact that the bills were prorated and some of the kWhrs were billable under the 2015 rate. In April we had an over collection because of the Surplus Credit of $10,000, the Spruce Mountain

[1] Based on actual expenses and revenue through September; estimates were used for October through December.

Rec Sales of $23,735.67 that reduced the Purchase Power expense. In September we had an over collection due to the billable kWhrs to customers were much higher due the extreme heat and humidity for the billing period which increased the revenue, and National Grid's Invoice for network Transmission Service for September came in as a negative amount of ($6,663.19) plus a couple of reimbursement checks from MMWEC totaling $1,269.67, all helped to decrease the power expenses resulting in an over collection of $98,793. *Please see Schedule C1 in Book 2.*

Using ENE's 2016 Power Assumptions for October, November and December, we estimate the cumulative over collection will be reduced to $185,609 ($59,377 Standard Offer Service, $2,052 Transition, & $124,180 Transmission) at the end of 2016. The estimated sales to customers for 2017 is 56,173 MWH which is calculated using a three year average for January – September and a two year average for October – December of this year plus the actual consumption from 2014 and 2015. *Please see Schedule E in Book* 2.

- The forecasted Transition cost for 2017 is $577,000 minus the estimated over collection of $2,052 divided by 56,173 MWH equals $10.24 per MWH or $0.01024 per kWh. This will result in an increase of 0.00067 in the Transition Rate.
- The forecasted 2017 Transmission cost is 1,927,962 minus the estimated over collection of $124,180 and divided by 56,173 MWH equals $32.11 per MWH or $0.03211 per kWh an increase of $0.0013 to the Transmission rate.
- The forecasted 2017 Standard offer cost for 2017 is $3,366,209 minus the estimated over collection of $59,377 equals $3,306,832 divided by 56,173 MWH equals $58.87 per MWH or $0.05887 per kWh an increase of $.00486 to the Standard offer rate.
- The District is also proposing to increase the Purchase Power Restricted Fund Credit from $125,000 to $250,000 this would flow increase the flow back of PPRFC by ($0.00223).
- The net result will be an increase of $0.0046 per kWh or an increase of 3.2%. A 500-Kilowatt Hour per month Residential Customer will see their bill increase from $72.85 to $75.14, or an increase of $2.30. *Please see Testimony Exhibit HJR-2.*

Other Factors that contributed to the over collection was the fact that Pascoag has received 3,935,000 interruptible kilowatt-hours (kWh) from the two New York Power Authority (NYPA) entitlements for the previous three quarters ending in September 2016. The average cost per kWh for January through September 2016 was $0.024/kWh for Niagara and $0.026 cents/kWh for St Lawrence. The cost this year was more consistent. The NYPA interruptible energy helped Pascoag keep its purchase power cost down in 2016.

Another factor in the cumulative over-collection can largely be attributed to the hedging of Pascoag's open position. We sought an approximate 100 % load-following hedge for the whole 2015-2017 term because of the volatility of the future spot-market pricing. The fixed prices of this hedge have protected Pascoag from the volatility we saw in 2014. The overall power supply portfolio including this 2016-2017 hedge is more fully discussed in the testimony of Michael Kirkwood.

The District has seen an increase in sales to customers during the months of July, August, and September due to the high humidity and high temperatures. The District has also seen increases in our customers' consumption as a result of the AMR meter project; we continue to change out the older meters (20+ years) with newer AMR meters.

The District flowed back $50,002.50 of the 2015/2016 Surplus funds for MMWEC January through May of 2016 and then we received a check for $68,177.61, in August of 2016 which was divided by 11 months and is being used to reduce the Purchase Power bills by $6,198 from August - December 2016, for a total of $30,990. The $37,188 balance will be flowed back in 2017 with a credit each month of $6,198 from January – June of 2017. MMWEC has also provided us with an estimate of the June 2017 Surplus Funds which is estimated to be $466,055; this will be the result of excess funds in the bond reserve account after the bond principal and interest payment are made on July 1, 2017. Please see **Testimony Exhibit HJR-6.**

- **Q5. You stated that the forecast in this filing contained actual expenses and revenue through September and that estimates were used for October, November and December. Will you be able to provide an update on the actual expenses at or prior to the hearing?**

A5. Yes, all the October power invoices should be received by November 30, 2016. The District will be able to provide actual expenses and revenue for October shortly after that date. The District will provide and Addendum to this filing incorporating that information.

When the November and December invoices are received and recorded, Pascoag will provide the Division with this information though the monthly updates.

- **Q6. What is the forecast for purchase power cost for 2017?**

A6. The District, working with it consultants at Energy New England ("ENE"), has submitted the 2017 forecast total of $5,871,171.00 which is a decrease of ($42,482) from the 2016 Budget of $5,913,653.

Table #6: ENE Forecast	**2017**
Energy/ Transition	$3,943,209
Transmission	$1,927,962
Total	**$5,871,171**

ENE has provided a summary sheet of the 2017 Bulk Power Cost Projections for Pascoag Utility District which is included as **Testimony Exhibit HJR-7.**

The major adjustments used by ENE are listed below and broken out in more detail in **Testimony Exhibit HJR-8**.

1. The Seabrook projections include a fixed cost reduction to $37.78/kw and surplus funds being applied, $37,188 for Jan- June 2017 and $211,845 for the period Aug-Dec 2017. ENE forecast the net adjustments for Seabrook will be a reduction of ($534,285).
2. With NYPA projections they changed the entitlements in St. Lawrence and Niagara from 2300kw to 1700kw from May – December 2017. They also applied a reduction of 26% to transmission due to the lower entitlement. The net adjustment to the NYPA projections was a net reduction of ($118,880)
3. ENE updated the Capacity projections to reflect the auction pricing, bilateral, and payments by the Lead Participants. The ISO FMC Cost will rise by $300,360. The net adjustments to the capacity is an increase of $312,393;
4. ENE Updated NextEra Rise Call Options which includes a price lock on 6-30-16 which resulted in a net decrease of ($35,426);
5. The Bilateral Transactions includes a contract extension for Miller Hydro (now Brown Bear Hydro), a place holder for REC sales on Spruce Mountain and a contract reduction for TransCanada 100% LF less fixed volumes that resulted in a net increase of $227,467;
6. A change from resales to purchases from ISO –NE Power resulting in an increase of $40,876;
7. The adjustments to estimated ISO Expenses will result in a $71,266 increase.

- **Q7. What are the proposed factors, and what impact will they have on a residential customer using 500 kilowatt-hours of electricity.**

A7. A residential customer using 500 Kilowatt-hours of electricity currently pays $72.85. Under the proposed rates, that customer would see his monthly bill increased to $75.14, an increase of $2.30. A detailed summary of current rates and requested rates is included in this filing as **Testimony Exhibit HJR-2.** The Factors proposed are listed in **Table #7** which also includes a Purchase Power Restricted Fund Credit("PPRFC") which was created to refund $250,000 of the estimated over collection that was mentioned earlier in this testimony.

Table 7: **Factor**	**Current (2016)**	**Proposed (2017)**	**Difference**
Standard Offer	$0.05401	$0.05887	.00486
Transition	$0.00957	$0.01024	.00067
Transmission	$0.03081	$0.03211	.0013
PPRFC	($0.00222)	($0.00445)	(0.00223)
Total	**$.09217**	**$0.09677**	**$.0046**

- **Q8. Is Pascoag using any growth factors in its calculations for 2017?**

A8. No, we have kept the load growth factor flat this year due to the sluggish economy and the fact that we have seen several businesses close this year in our service territory and several rental properties demolished on Pascoag Main Street. Two of the apartment buildings will be rebuilt with commercial space on the bottom floors and affordable apartments on the upper floors but we do not expect that to be completed until 2018.

- **Q9. Are there any other issues that impact Pascoag' financial position?**

A9. We continue to see high annual write offs. This year the uncollectable accounts hit an all-time high of $53,514. The District continues to have problems collecting money from its protected class and financial hardship classified customers. These problems are outlined more fully in the District's monthly RIPUC 1725 filing. **Table #8** is a history of the District's uncollectable account.

TABLE #8: History of the District's Write Offs	
Year:	**Write Off Amount:**
2011	$31,355
2012	$36,083
2013	$31,777
2014	$28,875
2015	$39,195
2016	$53,514

Q10. Does this conclude your testimony?

Q10A. Yes, it does.

PASCOAG
UTILITY DISTRICT

Pascoag Electric • Pascoag Water

253 Pascoag Main Street
P.O. Box 107
Pascoag, RI 02859
Phone: 401-568-6222
Fax: 401-568-0066
www.pud-ri.org

Testimony Exhibits HJR-1

Daniele International Inc. Increase in kW demand

Pascoag Utility District

Revision: 15600

10/05/2016 12:30:53 pm

ACCOUNT 10524001 RECONCILIATION

Page: 1

Account	Name	Address	Home Phone	Work Phone	Mobile Phone	Cyc
10524001	DANIELE INTERNATIONAL INC	PO BOX 106 PASCOAG, RI 02859	()-	(401)568-6228	(401)527-5317	1

Meter	Rdg	Rdg Dt	Rate	Dvc Type	# of Dvc	Mem Nbr
E5125	61248	09/27/2016	PA-I			

Dep Type	Prov	Srv Loc Nbr	Dep Amt	Dep Dt	Use

Provider	Cur AR	30 Day AR	60 Day AR	90 Day AR
EPUD	34,473.53	0.00	0.00	0.00

Srv Loc Nbr	S/S	YTD Rev	YTD Usage	Srv Map Loc	Rev Class	Sub	Route	Board Dist	Dist Office
10933	1	322,616.84	2,689,200	105 DAVIS DR B	3		20		Pascoag Utility District

BILLING HISTORY

	Oct 16	Sep 16	Aug 16	Jul 16	Jun 16	May 16	Apr 16	Mar 16	Feb 16	Jan 16	Dec 15	Nov 15
Rev:	27365.03	33345.58	27908.71	26481.54	22879.61	22879.61	24646.60	20093.23	20505.09	34506.07	27901.25	37325.18
Dmd:	7084.80	6937.20	6937.20	6715.80	6715.80	6715.80	6715.80	6715.80	6715.80	6715.80	6863.40	6863.40
Dvc:	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.66	0.66
PCA:	-640.96	-781.62	-653.75	-620.18	-535.46	-535.46	-577.02	-469.93	-473.13	-682.52	0.00	0.00
Rev Tot:	33809.47	39501.76	34192.76	32577.76	29060.55	29060.55	30785.98	26339.70	26748.36	40539.95	34765.31	44189.24
Tax:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other:	664.06	809.78	677.30	642.53	554.76	554.76	597.82	486.86	490.18	707.11	571.32	765.07
Total:	34473.53	40311.54	34870.06	33220.29	29615.31	29615.31	31383.80	26826.56	27238.54	41247.06	35336.63	44954.31
Pymnt:	-40311.54	-34715.01	-33375.34	-29615.31	-29615.31	-31383.80	-27712.16	-25113.21	-42486.79	-35336.63	-44954.31	-42947.85
NSF:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Total Rev:	325,837.50	Total Dmd:	81,696.60	Total Dvc:	7.32	Total PCA:	-5,970.03
Avg Rev:	27,153.12	Avg Dmd Rev:	6,808.05	Avg Reporting Rev:	33,961.18	Total Payment:	-417,567.26

USAGE HISTORY

	Oct 16	Sep 16	Aug 16	Jul 16	Jun 16	May 16	Apr 16	Mar 16	Feb 16	Jan 16	Dec 15	Nov 15
Usage:	288720	352080	294480	279360	241200	241200	259920	211680	213120	307440	248400	332640
Kw Dmd:	691.200	669.600	676.800	648.000	590.400	612.000	518.400	511.200	568.800	568.800	612.000	655.200
Bill Dmd:	691.200	676.800	676.800	655.200	655.200	655.200	655.200	655.200	655.200	655.200	669.600	669.600

Total Usage:	3,270,240	Total Kw Dmd:	7322.400	Total Bill Dmd:	7970.400
Avg Usage:	272,520	Avg Kw Dmd:	610.200	Avg Bill Dmd:	664.200

$$\begin{array}{r} 7322.40 \\ -\ 6782.40 \\ \hline 540. \end{array}$$

Kw Demand Increase

Pascoag Utility District

Revision: 15600

10/05/2016 12:31:28 pm

ACCOUNT 10524001 RECONCILIATION

Account	Name	Address	Home Phone	Work Phone	Mobile Phone	Cyc
10524001	DANIELE INTERNATIONAL INC	PO BOX 106 PASCOAG, RI 02859	()-	(401)568-6228	(401)527-5317	1

Meter	Rdg	Rdg Dt	Rate	Dvc Type	# of Dvc	Mem Nbr
E5125	61248	09/27/2016	PA-I			

Dep Type	Prov	Srv Loc Nbr	Dep Amt	Dep Dt	Use

Provider	Cur AR	30 Day AR	60 Day AR	90 Day AR
EPUD	34,473.53	0.00	0.00	0.00

Srv Loc Nbr	S/S	YTD Rev	YTD Usage	Srv Map Loc	Rev Class	Sub	Route	Board Dist	Dist Office
10933	1	322,616.84	2,689,200	105 DAVIS DR B	3		20		Pascoag Utility District

BILLING HISTORY

	Oct 15	Sep 15	Aug 15	Jul 15	Jun 15	May 15	Apr 15	Mar 15	Feb 15	Jan 15	Dec 14	Nov 14
Rev:	35069.89	33217.32	34344.97	26854.16	25565.41	26370.88	17591.32	32250.76	30336.13	36189.78	30757.97	34487.28
Dmd:	7158.60	7453.80	7527.60	7527.60	7527.60	7527.60	7527.60	7527.60	7527.60	7527.60	7527.60	7527.60
Dvc:	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.72	0.72	0.72
PCA:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rev Tot:	42229.15	40671.78	41873.23	34382.42	33093.67	33899.14	25119.58	39779.02	37864.39	43718.10	38286.29	42015.60
Tax:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other:	718.70	680.62	703.80	549.79	523.30	539.86	359.35	660.74	621.00	736.92	625.97	702.14
Total:	42947.85	41352.40	42577.03	34932.21	33616.97	34439.00	25478.93	40439.76	38485.39	44455.02	38912.26	42717.74
Pymnt:	-41352.40	-42577.03	-34932.21	-33616.97	-34439.00	-25478.93	-40439.76	-38485.39	-6595.69	-30623.42	-88865.91	-47882.87
NSF:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Total Rev:	363,035.87	Total Dmd:	89,888.40	Total Dvc:	8.10	Total PCA:	0.00
Avg Rev:	30,252.99	Avg Dmd Rev:	7,490.70	Avg Reporting Rev:	37,743.69	Total Payment:	-465,289.58

USAGE HISTORY

	Oct 15	Sep 15	Aug 15	Jul 15	Jun 15	May 15	Apr 15	Mar 15	Feb 15	Jan 15	Dec 14	Nov 14
Usage:	312480	295920	306000	239040	227520	234720	156240	287280	270000	320400	272160	305280
Kw Dmd:	655.200	626.400	619.200	604.800	496.800	525.600	640.800	0.000	612.000	669.600	633.600	698.400
Bill Dmd:	698.400	727.200	734.400	734.400	734.400	734.400	734.400	734.400	734.400	734.400	734.400	734.400

Total Usage:	3,227,040	Total Kw Dmd:	6782.400	Total Bill Dmd:	8769.600
Avg Usage:	268,920	Avg Kw Dmd:	565.200	Avg Bill Dmd:	730.800

Testimony
Exhibit HJR-1

Pascoag Utility District

Revision: 15600

10/05/2016 12:34:17 pm

ACCOUNT 10686001 RECONCILIATION

Page: 1

Account	Name	Address	Home Phone	Work Phone	Mobile Phone	Cyc
10686001	GIO INTERNATIONAL FOODS INC	PO BOX 106 PASCOAG, RI 02859	()-	NONE LISTED	()-	1

Meter	Rdg	Rdg Dt	Rate	Dvc Type	# of Dvc	Mem Nbr
E9921	38407	09/27/2016	PA-I			

Dep Type	Prov	Srv Loc Nbr	Dep Amt	Dep Dt	Use

Provider	Cur AR	30 Day AR	60 Day AR	90 Day AR
EPUD	5,484.58	0.00	0.00	0.00

Srv Loc Nbr	S/S	YTD Rev	YTD Usage	Srv Map Loc	Rev Class	Sub	Route	Board Dist	Dist Office
936	1	54,665.28	412,560	180 DAVIS DR	3	1	20		Pascoag Utility District

BILLING HISTORY

	Oct 16	Sep 16	Aug 16	Jul 16	Jun 16	May 16	Apr 16	Mar 16	Feb 16	Jan 16	Dec 15	Nov 15
Rev:	4062.03	4651.02	4281.01	4348.97	3389.97	3473.04	3873.25	3782.63	3664.57	5419.87	3433.05	4140.07
Dmd:	1418.60	1467.80	1467.80	1467.80	1467.80	1467.80	1467.80	1467.80	1467.80	1467.80	1467.80	1574.40
Dvc:	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.66	0.66
PCA:	-92.88	-106.74	-98.04	-99.63	-77.08	-79.03	-88.44	-86.31	-82.41	-105.32	0.00	0.00
Rev Tot:	5388.35	6012.68	5651.37	5717.74	4781.29	4862.41	5253.21	5164.72	5050.56	6782.95	4901.51	5715.13
Tax:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other:	96.23	110.58	101.57	103.22	79.86	81.88	91.63	89.42	85.38	109.11	68.26	82.80
Total:	5484.58	6123.26	5752.94	5820.96	4861.15	4944.29	5344.84	5254.14	5135.94	6892.06	4969.77	5797.93
Pymnt:	-6123.26	-5752.94	-5820.96	-4861.15	-4944.29	-5344.84	-5418.14	-4971.94	-6892.06	-4969.77	-5797.93	-6049.94
NSF:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Total Rev:	48,519.48	Total Dmd:	17,671.00	Total Dvc:	7.32	Total PCA:	-915.88
Avg Rev:	4,043.29	Avg Dmd Rev:	1,472.58	Avg Reporting Rev:	5,515.87	Total Payment:	-66,947.22

USAGE HISTORY

	Oct 16	Sep 16	Aug 16	Jul 16	Jun 16	May 16	Apr 16	Mar 16	Feb 16	Jan 16	Dec 15	Nov 15
Usage:	41840	48080	44160	44880	34720	35600	39840	38880	37120	47440	29680	36000
Kw Dmd:	136.000	138.400	136.000	135.200	128.800	126.400	127.200	127.200	127.200	128.000	125.600	120.000
Bill Dmd:	138.400	143.200	143.200	143.200	143.200	143.200	143.200	143.200	143.200	143.200	143.200	153.600

Total Usage:	478,240	Total Kw Dmd:	1556.000	Total Bill Dmd:	1724.000
Avg Usage:	39,853	Avg Kw Dmd:	129.667	Avg Bill Dmd:	143.667

1556.00
- 1417.60
138.40 KW Demand Increase

Pascoag Utility District

Revision: 15600

10/05/2016 12:38:13 pm

ACCOUNT 10686001 RECONCILIATION

Account	Name	Address	Home Phone	Work Phone	Mobile Phone	Cyc
10686001	GIO INTERNATIONAL FOODS INC	PO BOX 106 PASCOAG, RI 02859	()-	NONE LISTED	()-	1

Meter	Rdg	Rdg Dt	Rate	Dvc Type	# of Dvc	Mem Nbr
E9921	38407	09/27/2016	PA-I			

Dep Type	Prov	Srv Loc Nbr	Dep Amt	Dep Dt	Use

Provider	Cur AR	30 Day AR	60 Day AR	90 Day AR
EPUD	5,484.58	0.00	0.00	0.00

Srv Loc Nbr	S/S	YTD Rev	YTD Usage	Srv Map Loc	Rev Class	Sub	Route	Board Dist	Dist Office
936	1	54,665.28	412,560	180 DAVIS DR	3	1	20		Pascoag Utility District

BILLING HISTORY

	Oct 15	Sep 15	Aug 15	Jul 15	Jun 15	May 15	Apr 15	Mar 15	Feb 15	Jan 15	Dec 14	Nov 14
Rev:	4354.86	4900.78	4757.59	3621.00	4363.81	3719.44	2546.80	4757.59	4885.81	4571.72	4868.98	5292.35
Dmd:	1607.20	1697.40	1697.40	1836.80	1836.80	1836.80	1836.80	1836.80	1836.80	1836.80	1836.80	1836.80
Dvc:	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.72	0.72	0.72
PCA:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rev Tot:	5962.72	6598.84	6455.65	5458.46	6201.27	5556.90	4384.26	6595.05	6723.27	6409.24	6706.50	7129.87
Tax:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other:	87.22	98.44	95.50	72.13	87.40	74.15	50.05	95.50	98.07	91.08	97.15	105.80
Total:	6049.94	6697.28	6551.15	5530.59	6288.67	5631.05	4434.31	6690.55	6821.34	6500.32	6803.65	7235.67
Pymnt:	-6697.28	-6551.15	-5530.59	-6288.67	-5631.05	-4434.31	-6690.55	-6821.34	-6500.32	-6705.11	-7334.21	-7601.15
NSF:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Total Rev:	52,640.73	Total Dmd:	21,533.20	Total Dvc:	8.10	Total PCA:	0.00
Avg Rev:	4,386.73	Avg Dmd Rev:	1,794.43	Avg Reporting Rev:	6,181.16	Total Payment:	-76,785.73

USAGE HISTORY

	Oct 15	Sep 15	Aug 15	Jul 15	Jun 15	May 15	Apr 15	Mar 15	Feb 15	Jan 15	Dec 14	Nov 14
Usage:	37920	42800	41520	31360	38000	32240	21760	41520	42640	39600	42240	46000
Kw Dmd:	143.200	141.600	143.200	133.600	136.800	128.800	139.200	0.000	0.000	140.800	153.600	156.800
Bill Dmd:	156.800	165.600	165.600	179.200	179.200	179.200	179.200	179.200	179.200	179.200	179.200	179.200

Total Usage:	457,600	Total Kw Dmd:	1417.600	Total Bill Dmd:	2100.800
Avg Usage:	38,133	Avg Kw Dmd:	118.133	Avg Bill Dmd:	175.067

Pascoag Utility District

Revision: 15600

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ACCOUNT 10524003 RECONCILIATION

Page: 1

Account	Name	Address	Home Phone	Work Phone	Mobile Phone	Cyc
10524003	DANIELE INTERNATIONAL INC	PO BOX 106 PASCOAG, RI 02859	()-	(401)568-6228	(401)527-5317	1

Meter	Rdg	Rdg Dt	Rate	Dvc Type	# of Dvc	Mem Nbr
E1096	92829	09/27/2016	PA-I	400 Watt Sodium	5	

Dep Type	Prov	Srv Loc Nbr	Dep Amt	Dep Dt	Use

Provider	Cur AR	30 Day AR	60 Day AR	90 Day AR
EPUD	35,122.63	0.00	0.00	0.00

Srv Loc Nbr	S/S	YTD Rev	YTD Usage	Srv Map Loc	Rev Class	Sub	Route	Board Dist	Dist Office
932	1	321,900.33	2,714,635	105 DAVIS DR M	3	1	20		Pascoag Utility District

BILLING HISTORY

	Oct 16	Sep 16	Aug 16	Jul 16	Jun 16	May 16	Apr 16	Mar 16	Feb 16	Jan 16	Dec 15	Nov 15
Rev:	28467.50	33564.56	28852.61	27319.72	21324.07	20757.73	27161.15	20236.69	19808.49	34819.30	27498.52	35920.10
Dmd:	6551.80	6428.80	6478.00	6478.00	6478.00	6478.00	6478.00	6478.00	6478.00	6478.00	6478.00	6478.00
Dvc:	79.30	79.30	79.30	79.30	79.30	79.30	79.30	79.30	79.30	79.30	79.36	79.36
PCA:	-666.89	-786.77	-675.95	-639.89	-498.88	-485.56	-636.16	-473.30	-456.96	-688.73	0.00	0.00
Rev Tot:	34431.71	39285.89	34733.96	33237.13	27382.49	26829.47	33082.29	26320.69	25908.83	40687.87	34055.88	42477.46
Tax:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other:	690.92	815.12	700.30	662.95	516.86	503.06	659.09	490.36	473.43	713.55	563.04	736.18
Total:	35122.63	40101.01	35434.26	33900.08	27899.35	27332.53	33741.38	26811.05	26382.26	41401.42	34618.92	43213.64
Pymnt:	-40101.01	-35589.31	-33745.03	-27899.35	-27332.53	-33741.38	-28631.45	-24561.86	-41401.42	-34618.92	-43213.64	-41559.45
NSF:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Total Rev:	325,730.44	Total Dmd:	77,760.60	Total Dvc:	951.72	Total PCA:	-6,009.09
Avg Rev:	27,144.20	Avg Dmd Rev:	6,480.05	Avg Reporting Rev:	33,624.25	Total Payment:	-412,395.35

USAGE HISTORY

	Oct 16	Sep 16	Aug 16	Jul 16	Jun 16	May 16	Apr 16	Mar 16	Feb 16	Jan 16	Dec 15	Nov 15
Usage:	300400	354400	304480	288240	224720	218720	286560	213200	205840	310240	244800	320080
Kw Dmd:	639.200	624.000	600.000	536.000	517.600	467.200	548.800	466.400	454.400	524.800	586.400	615.200
Bill Dmd:	639.200	627.200	632.000	632.000	632.000	632.000	632.000	632.000	632.000	632.000	632.000	632.000

Total Usage:	3,271,680	Total Kw Dmd:	6580.000	Total Bill Dmd:	7586.400
Avg Usage:	272,640	Avg Kw Dmd:	548.333	Avg Bill Dmd:	632.200

6580.00
- 6572.00
8.00 Kw Demand Increase

Pascoag Utility District

Revision: 15600

10/05/2016 12:32:42 pm

ACCOUNT 10524003 RECONCILIATION

Account	Name	Address	Home Phone	Work Phone	Mobile Phone	Cyc
10524003	DANIELE INTERNATIONAL INC	PO BOX 106 PASCOAG, RI 02859	()-	(401)568-6228	(401)527-5317	1

Meter	Rdg	Rdg Dt	Rate	Dvc Type	# of Dvc	Mem Nbr
E1096	92829	09/27/2016	PA-I	400 Watt Sodium	5	

Dep Type	Prov	Srv Loc Nbr	Dep Amt	Dep Dt	Use

Provider	Cur AR	30 Day AR	60 Day AR	90 Day AR
EPUD	35,122.63	0.00	0.00	0.00

Srv Loc Nbr	S/S	YTD Rev	YTD Usage	Srv Map Loc	Rev Class	Sub	Route	Board Dist	Dist Office
932	1	321,900.33	2,714,635	105 DAVIS DR M	3	1	20		Pascoag Utility District

BILLING HISTORY

	Oct 15	Sep 15	Aug 15	Jul 15	Jun 15	May 15	Apr 15	Mar 15	Feb 15	Jan 15	Dec 14	Nov 14
Rev:	33897.49	34479.22	36457.07	27749.12	29288.44	26934.70	13725.09	32429.75	30246.58	36811.34	30694.92	36243.84
Dmd:	6888.00	7248.80	7773.60	7773.60	7773.60	7773.60	7773.60	7773.60	7773.60	7773.60	7773.60	7773.60
Dvc:	79.36	79.36	79.36	79.36	79.36	79.36	79.36	79.36	79.36	79.42	79.42	79.42
PCA:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rev Tot:	40864.85	41807.38	44310.03	35602.08	37141.40	34787.66	21578.05	40282.71	38099.54	44664.36	38547.94	44096.86
Tax:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other:	694.60	706.56	747.22	568.19	599.84	551.45	279.86	664.42	619.16	749.62	624.68	738.02
Total:	41559.45	42513.94	45057.25	36170.27	37741.24	35339.11	21857.91	40947.13	38718.70	45413.98	39172.62	44834.88
Pymnt:	-42513.94	-45057.25	-36170.27	-37741.24	-35339.11	-21857.91	-40947.13	-38718.70	-83273.31	-46148.17	0.00	-50350.49
NSF:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Total Rev:	368,957.56	Total Dmd:	91,872.80	Total Dvc:	952.50	Total PCA:	0.00
Avg Rev:	30,746.46	Avg Dmd Rev:	7,656.07	Avg Reporting Rev:	38,402.53	Total Payment:	-478,117.52

USAGE HISTORY

	Oct 15	Sep 15	Aug 15	Jul 15	Jun 15	May 15	Apr 15	Mar 15	Feb 15	Jan 15	Dec 14	Nov 14
Usage:	302000	307200	324880	247040	260800	239760	121680	288880	269200	325920	271600	320880
Kw Dmd:	627.200	632.000	624.800	597.600	600.800	473.600	554.400	0.000	535.200	624.800	630.400	672.000
Bill Dmd:	672.000	707.200	758.400	758.400	758.400	758.400	758.400	758.400	758.400	758.400	758.400	758.400

Total Usage:	3,279,840	Total Kw Dmd:	6572.800	Total Bill Dmd:	8963.200
Avg Usage:	273,320	Avg Kw Dmd:	547.733	Avg Bill Dmd:	746.933

PASCOAG
UTILITY DISTRICT

Pascoag Electric • Pascoag Water

253 Pascoag Main Street
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Testimony Exhibits HJR-2

2017 Forecasted Rates & Comparison of Requested Rates to Current Rates

Schedule H

Forecast Rates

Transition Cost Calculations:				
Estimated Sales (MWH) to customers			56,173	See Schedule F-2, Line 113
Forecast Transition Cost			$577,000	See Schedule F-2, line 71
Historic Transistion Revenue			($548,004)	See Schedule A-3, Line 153
Historic Transition Expense		$	534,000	See Schedule A-2, Line 78
Carry over from prior period (12/31/2015)			$11,952	See Schedule C-3, Line 122
	Total		$574,948	
Cost Per MWH		**$**	**10.24**	**Transition Charge**
Transmission Cost Calculations:				
Estimated Sales (MWH) to customers			56,173	See Schedule F-2, Line 113
Forecast Transmission Cost			$1,927,962	See Schedule F-2, line 77
Historic Transmission Revenue			($1,747,776)	See Schedule A-3, Line 155
Historic Transmission Expense		$	1,632,502	See Schedule A-2, Line 86
Carry over from prior period (12/31/2015)			($8,906)	See Schedule C-4, Line 120
	Total		$1,803,782	
Cost per MWH		**$**	**32.11**	**Transmission Charge**
Standard Offer Calculation:				
Estimated Sales (MWH) to customers			56,173	See Schedule F-2, Line 113
Forecast Standard Offer			$3,366,209	See Schedule F-2, line 100
Historic SOS Revenue			($3,106,087)	See Schedule A-3, Line 154
Historic SOS Expense		$	3,536,407	See Schedule A-2, Line 121
Carry over from prior period (12/31/2015)			($489,697)	See Schedule C-2, Line 123
	Total		$3,306,832	
Cost per MWH		**$**	**58.87**	**Standard OfferService**
(1) This is the net amount including any over/(under) recovery				
Purchase Power Reserve Fund Credit				
Estmated Sale (MWH) to customers			56,173	See Schedule F-2, Line 113
Total Flow back for 2017		$	(250,000.00)	
Cost Per MWH		**$**	**(4.45)**	**Purchase Power Reserve Fund Credit**
(2) this is the net amount including the PPRFC				
Total				**$ 96.76**

Revenue/Expense Proof:

Forecast Transition Cost	$	577,000	See Schedule F-2, line 71		
Over/Under Collection at period end	$	(2,052)	Schedule C-3, Line 142		
	$	574,948	$		10.24
Forecast Transmission Cost	$	1,927,962	See Schedule F-2, line 77		
Over/Under Collection at period end	$	(124,180)	Schedule C-4, Line 139		
	$	1,803,782	$		32.11
Forecast SOS Cost	$	3,366,209	See Schedule F-2, line 100		
Over/Under Collection at period end		($59,377)	Schedule C-2, Line 143		
	$	3,306,832	$		58.87
Purchase Power Reserve Fund Credit	$	(250,000.00)	$		(4.45)
			$		**96.76**

Testimony
Exhibit HJR-2

Schedule H-1

Pascoag Utility District - Electric Department
Comparison of Current Rate vs. Proposed Rate
Impact on a 500 KilowattHour Residential Customer

Column 1 Approved Rate December 2015 (For 2016)			Column 2 Rate Requested December 2016 (For 2017)		
	Unit Cost	Total		Unit Cost	Total
Customer Charge		$ 6.00	Customer Charge		$ 6.00
Distribution	$ 0.03922	$ 19.61	Distribution	$ 0.03922	$ 19.61
Transition	$ 0.00957	$ 4.79	Transition	$ 0.01024	$ 5.12
Standard Offer	$ 0.05401	$ 27.01	Standard Offer	$ 0.05887	$ 29.43
Transmission	$ 0.03081	$ 15.41	Transmission	$ 0.03211	$ 16.06
DSM/ Renewables	$ 0.00230	$ 1.15	DSM/Renewables	$ 0.00230	$ 1.15
PPRFC	$ (0.00222)	$ (1.11)	PPRFC	$ (0.00445)	$ (2.23)
Total		$ 72.85	Total		$ 75.14
Net Increase/(Decrease)		$ (9.85)	Net Increase/(Decrease)		$ 2.30
Percent Increase/(Decrease)		-11.9%	Percent Increase/(Decrease)		3.2%
Transition	$ 0.00957		Transition	$ 0.01024	
SOS	$ 0.05401		SOS	$ 0.05887	
PPRFC	$ (0.00222)		PPRFC	$ (0.00445)	
Transmission	$ 0.03081		Transmission	$ 0.03211	
Total	$ 0.09217		Total	$ 0.09676	

PASCOAG
UTILITY DISTRICT

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Testimony Exhibits HJR-3

Proposed Purchase Power Restricted Fund Credit

Proposed Purchase Power Restricted Fund Credit ("PPRFC")

If approved by Division the District proposes to flow back $250,000 of the over collection back to the customers through a PPRFC of 4.44 mill per kilowatt hour reduction ($0.00444)

Date	Transfer	Balance to refund
		$ 250,000.00
1/1/2017	$ 20,833.37	$ 229,166.63
2/1/2017	$ 20,833.33	$ 208,333.30
3/1/2017	$ 20,833.33	$ 187,499.97
4/1/2017	$ 20,833.33	$ 166,666.64
5/1/2017	$ 20,833.33	$ 145,833.31
6/1/2017	$ 20,833.33	$ 124,999.98
7/1/2017	$ 20,833.33	$ 104,166.65
8/1/2017	$ 20,833.33	$ 83,333.32
9/1/2017	$ 20,833.33	$ 62,499.99
10/1/2017	$ 20,833.33	$ 41,666.66
11/1/2017	$ 20,833.33	$ 20,833.33
12/1/2017	$ 20,833.33	$ (0.00)
Total	**$ 250,000.00**	

Journal Entry to Record:

	Debit	Credit
Operating Cash	$ 20,833.33	
PPRF		$ 20,833.33

If approved by the RIPUC, this entry would be done once a month to transfer money equal to the PPRFC received by the electric customers through their monthly bills.

PASCOAG
UTILITY DISTRICT

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Testimony Exhibits HJR-4

Summary of Cash Flow

Summary of Cash Flow - January 2016

Operating Cash balance forward	$ 258,090		
Projected Purchased Power Expense:			
ENE	($224,021)		
·oject 6 (MMWEC & HQ)	($93,309)		
NYPA	($35,505)		
ENE/ISO	($114,318)		
Deferred PP Credit	$10,001		
			($457,153)
Customer Payments	$ 762,946		
NSF cks	($587)		
Payroll, benefits	($201,131)		
Transfer to PPRF	($15,000)	DPI Base rate - for Jan	
Encumbered for RF	$0		
Transfer to RF Jan	($25,500)		
Transfer to RF Feb	($25,500)		
Transfer from RF	$43,276	(1)	
Transfer from RF	$34,609	(2)	
transfer to YE Account	$0		
Misc. vendor payments	($226,203)		
Encumber for PP - from DEC	$776,000		
Encumber for PP - for Jan	($582,390)		
	$ 341,459		

Other Financial Information:

Accounts Payable Balance	$ 91,045
Accounts Receivable Balance	$ 688,868

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$ 10,000		
Storm Fund	$ 59,173		
Working Cash Reserve	$ 21,331		
Dedicated DSM Fund			
Total Savings/Investment (NR)	$ 90,504		
Year-End Reconciliation Account	**$ 541,859**	(Year to-date over collection)	
Restricted Account(Debt/Capital)	**$ 544,988**		
Restricted Account Rate Stabilization flow back (RSF)	**$ 125,000**		
Restricted Account (Purchase Pwr)	**$ 669,341**		
Net All Saving/Investment			**$ 1,971,692**

Misc. Accounts:

Customer Deposit Holding Account GL235.0	$ 307,983
Working Capital - on Deposit w/ ENE GL165.06	$ 169,369
Working Capital - on Deposit w/MMWEC GL165.02	$ 2,256
Deffered PP Credit Account	$ 50,003

Restricted Fund 2016			**$ 306,000**			
Jan-16	$	25,500				
Feb-16	$	25,500				
Mar-16						
Apr-16						
May-16						
Jun-16						
Jul-16						
Aug-16						
Sep-16						
Oct-16						
Nov-16				**Annual Funding Level**	**% Complete**	**Funding Requirement**
Dec-16						
Total Transfer	**$**	**51,000**		$ 306,000	17%	$ 255,000

Storm Fund - 2016			**$ 20,000**			
Q/E 3/16	$	-				
Q/E 6/16	$	-				
Q/E 9/16	$	-		**Annual Funding Level**	**% Complete**	**Funding Requirement**
Q/E 12/16	$	-				
Total Transfer	**$**	-		$ 20,000	0%	$ 20,000

(1) Capital Items: $12,500 Boiler conversion; $30,776.48 Mapping
(2) Switches $3216, Mapping $21675.12; Office paint woodwork $5195.76; security syst $2051.76; bookcases$1168, LED Office Lights $1302.16

Testimony
Exhibit HJR-4

Summary of Cash Flow - February 2016

Operating Cash balance forward	$341,459	
Projected Purchased Power Expense:		
ENE	($245,222)	
Project 6 (MMWEC & HQ)	($76,523)	
NYPA	($30,544)	
ENE/ISO	($126,499)	
Deferred PP Credit	$10,001	
		($468,788)
Customer Payments	$752,890	
NSF cks	($550)	
Payroll, benefits	($163,303)	
Transfer to PPRF	($12,130)	DPI Base rate - for DEC
Encumbered for RF March	($25,000)	
Transfer from RF	$0	
transfer from Rate Stabilization fund	$20,833	
transfer to YE Account	$0	
Misc. vendor payments	($119,802)	
Encumber for PP - from Jan	$582,390	
Encumber for PP - for March	($675,000)	
	$232,999	

Other Financial Information:

Accounts Payable Balance	($200)
Accounts Receivable Balance	$647,359

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$10,000	
Storm Fund	$59,173	
Working Cash Reserve	$21,473	
Dedicated DSM Fund		
Total Savings/Investment (NR)	$90,646	
Year-End Reconciliation Account	$542,275	(Year to-date over collection)
Restricted Account(Debt/Capital)	$518,103	
Restricted Account (RSF) Bal to refund	$104,167	
Restricted Account (Purchase Pwr)	$785,638	
Net All Saving/Investment		

Misc. Accounts:		**$ 2,040,829.00**
Customer Deposit Holding Account GL235.0	$304,183	
Working Capital - on Deposit w/ ENE GL165.06	$169,340	
Working Capital - on Deposit w/MMWEC GL165.02	$2,255	
Deferred PP Credit Account	$40,002	

Restricted Fund 2016 Goal			**$306,000**				
	16-Jan	$25,500					
	16-Feb	$25,500					
	16-Mar						
	16-Apr						
	16-May						
	16-Jun						
	16-Jul						
	16-Aug						
	16-Sep						
	16-Oct						
	16-Nov	$-					
	16-Dec	$-		Annual		%	Funding
Total Transfer		**$51,000**		Funding Level		Complete	Requirement
					$306,000	17%	$255,000

Storm Fund - 2016			$20,000				
Q/E 3/16							
Q/E 6/16							
Q/E 9/16							
Q/E 12/16				Annual		%	Funding
Total Transfer		$-		Funding Level		Complete	Requirement
					$20,000	0%	$20,000

Summary of Cash Flow - March 2016

Operating Cash balance forward	$232,999		
Projected Purchased Power Expense:			
ENE	($206,269)		
Project 6 (MMWEC & HQ)	($84,160)		
NYPA	($52,657)		
ENE/ISO	($138,716)		
Deferred PP Credit	$10,001		
			($471,801)
Customer Payments	$827,925		
NSF cks	($253)		
Payroll, benefits	($152,012)		
Transfer to RF Capital- March	($25,500)		
Encumbered for RF Capital April	($25,500)		
Transfer from RF Capital	$31,406		(1)
transfer from PPRF to Rate Stabilization fund	$10,417		
DPI transfer to PPRF	($17,870)	DPI Base rate - for March	
Misc. vendor payments	($158,635)		
Encumber for PP - from FEB	$675,000		
Encumber for PP - for April	($595,000)		
	$331,176		

Other Financial Information:

Accounts Payable Balance	$19,760
Accounts Receivable Balance	$526,142

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$10,000	
Storm Fund	$64,173	
Working Cash Reserve	$21,473	
Dedicated DSM Fund		
Total Savings/Investment (NR)	$95,646	
Year-End Reconciliation Account	$542,275	
Restricted Account(Debt/Capital)	$512,197	(Year to-date over collection)
Restricted Account (RSF) Bal to refund	$93,750	
Restricted Account(Purchase Pwr)	$793,092	
Net All Saving/Investment		
		$ 2,036,959.66

Misc. Accounts:

Customer Deposit Holding Account GL235.0	$307,183
Working Capital - on Deposit w/ ENE GL165.06	$169,340
Working Capital - on Deposit w/MMWEC GL165.02	$2,255
Deferred PP Credit Account	$30,001

Restricted Fund 2016 Goal			**$306,000**			
	16-Jan	$ 25,500				
	16-Feb	$ 25,500				
	16-Mar	$ 25,500				
	16-Apr					
	16-May					
	16-Jun					
	16-Jul					
	16-Aug					
	16-Sep					
	16-Oct					
	16-Nov	$-				
	16-Dec	$-		Annual	%	Funding
Total Transfer		**$ 76,500**		Funding Level	Complete	Requirement
				$306,000	25%	$229,500
Storm Fund - 2016 Goal			**$20,000**			
Q/E 3/16		$ 5,000				
Q/E 6/16						
Q/E 9/16						
Q/E 12/16				Annual	%	Funding
Total Transfer		**$ 5,000**		Funding Level	Complete	Requirement
				$20,000	25%	$15,000

Capital Item
(1) Mapping Project $13,869.04 , Mapping $17,537.00

Testimony
Exhibit HJR-4

Summary of Cash Flow - April 2016

Operating Cash balance forward	$331,176		
Projected Purchased Power Expense:			
ENE	($152,629)		
Project 6 (MMWEC & HQ)	($87,708)		
NYPA	($35,196)		
ENE/ISO	($140,451)		
Deferred PP Credit	$10,001		
			($405,983)
Customer Payments	$800,647		
NSF Checks	$0		
Payroll, benefits	($165,035)		
	$1,050		
Transfer to RF Capital- April	($25,500)		
Encumbered for RF Capital May	($25,500)		
Transfer from RF Capital	$0		(1)
Transfer from PPRF to Rate Stabilization fund	$10,417		
DPI transfer to PPRF	($15,000)	DPI Base rate - for March	
Misc. vendor payments	($145,258)		
Encumber for PP - from FEB	$595,000		
Encumber for PP - for April	($700,000)		
	$256,014		

Other Financial Information:			
Accounts Payable Balance	$0		
Accounts Receivable Balance	$532,713		
Summary of Savings/Investments: (Not Restricted)			
Contingency/Emergency	$10,000		
Storm Fund	$45,494		
Working Cash Reserve	$35,242		
Dedicated DSM Fund			
Total Savings/Investment (NR)	$90,736		
Year-End Reconciliation Account	$542,275	(Year to-date over collection)	
Restricted Account(Debt/Capital)	$536,647		
Restricted Account (RSF) Bal to refund	$93,750		
Restricted Account (Purchase Pwr)	$805,987		
Net All Saving/Investment			
Misc. Accounts:		**$**	**2,069,395.21**
Customer Deposit Holding Account GL235.0	$310,933		
Working Capital - on Deposit w/ ENE GL165.06	$169,463		
Working Capital - on Deposit w/MMWEC GL165.02	$2,260		
Deferred PP Credit Account	$20,001		

Restricted Fund 2016 Goal **$306,000**

16-Jan	$	25,500
16-Feb	$	25,500
16-Mar	$	25,500
16-Apr	$	25,500
16-May		
16-Jun		
16-Jul		
16-Aug		
16-Sep		
16-Oct		
16-Nov		
16-Dec		
Total Transfer	**$**	**102,000**

Annual Funding Level	% Complete	Funding Requirement
$306,000	33%	$204,000

Storm Fund - 2016 Goal **$20,000**

Q/E 3/16	$	5,000
Q/E 6/16		
Q/E 9/16		
Q/E 12/16		
Total Transfer	**$**	**5,000**

Annual Funding Level	% Complete	Funding Requirement
$20,000	25%	$15,000

Capital Item
(1) NE Electrical Fluke Measuring Tool

Summary of Cash Flow -May 2016

Operating Cash balance forward	$256,014		
Projected Purchased Power Expense:			
ENE	($101,984)		
Project 6 (MMWEC & HQ)	($86,047)		
NYPA	($36,484)		
ENE/ISO	($122,743)		
Deferred PP Credit	$10,001		
			($337,257)
Customer Payments	$665,075		
NSF Checks	($96)		
Payroll, benefits	($158,459)		
Transfer to RF Capital- May	($25,500)		
Encumbered for RF Capital June	($25,500)		
Transfer from RF Capital	$48,914		(1)
Transfer from PPRF to Rate Stabilization fund	$10,417		
DPI transfer to PPRF	($15,000)	DPI Base rate - for March	
Misc. vendor payments	($159,101)		
Encumber for PP - from April	$700,000		
Encumber for PP - for June	($590,000)		
	$369,507		
Other Financial Information:			
Accounts Payable Balance	$0		
Accounts Receivable Balance	$482,190		
Summary of Savings/Investments: (Not Restricted)			
Contingency/Emergency	$10,000		
Storm Fund	$45,494		
Working Cash Reserve	$35,242		
Dedicated DSM Fund			
Total Savings/Investment (NR)	$90,736		
Year-End Reconciliation Account	$542,275	(Year to-date over collection)	
Restricted Account(Debt/Capital)	$520,278		
Rate Stabilization fund (RSF) Bal. left to refund	$83,334		
Restricted Account (Purchase Pwr)	$810,570		
Net All Saving/Investment			
Misc. Accounts:		**$**	**2,047,193.39**
Customer Deposit Holding Account GL235.0	$307,183		
Working Capital - on Deposit w/ ENE GL165.06	$169,340		
Working Capital - on Deposit w/MMWEC GL165.02	$2,255		
Deferred PP Credit Account	$10,001		

Restricted Fund 2016 Goal			**$306,000**			
	16-Jan	$ 25,500				
	16-Feb	$ 25,500				
	16-Mar	$ 25,500				
	16-Apr	$ 25,500				
	16-May	$ 25,500				
	16-Jun					
	16-Jul					
	16-Aug					
	16-Sep					
	16-Oct					
	16-Nov	$-				
	16-Dec	$-				
Total Transfer		**$ 127,500**		Annual Funding Level	% Complete	Funding Requirement
				$306,000	42%	$178,500
Storm Fund - 2016 Goal			**$20,000**			
Q/E 3/16		$ 5,000				
Q/E 6/16						
Q/E 9/16						
Q/E 12/16						
Total Transfer		**$ 5,000**		Annual Funding Level	% Complete	Funding Requirement
				$20,000	25%	$15,000

Capital Item
(1) Dodge Ram Dump Truck $45744 , Tablet $3170

Testimony
Exhibit HJR-4

Summary of Cash Flow -June 2016

Operating Cash balance forward	$323,763	
Projected Purchased Power Expense:		
ENE	($136,816)	
Project 6 (MMWEC & HQ)	($80,232)	
NYPA	($39,977)	
ENE/ISO	($115,020)	
deferred PP Credit	$0	
		($372,045)
Customer Payments	$800,380	
NSF Checks	($1,359)	
Payroll, benefits	($142,216)	
Encumbered PP From May	$25,500	
Transfer to RF Capital- June	($25,500)	
Encumbered for RF Capital July	($25,500)	
Transfer from RF Capital	$978	(1)
transfer from PPRF to Rate Stabilization fund	$10,417	
DPI transfer to PPRF	($15,000)	DPI Base rate - for June
Misc. vendor payments	($63,231)	
Encumber for PP - from May	$590,000	
Encumber for PP - for July	($700,000)	
	$406,187	

Other Financial Information:

Accounts Payable Balance	$0
Accounts Receivable Balance	$441,868

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$10,000	
Storm Fund	$55,494	
Working Cash Reserve	$25,288	
Dedicated DSM Fund		
Total Savings/Investment (NR)	$90,782	
Year-End Reconciliation Account	$542,603	(Year to-date over collection)
Restricted Account(Debt/Capital)	$544,799	
Rate Stabilization fund (RSF) Bal. left to refund	$62,501	
Restricted Account (Purchase Pwr)	$815,153	
Net All Saving/Investment		
		$2,055,838

Misc. Accounts:

Customer Deposit Holding Account GL235.0	$307,183
Working Capital - on Deposit w/ ENE GL165.06	$169,531
Working Capital - on Deposit w/MMWEC GL165.02	$2,262
Deferred PP Credit Account	$0

Restricted Fund 2016 Goal **$306,000**

16-Jan	$ 25,500					
16-Feb	$ 25,500					
16-Mar	$ 25,500					
16-Apr	$ 25,500					
16-May	$ 25,500					
16-Jun	$ 25,500					
16-Jul						
16-Aug						
16-Sep						
16-Oct						
16-Nov						
16-Dec						
Total Transfer	**$ 153,000**		Annual Funding Level	$306,000	% Complete 50%	Funding Requireme $153,000

Storm Fund - 2016 Goal **$20,000**

Q/E 3/16	$ 5,000.00				
Q/E 6/16	$ 5,000.00				
Q/E 9/16					
Q/E 12/16					
Total Transfer	**$ 10,000**	Annual Funding Level	$20,000	% Complete 50%	Funding Requireme $10,000

Capital Item

(1) Johns Workstation and Monitors

Summary of Cash Flow -July 2016

Operating Cash balance forward	$406,187		
Projected Purchased Power Expenes:			
ENE	($173,916)		
Project 6 (MMWEC & HQ)	($78,323)		
NYPA	($34,291)		
ENE/ISO	($118,210)		
Deferred PP Credit	$0		
			($404,740)
Customer Payments	$627,978		
NSF Checks	($830)		
Payroll, benefits	($132,480)		
Encumbered PP From June	$25,500		
Transfer to RF Capital- July	($25,500)		
Encumbered for RF Capital August	($25,500)		
Transfer from RF Capital	$17,075		(1)
Transfer from PPRF to Rate Stabilization fund	$10,417		
DPI tranfer to PPRF	($15,000)	DPI Base rate - for July	
Misc. vendor payments	($131,288)		
Encumber for PP - from JUNE	$700,000		
Encumber for PP - for Aug	($752,000)		
	$299,819		

Other Financial Information:

Accounts Payable Balance	$10,620		
Accounts Receivable Balance	$537,930		
Summary of Savings/Investments: (Not Restricted)			
Contingency/Emergency	$10,000		
Storm Fund	$55,494		
Working Cash Reserve	$25,288		
Dedicated DSM Fund			
Total Savings/Investment (NR)	$90,782		
Year-End Reconciliation Account	$542,710	(Year to-date over collection)	
Restricted Account(Debt/Capital)	$553,224		
Rate Stablization fund (RSF) Bal. left to refund	$52,084		
Restricted Account(Purchase Pwr)	$819,737		
Net All Saving/Investment			
			$2,058,537

Misc. Accounts:

Customer Deposit Holding Account GL235.0	$313,482
Working Capital - on Deposit w/ ENE GL165.06	$169,531
Working Capital - on Deposit w/MMWEC GL165.02	$2,262
Deferred PP Credit Account	$0

Restricted Fund 2016 Goal **$306,000**

16-Jan	$	25,500
16-Feb	$	25,500
16-Mar	$	25,500
16-Apr	$	25,500
16-May	$	25,500
16-Jun	$	25,500
16-Jul	$	25,500
16-Aug		
16-Sep		
16-Oct		
16-Nov		
16-Dec		
Total Transfer	**$**	**178,500**

Annual Funding Level	% Complete	Funding Requirement
$306,000	58%	$127,500

Storm Fund - 2016 Goal **$20,000**

Q/E 3/16	$ 5,000.00
Q/E 6/16	$ 5,000.00
Q/E 9/16	
Q/E 12/16	
Total Transfer	**$ 10,000**

Annual Funding Level	% Complete	Funding Requirement
$20,000	50%	$10,000

Capital Item
(1) Dump Bed for Truck

Testimony
Exhibit HJR-4

Summary of Cash Flow -August 2016

Operating Cash balance forward	$299,819	
Projected Purchased Power Expense:		
ENE	($261,510)	
Project 6 (MMWEC & HQ)	($79,807)	
NYPA	($27,867)	
ENE/ISO	($125,279)	
Deferred PP Credit	$0	
		($494,463)
Customer Payments	$737,797	
NSF Checks	($603)	
Payroll, benefits	($169,171)	
Encumbered PP From July	$25,500	
Transfer to RF Capital- August	($25,500)	
Encumbered for RF Capital Sept	($25,500)	
Transfer from RF Capital	$23,256	(1)
Transfer from PPRF to Rate Stabilization fund	$10,417	
DPI transfer to PPRF	($15,221)	DPI Base rate - for July
Misc. vendor payments	($82,289)	
Encumber for PP - from July	$752,000	
Encumber for PP - for Sept	($750,000)	
	$286,042	

Other Financial Information:

Accounts Payable Balance	8415
Accounts Receivable Balance	$630,004

Summary of Savings/Investments: (Not Restricted)

Contingency/Emergency	$10,000	
Storm Fund	$55,494	
Working Cash Reserve	$25,334	
Dedicated DSM Fund		
Total Savings/Investment (NR)	$90,828	
Year-End Reconciliation Account	$542,814	(Year to-date over collection)
Restricted Account(Debt/Capital)	$555,468	
Rate Stabilization fund (RSF) Bal. left to refund	$41,667	
Restricted Account(Purchase Pwr)	$824,541	
Net All Saving/Investment		
		$2,055,318

Misc. Accounts:

Customer Deposit Holding Account GL235.0	$313,482
Working Capital - on Deposit w/ ENE GL165.06	$169,531
Working Capital - on Deposit w/MMWEC GL165.02	$2,262
Deferred PP Credit Account	$68,178

Restricted Fund 2016 Goal			**$306,000**				
	16-Jan	$ 25,500					
	16-Feb	$ 25,500					
	16-Mar	$ 25,500					
	16-Apr	$ 25,500					
	16-May	$ 25,500					
	16-Jun	$ 25,500					
	16-Jul	$ 25,500					
	16-Aug	$ 25,500					
	16-Sep						
	16-Oct						
	16-Nov						
	16-Dec			Annual		%	Funding
Total Transfer		**$ 204,000**		Funding Level		Complete	Requirement
					$306,000	67%	$102,000

Storm Fund - 2016 Goal		**$20,000**				
Q/E 3/16	$ 5,000.00					
Q/E 6/16	$ 5,000.00					
Q/E 9/16						
Q/E 12/16			Annual		%	Funding
Total Transfer	**$ 10,000**		Funding Level		Complete	Requirement
				$20,000	50%	$10,000

Capital Item

(1) Fork Lift $17,500;
Tools $543; Microsoft Licenses $5213

Testimony
Exhibit HJR-4

Summary of Cash Flow -September 2016

Operating Cash balance forward	$286,042		
Projected Purchased Power Expense:			
ENE	($265,704)		
Project 6 (MMWEC & HQ)	($82,401)		
NYPA	($28,156)		
ENE/ISO	($163,216)		
Deferred PP Credit	$6,198		
			($533,279)
Customer Payments	$824,221		
NSF Checks	($401)		
Payroll, benefits	($143,866)		
Encumbered PP From August	$25,500		
Transfer to RF Capital- Sept	($25,500)		
Encumbered for RF Capital October	($25,500)		
Transfer from RF Capital	$15,886		(1)
Transfer from PPRF to Rate Stabilization fund	$10,417		
DPI transfer to PPRF	($15,172)	DPI Base rate - for July	
Misc. vendor payments	($91,819)		
Encumber for PP - from August	$750,000		
Encumber for PP - for October	($700,000)		
	$376,529		

Other Financial Information:			
Accounts Payable Balance	$0		
Accounts Receivable Balance	$677,831		
Summary of Savings/Investments: (Not Restricted)			
Contingency/Emergency	$10,000		
Storm Fund	$60,494		
Working Cash Reserve	$20,424		
Dedicated DSM Fund			
Total Savings/Investment (NR)	$90,918		
Year-End Reconciliation Account	$542,932	(Year to-date over collection)	
Restricted Account(Debt/Capital)	$565,083		
Rate Stabilization fund (RSF) Bal. left to refund	$31,251		
Restricted Account (Purchase Pwr)	$829,296		
Net All Saving/Investment			
Misc. Accounts:			**$2,059,479**
Customer Deposit Holding Account GL235.0	$318,783		
Working Capital - on Deposit w/ ENE GL165.06	$169,612		
Working Capital - on Deposit w/MMWEC GL165.02	$2,266		
Deferred PP Credit Account	$61,980		

Restricted Fund 2016 Goal			**$306,000**			
	16-Jan	$ 25,500				
	16-Feb	$ 25,500				
	16-Mar	$ 25,500				
	16-Apr	$ 25,500				
	16-May	$ 25,500				
	16-Jun	$ 25,500				
	16-Jul	$ 25,500				
	16-Aug	$ 25,500				
	16-Sep	$ 25,500				
	16-Oct					
	16-Nov					
	16-Dec			Annual Funding Level	% Complete	Funding Requirement
Total Transfer		**$ 229,500**		$306,000	75%	$76,500

Storm Fund - 2016 Goal		**$20,000**			
Q/E 3/16	$ 5,000.00				
Q/E 6/16	$ 5,000.00				
Q/E 9/16	$ 5,000.00				
Q/E 12/16			Annual Funding Level	% Complete	Funding Requirement
Total Transfer	**$ 15,000**		$20,000	75%	$5,000

Capital Item

(1) Radio Equipment for Dump Truck $1028;
URD Tool $1924.43; Transformer $12,934

PASCOAG
UTILITY DISTRICT

Pascoag Electric • Pascoag Water

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Testimony Exhibits HJR-5

AR/AP Summary

Summary of Accounts Payable (1)

	1 - 30 Days	31 - 60 Days	61 - 90 Days	Over 90 Days	Balance
Jan 11	$ 88,951	$ 19,858			$ 108,809
Feb 11	$ 44,864	$ 13,321			$ 58,185
Mar 11	$ 53,446				$ 53,446
Apr 11	$ 16,400				$ 16,400
May 11	$ 44,575	$ 19,206	$ 9,211		$ 72,992
Jun 11	$ 40,464	$ 5,427			$ 45,891
Jul 11	$ 19,194				$ 19,194
Aug 11	$ 34,438				$ 34,438
Sept 11	$ 18,850				$ 18,850
Oct 11	$ 6,860				$ 6,860
Nov 11	$ 34,014	$ 3,699			$ 37,713
Dec 2011	$ 12,911				$ 12,911
Jan 2012	$ 3,479				$ 3,479
Feb 2012	$ 115				$ 115
March 2012	$ 14,561				$ 14,561
April 2012	$ 12,434				$ 12,434
May 2012	$ 32,972				$ 32,972
June 2012	$ 5,337				$ 5,337
July 2012	$ 2,724				$ 2,724
August 2012	$ 11,392				$ 11,392
September 2012	$ 16,890				$ 16,890
October 2012	$ 6,683				$ 6,683
November 2012	$ 14,999				$ 14,999
December 2012	$ 5,618				$ 5,618
January 2013	$ 8,272				$ 8,272
February 2013	$ 2,588				$ 2,588
March 2013	$ 245				$ 245
April 2013	$ 350				$ 350
May 2013	$ -				$ -
June 2013	$ 10,184				$ 10,184
July 2013	$ 9,697				$ 9,697
August 2013	$ 31,792				$ 31,792
September 2013	$ 5,222				$ 5,222
October 2013	$ 1,219				$ 1,219
November 2013	$ 4,590				$ 4,590
December 2013	$ 7,517	$ 7,238	$ 5,728		$ 20,483
January 2014	$ 9,277				$ 9,277
February 2014	$ 1,596	$ 8,823			$ 10,419
March 2014	$ 11,974	$ 12,243	$ 16,895		$ 41,112
April 2014	$ 5,594	$ 18,637			$ 24,231
May 2014	$ 52,565				$ 52,565
June 2014	$ 24,198				$ 24,198
July 2014	$ 47,467				$ 47,467
August 2014	$ 42,983				$ 42,983
Sept 2014	$ 15,616				$ 15,616
Oct 2014					$ -
Nov 2014	$ 48,751				$ 48,751
Dec 2014	$ 17,177				$ 17,177
Jan-15	$ 75,138				$ 75,138
Feb-15	$ 10,011				$ 10,011
Mar-15	$ 10,681				$ 10,681
Apr-15	$ 86,528				$ 86,528
May-15	$ 32,765				$ 32,765
Jun-15	$ 20,198				$ 20,198
Jul-15	$ 2,943				$ 2,943
Aug-15	$ 44,205				$ 44,205
Sep-15	$ 4,144				$ 4,144
Oct-15	$ 42,735				$ 42,735
Nov-15	$ 17,886				$ 17,886
Dec-15	$ 1,311				$ 1,311
Jan-16	$ 54,364				$ 54,364
Feb-16	$ (200)				$ (200)
Mar-16	$ 30,862				$ 30,862
Apr-16	$ -				$ -
May-16	$ 45,744				$ 45,744
Jun-16	$ 34,003				$ 34,003
Jul-16	$ 10,620				$ 10,620
Aug-16	$ 8,415				$ 8,415

Summary of Accounts Payable (1)

Sep-16	$ -	$ -

(1) As of the end of the month, not the end of the accounting period

Summary of Accounts Receivable

	1 - 30 Days	31 - 60 Days	61 - 90 Days	Over 90 Days	Balance	
Jan 11	$ 450,388	$ 100,876	$ 31,926	$ 47,450	$ 630,640	
Feb 11	$ 448,389	$ 131,298	$ 39,578	$ 51,404	$ 670,669	
Mar 11	$ 304,438	$ 111,482	$ 38,110	$ 49,255	$ 503,285	
Apr 11	$ 345,832	$ 94,256	$ 40,915	$ 51,256	$ 532,259	
May 11	$ 300,380	$ 110,420	$ 27,838	$ 50,626	$ 489,264	
Jun 11	$ 276,381	$ 71,421	$ 21,131	$ 49,402	$ 418,335	
Jul 11	$ 357,351	$ 67,649	$ 14,772	$ 52,356	$ 492,128	
Aug 11	$ 416,316	$ 102,619	$ 13,487	$ 52,552	$ 584,974	
Sept 11	$ 426,478	$ 104,613	$ 19,024	$ 53,944	$ 604,059	
Oct 11	$ 277,270	$ 115,253	$ 19,070	$ 55,117	$ 466,710	
Nov 11	$ 279,731	$ 81,547	$ 39,877	$ 62,836	$ 463,991	
Dec 11	$ 310,415	$ 80,636	$ 31,743	$ 45,586	$ 468,380	w/o $31,355
Jan 12	$ 357,987	$ 80,400	$ 33,331	$ 49,753	$ 521,471	
Feb 12	$ 287,214	$ 100,680	$ 31,835	$ 52,032	$ 471,761	
March 2012	$ 262,535	$ 81,095	$ 36,962	$ 50,863	$ 431,455	
April 2012	$ 270,258	$ 84,771	$ 31,753	$ 56,978	$ 443,760	
May 2012	$ 243,911	$ 69,904	$ 22,454	$ 55,862	$ 392,131	
June 2012	$ 273,935	$ 51,677	$ 21,763	$ 57,536	$ 404,911	
July 2012	$ 322,261	$ 62,174	$ 12,657	$ 57,456	$ 454,548	
August 2012	$ 389,238	$ 77,173	$ 13,826	$ 57,775	$ 538,012	
September 2012	$ 450,684	$ 98,213	$ 13,308	$ 58,471	$ 620,676	
October 2012	$ 227,297	$ 110,469	$ 15,766	$ 21,373	$ 374,905	w/o $36,083
November 2012	$ 304,511	$ 59,474	$ 36,017	$ 25,943	$ 425,945	
December 2012	$ 458,273	$ 60,113	$ 26,149	$ 40,248	$ 584,783	
January 2013	$ 329,564	$ 85,844	$ 32,713	$ 43,531	$ 491,652	
February 2013	$ 383,060	$ 101,903	$ 35,440	$ 46,106	$ 566,509	
March 2013	$ 290,317	$ 85,366	$ 28,677	$ 50,131	$ 454,491	
April 2013	$ 259,318	$ 67,822	$ 33,749	$ 48,731	$ 409,620	
May 2013	$ 228,552	$ 68,929	$ 22,080	$ 45,870	$ 365,431	
June 2013	$ 288,616	$ 64,757	$ 19,800	$ 48,036	$ 421,209	
July 2013	$ 287,141	$ 53,393	$ 16,822	$ 47,458	$ 404,814	
August 2013	$ 340,709	$ 65,483	$ 12,813	$ 46,749	$ 465,754	
September 2013	$ 289,175	$ 72,977	$ 15,023	$ 45,583	$ 422,758	
October 2013	$ 225,915	$ 60,602	$ 17,463	$ 44,486	$ 348,466	
November 2013	$ 369,027	$ 56,777	$ 26,592	$ 23,873	$ 476,269	w/o $31,777
December 2013	$ 279,105	$ 78,898	$ 25,738	$ 34,618	$ 418,359	
January 2014	$ 395,468	$ 71,815	$ 31,516	$ 40,198	$ 538,997	
February 2014	$ 472,925	$ 117,649	$ 32,657	$ 45,558	$ 668,789	
March 2014	$ 318,299	$ 114,973	$ 43,391	$ 45,123	$ 521,786	
April 2014	$ 328,138	$ 88,477	$ 44,477	$ 46,310	$ 507,402	
May 2014	$ 284,669	$ 86,838	$ 33,958	$ 54,232	$ 459,697	
June 2014	$ 298,111	$ 74,194	$ 30,695	$ 58,030	$ 461,030	
July 2014	$ 380,523	$ 62,169	$ 22,280	$ 63,457	$ 528,429	
August 2014	$ 462,507	$ 92,298	$ 17,761	$ 64,652	$ 637,218	
Sept 2014	$ 410,525	$ 110,602	$ 23,333	$ 66,424	$ 610,884	
Oct 2014					$ -	
Nov 2014	$ 433,822	$ 133,780	$ 43,440	$ 78,222	$ 689,264	
Dec 2014	$ 353,903	$ 108,526	$ 41,145	$ 89,572	$ 593,146	
Jan-15	$ 506,348	$ 90,604	$ 45,009	$ 103,859	$ 745,820	w/o $28,875 for 2014
Feb-15	$ 429,234	$ 162,762	$ 40,753	$ 85,380	$ 718,129	
Mar-15	$ 432,402	$ 96,640	$ 45,682	$ 83,644	$ 658,368	
Apr-15	$ 411,978	$ 94,282	$ 39,769	$ 89,359	$ 635,388	
May-15	$ 305,533	$ 119,302	$ 39,779	$ 94,276	$ 558,890	
Jun-15	$ 351,482	$ 92,222	$ 37,770	$ 103,028	$ 584,502	
Jul-15	$ 375,541	$ 59,086	$ 23,552	$ 107,498	$ 565,677	
Aug-15	$ 474,121	$ 98,486	$ 28,010	$ 106,592	$ 707,209	
Sep-15	$ 433,472	$ 94,561	$ 22,410	$ 104,657	$ 655,100	
Oct-15	$ 310,621	$ 82,681	$ 27,282	$ 66,044	$ 486,628	w/o $39,195 for 2015
Nov-15	$ 370,036	$ 71,927	$ 42,145	$ 79,261	$ 563,369	
Dec-15	$ 353,063	$ 75,971	$ 34,694	$ 98,663	$ 562,391	
Jan-16	$ 469,703	$ 76,937	$ 34,137	$ 108,089	$ 688,867	
Feb-16	$ 414,899	$ 87,054	$ 33,409	$ 111,997	$ 647,359	
Mar-16	$ 295,627	$ 81,596	$ 39,812	$ 109,108	$ 526,143	
Apr-16	$ 323,808	$ 61,899	$ 33,694	$ 113,310	$ 532,711	
May-16	$ 279,773	$ 64,449	$ 24,040	$ 113,929	$ 482,191	
Jun-16	$ 270,800	$ 42,320	$ 18,254	$ 110,494	$ 441,868	
Jul-16	$ 357,019	$ 50,745	$ 17,027	$ 113,139	$ 537,930	

Summary of Accounts Receivable

	1 - 30 Days	31 - 60 Days	61 - 90 Days	Over 90 Days	Balance	
Aug-16	$ 447,418	$ 55,992	$ 16,412	$ 110,182	$ 630,004	
Sep-16	$ 485,063	$ 67,896	$ 17,166	$ 107,706	$ 677,831	
Oct-16						w/o $53,514 for 2016

PASCOAG
UTILITY DISTRICT

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www.pud-ri.org

Testimony Exhibits HJR-6

Surplus Fund Check

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC CO.

Testimony
Exhibit HJR-6

Vendor Number	Vendor Name	Check No.	Check Date
1150	Pascoag Utility District	146380	8/18/2016

Reference	Invoice Date	Invoice Number	Invoice Amount	Discount	Net Check Amount
Invoice Summary	8/17/2016	08172016	68,177.61		68,177.61
			68,177.61		68,177.61

GL 253.0 deffered Credit

68 177.61 ÷ 11 months = $6197.96

Aug - Dec 5 months   Jan - June 6 months

Aug = 6198.01

Journal: 2016006494   Date: Aug 23, 2016
Set: 0   Time: 11:06:12

Project 6 Surplus funds
Miscellaneous Activity   68177.61

surplus funds to deffered credit gl 253.00

Total To-Be-Paid: 68177.61
146380 Check: 68177.61

Change Due: 0.00

2 162 pscgcsh2 1 24

MMWEC
MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC CO.
327 MOODY STREET
LUDLOW, MA 01056

Bank of America
52-153-112

Check No.	Check Date	Vendor No.
146380	8/18/2016	1150

Check Amount
$****68,177.61
Not Valid After 365 Days

Pay SIXTY EIGHT THOUSAND ONE HUNDRED SEVENTY SEVEN AND 61/100*******************************

To the Order of
Pascoag Utility District
253 Pascoag-Main Street
PO Box 107
Pascoag RI 02859

Two signatures required over $25,000.00

⑈00146380⑈ ⑆011201539⑆ 000080242607⑈

Testimony
Exhibit HJR-6

	Town	Nuclear Project 3	Nuclear Project 4	Nuclear Project 5	Nuclear Project 6	Subtotal Surplus Funds	Wyman Winter Reliability Revenues	Peaking Winter Reliability Chargeback	RNS Revenues	2016 Total
1150	Pascoag	$ -	$ -	$ -	$ 50,538.08	$ 50,538.08	$ -	$ -	$ 17,639.53	$ 68,177.61

Testimony
Exhibit HJR-6

Town	Nuclear Project 3	Nuclear Project 4	Nuclear Project 5	Nuclear Project 6	2017 Preliminary Estimate Total
Pascoag	$ -	$ -	$ -	$ 466,054.52	$ 466,054.52

Testimony
Exhibit HJR-6

From: Carol Martucci [mailto:CMartucci@mmwec.org]
Sent: Thursday, July 14, 2016 11:13 AM
To: Harle Round
Subject: Surplus Funds 2016 - Please reply with distribution selection

Attached is a schedule with the estimated Surplus Funds as of June 30, 2016 for Nuclear Project No. 3, Nuclear Project No. 4, Nuclear Project No. 5 and Project No. 6 (as applicable to your system).

Please note the amount attached includes an estimate for MMWEC's arbitrage payment, which will be trued up before we issue the final checks or credits once we receive the final analysis. We do not expect the final Surplus Fund amount to be significantly different than the estimate.

We can distribute the Surplus Funds using any of the following options:
1) Credit against future billings beginning with invoice(s) dated on or around August 20, 2016 and continuing as credit against future months' invoices, until the full credit has been expended.
2) Issue a check for the entire amount of the Surplus Funds, to be issued on or around August 20, 2017.
3) Request MMWEC transfer the Surplus Funds balance into the Participant's Reserve Trust or Working Capital account.

Finally, we have also attached an estimate of the June 30, 2017 Surplus Funds for Nuclear Project No. 3, Nuclear Project No. 4, Nuclear Project No. 5 and Project No. 6 (as applicable to your system). As previously noted, the Project Six Surplus Funds distribution for the contract year ending June 2017 is much higher than prior years. This is primarily the result of excess funds in the bond reserve account after the bond principal and interest payment on July 1, 2017. The General Bond Resolution for Project Six states that the bond reserve must not be less than $30.5 million or such lesser amount as is required to pay all remaining principal and interest until maturity. After the principal payment on July 1, 2017, the amount of outstanding principal and interest will be lower than $30.5 million and the excess funds will be distributed to the Participants through the Surplus Fund assessment. This notice is being provided to you well in advance of the distribution for your financial planning purposes. The July 2017 Surplus Funds may be returned to each Participant using similar options noted above.

Please reply with which option you would prefer by Monday, August 1st. Feel free to contact me with any questions on the Surplus Funds.

Thanks!

Carol

Carol Martucci | Director – Accounting & Financial Reporting
Massachusetts Municipal Wholesale Electric Company
PO Box 426, 327 Moody St. Ludlow, MA 01056
P 413-308-1375 | www.mmwec.org

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Testimony Exhibits HJR-7

ENE Bulk Power Cost Projections for 2017

Bulk Power Cost Projections
Pascoag Utility District
January 2017 through December 2017

System Peak Demand (KW)			11,810								
System Energy Requirements (MWH)			59,767		2.918				TRANS.		
			FIXED COSTS			ENERGY VARIABLE COSTS			COSTS	TOTAL COSTS	
			Budget		CF		Budget		Budget	Budget	
RESOURCES		(KW)	($/KW-MO)	($)	(%)	MWH	($/MWH)	($)	($)	($)	($/MWH)
NYPA Firm	19.94%	1,800	4.07	87,912	75	11,808	4.92	58,095	292,870	438,877	37.17
Seabrook (Project 6)	17.59%	1,331	22.18	354,287	90	10,515	6.16	64,724	808	419,819	39.92
	29,524	========		========		========		========	========	========	========
SUBTOTAL - BASE		3,131		442,199		22,323		122,819	293,678	858,696	77.09
FCM Payments by LP				-7,359		0		0	0	-7,359	
ISO FCM Costs				743,616		0		0	0	743,616	
NextEra Rise Capacity Purchase				30,120		0		0	0	30,120	
NextEra Rise Energy Purchase				76,610		5,840	37.47	218,836	0	295,446	50.59
Miller Hydro Purchase	2.66%			0		1,588	48.00	76,232	0	76,232	48.00
Spruce Mtn Purchase	2.71%			0		1,617	64.25	103,894	0	103,894	64.25
TransCanada "Bal Power" Purchase	44.96%			0		26,873	70.30	1,889,182	0	1,889,182	70.30
	0.00%			0		0		0	0	0	
		========		========		========		========	========	========	========
SUBTOTAL - INTERMEDIATE		0		842,987		35,918		2,288,145	0	3,131,132	87.17
NYPA Peak		100	4.07	4,884	13	110	4.92	539	4,800	10,223	93.36
		========		========		========		========	========	========	========
SUBTOTAL - PEAKING		100		4,884		110		539	4,800	10,223	93.36
ISO Energy Net Interchange	2.37%					1,416	-6.49	-9,189	0	-9,189	-6.49
Service Billing				1,200		0		0	0	1,200	0.02
Hydro Quebec I		934		-9,361		0		0	5,450	-3,911	-0.07
ENE All Req/Short Supply				84,600		0		0	0	84,600	1.42
ISO Annual Fee				5,417		0		0	0	5,417	0.09
ISO Load Based Charges				88,157		0		0	0	88,157	1.48
ISO Scheduled Charges				80,812		0		0	0	80,812	1.35
NEPOOL OATT Charge				0		0		0	1,183,453	1,183,453	19.80
Network Transmission Service (NGRID)				0		0		0	366,000	366,000	6.12
DAF (Subtransmission Ch)				0		0		0	74,580	74,580	1.25
		========		========		========		========	========	========	========
SUBTOTAL - OTHER CHARGES		934		250,825		0		0	1,629,484	1,880,308	31.46
		========		========		========		========	========	========	========
TOTAL		4,165		1,540,895		59,767	40.19	2,402,314	1,927,962	5,871,171	98.23

E T =

$ 3,943,209

System Peak Demand (KW)
System Energy Requirements (MWH)

59,024

RESOURCES	Fixed 2016	Fixed Variance	Energy 2016	Energy Variance	Trans 2016	Trans Variance	Total 2016	Total Variance	
NYPA Firm	$ 107,448	$ (19,536)	$ 71,309	$ (13,213)	$ 379,000	$ (86,130)	$ 557,757	$ (118,880)	
Seabrook (Project 6)	$ 879,972	$ (525,686)	$ 73,339	$ (8,615)	$ 793	$ 15	$ 954,105	$ (534,285)	
	========	========	========	========	========	========	========	========	
SUBTOTAL - BASE	$ 987,420	$ (545,222)	$ 144,647	$ (21,828)	$ 379,793	$ (86,115)	$ 1,511,861	$ (653,165)	
FCM Payments by LP	$ (22,492)	$ 15,133	$ -	$ -	$ -	$ -	$ (22,492)	$ 15,133	
ISO FCM Costs	$ 443,256	$ 300,360	$ -	$ -	$ -	$ -	$ 443,256	$ 300,360	
NextEra Rise Capacity Purchase	$ 33,220	$ (3,100)	$ -	$ -	$ -	$ -	$ 33,220	$ (3,100)	
NextEra Rise Energy Purchase	$ 65,950	$ 10,660	$ 264,922	$ (46,086)	$ -	$ -	$ 330,872	$ (35,426)	
Miller Hydro Purchase	$ -	$ -	$ 43,732	$ 32,500	$ -	$ -	$ 43,732	$ 32,500	
Spruce Mtn Purchase	$ -	$ -	$ 83,537	$ 20,357	$ -	$ -	$ 83,537	$ 20,357	
TransCanada "Bal Power" Purchase	$ -	$ -	$ 1,714,572	$ 174,610	$ -	$ -	$ 1,714,572	$ 174,610	2483.784
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	========	========	========	========	========	========	========	========	
SUBTOTAL - INTERMEDIATE	$ 519,934	$ 323,053	$ 2,106,764	$ 181,381	$ -	$ -	$ 2,626,697	$ 504,434	
NYPA Peak	$ 4,884	$ -	$ 540	$ (1)	$ 4,800	$ -	$ 10,224	$ (1)	
	========	========	========	========	========	========	========	========	
SUBTOTAL - PEAKING	$ 4,884	$ -	$ 540	$ (1)	$ 4,800	$ -	$ 10,224	$ (1)	
ISO Energy Net Interchange	$ -	$ -	$ (50,064)	$ 40,876	$ -	$ -	$ (50,064)	$ 40,876	
Service Billing	$ 1,200	$ -	$ -	$ -	$ -	$ -	$ 1,200	$ -	
Hydro Quebec I	$ (8,562)	$ (800)	$ -	$ -	$ 5,923	$ (473)	$ (2,638)	$ (1,273)	
ENE All Req/Short Supply	$ 83,400	$ 1,200	$ -	$ -	$ -	$ -	$ 83,400	$ 1,200	
ISO Annual Fee	$ 5,340	$ 77	$ -	$ -	$ -	$ -	$ 5,340	$ 77	
ISO Load Based Charges	$ 186,233	$ (98,075)	$ -	$ -	$ -	$ -	$ 186,233	$ (98,075)	
ISO Scheduled Charges	$ 84,448	$ (3,636)	$ -	$ -	$ -	$ -	$ 84,448	$ (3,636)	
NEPOOL OATT Charge	$ -	$ -	$ -	$ -	$ 1,010,553	$ 172,900	$ 1,010,553	$ 172,900	
Network Transmission Service (NGRID)	$ -	$ -	$ -	$ -	$ 366,000	$ -	$ 366,000	$ -	
DAF (Subtransmission Ch)	$ -	$ -	$ -	$ -	$ 80,400	$ (5,820)	$ 80,400	$ (5,820)	
	========	========	========	========	========	========	========	========	
SUBTOTAL - OTHER CHARGES	$ 352,058	$ (101,234)	$ -	$ -	$ 1,462,876	$ 166,608	$ 1,814,934	$ 65,374	
	========	========	========	========	========	========	========	========	
TOTAL	$ 1,864,296	$ (323,402)	$ 2,201,887	$ 200,427	$ 1,847,469	$ 80,492	$ 5,913,653	$ (42,482)	
	E	-17.3%	E 9.10%		T	4.36%			

3,943,209

1,927,962

PASCOAG
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Testimony Exhibits HJR-8

ENE Budget Assumptions for 2017

2017 Budget Assumptions

MWH		Total Costs	$/MWH
59,024	**2016 Budget**	$ 5,913,653	$ 100.19
59,767	**2017 Budget**	$ 5,871,171	$ 98.23
744	**Total Increase (+) /Decrease (-) of**	$ (42,482)	$ 1.96

Details of Increase:

		Adj:	Total Adj of :
1 Seabrook Projections - Updated to reflect 3/30/16 Budget			
	Fixed Cost - reduced to $37.78/kw, and applied Surplus Credit of $6,198 for January through June, and $42,375 for August through December	$ (525,686)	
	Energy - reduced to $6.16/MWH	$ (8,615)	
	Transmission - increased based on projections	$ 15	$ (534,285)
2 NYPA Projections based on historical deliveries and costs			
	Fixed Costs - changed entitlement from 2300kw to 1700kw for May through December 2017	$ (19,536)	
	Energy - Capacity Factor set at 75%, lower purchases due to the entitlement reduction	$ (13,213)	
	Transmission - based on 3 year historical actuals with a 2.5% increase; applied a reduction of 26% starting in June 2017 due to the lower entitlement	$ (86,130)	$ (118,880)
3 Capacity - Updated Projection to reflect auction pricing, bilaterals, and payments by LP			
	FCM Payments by LP	$ 15,133	
	ISO FCM Costs	$ 300,360	
	FCM Bilateral Costs* Price Reduction	$ (3,100)	$ 312,393
4 Updated NextEra Rise Call Option			
	Fixed Cost - Applied Capacity cost against ISO credit in item#3	$ 10,660	
	Energy - Updated to include the Price Lock on 6/30/16	$ (46,086)	$ (35,426)
5 Bilateral Transactions			
	Energy - Miller Hydro - update projection to include contract extension	$ 32,500	
	Energy - Spruce Mtn - update projects based on historical deliveries includes placeholder for REC Sales	$ 20,357	
	Energy - TransCanada 100% LF less Fixed Volumes *contract reduction does not include Miller Hydro extension	$ 174,610	$ 227,467
6 Change from resales to purchases from the ISO-NE for Power			$ 40,876
7 ENE All Req/Short Supply			
	Estimated increase from $6,950/mo to $7,050/mo		$ 1,200
8 Adjustments to Estimated ISO Expenses			
	Annual Fee	$ 77	
	Load Based Charges to account for reduced expenses for Winter Reliability	$ (98,075)	
	Scheduled Charges	$ (3,636)	
	Transmission Increase effective 6/1/16 & 6/1/17	$ 172,900	$ 71,266
9 NGRID Network Transmission Charges			
Jan - Mar	Increase based on historical invoices		$ -
10 DAF Subtransmission Charges			
Jan-Dec	Reduced from $6,700/mo to $6,215 based invoices from 2015/2016		$ (5,820)
11 HQ Transmission Charges			
	Include the Use Rights and FCM Credit associated with the HQ ICC transfer		
Jan - Dec	Use Rights Value	$ (473)	
	FCM Credit	$ (800)	$ (1,273)

Total Adjustment	**$ (42,481)**
Variance	$ (1)

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Testimony Exhibits HJR-9

ENE Budget Assumptions for 2016 &

Pascoag Utility District-Estimated Expense by Component Sheets for Oct-Dec 2016

Testimony
Exhibit HJR-9

	A	B	C	D	E	F	G	H	I
640	Pascoag Utility District - Expense by Rate Component								
641	October 2016 ESTIMATE								
642	**Energy Component**	**Kwhrs**		**Standard Offer**		**Transmission**		**Total**	**Average**
643									
644	**MMWEC - Project 6**								
645	Project 6	972,000		$ 79,542.81		$ 66.11		$ 79,608.92	
646	Credit			$ (6,197.96)				$ (6,197.96)	
647	**Total MMWEC-Project 6**	**972,000**		**$ 73,344.85**		**$ 66.11**		**$ 73,410.96**	**$ 0.0755**
648									
649	**MMWEC Non-PSA**								
650	Admin Exp			$ 100.00				$ 100.00	
651	HQI			$ (713.47)		$ 439.81		$ (273.66)	
652	HQII							$ -	
653	HQIII							$ -	
654	NYPA Billing correction								
655	**Total MMWEC Non PSA**			**$ (613.47)**		**$ 439.81**		**$ (173.66)**	
656									
657	**NYPA - Niagara & St Lawrence**								
658	Demand			$ 9,361.00				$ 9,361.00	
659	Energy	1,237,000		$ 6,085.55				$ 6,085.55	
660	NYISO Ancillary					$ 11,400.00		$ 11,400.00	
661	TUC Charges							$ -	
662	ISO True up Charges/credits							$ -	
663	**Total - Niagara & ST LAWRENCE**	**1,237,000**		**$ 15,446.55**		**$ 11,400.00**		**$ 26,846.55**	**$ 0.0217**
664									
665									
666	**National Grid**								
667	**Direct Assignment Facilities (DAR)**					$ 6,700.00		$ 6,700.00	
668	**LNS - NGrid**					$ 30,500.00		$ 30,500.00	
669	**Total National Grid**					**$ 37,200.00**		**$ 37,200.00**	
670									
671	**Energy New England**								
672	All Requirements/ST Power Sply			$ 6,950.00				$ 6,950.00	
673	Spruce Mountain	154,000		$ 15,285.29				$ 15,285.29	$ 0.0993
674	Spruce Mountain - REC Sales							$ -	
675	Spruce Mountain - FCM Credit							$ -	
676	Miller Hydro/Brown Bear II							$ -	#DIV/0!
677	Energy Purchase Trans Canada	1,635,000		$ 114,910.55				$ 114,910.55	$ 0.0703
678	Financial Settlement Trans Canada							$ -	#DIV/0!
679	HQ Administrative Fee							$ -	#DIV/0!
680	HQ Use Right Payment							$ -	
681	HQ HQICC Payment							$ -	
682	Financial Settlement - Exelon							$ -	#DIV/0!
683	Next Era Rise Capacity Purchase			$ 2,510.00				$ 2,510.00	#DIV/0!
684	Option Energy Purchase NextEra	496,000		$ 19,577.52				$ 19,577.52	$ 0.0395
685	UCAP PURHASES -NEXTERA							$ -	
686	FCM Payments by LP			$ (321.05)				$ (321.05)	
687	ISO FCM Costs			$ 35,894.25				$ 35,894.25	
688	FCM Bilateral							$ -	
689	ISO Interchange	61,000		$ 1,738.47				$ 1,738.47	$ 0.0285
690	ISO Load Base Charges			$ 8,033.84				$ 8,033.84	
691	ISO Monthly Charges							$ -	
692	ISO Scheduled Charges			$ 8,062.26				$ 8,062.26	#DIV/0!
693	NEPOOL OATT					$ 97,160.85		$ 97,160.85	
694	MH CM Credit							$ -	
695	**Total -Energy New England**	**2,346,000**		**$ 212,641.13**		**$ 97,160.85**		**$ 309,801.98**	
696									
697	**Power Cost - October 2016**	**4,555,000**	**0**	**300,819.06**		**$ 146,266.77**		**$ 447,085.83**	**$ 0.0982**
698									
699	**NYPA Interruptible Kwhrs:**			**Month**		**Y-T-D**			
700	Niagara					1,799,000			
701	St Lawrence					2,136,000			
702				-		3,935,000			

E= 307017.01 -surplus funds(- 6197.96) = $300819.05

E= 307,017.01 ENE
T= 146,266.77 ENE
- surplus funds - $ 6197.96
447,085.82

Testimony
Exhibit HJR-9

Bulk Power Cost Projections
Pascoag Utility District
October-16

FCA7
System Peak Demand (KW) 8,599
System Energy Requirements (MWH) 4,555

RESOURCES	(KW)	FIXED COSTS Budget ($/KW-MO)	FIXED COSTS Budget ($)	CF (%)	ENERGY VARIABLE COSTS MWH	ENERGY VARIABLE COSTS Budget ($/MWH)	ENERGY VARIABLE COSTS ($)	TRANS. COSTS Budget ($)	TOTAL COSTS Budget ($)	TOTAL COSTS Budget ($/MWH)
NYPA Firm	2,200	4.07	$ 8,954.00	75	1,228	4.92	$ 6,039.79	$ 11,000.00	$ 25,993.79	21.17
Seabrook (Project 6)	1,331	$ 55.09	$ 73,331.04	98.2	972	$ 6.39	$ 6,211.77	$ 66.11	$ 79,608.92	81.87
SUBTOTAL - BASE	3,531		$ 82,285.04		2,200		$ 12,251.56	$ 11,066.11	$ 105,602.71	48.00
FCM Payments by LP			$ (321.05)						$ (321.05)	N/A
ISO FCM Costs			$ 35,894.25						$ 35,894.25	N/A
NextEra Rise Capacity Purchase			$ 2,510.00						$ 2,510.00	N/A
NextEra Rise Energy Purchase	1,000		$ 6,250.00		496	26.87	$ 13,327.52		$ 19,577.52	39.47
Miller Hydro Purchase					0	57.35	$ -		$ -	#DIV/0!
Spruce Mtn Purchase					154	99.25	$ 15,285.29		$ 15,285.29	99.25
TransCanada "Bal Power" Purchase					1,635	70.30	$ 114,910.55		$ 114,910.55	70.30
									$ -	#DIV/0!
SUBTOTAL - INTERMEDIATE	1,000		$ 44,333.20		2,285		$ 143,523.36	$ -	$ 187,856.56	82.23
NYPA Peak	100	4.07	$ 407.00	12.5	9	4.92	$ 45.76	$ 400.00	$ 852.76	91.69
SUBTOTAL - PEAKING	100		$ 407.00		9		$ 45.76	$ 400.00	$ 852.76	91.69
ISO Energy Net Interchange					61	28.61	$ 1,738.47	$ -	$ 1,738.47	28.61
Service Billing			$ 100.00		0	0.00	$ -	$ -	$ 100.00	0.02
Hydro Quebec I	934	0	$ (713.48)	0	0	0	$ -	$ 439.81	$ (273.66)	-0.06
ENE All Req/Short Supply			$ 6,950.00			0.00	$ -	$ -	$ 6,950.00	1.53
ISO Annual Fee									$ -	0.00
ISO Load Based Charges			$ 8,033.84						$ 8,033.84	1.76
ISO Scheduled Charges			$ 8,062.26						$ 8,062.26	1.77
NEPOOL OATT Charge			$ -		0	0.00	$ -	$ 97,160.85	$ 97,160.85	21.33
Network Transmission Service (NGRID)			$ -		0	0.00	$ -	$ 30,500.00	$ 30,500.00	6.70
DAF (Subtransmission Ch)			$ -		0	0.00	$ -	$ 6,700.00	$ 6,700.00	1.47
SUBTOTAL - OTHER CHARGE!	934		$ 22,432.63		0		$ -	$ 134,800.66	$ 157,233.29	34.52
TOTAL	2,034		E $ 149,457.86		4,555		E $ 157,559.15	$ 146,266.77	$ 453,283.79	99.52

Testimony
Exhibit HJR-9

2016 Budget Assumptions

MWH		Total Costs	$/MWH
57,771	2015 Budget	$ 5,867,488	$ 101.57
59,024	2016 Budget	$ 5,916,965	$ 100.25
1,253	Total Increase (+) /Decrease (-) of	$ 49,477	$ 1.32

Details of Increase:

	Adj:	Total Adj of :
1 Seabrook Projections - Updated to reflect 3/25/15 Budget		
Fixed Cost - reduced from $56.06/kw to $55.09/kw, no Surplus Fund credit	$ (15,418)	
Energy - reduced to $6.39/MWH	$ (7,417)	
Transmission - reduced based on projections	$ (443)	$ (23,277)
2 NYPA Projections based on historical deliveries and costs		
Fixed Costs - increased from $3.97/kw to $4.07/kw	$ -	
Energy - no pricing change capacity kept at 75%	$ 195	
Transmission - based on historical actuals with a 2.5% increase	$ (29,000)	$ (28,805)
3 Capacity - Updated Projection to reflect auction pricing, bilaterals, and payments by LP		
FCM Payments by LP	$ 22,652	
ISO FCM Costs	$ 45,597	
FCM Bilateral Costs*	$ (73,190)	$ (4,941)
4 Updated NextEra Rise Call Option		
Fixed Cost - Applied Capacity cost against ISO credit in item#3	$ 12,920	
Energy - Update prices based on Current Market Pricing	$ (130,573)	$ (117,653)
5 teral Transactions		
Energy - Miller Hydro - update projects based on historical deliveries	$ (50,974)	
Energy - Spruce Mtn - update projects based on historical deliveries includes placeholder for REC Sales	$ 24,544	
Energy - TransCanada 100% LF less Fixed Volumes	$ 87,892	$ 61,462
6 Change from resales to purchases from the ISO-NE for Power		$ 43,813
7 ENE All Req/Short Supply		
Estimated increase from $6,850/mo to $6,950/mo		$ 1,200
8 Adjustments to Estimated ISO Expenses		
Annual Fee	$ (102)	
Load Based Charges to account for Winter Reliability	$ (11,009)	
Scheduled Charges	$ (1,125)	
Transmission Increase effective 6/1/15 & 6/1/16	$ 51,449	
		$ 39,214
9 NGRID Network Transmission Charges		
Jan - Mar Increase based on historical invoices		$ 96,000
9 HQ Transmission Charges		
Include the Use Rights and FCM Credit associated with the HQ ICC transfer		
Jan - Dec Use Rights Value	$ (8,975)	
FCM Credit	$ (8,562)	
		$ (17,537)
Total Adjustment		**$ 49,476**
Variance		$ 1

Testimony
Exhibit HJR-9

	A	B	C	D	E	F	G	H	I
704	Pascoag Utility District - Expense by Rate Component								
705	November 2016 -Estimate								
706	Energy Component	Kwhrs		Standard Offer		Transmission		Total	Average
707									
708	MMWEC - Project 6								
709	Project 6 SeaBrook	940,000		$ 79,334.09		$ 66.11		$ 79,400.20	
710	Credit			$ (6,197.96)				$ (6,197.96)	
711	Total MMWEC-Project 6	940,000		$ 73,136.13		$ 66.11		$ 73,202.24	$ 0.0779
712									
713	MMWEC Non-PSA								
714	Admin Exp			$ 100.00				$ 100.00	
715	HQI			$ (713.48)		$ 464.34		$ (249.14)	
716	HQII							$ -	
717	HQIII							$ -	
718	NYPA Billing correction								
719	Total MMWEC Non PSA			$ (613.48)		$ 464.34		$ (149.14)	
720									
721	NYPA - Niagara & St Lawrence								
722	Demand			$ 9,361.00				$ 9,361.00	
723	Energy	1,197,000		$ 5,889.24				$ 5,889.24	
724	NYISO Ancillary							$ -	
725	TUC Charges					$ 17,400.00		$ 17,400.00	
726	ISO True up Charges/credits							$ -	
727	Total - Niagara	1,197,000		$ 15,250.24		$ 17,400.00		$ 32,650.24	$ 0.0273
728									
729									
730	National Grid								
731	Direct Assignment Facilities (DAR)					$ 30,500.00		$ 30,500.00	
732	LNS - NGrid					$ 6,700.00		$ 6,700.00	
733	Total National Grid					$ 37,200.00		$ 37,200.00	
734									
735	Energy New England								
736	All Requirements/ST Power Sply			$ 6,950.00				$ 6,950.00	
737	Spruce Mountain	173,000		$ 17,567.25				$ 17,567.25	$ 0.1015
738	Spruce Mountain - REC Sales			$ (18,797.88)				$ (18,797.88)	
739	Spruce Mountain - FCM Credit							$ -	
740	Miller Hydro/Brown Bear II							$ -	#DIV/0!
741	Energy Purchase Trans Canada	1,938,000		$ 136,211.25				$ 136,211.25	$ 0.0703
742	Financial Settlement Trans Canada							$ -	#DIV/0!
743	HQ Administrative Fee							$ -	#DIV/0!
744	HQ Use Right Payment							$ -	
745	HQ HQICC Payment							$ -	
746	Financial Settlement - Exelon							$ -	#DIV/0!
747	NextEra Capacity Purchase			$ 2,510.00				$ 2,510.00	#DIV/0!
748	Option Energy Purchase NextEra	480,000		$ 25,277.20				$ 25,277.20	$ 0.0527
749	UCAP PURHASES -NEXTERA							$ -	
750	FCM Payments by LP			$ (321.05)				$ (321.05)	
751	ISO FCM Costs			$ 35,894.25				$ 35,894.25	
752	FCM Bilateral							$ -	#DIV/0!
753	ISO Interchange	69,000		$ 2,856.20				$ 2,856.20	$ 0.0414
754	ISO Load Base Charges			$ 12,088.33				$ 12,088.33	
755	ISO Monthly Charges							$ -	#DIV/0!
756	ISO Scheduled Charges			$ 7,545.36				$ 7,545.36	
757	NEPOOL OATT					$ 73,316.27		$ 73,316.27	
758	MH CM Credit	2,660,000		$ 227,780.91		$ 73,316.27		$ 301,097.18	
759									
760	Power Cost November 2016	4,797,000	0	315,553.80		$ 128,446.72		$ 444,000.52	$ 0.0926
761									
762	NYPA Interruptible Kwhrs:			Month		Y-T-D			
763	Niagara					1,799,000			
764	St Lawrence					2,136,000			
765				-		3,935,000			

E = 321,751.77
T = 128,466.71
surplus funds - 6197.96
444,020.52

Bulk Power Cost Projections
Pascoag Utility District
November-16

FCA7
System Peak Demand (KW) 9,876
System Energy Requirements (MWH) 4,796

RESOURCES	(KW)	FIXED COSTS Budget ($/KW-MO)	FIXED COSTS Budget ($)	CF (%)	ENERGY VARIABLE COSTS MWH	ENERGY VARIABLE COSTS Budget ($/MWH)	ENERGY VARIABLE COSTS ($)	TRANS. COSTS Budget ($)	TOTAL COSTS Budget ($)	TOTAL COSTS Budget ($/MWH)
NYPA Firm	2,200	4.07	$ 8,954.00	75	1,188	4.92	$ 5,844.96	$ 17,000.00	$ 31,798.96	26.77
Seabrook (Project 6)	1,331	$ 55.09	$ 73,331.04	98.1	940	$ 6.39	$ 6,003.05	$ 66.11	$ 79,400.19	84.49
SUBTOTAL - BASE	3,531		$ 82,285.04		2,128		$ 11,848.01	$ 17,066.11	$ 111,199.15	52.26
FCM Payments by LP			$ (321.05)						$ (321.05)	N/A
ISO FCM Costs			$ 35,894.25						$ 35,894.25	N/A
NextEra Rise Capacity Purchase			$ 2,510.00						$ 2,510.00	N/A
NextEra Rise Energy Purchase	1,000		$ 6,250.00		480	39.64	$ 19,027.20		$ 25,277.20	52.66
Miller Hydro Purchase					0	57.35	$ -		$ -	#DIV/0!
Spruce Mtn Purchase					173	99.25	$ (1,230.63)		$ (1,230.63)	-7.12 Net
TransCanada "Bal Power" Purchase					1,938	70.30	$ 136,211.25		$ 136,211.25	70.30
									$ -	#DIV/0!
SUBTOTAL - INTERMEDIATE	1,000		$ 44,333.20		2,590		$ 154,007.82	$ -	$ 198,341.02	76.57
NYPA Peak	100	4.07	$ 407.00	12.5	9	4.92	$ 44.28	$ 400.00	$ 851.28	94.59
SUBTOTAL - PEAKING	100		$ 407.00		9		$ 44.28	$ 400.00	$ 851.28	94.59
ISO Energy Net Interchange					69	41.36	$ 2,856.20	$ -	$ 2,856.20	41.36
Service Billing			$ 100.00		0	0.00	$ -	$ -	$ 100.00	0.02
Hydro Quebec I	934	0	$ (713.48)	0	0	0	$ -	$ 464.34	$ (249.14)	-0.05
ENE All Req/Short Supply			$ 6,950.00			0.00	$ -	$ -	$ 6,950.00	1.45
ISO Annual Fee									$ -	0.00
ISO Load Based Charges			$ 12,088.33						$ 12,088.33	2.52
ISO Scheduled Charges			$ 7,545.36						$ 7,545.36	1.57
NEPOOL OATT Charge			$ -		0	0.00	$ -	$ 73,316.27	$ 73,316.27	15.29
Network Transmission Service (NGRID)			$ -		0	0.00	$ -	$ 30,500.00	$ 30,500.00	6.36
DAF (Subtransmission Ch)			$ -		0	0.00	$ -	$ 6,700.00	$ 6,700.00	1.40
SUBTOTAL - OTHER CHARGES	934		$ 25,970.22		0		$ -	$ 110,980.60	$ 136,950.82	28.55
TOTAL	2,034	E	$ 152,995.46		4,796	E	$ 168,756.31	$ T 128,446.71	$ 450,198.48	93.87

Testimony
Exhibit HJR-9

Testimony
Exhibit HJR-9

	A	B	C	D	E	F	G	H	I
767	**Pascoag Utility District - Expense by Rate Component**								
768	December 2016 Estimate								
769	Energy Component	Kwhrs		Standard Offer		Transmission		Total	Average
770									
771	MMWEC - Project 6								
772	Project 6	972,000		$ 79,542.81		$ 66.11		$ 79,608.92	
773	Credit			$ (6,197.96)				$ (6,197.96)	
774	**Total MMWEC-Project 6**	**972,000**		**$ 73,344.85**		**$ 66.11**		**$ 73,410.96**	**$ 0.0755**
775									
776	MMWEC Non-PSA								
777	Admin Exp			$ 100.00				$ 100.00	
778	HQI			$ (713.47)		$ 439.81		$ (273.66)	
779	HQII							$ -	
780	HQIII							$ -	
781	NYPA Billing correction								
782	**Total MMWEC Non PSA**			**$ (613.47)**		**$ 439.81**		**$ (173.66)**	
783									
784	NYPA - Niagara & St Lawrence								
785	Demand			$ 9,361.00				$ 9,361.00	
786	Energy	1,237,000		$ 6,085.55				$ 6,085.55	
787	NYISO Ancillary							$ -	
788	TUC Charges					$ 28,400.00		$ 28,400.00	
789	ISO True up Charges/credits							$ -	
790	**Total - Niagara**	**1,237,000**		**$ 15,446.55**		**$ 28,400.00**		**$ 43,846.55**	**$ 0.0354**
791									
792									
793	National Grid								
794	Direct Assignment Facilities (DAR)					$ 30,500.00		$ 30,500.00	
795	LNS - NGrid					$ 6,700.00		$ 6,700.00	
796	**Total National Grid**					**$ 37,200.00**		**$ 37,200.00**	
797									
798	Energy New England								
799	All Requirements/ST Power Sply			$ 6,950.00				$ 6,950.00	
800	Spruce Mountain	128,000		$ 12,700.82				$ 12,700.82	$ 0.0992
801	Spruce Mountain - REC Sales							$ -	
802	Spruce Mountain - FCM Credit							$ -	
803	Miller Hydro/Brown Bear II							$ -	#DIV/0!
804	Energy Purchase Trans Canada							$ -	#DIV/0!
805	Financial Settlement Trans Canada	3,058,000		$ 215,010.78				$ 215,010.78	$ 0.0703
806	HQ Administrative Fee							$ -	#DIV/0!
807	HQ Use Right Payment							$ -	
808	HQ HQICC Payment							$ -	
809	Financial Settlement - Exelon							$ -	#DIV/0!
810	NextEra Rise Capacity Purchases			$ 2,510.00				$ 2,510.00	#DIV/0!
811	Option Energy Purchase NextEra	496,000		$ 35,970.32				$ 35,970.32	$ 0.0725
812	UCAP PURHASES -NEXTERA							$ -	
813	FCM Payments by LP			$ (321.05)				$ (321.05)	
814	ISO FCM Costs			$ 35,894.25				$ 35,894.25	
815	FCM Bilateral							$ -	#DIV/0!
816	ISO Interchange	-561,000		$ (30,768.39)				$ (30,768.39)	
817	ISO Load Base Charges			$ 53,774.52				$ 53,774.52	#DIV/0!
818	ISO Monthly Charges							$ -	
819	ISO Scheduled Charges			$ 8,065.97				$ 8,065.97	
820	NEPOOL OATT					$ 84,200.90		$ 84,200.90	
821		**3,121,000**		**$ 339,787.22**		**$ 84,200.90**		**$ 423,988.12**	
822									
823	**Net Metering Customers**							**$ -**	
824									
825	**Power Cost - December 2016**	**5,330,000**	**0**	**$ 427,965.15**		**$ 150,306.82**		**$ 578,271.97**	**$ 0.1085**
826									
827	**NYPA Interruptible Kwhrs:**			**Month**		**Y-T-D**			
828	Niagara					1,799,000			
829	St Lawrence					2,136,000			
830				-		3,935,000			

Bulk Power Cost Projections
Pascoag Utility District
December-16

E = 434,163.10
T = 150,306.83
- Surplus funds - $6197.96
$578,271.97

FCA7
System Peak Demand (KW) 11,186
System Energy Requirements (MWH) 5,331

RESOURCES	(KW)	FIXED COSTS Budget ($/KW-MO)	FIXED COSTS Budget ($)	CF (%)	ENERGY VARIABLE COSTS MWH	ENERGY VARIABLE COSTS Budget ($/MWH)	ENERGY VARIABLE COSTS ($)	TRANS. COSTS Budget ($)	TOTAL COSTS Budget ($)	TOTAL COSTS ($/MWH)
NYPA Firm	2,200	4.07	$ 8,954.00	75	1,228	4.92	$ 6,039.79	$ 28,000.00	$ 42,993.79	35.02
Seabrook (Project 6)	1,331	$ 55.09	$ 73,331.04	98.2	972	$ 6.39	$ 6,211.77	$ 66.11	$ 79,608.92	81.87
	========		========		========		========	=========	=======	=======
SUBTOTAL - BASE	3,531		$ 82,285.04		2,200		$ 12,251.56	$ 28,066.11	$ 122,602.71	55.73
FCM Payments by LP			$ (321.05)						$ (321.05)	N/A
ISO FCM Costs			$ 35,894.25						$ 35,894.25	N/A
NextEra Rise Capacity Purchase			$ 2,510.00						$ 2,510.00	N/A
NextEra Rise Energy Purchase	1,000		$ 6,250.00		496	59.92	$ 29,720.32		$ 35,970.32	72.52
Miller Hydro Purchase					0	57.35	$ -		$ -	#DIV/0!
Spruce Mtn Purchase					128	99.25	$ 12,700.82		$ 12,700.82	99.25
TransCanada "Bal Power" Purchase					3,058	70.30	$ 215,010.78		$ 215,010.78	70.30
									$ -	#DIV/0!
	========		========		========		========	=========	=======	=======
SUBTOTAL - INTERMEDIATE	1,000		$ 44,333.20		3,682		$ 257,431.92	$ -	$ 301,765.12	81.95
NYPA Peak	100	4.07	$ 407.00	12.5	9	4.92	$ 45.76	$ 400.00	$ 852.76	91.69
	========		========		========		========	=========	=======	=======
SUBTOTAL - PEAKING	100		$ 407.00		9		$ 45.76	$ 400.00	$ 852.76	91.69
ISO Energy Net Interchange					-561	54.83	$ (30,768.39)	$ -	$ (30,768.39)	54.83
Service Billing			$ 100.00		0	0.00	$ -	$ -	$ 100.00	0.02
Hydro Quebec I	934	0	$ (713.48)	0	0	0	$ -	$ 439.81	$ (273.66)	-0.05
ENE All Req/Short Supply			$ 6,950.00			0.00	$ -	$ -	$ 6,950.00	1.30
ISO Annual Fee									$ -	0.00
ISO Load Based Charges			$ 53,774.52						$ 53,774.52	10.09
ISO Scheduled Charges			$ 8,065.97						$ 8,065.97	1.51
NEPOOL OATT Charge			$ -		0	0.00	$ -	$ 84,200.90	$ 84,200.90	15.80
Network Transmission Service (NGRID)			$ -		0	0.00	$ -	$ 30,500.00	$ 30,500.00	5.72
DAF (Subtransmission Ch)			$ -		0	0.00	$ -	$ 6,700.00	$ 6,700.00	1.26
	========		========		========		========	=========	=======	=======
SUBTOTAL - OTHER CHARGES	934		$ 68,177.01		0		$ -	$ 121,840.71	$ 190,017.73	35.65
	========		========		========		========	=========	=======	=======
TOTAL	2,034	E	$ 195,202.25		5,331	E	$ 238,960.85	$ T 150,306.83	$ 584,469.93	109.64

Testimony
Exhibit HJR-9