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

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

RIPUC Docket No.: 4895

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 2019?

A. M. Kirkwood Pascoag's power portfolio for 2019, 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 2019 Power Entitlements

Miller (Brown Bear)	2%	(Hydro)
Spruce Mountain	3%	(Wind)
Canton Wind	2%	(Wind)
NYPA (PASNY)	17%	(Hydro)
Seabrook	18%	(Nuclear)
NextEra RISE	9%	(virtual gas-fired)
NextEra hedge	14%	(mostly fossil fuel)
PSEG Load Follow	35%	(mostly fossil fuel)
	100%	

The total renewable/sustainable power in this portfolio is 24%. This represents mostly hydro power (NYPA and Brown Bear Hydro) at 19%, with two wind entitlements, Spruce Mountain and Canton Wind, estimated to contribute 5% of the District's total annual purchased energy in 2019.

Pascoag's total non-carbon based energy for 2019 is 42% of its requirements and includes a mix of the previously mentioned hydro and wind power resources, together with non-carbon based nuclear power from Pascoag's Seabrook entitlement.

The remaining 58% of Pascoag's energy requirement is mainly fossil fuel sourced through a 3-year contract entered into with PSEG Energy Resources & Trade LLC ("PSEG") which commenced in January 2018 and ends at the end of 2020, a virtual gas-fired unit transaction with NextEra Energy Power Marketing ("NextEra RISE") that began in June of 2013, and a two-year block energy deal with NextEra Energy Marketing, LLC ("NextEra") to fill out Pascoag's energy needs in 2018 and 2019 ("NextEra hedge") to further protect our customers from unanticipated price spike's caused by extreme weather or other unusual events in the wholesale markets. ***Testimony Exhibit 1-MRK*** highlights this mix or resources in graphic form.

Pursuant to a supplemental filing Pascoag provided to the Commission on January 11, 2018, Pascoag Utility District ("Pascoag") provided the contract between itself and Tangent Energy Solutions ("Tangent") for load reducing power from a newly constructed 1.1 megawatt gas-fired peak generation facility owned by Tangent and sited at Pascoag's main office and operations campus at 253 Pascoag Main Street, Pascoag, Rhode Island ("Tangent Peaker").

The Tangent Peaker is intended to help Pascoag reduce its peak load obligations in order to lower both bulk system transmission charges as well as ISO-New England ("ISO-NE") Forward Capacity Market charges through the operation of the unit during peak hours of the month and/or year. The Tangent Peaker is also able to produce occasional energy savings at times of high locational marginal prices through the sharing arrangement as specified in the contract provisions and as described further below. Pascoag did not include any estimates of such energy savings because of their sporadic nature, since the energy is dispatched usually only during abnormal market conditions which manifests themselves in high spot market prices.

The Tangent unit entered commercial operation in October 2017 after several months of construction and commissioning.

Tangent was and is responsible for the construction, financing, operation and gas supply risk for the implementation of this peak load facility, and Pascoag has agreed to a benefit sharing arrangement with Tangent, with the ultimate goal for Pascoag to be able to exercise an option to purchase the facility on or before the end of the 20-year term. The facility is able to be dispatched remotely via Tangent's off-site operations center, and Tangent retains complete operational control and the responsibility to assess daily system conditions to optimize the dispatch of the unit against the likely monthly and annual New England peak loads.

The Service Fees that generate savings to Pascoag can be found in Schedule A of the Electricity Purchase Agreement between Tangent and Pascoag ("Agreement"), attached here as *Testimony Exhibit 2-MRK* and such fees are comprised of the following items:

- Transmission Charge Savings Service Fee – actual verified transmission cost savings by running the unit during the monthly ISO-NE peak. Pascoag pays Tangent 90% of the verified savings and retains 10% of the savings for reduction of customer costs.
- Capacity Charge Savings Service Fee – actual verified capacity cost savings by running the unit at time of annual ISO-NE peak. Pascoag pays Tangent 90% of the verified savings and retains 10% of the savings for reduction of customer costs.
- Energy Charge Services Fee – the payment by Pascoag to Tangent for the generation provided by the unit each month at the hourly energy rate for ISO-NE at the Rhode Island Load Zone.
- Energy Service Fee Rebate – a rebate paid by Tangent to Pascoag which amounts to 50% of the difference between the costs of natural gas for all kWh of the unit produced during the year vs. the total Energy Charge Service Fees paid by Pascoag for that year.
- ISO-NE Program Service Fee Rebate – this is a catch all provision to enable the parties to enter the generating unit into existing or new ISO-NE programs that may be available to provide additional revenues for the project. 10% of any such savings will be used to reduce the costs to Pascoag's customers.

At such time, if any, that Pascoag exercises its right to purchase the facility in accordance with the Termination/Buyout Schedule as determined in Schedule B of the Agreement, all savings thereafter would accrue 100% to Pascoag's customers.

Q. Please provide an update on Pascoag's power purchase agreements entered into recently in order to hedge the rest of Pascoag's requirements in 2019 through 2020.

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 which set the ISO-NE clearing prices a majority of the time. Pascoag and its power supply advisor, Energy New England (ENE), thought it would be best to protect Pascoag's remaining open power supply position, and so first put in a three year load following deal for the period 2015 through 2017 to fill in most of the remainder of our customer energy needs during that period. In December of 2016, Pascoag and ENE decided to go out to the market for another load following deal for the 2018 through 2020 period while forward prices looked favorable. ENE on Pascoag's behalf received several bids for the period 2018 through 2020, and Pascoag was able to secure a load following deal with PSEG Energy Resources & Trade LLC ("PSEG") for a very favorable rate of $0.04575/ kWh for all hours (see *Testimony Exhibit 3-MRK* attached). Pascoag and ENE did leave approximately 7-8% room in Pascoag's overall power supply portfolio unhedged for the period starting in 2018 to allow Pascoag to further query the market should prices continue to improve. In July of 2017, ENE and Pascoag again queried the market for the remaining position for 2018 and 2019, and NextEra Energy Marketing, LLC ("NextEra") quoted the most favorable price at $0.0390/kWh for 2018 and $0.0388/kWh for 2019. Pascoag filled the remainder of its open position for that period with this hedging instrument and such values are included in our 2019 projection in this filing (see *Testimony Exhibit 4-MRK* attached).

Q. Was Pascoag successful in obtaining a competitive supply to hedge its remaining open positions for the upcoming periods?

A. Yes, as stated above Pascoag and ENE ran solicitations for the 2018-2020 time period by seeking competitively supplied wholesale power. The load following deal with PSEG struck in December 2016 has a structure similar to our expired 2012-2014 agreement with Exelon and our expired 2015-2017 agreement with TransCanada in that it follows our hourly load profile after taking into consideration the other contractual commitments we have in place. The block energy deal with NextEra then fills in a baseload portion of our load curve to bring us close to 100% for 2018 and 2019, all of this at very competitive prices. Further, Pascoag after being offered, through ENE, a deal being put together for a consortium of Massachusetts public power entities together with Pascoag in Rhode Island, executed a transaction in late 2017 with NextEra Energy Marketing, LLC ("NextEra EM Seabrook") that will commence on January 1, 2020. As such, it is not included in our 2019 portfolio but will be included in our projections when we file our 2020 Standard Offer reconciliation late next year. The transaction with NextEra EM Seabrook is for a firm supply of 0.5 MW each hour from this carbon-free nuclear facility, and includes associated Nuclear-based Emissions Free Energy Certificates ("EFECs"). The price for all power under this transaction in 2020 shall be $40.87/MWh delivered to the Mass. Hub(see *Testimony Exhibit 5-MRK* attached) .

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. Pascoag already had in place EEI Master Agreements with PSEG, Shell, TransCanada, NextEra Energy, Exelon/Constellation Energy and Macquarie Energy. In late 2017, Pascoag further broadened the list by negotiating and signing an EEI Master Agreement with Dynegy Marketing and Trade, LLC ("Dynegy"). 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 and potential partners' credit worthiness prior to Pascoag requesting bids. 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, Shell, TransCanada and now PSEG as well as the recent block energy deal with NextEra as well as the recent NextEra EM Seabrook deal. These EEI Master Agreements 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 periodic review and rating of our company. Pascoag has maintained an A- rating with S&P from 2008 to the present.

Q. The Pascoag entitlement with Miller Hydro expired in May of 2016. Please describe the extension to this contract that was negotiated in order to replace this beneficial renewable energy entitlement.

A. M. Kirkwood 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, now known as Brown Bear Hydro.

The key terms of the extended contract for the going-forward period of the agreement are as follows:

Price for Facility Energy and Ancillary Services:

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 renewable 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 the past few years, and reached an agreement with ISM Solar Development LLC ("ISM Solar") and National Grid in July of 2016. The agreement, together with the filing before the Rhode Island Public Utilities Commission ("PUC"), and the subsequent PUC approval in May, 2017 can all be found in Docket

No. 4636. In summary, the agreement allows for ISM Solar, which is on the border of our service territory, to interconnect and sell energy directly to National Grid, in return for a monthly payment from ISM Solar to Pascoag of $3,300 ($39,600 annually) to compensate the Pascoag customers for lost benefits of power directly from a solar farm, namely potential reductions to transmission and capacity charges. The ISM Solar facility has recently commenced construction, and we expect the facility to be operational in the 3rd or 4th quarter of 2019. Pascoag continues to negotiate with other solar developers for a possible future agreement for a solar farm in its service territory.

Q. Does Pascoag wish to ask for consideration of a different rate treatment for its legal expenses that are associated with power supply matters, such as its general power supply contract negotiations and specific negotiations with New York Power Authority for St. Lawrence and Niagara hydropower, or pleadings at FERC that are intended to help keep power supply prices as cost-effective as possible through just and reasonable power/transmission rates?

A. M. Kirkwood Yes, Pascoag is currently involved with a consortium of several Massachusetts public power utilities in three cases currently before the Federal Energy Regulatory Commission ("FERC") related to ISO-NE's requested waiver of the Mystic Station (owned by Exelon) retirement bid. Exelon had submitted a retirement request to ISO-NE during the FCA-13 retirement request process, but ISO-NE desires to prevent Mystic's retirement due to fuel security and reliability issues. ISO-NE filed a request for a waiver with FERC from the normal rules in order to keep Mystic from retiring. A second related case before FERC was filed by Exelon based on the ISO-NE requested waiver and desire to retain the Mystic units, with Exelon requesting cost-of-service treatment in place of revenues from the Forward Capacity Market should they be required to continue to operate the Mystic units per ISO-NE's request. A third related case involves Exelon's filing to include the costs of the associated Distrigas LNG terminal in its Mystic cost-of-service. Distrigas is the sole provider of natural gas to the Mystic units in question. Exelon is in the process of acquiring this LNG terminal from its current owner, Engie. Pascoag and several Massachusetts utilities retained the Washington D.C. based legal firm, Duncan and Allen, to represent public power's interest in these proceedings in order to minimize any unjust and unreasonable cost impacts to our applicable customers. These cases are cost-intensive from both a legal and financial consulting perspective. Pascoag believes it is doing the right thing by fighting for reduced costs which will be enjoyed by our customers through lower Standard Offer rates should we prevail at FERC, but is concerned that it is paying for such legal and financial services through its base rate revenues, which usually remain static for several years until a new rate case if filed. Pascoag points out that it works very hard to avoid base rate increases, and in fact has not requested a base rate change since 2013. Pascoag would like permission from the Commission to isolate legal expenses that are related to power supply matters, and collect such expenses through its annual power cost reconciliation process through its Standard Offer and Transmission rates. Pascoag's rationale is that cases such as the Mystic cases involve the company trying to optimize and protect our power portfolio by preventing costs that are not just and reasonable from being passed on to our customers. We believe it would be appropriate that instead of the legal expenses related to these cases or power supply matters in general being funded from base rate revenues, that they instead be funded as a fixed cost component in our purchased power or transmission reconciliations. Pascoag hereby respectively requests the Commission to allow Pascoag to move to such rate treatment prospectively for legal expenses associated with power supply or transmission matters.

By way of providing relevant information about these often unexpected and unplanned expenses, Pascoag queried its accounts payable system for the past five years related to power supply and transmission matters. Two firms are generally used in this regard; Duncan and Allen works to help insure appropriate terms and conditions in any power contracts or EEI Master Agreements that Pascoag enters into, and also to represent our needs in cases before FERC related to the power or transmission markets within ISO-NE. Jennings Strouss & Salmon PLC has represented the "Neighboring States", including Rhode Island, in NYPA preference power negotiations or proceedings. The most recent example of these NYPA legal expenses were in the renegotiation of the St. Lawrence hydro contract that was ongoing in 2016 and 2017, and signed by the Neighboring States and NYPA in 2017 and finally approved by the Governor of New York in 2018.

Such expenses are variable, hard to predict, and subject to various supplemental filings/pleadings as they play out at FERC. The totals for the Duncan & Allen and Jennings and Strouss expenses over the past five years have been as follows:

2013	$ 1,283.75	
2014	$ 5,833.57	
2015	$ 2,931.56	
2016	$ 11,383.35	
2017	$ 4,190.47	
2018	$ 22,085.18	(through September billing)

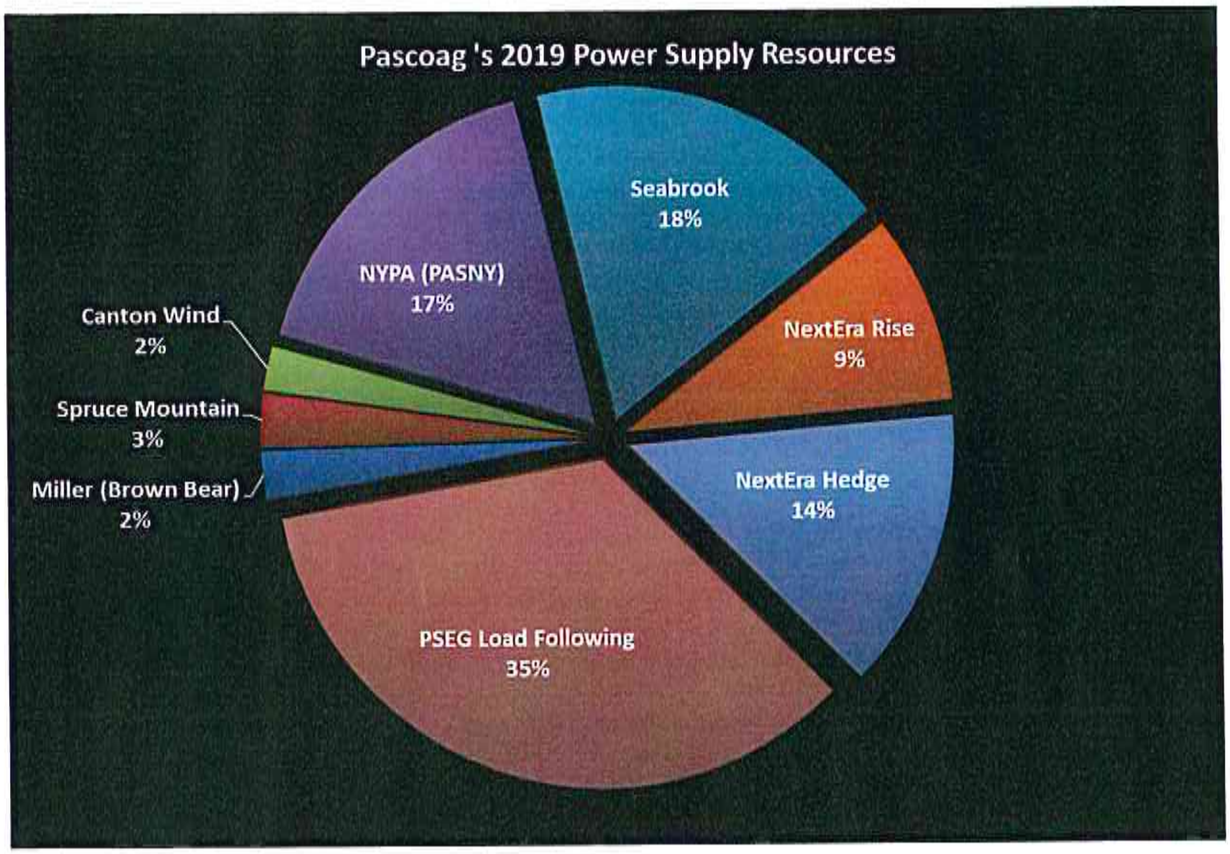
These expenses, which vary greatly from year to year as seen above, include expert witnesses required by both law firms to exam and perform forensics on the various financial schedules and calculations proposed by outside parties in their cost-of-service or other financial proposals being negotiated or litigated.

Pascoag believes that allowing such actual expenses to be added to its power supply (and transmission, where appropriate) expenses and subject to its annual reconciliation schedules, will incentivize Pascoag to continue to negotiate and/or litigate for fair and equitable supply costs without the worry of these often unexpected expenses impacting a very lean base rate revenue stream.

Q. Does this conclude your portion of the testimony?

A. M. Kirkwood Yes it does.

Testimony Exhibit 1-MRK



Testimony Exhibit 2-MRK

Electricity Purchase Agreement between

Tangent Energy Solutions and Pascoag Utility District

CONFIDENTIAL

Electricity Purchase Agreement

This **ELECTRICITY PURCHASE AGREEMENT** (together with all Appendices referenced in its text as if set forth herein in full, this "**Agreement**") is made and entered on April 1, 2016 (the "**Effective Date**") by and between:

Customer: Pascoag Utility District **Contact:** Michael Kirkwood **Address:** PO Box 107, Pascoag, Rhode Island, 02859	**Supplier**: Tangent Energy Solutions **Contact:** George Hunt **Address:** 206 Gale Lane ,Suite C PO Box 1140 Kennett Square PA 19348
Phone: 401 568 6222 **Fax:** **Email:** mkirkwood@pud-ri.org	**Phone:** 610-888-2800 x 203 **Fax:** 610-444-2822 **Email:** dturner@tangentenergy.com
Facility Location: **Contact:** Mike Kirkwood **Address:** 253 Pascoag Main Street Pascoag, RI 02859 **Phone:** 401 568 6222 **Fax:** **Email:** mkirkwood@pud-ri.org	**System Description :** Refer to Schedule F - TBD
Customer is (check one): ☐ the owner and occupant of the Facility ☐ the owner (but not the occupant) of the Facility ☐ the lessor and occupant of the Facility.	**Initial Delivery Term:** The "Initial Delivery Term" means the Initial Delivery Year plus an additional fifteen Delivery Years

Each of Customer and Supplier are sometimes referred to in this Agreement as a "**Party**" and collectively as the "**Parties.**"

Recitals

A. Customer wishes to have Supplier, and Supplier wishes to: (i) arrange for the design, procurement, installation and construction of a natural gas electricity generating system that meets the parameters described above (the "**System**") at the Facility Location and interconnection of the System with the Utility, (ii) own, operate and maintain the System as a load reducer and (iii) sell all electricity generated by the System to Customer at the Facility.

B. Customer wishes to purchase from Supplier all of the electricity generated by the System.

Agreement

NOW, THEREFORE, in consideration of the premises, the mutual promises and covenants set forth in this Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto agree as follows:

1. Each of the following documents shall be deemed part of this Agreement and are incorporated herein by this reference as though set forth herein in their entirety:

Schedule A	Service Fees
Schedule B	Termination/Buyout Schedule
Schedule C	Customer's Facility and Easement Area
Schedule D	General Terms and Conditions
Schedule E	Customer-Specific Terms and Conditions
Schedule F	System Description

2. This Agreement, together with all Appendices and Schedules hereto, embodies the entire agreement and understanding of the Parties with respect to the subject matter hereof and supersedes all prior or contemporaneous agreements and understandings of the Parties, verbal or written, relating to the subject matter hereof.

3. Any waiver of the provisions of this Agreement must be in writing and will not be implied by any usage of trade, course of dealing or course of performance. No failure of either Party to enforce any term of this Agreement will be deemed to be a waiver. No exercise of any right or remedy under this Agreement by Customer or Supplier shall constitute a waiver of any other right or remedy contained or provided by law. Any delay or failure of a Party to exercise, or any partial exercise of, its rights and remedies under this Agreement shall not operate to limit or otherwise affect such rights or remedies. Any waiver of performance under this Agreement shall be limited to the specific performance waived and shall not, unless otherwise expressly stated in writing, constitute a continuous waiver or a waiver of future performance.

4. No provision of this Agreement shall be construed or represented as creating a partnership, trust, joint venture, fiduciary or any similar relationship between the Parties. No Party is authorized to act on behalf of the other Party and neither shall be considered the agent of the other.

5. This Agreement is made and entered into for the sole protection and legal benefit of Customer and Supplier, and their permitted successors and assigns, and, except to the extent otherwise expressly set forth herein, no other Person shall be a direct or indirect legal beneficiary of, or have any direct or indirect cause of action or claim in connection with, this Agreement.

6. This Agreement may be modified only by a writing that is signed by both Parties.

7. If any provision of this Agreement is determined to be illegal or unenforceable, such determination will not affect any other provision of this Agreement and all other provisions of this Agreement will remain in full force and effect.

8. Both Parties have been represented by counsel of their choice in connection with the negotiation, execution and delivery of this Agreement, and as such no provision of this Agreement shall be construed or interpreted for or against either Party based upon any contention that such provision was drafted solely by such Party or its counsel.

9. THIS AGREEMENT SHALL BE GOVERNED BY, AND INTERPRETED AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF RHODE ISLAND, EXCLUDING ANY CHOICE OF LAW RULES THAT MIGHT DIRECT THE APPLICATION OF THE LAWS OF A DIFFERENT JURISDICTION, IRRESPECTIVE OF THE PLACES OF EXECUTION OR OF THE ORDER IN WHICH SIGNATURES OF THE PARTIES ARE AFFIXED OR OF THE PLACE OF PERFORMANCE.

10. This Agreement may be executed in any number of separate counterparts, each of which when so executed shall be deemed an original, and all of said counterparts taken together shall be deemed to constitute but one and the same instrument.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives as of the Effective Date.

Supplier:	**Customer**
Tangent Energy Solutions	Pascoag Utility District
By: George C. Hunt	By: Michael R. Kirkwood
Name: George C. Hunt	Name: Michael R. Kirkwood
Title: SVP	Title: General Manager

Pursuant to, and for purposes of, Article 13 of the General Terms and Conditions set forth in Schedule D, following execution of this Agreement by Supplier and Customer, Supplier may cause System Lender to execute a counterpart of this Agreement and deliver the same to each of Supplier and Customer.

System Lender:

____

By:____________________

Name:____________________

Title:____________________

Date:____________________

Schedule A
Service Fees

As consideration for the delivery of electricity from the System to the Customer at the Point of Common Coupling, (the "Service, Customer agrees to pay to Supplier the following fees (collectively, the "Service Fees"):

Transmission Charge Savings Service Fee

- With respect to each Applicable Transmission Savings Month, a fee equal to ninety percent (90%) of the Transmission Charge Savings realized by Customer.

Capacity Charge Savings Service Fee

- With respect to each Applicable Capacity Savings Year, an annual fee equal to ninety percent (90%) of the Capacity Charge Savings realized by Customer.

Energy Charge Service Fee

- With respect to each calendar month, a monthly fee equal to the sum of the product of the hourly MW Reduced by the corresponding hourly energy rate for ISO-NE. The Parties agree that the real-time LMP for Customer's applicable zone (currently Rhode Island Load Zone Location ID 4005) is the applicable energy rate for ISO-NE upon the Effective Date. If there is change, the Parties agree to adjust the rate accordingly

Energy Service Fee Rebate

- With respect to each calendar year, a rebate to be paid by Supplier to Customer equal to the cumulative Energy Charge Service Fees less the Supplier's total cost of natural gas for the year multiplied by 50%. If the Supplier's cost of natural gas exceeds the Energy Charge Service Fee, the Energy Service Fee Rebate will be set to zero for that calendar year.

ISO-NE Program Service Fee Rebate

- With agreement with Customer, whose agreement cannot be unreasonably withheld, Supplier will enroll System in applicable ISO-NE Programs to generate payments from ISO-NE The Supplier will interface with ISO-NE to operate the System in the applicable and available ISO-NE programs that Supplier chooses to generate payments from ISO-NE to Supplier. With respect to each calendar month, a rebate to be paid by Supplier to Customer equal to the payments received from ISO-NE in the previous month multiplied by ten percent (10%).

Schedule B
Termination/Buyout Schedule

	Net Revenue Target
Initial Delivery Year	$2,246,264
Delivery Year 1	$2,246,264
Delivery Year 2	$2,420,238
Delivery Year 3	$2,589,219
Delivery Year 4	$2,752,873
Delivery Year 5	$2,910,845
Delivery Year 6	$3,062,760
Delivery Year 7	$3,208,219
Delivery Year 8	$3,346,799
Delivery Year 9	$3,478,051
Delivery Year 10	$3,601,501
Delivery Year 11	$3,716,643
Delivery Year 12	$3,822,944
Delivery Year 13	$3,919,837
Delivery Year 14	$4,006,720
Delivery Year 15	$4,082,956
Delivery Year 16	$4,123,785
Delivery Year 17	$4,165,023
Delivery Year 18	$4,206,673
Delivery Year 19	$4,248,740
Delivery Year 20	$4,291,228

Termination / Buyout Value will be equal to the applicable Net Revenue Target less the Cumulative Net Margin earned by Supplier up to and including the Termination Date.

Cumulative Net Margin will be equal to the cumulative amount Supplier has invoiced and Customer has paid under Schedule A (including the Energy Service Fee Rebate and the ISO-NE Program Service Fee Rebate) less the Supplier's cumulative cost for natural gas up to and including the Termination Date.

Schedule C
Customer's Facility and Easement Area

Legal Description of Facility Location

Note: To be determined prior to the issuance of the Installation Notice

Description/Map of Easement Area and General Location of System

Note: To be determined prior to the issuance of the Installation Notice

Facility Point of Common Coupling

Note: To be determined prior to the issuance of Installation Notice

Schedule D
General Terms and Conditions

[See Attached.]

Schedule E
Customer-Specific Terms and Conditions

[To be provided as needed.]

Schedule F
System Description

1.1 MW generation system including lean burn natural gas engine manufactured Cummins Power Generation, remote radiator, switchgear, and ancillary equipment

(full description of system and related equipment to be added after final engineering and design approval)

Confirmation Letter for:

Load following deal with PSEG Energy Resources & Trade LLC

Confirmation Letter

This Confirmation (the "Confirmation") shall confirm the agreement reached on December 6, 2016 (the "Trade Date") between PSEG Energy Resources & Trade LLC ("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 as dated therein (the "Master Agreement") between Seller and Pascoag and constitutes part of and is subject to the terms and provisions of such Master Agreement.

1. <u>Definitions</u>. 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 "Confirmation" shall have the meaning given such term in the first paragraph of this Confirmation.

1.4 "Seller Estimated Load" shall have the meaning set forth in Section 3.3.

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

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

1.7 "HE" shall mean hour ending.

1.8 "Hedged Percentage" shall mean one hundred percent (100%) of the gross hourly wholesale energy requirements as measured at the ISO-NE Pool Transmission Facilities ("PTF") of Pascoag's ratepayers located in Pascoag's service territory as of the Trade Date.

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

1.10 "IBT" means internal bilateral transaction between Buyer Seller for electricity market products inside of the New England Control Area that transfers an obligation between the Buyer and Seller.

1.11 "IBT Container" shall mean the form of electronic contract submittal, as implemented by the ISO-NE Market System effective March 1, 2003, and as amended or may be amended during the Term that only requires Seller to confirm the general parameters of the IBT and not the hourly schedules of energy delivery.

1.12 "Load" means the energy that Seller shall make available to Pascoag hourly in order to serve the Hedged Percentage, as represented by 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 energy requirements related to (i) any wholesale or aggregation transaction to which Pascoag is a Party; (ii) any acquisition, annexation, merger, joint venture, partnership, or other similar transaction that Pascoag may undertake; or (iii) the addition of any single customer of Pascoag whose peak load in any single hour is greater than 1 MW, or (iv) the addition of any generation behind the meter of Pascoag whose energy production in any single hour is greater than 1 MW or has the net impact of reducing the load by more 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, Seller and Pascoag agree to meet to discuss whether changes may be made to this Confirmation to address how Pascoag's additional load obligation can be met under this Confirmation; provided however, neither Party shall be required to accept a change with which it, in its sole judgment, disagrees.

1.13 "Load Cap" shall mean 14 MW.

1.14 "Load Following Energy" shall mean that Seller shall provide energy to Pascoag to serve the Load by scheduling an amount of energy during On-Peak Hours, Off-Peak Hours and 2x16 Hours on the day after each Operating Day that is equal to the amount of Load for each hour of such Operating Day.

1.15 "Marginal Losses" shall have the meaning given such term as defined in the ISO-NE Operating Agreement.

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

1.17 "MW" shall mean megawatts.

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

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

1.20 "On-Peak Energy" shall be energy scheduled during On-Peak Hours.

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

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

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

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

2. Term. Seller's obligation to confirm and sell energy, as defined in this Confirmation, and Pascoag's obligation to schedule and pay for energy shall become effective on HE 0100 EPT, on January 1, 2018 and shall remain in effect through HE 2400, EPT, on December 31, 2020 (the "Term") unless earlier terminated pursuant to this Confirmation ("Term of Service"); 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 Term, Seller shall confirm and sell and Pascoag shall schedule and purchase 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, 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. Pascoag shall schedule or cause the scheduling of energy and Seller shall confirm the energy schedule in accordance with ISO-NE Rules.

3.3 Scheduling of Energy. Seller shall confirm Load Following Energy to Pascoag in accordance with Section 3.3.1 in the form of an IBT for day-ahead market energy. If Buyer does not know the actual amount of the RTLO in time to schedule the energy on the day after the Operating Day pursuant to ISO-NE scheduling timelines, Buyer 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 "Buyer Estimated Load"). If Pascoag's actual Load differs from the Buyer 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, Buyer shall schedule energy by submitting one IBT Container for such Operating Day. The schedule for the IBT Container shall leave the Marginal Loss box checked, the default position for scheduling the IBT Container. If there is a failure of Seller to schedule or Buyer to confirm the IBT Container prior to the ISO-NE deadline, then Buyer and Seller agree to financially settle the Pascoag RTLO in accordance with Section 3.3.2.

3.3.1 Load Calculation. Buyer 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 capped at the Load Cap

3.3.2 Settlement of Seller Estimated Load. In the event that Buyer 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 ISO-NE Rules for the hours when Buyer 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 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. Buyer shall schedule all deliveries of energy to the Rhode Island Zone (ISO-NE Node #4005) (the "Delivery Point"). Seller shall bear all costs and losses of supplying energy hereunder to the Delivery Point and Pascoag shall bear all costs and losses at and after the Delivery Point. Title to all energy shall pass at the Delivery Point.

5. Purchase Price. Pascoag shall pay Seller, each month during the 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"). The Purchase Price shall not be subject to adjustment or change except as set forth herein.

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 confirm and deliver Load Following Energy for any changes to the Load resulting from any excess Load over the Load Cap. To the extent that Pascoag does incur such an additional load obligation in excess of the Load Cap, Seller and Pascoag agree to meet to discuss whether changes may be made to this Confirmation to address how Pascoag's additional load obligation can be met under this Confirmation; provided however, neither Seller nor Pascoag shall be required to accept a change with which it, in its sole judgment, disagrees.

6.2 Involuntary Demand Response. If Pascoag becomes subject to any load interruption or demand-side management program (collectively, "DR Programs") imposed by applicable law or ISO-NE that affects Pascoag's Load 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 sixty (60) days, as soon as practicable, advance written notice of such requirements and provide a description of such DR Program in reasonable detail. Seller and Pascoag agree to meet to discuss whether changes may be made to the prices set forth in Exhibit A; provided however, neither Party shall be required to accept a change with which it, in its sole judgment, disagrees. In the event that Pascoag and Seller cannot agree to such changes, then either Party may terminate this Confirmation upon 90 days' prior written notice without any further action.

6.3 Voluntary Demand Response. Prior to Pascoag instituting any DR Program, Pascoag will provide at least sixty (60) days advance written notice to Seller of such DR Program and a description of such DR Program in reasonable detail. In addition, if such DR Program would reduce Load by more than 1 MW in any hour, whether alone or aggregated with other DR Programs, 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 90 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 first set forth above.

PSEG ENERGY RESOURCES & TRADE LLC

By: John P. Scarlata
Its: Vice President

PASCOAG UTILITY DISTRICT

By: Michael R. Kirkwood
Its: General Manager

GR
12/7/16

12/7/16

S.C
12/7/16

12/7/2016

12/7/2016.

SCHEDULE 1

Fixed Volumes

Pascoag's Fixed Volumes for 2018			
2018	5x16	7x8	2x16
Jan	4.828	3.221	4.221
Feb	4.802	3.214	4.214
Mar	4.835	3.156	4.156
Apr	4.999	3.333	4.333
May	4.728	3.047	4.047
Jun	4.731	3.074	4.074
Jul	4.593	3.094	4.094
Aug	4.665	3.116	4.116
Sep	4.656	3.165	4.165
Oct	3.252	1.837	2.837
Nov	4.696	3.174	4.174
Dec	4.581	3.009	4.009

Pascoag's Fixed Volumes for 2019			
2019	5x16	7x8	2x16
Jan	5.328	3.721	4.721
Feb	5.302	3.714	4.714
Mar	5.335	3.656	4.656
Apr	5.499	3.833	4.833
May	5.228	3.547	4.547
Jun	5.231	3.574	4.574
Jul	5.093	3.594	4.594
Aug	5.165	3.616	4.616
Sep	5.156	3.665	4.665
Oct	5.083	3.668	4.668
Nov	5.196	3.674	4.674
Dec	5.081	3.509	4.509

Pascoag's Fixed Volumes for 2020			
2020	5x16	7x8	2x16
Jan	5.828	4.221	5.221
Feb	5.802	4.214	5.214
Mar	5.835	4.156	5.156
Apr	4.667	3.001	4.001
May	5.728	4.047	5.047
Jun	5.731	4.074	5.074
Jul	5.593	4.094	5.094
Aug	5.665	4.116	5.116
Sep	5.656	4.165	5.165
Oct	5.583	4.168	5.168
Nov	5.696	4.174	5.174
Dec	5.581	4.009	5.009

Exhibit A

Pricing – RI Zone (pnode ID# 4005) $/MWh

Monthly Pricing for 2018 / 2019 / 20120			
Month	**On-Peak**	**Off-Peak**	**2x16**
January	$45.75	$45.75	$45.75
February	$45.75	$45.75	$45.75
March	$45.75	$45.75	$45.75
April	$45.75	$45.75	$45.75
May	$45.75	$45.75	$45.75
June	$45.75	$45.75	$45.75
July	$45.75	$45.75	$45.75
August	$45.75	$45.75	$45.75
September	$45.75	$45.75	$45.75
October	$45.75	$45.75	$45.75
November	$45.75	$45.75	$45.75
December	$45.75	$45.75	$45.75

Testimony Exhibit 4-MRK

Confirmation Letter for:

Hedging deal with NextEra Energy Marketing, LLC

CONFIRMATION OF POWER PURCHASE AND SALE TRANSACTION

Date:	July 20, 2017
Transaction Number:	2059036
To:	Pascoag Utility District (Buyer)
Trader:	
From:	NextEra Energy Marketing, LLC (Seller)
Trader:	Elliot Bonner

This confirmation confirms the terms and conditions of the physical power transaction entered into between the parties.

Trade Date:	July 19, 2017
Type of Transaction:	FIRM (LD)
Term:	From and including: 01/01/2019 Through: 12/31/2019
Delivery Period:	Hour Type: 7x24 Days of Week: Monday through Sunday, including NERC holidays Hour Endings: 0100 through 2400 Time Zone: Eastern Prevailing Time (EPT)
Contract Quantity:	1.000 MW
Total Contract Quantity:	8,760 MWH
Contract Price:	$ 38.80000/MWH
Delivery Point:	.Z.RHODEISLAND
Scheduling Rules:	Seller shall schedule DAY-AHEAD physical delivery of the Contract Quantity to Buyer at the Delivery Point to occur during the applicable Delivery Period in accordance with the rules and procedures of the Transmission Provider.
Special Terms:	Parties shall allocate the Marginal Loss Revenue Load Obligation pursuant to Section III.3.2.1(b)(v) of Market Rule 1 to Seller for the applicable amount of Energy delivered under this Transaction.

Governing Terms: Unless otherwise noted in this confirmation, this transaction is governed by the terms and conditions of the Master Agreement between NextEra Energy Marketing, LLC and Pascoag Utility District executed on September 30, 2010.

CONFIRMATION OF POWER PURCHASE AND SALE TRANSACTION

Upon receipt:

1. If this confirmation **does not reflect** your understanding of this Transaction please notify the Risk Management Department of NextEra Energy Marketing, LLC by **fax at 561-625-7517 or email to NextEra.Confirmations@NextEraEnergy.com**.
2. If this confirmation reflects your understanding of this Transaction please sign where indicated **and fax to 561-625-7517 or email to NextEra.Confirmations@NextEraEnergy.com**.

NextEra Energy Marketing, LLC		**Pascoag Utility District**	
By:	Nicole Lawrence	By:	Michael R. Kirkwood
Name:	Nicole Lawrence	Name:	Michael R. Kirkwood
Title:	Associate Trading Risk Analyst	Title:	General Manager
Date:	July 20, 2017	Date:	July 20, 2017
Contact:	phone:561-304-6181 fax:561-625-7517	Contact:	401-568-2459

Testimony Exhibit 5-MRK

Confirmation Letter for:

Energy & EFECs between Pascoag Utility District and NextEra Energy Marketing, LLC

CONFIRMATION FOR
ENERGY & EFECs
BETWEEN
PASCOAG UTILITY DISTRICT AND
NEXTERA ENERGY MARKETING, LLC
October 30, 2017

This transaction is by and between NextEra Energy Marketing, LLC ("NEM") and Pascoag Utility District ("Buyer") (each a "Party" and collectively, the "Parties") and is dated as of October 30, 2017. This Confirmation confirms the terms and conditions of the transaction (the "Transaction") entered into between the Parties on the Trade Date specified below (this "Confirmation"). This Confirmation constitutes the entire agreement and understanding of the Parties with respect to its subject matter and supersedes all oral communication and prior writings (except as otherwise provided herein).

The terms of the Transaction are as follows:

TRADE DATE:	October 31, 2017
SELLER:	NextEra Energy Marketing, LLC ("NEM" or "Seller")
BUYER:	Pascoag Utility District ("Buyer")
TERM:	Hour Ending 0100 on January 1, 2020 through Hour Ending 2400 on December 31, 2029
PRODUCTS:	Energy on a firm basis ("Energy") and Nuclear-based Emissions Free Energy Certificates ("EFECs")
MONTHLY ENERGY AND EFECs COST:	During each month of the Term, Buyer shall pay the applicable Contract Price times the applicable monthly Contract Quantity delivered to the Delivery Point.
CONTRACT QUANTITY:	The MW per hour (MWh) of Energy for each hour of each calendar year in the Term listed in Appendix A.
DELIVERY POINT:	The Delivery Point for the Energy means the Pool Transmission Facilities (the "PTF") at the Internal Hub having Location ID 4000 and Location Name Description .H.INTERNAL_HUB (the "Hub") as defined in Market Rule 1; provided, however, if, at any time during the Term, the Delivery Point ceases to exist as a single trading hub, then the Delivery Point shall be determined in the following manner: (a) if multiple hubs are implemented, the Delivery Point shall be the PTF at the hub that is substantially similar to the Hub; and (b) if there is no substantially similar hub, the Parties agree that the Delivery Point shall be represented by the arithmetic average of the Nodal Prices for the Nodes that constituted the Hub as of the Trade Date.
CONTRACT PRICE:	For calendar year 2020, the Contract Price for Energy and EFECs will be \$40.87/MWh. Starting with calendar year 2021 until the end of the Term, the Contract Price will

	be subject to annual increases by applying a 2.5% escalation factor (e.g. the Contract Price for calendar year 2021 shall be equal to the Contract Price for calendar year 2020 multiplied by 1.025). The attached Appendix A includes the Contract Prices for each calendar year during the Term.
<u>ENERGY SCHEDULING</u>:	The Contract Quantity shall be scheduled pursuant to a Day-Ahead Internal Bilateral Transaction ("IBT"). The Parties agree that for any IBT scheduled for the Contract Quantity, such transaction shall be included in the calculation of the Marginal Loss Revenue Load Obligation pursuant to Section III.3.2.1(b)(v) of Market Rule 1 and the box indicating "Impacts Marginal Loss Revenue Allocation" will be checked when the Energy is scheduled with ISO-NE. In accordance with ISO-NE Rules, Buyer shall timely confirm each IBT submitted by Seller.
<u>EFECs</u>:	Seller shall assign and transfer to Buyer EFECs meeting the requirements set forth in Rule 2.3 in the NEPOOL GIS Operating Rules in amounts equal to the Contract Quantity.
<u>FAILURE TO DELIVER OR RECEIVE</u>	Only in relation to failure to deliver or receive Energy under this Transaction: a) The definition of Replacement Price in Section 1.51 shall be amended to delete the entire definition and replace it with: "The Replacement Price shall be the Locational Marginal Price for the Day-Ahead market at the Delivery Point, for each hour the Product was not delivered by Seller at the Delivery Point." b) The definition of Sales Price in Section 1.53 shall be amended to delete the entire definition and replace it with: "The Sales Price shall be the Locational Marginal Price for the Day-Ahead market at the Delivery Point, for each hour the Product was not received by Buyer at the Delivery Point." Only in relation to failure to deliver or receive EFECs under this Transaction, Article 4 shall be deleted and replaced with: "In the event Seller fails to deliver EFECs to the Buyer, Seller shall credit Buyer an amount equal to the product of (i) the amount of EFECs not delivered <u>*multiplied*</u> by (ii) the price at which Buyer, acting in a commercially reasonable and timely manner, purchases replacement EFECs; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges."
<u>BUYER'S CREDIT SUPPORT</u>	For purposes of this Transaction, Section 8.2(c) – 8.2(e) shall be considered "inapplicable." For purposes of this Transaction, Section 8.2(b) is deleted in its entirety and replaced with the following: "Within ten (10) Business Days of the execution of this Confirmation, NextEra Energy Capital Holdings, Inc. shall increase an existing guarantee provided by

	Seller to Buyer by the applicable amount provided in Appendix B. Such guaranty agreement shall guarantee the payment obligations of the Seller to the Buyer contained in this Confirmation, as provided in such guaranty agreement. Such guaranty agreement shall be effective on the Trade Date and shall continue in effect during the entire Term; provided that the amount of such guaranty shall decrease on an annual basis in accordance with the amounts provided in Appendix B. Upon the request of Seller, Buyer shall promptly take such action as is reasonably necessary to effectuate any permitted reduction. If the Guarantor elects to terminate such guaranty agreement then Seller shall provide Buyer written notice of Guarantor's notice of termination promptly upon its receipt of such notice from the Guarantor. Five (5) Business Days prior to the effective date and time of the termination of such guaranty agreement, Seller shall replace such guaranty agreement with: (i) a Letter of Credit in a form reasonably acceptable to Buyer in the same amount as such guaranty agreement, (ii) cash in the same amount as such guaranty agreement; or (iii) a guaranty from another entity with an Investment Grade Credit Rating who is reasonably satisfactory to Buyer and such guaranty is substantially in the form of the existing guaranty agreement ("Qualified Guarantor") and in the same amount as the terminated guaranty agreement. The amounts required in subsection (i)-(iii) in relation to this Transaction shall not exceed the applicable amount in Appendix B. If the Guarantor assigns said guaranty agreement to an entity that is not a Qualified Guarantor, then Seller shall provide Buyer written notice of Guarantor's assignment promptly upon its receipt of such notice from the Guarantor. Within five (5) Business Days prior to the effective date and time of such assignment, Seller shall replace such guaranty agreement with: (i) a Letter of Credit in a form reasonably acceptable to Buyer in the same amount as such guaranty agreement, (ii) cash in the same amount as such guaranty agreement; or (iii) a guaranty issued by a Qualified Guarantor in the same amount as the assigned guaranty agreement. The amounts required in subsection (i)-(iii) in relation to this Transaction shall not exceed the applicable amount in Appendix B. In the event that Seller has caused a Letter of Credit to be issued for the benefit of Buyer or transferred cash to Buyer on any Business Day, Seller may request a reduction or return of such Letter of Credit or cash, provided that, after giving effect to the requested reduction or return, (i) Seller shall not have an unsatisfied credit support obligation; (ii) no Event of Default with respect to Seller shall have occurred and be continuing; and (iii) no Early Termination Date has occurred or been designated as a result of an Event of Default with respect to Seller for which there exist any unsatisfied payment obligations. Any permitted return or reduction of credit support described shall be effected within three (3) Business Days of such request. "Investment Grade Credit Rating" means a Credit Rating of at least BBB- from S&P or Baa3 from Moody's; provided, in the event of nonequivalent ratings, the lower rating shall be the determinant rating for any Credit Rating based criterion set forth in this Confirmation.
<u>NEM'S CREDIT SUPPORT</u>	For purposes of this Transaction, Section 8.1(c) – 8.1(e) shall be considered "inapplicable."

	For purposes of this Transaction, Section 8.1(b) is deleted in its entirety and replaced with the following: "(a) Buyer shall have no obligation to post any Performance Assurance to Seller prior to the commencement of the Term. (b) If, from time to time during the Term, (i) Buyer is subject to an Event of Default; or (ii) Buyer fails to have an Investment Grade Credit Rating, then Seller may request that Buyer provide it with Performance Assurance in the form of Alternative Credit Support in an amount equal to Seller's Exposure (defined below) (rounded up to the nearest integral multiple of $50,000 dollars), provided that the amount of Alternative Credit Support shall not exceed the Required Buyer Credit Support Amount as set forth in Appendix B ("Buyer's Credit Support Cap"); provided further that Buyer's Credit Support Cap shall decrease on an annual basis in accordance with the amounts provided in Appendix B. Buyer shall provide such Alternative Credit Support to Seller within five (5) Business Days after receipt of Seller's request. On any Business Day, Buyer may request a return of the Alternative Credit Support previously provided by Buyer for the benefit of Seller, provided that, after giving effect to the requested return of Alternative Credit Support, (x) none of the events described above in clauses (i), or (ii) has occurred and is continuing; (y) no Event of Default with respect to Buyer shall have occurred and be continuing; and (z) no Early Termination Date has occurred or been designated as a result of an Event of Default with respect to Buyer for which there exist any unsatisfied payment obligations. Any permitted return of Alternative Credit Support shall be effected within three (3) Business Days of such request. "Seller's Exposure" means the Termination Payment calculated by Seller in a commercially reasonable manner for this Transaction only, as if such day were an Early Termination Date. "Alternative Credit Support" means cash or a Letter of Credit; notwithstanding the foregoing, however, Alternative Credit Support as applied to Buyer shall mean cash only if Buyer is a Massachusetts municipal light plant.
<u>DOWNGRADE EVENT</u>	If Buyer or NEM's Guarantor, as applicable, is subject to a Downgrade Event, the affected Party shall provide, as soon as reasonably possible, written notice to the other Party of such Downgrade Event and then within three (3) Business Days after a request of the non-downgraded Party, the Party subject to the Downgrade Event shall deliver Alternative Credit Support to the other Party; provided that if Seller is subject to the Downgrade Event, it shall deliver Alternative Credit Support in the amount provided for in Appendix B, and if Buyer is subject to the Downgrade Event, it shall deliver Alternative Credit Support in an amount determined in accordance with the section 'NEM's Credit Support' above. For purposes of this section, if a Buyer or NEM's Guarantor, as applicable, is rated by both S&P and Moody's, then a downgrade by either such agency below an Investment Grade Credit Rating shall constitute a Downgrade Event with respect to such party. "Downgrade Event" means the failure to have an Investment Grade Credit Rating.

COLLATERAL ANNEX	If there is a Collateral Annex in place, this Transaction shall not be considered when calculating the "Exposure Amount" thereunder.
INVOICE ADJUSTMENT	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 invoice 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 more current data received by Seller from ISO-NE.
CLEAN ENERGY STANDARD:	Seller shall make commercially reasonable efforts to provide to Buyer with relevant documentation and attestations requested for compliance with provisions of the potential Clean Energy Standard legislation ("CES") potentially allowing Buyer to utilize this Confirmation to reduce any CES obligations.
APPLICABLE MARKET RULES	"Applicable Market Rules" means (i) the ISO-NE Transmission Markets and Services Tariff, ISO-NE Market Rule 1, the ISO-NE Manuals, the ISO-NE Participants' Agreement, and any other ISO-NE and/or NEPOOL operating agreements, in each case as accepted for filing by the FERC and as amended, replaced or supplemented from time to time; and (ii) all rules and regulations adopted by NEPOOL and/or ISO-NE, and/or any directives issued by ISO-NE, including without limitation all operating procedures, planning procedures and market rules and procedures issued or adopted by NEPOOL and/or ISO-NE and its satellite agencies or affiliates, or their successors, in each case as amended, replaced or supplemented from time to time.
CHANGES IN APPLICABLE MARKET RULES & REGULATORY EVENTS:	If any governmental authority adopts, enacts, or otherwise imposes a new law, rule, directive or regulation which either makes a Party's performance under this Confirmation unlawful or makes this Transaction unenforceable, impossible or impracticable and such governmental action does not constitute a Force Majeure, the Parties shall negotiate in good faith to amend the terms of this Transaction and to determine the appropriate changes, if any, so that the Party affected by such change is able to lawfully perform its obligations without materially adversely affecting the financial benefit hereunder to either Party. For purposes of this Confirmation, a new law, rule, directive or regulation shall include changes relating to the ISO-NE Tariff, ISO-NE Protocols and the NEPOOL GIS, that causes (a) a material change in the meaning of a term defined herein or incorporated herein by reference, or (b) a material change in the manner in which a Party is required to perform its obligations under this Confirmation (including changes relating to ISO-NE's ability to support or settle the Product) such that the Confirmation no longer reflects the intent of the Parties.
GOVERNING TERMS	This Confirmation supplements, forms a part of, and is subject to, the terms of the EEI Master Agreement dated as of September 30, 2010 between NEM and Buyer (the "Master Agreement"), This Confirmation shall constitute a "Confirmation" within the meaning of the Master Agreement that supplements, forms a part of and is subject to the Master Agreement. All the terms of the Master Agreement (as such terms may be amended from time to time) shall, apply to this Transaction

	except as modified herein. In the event of any inconsistency between a provision of the Master Agreement and a provision of this Confirmation, the provision of this Confirmation shall control for purposes of this Transaction.

NEM and Buyer execute this Confirmation effective on the Trade Date referenced above.

NextEra Energy Marketing, LLC

By: ______________________

Name: Mark Palanchian

Title: Vice President and Managing Director Nextera Energy Marketing, LLC

Legal Review Completed AHR

CREDIT SDW

Pascoag Utility District

By: Michael R. Kirkwood

Name: Michael R. Kirkwood

Title: General Manager

Appendix A
Contract Price

Applicable Calendar Year	Contract Price ($/MWh)
2020	$40.87
2021	$41.89
2022	$42.94
2023	$44.01
2024	$45.11
2025	$46.24
2026	$47.40
2027	$48.58
2028	$49.80
2029	$51.04

Contract Quantity

Applicable Calendar Year	Contract Quantity (MW)
2020	0.5
2021	0.5
2022	0.5
2023	0.5
2024	0.5
2025	0.5
2026	0.5
2027	0.5
2028	0.5
2029	0.5

Appendix B

Credit Support Amounts for Seller and/or Buyer

Period			Required Seller Credit Support Amount ($/MW)(1)	Required Buyer Credit Support Amount ($/MW)(1)
10/31/2017	-	12/31/2020	$385,000	$385,000
1/1/2021	-	12/31/2021	$375,000	$375,000
1/1/2022	-	12/31/2022	$375,000	$375,000
1/1/2023	-	12/31/2023	$375,000	$375,000
1/1/2024	-	12/31/2024	$350,000	$350,000
1/1/2025	-	12/31/2025	$300,000	$300,000
1/1/2026	-	12/31/2026	$265,000	$265,000
1/1/2027	-	12/31/2027	$240,000	$240,000
1/1/2028	-	12/31/2028	$190,000	$190,000
1/1/2029	-	12/31/2029	$135,000	$135,000

(1) Note: Required security amounts in the table above correspond to 1 MW. Required security amounts applicable to this Confirmation will be determined by multiplying (i) the amounts in the table above times (ii) the maximum MW value included in the Contract Quantity table in Appendix A.

Testimony & Testimony Exhibits

Harle J. Round, Manager, Finance & Customer Service

- **Q1. Please provide an update of the status of the Pascoag's fuel reconciliation for the period ending December 31, 2018.**

  A1. As of this filing dated (November 5, 2018), this submittal contains actual expenses and revenues through September 2018. The fourth quarter (October through December) is based on estimates provided by Energy New England ('ENE"). The projected reconciliation at December 31, 2018 is estimated to be an under collection of ($44,084).

- **Q2. Before you get into the details of the under 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's 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 withdrawals were approved in RIPUC Docket 4762 which was $266,167 reimbursement of the PPRFC that is being issued back to the customers through a credit on their electric bills. The balance in this account is now at $ 578,802.24 as of the November transfer. A summary of the PPRF for 2018 can be seen below in **Table #1**.

	Table # 1		**PURCHASE POWER RESTRICTED FUND**		
MONTH/YEAR	**DEPOSIT**	**WITHDRAWAL**	**Net increase/ (decrease)**	**INTEREST**	**BALANCE**
START BALANCE					**$659,963.20**
JAN 2018 True-up of 2017	$10,198.71		$10,198.71		$670,161.91
Jan 2018	$14,155.25	($22,180.62)	($8,025.37)		$662,136.54
Feb 2018	$14,149.25	($22,180.58)	($8,031.33)		$654,105.21
March 2018	$14155.25	($22,180.58)	($8,025.33)		$646,079.88
April 2018	$14,155.25	($22,180.58)	($8,025.33)		$638,054.55
May 2018	$14,155.25	($22,180.58)	($8,025.33)		$630,029.22
June 2018	$14,155.25	($22,180.58)	($8,025.33)		$622,003.89
July 2018	$14,155.25	($22,180.58)	($8,025.33)		$613,978.56
Aug 2018	$13,786.25	($22,180.58)	($8,394.33)		$605,584.23
Sept 2018	$13,359.85	($22,180.58)	($8,820.73)		$596,763.50
Oct 2018	$13,204.05	($22,180.58)	($8,976.53)		$587,786.97
Nov 2018	$13,195.85	($22,180.58)	($8,984.75)		$578,802.24

The kW Demand charges for DPI have decreased on their combined electric accounts. The District compared the data from November of 2017 through October of 2018. Please see **Testimony Exhibit HJR-1**. All three accounts remain active and the last information the District received from DPI, which was in December of 2016 regarding their continuing operations, indicated that eventually only one product line will remain at Davis Drive. They have recently installed some expensive equipment into their buildings in Pascoag, however, we are hopeful that they will continue operations in the District's Territory indefinitely.

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 $563,208 by year end. If we back out the PPRF approved level of $550,000 this would leave a balance of $13,208. As of October, 31 2018, the District has flowed back $ 221,685.53 through a billing credit. The District would like to decrease the flow back to customers to $156,356 in 2019 through the Purchase Power Restricted Fund Credit and re-evaluate the excess balance with next year's rate filing based on sales to DPI at that time. The credit would result in a 2.83 mill ($0.00283) per kilowatt hour in the proposed rates for 2019, please see **Testimony Exhibit HJR-2** which is included in this filing. The proposed reduction in the PPRF is also outlined in **Testimony Exhibit HJR-3.**

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 November, the District has fully funded the account to the $306,000 level for 2018. The balance in this account is $724,989.34 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 $200,000 Bucket Truck and use $50,000 for the engineering on a new substation in 2019, along with several smaller capital purchases. The 2018 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 Purchases			**$572,467.32 Start Bal**
JAN 2018	$25,500	($41,921)			$556,046.32
FEB 2018	$25,500	($3,829.85)			$577,716.47
MAR 2018	$25,500				$603,216.47

APRIL 2018	$25,500				$628,716.47
MAY 2018	$25,500	($1,019.71)			$653,196.76
JUNE 2018	$51,000	($84,127.42)			$620,069.34
JULY 2018					$620,069.34
AUG 2018	$25,500	($8,560)			$637,009.34
SEPT 2018	$25,500				$662,509.34
OCT 2018	$25,500				$688,009.34
NOV 2018	$51,000	($14,020)			$724,989.34
DEC 2018					
Total	**$306,000**	**($153,478)**			**$724,989.34**

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. Please see **Table #3** for the activity.

Table #3 Storm Fund Goal for 2018 is $20,000 ($5,000 per quarter)			
Start Balance (Dec 2017)	$85,494		
Date	Deposit	Withdrawal	Balance
2-2018		(19,643.50)	$65,821
3-2018	$5,000		$70,851
6-2018	$5,000	(29,941.38)	$45,909
9-2018	$5,000		$50,909
10-2018	$5,000		$55,909

As of this filing, Pascoag has met all of our financial obligations. The Cash Flow Summaries for fiscal year 2018 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 under collection and then break it out by factor.**

A3. The cumulative under-collection of the combined Standard Offer, Transition Charge and Transmission charge is expected to be ($44,084) as shown in **Table #4 and Table #5.** Actual revenue exceeded expenses in January – May and September which increased the cumulative over collection. Starting in June –August the expenses exceeded revenue and the cumulative over collection was reduced. Using Energy New England's forecast, the expenses will exceed revenue in October, November and December. Please note that the 2018 Bulk Power Projection from ENE includes the Surplus funds credit related to Seabrook. The under collection is estimated to be ($44,084). Please see **Testimony Exhibit HJR-9 for ENE's projections for October – December 2018.**

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

	Start Bal	Revenue	Expense	Monthly	Cumulative
Jan-18	$74,271	$532,439	$449,000	$83, 439	$157,710
Feb-18	$157,710	$502,990	$437,025	$65,964	$223,674
Mar-18	$223,674	$441,655	$409,135	$32,521	$256,195
Apr-18	$256,195	$444,908	$374,115	$70,793	$326,987
May-18	$326,987	$396,124	$393,091	$ 3,033	$330,020
Jun-18	$330,020	$411,170	$473,488	($62,318)	$267,702
Jul-18	$267,702	$510,524	$575,303	($64,779	$202,923
Aug-18	$202,923	$587,743	$602,743	($15,000)	$187,923
Sep-18	$187,923	$553,203	$528,223	$24,980	$212,903
Oct-18 EST	$212,903	$427,181	$540,148	($112,967)	$ 99,937
Nov-18 EST	$ 99 937	$421,411	$501,501	($80,091)	$ 19,846
Dec-18 EST	$19,846	$479,940	$543,870	($63,930)	($44,084)
	Period Cumulative Over/(Under) collection				
Forecast Cumulative Over/(Under) Collection at 12/31/18					($44,084)

Table #5	**Summary of Year-End Cumulative Over/ (Under) Collection as of 12/31/2018**[1]
Standard Offer	($ 173,865)
Transition	$ 42,982
Transmission	$ 86,799
Total	($ 44,084)

- **Q4. Please provide reasons for the Under collection in 2018.**

A4. The District started the year with a cumulative over collection for the combined Standard Offer, Transition Charge, and Transmission Charge of $74,271 from 2017. 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

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

make up the gap in revenue when the rate reduction began flowing the over collection back to the District's customers in 2018. The balance in this account is $212,903 which is reconciled to the September Schedule C-1, Line 169 G in Book 2. The District had under collections for three of the nine months, June, July and August, which helped to bring down the cumulative over collection. The District applied the deferred surplus funds from 2017/2018 January through June for a total credit of $266,797.98 under the Project 6 Seabrook power bills. Then in September of 2018, we received our surplus fund check for $30,656.52 and began applying a credit to the Project 6 Seabrook power bills in August and September. The credit is $2,787.02 per month which will be continued to be applied each month through June of 2019. The District received Other Credits to the Project 6 Seabrook portion of our power supply totaling $27,543.08. The District received the following REC sales credits for 2018: Spruce Mountain $6,615, Canton Mountain was $2,983.07, and Brown Bear was $354, which help to reduce the Purchase Power expenses. **Copies of the Surplus checks and the Other Credits, along with the a copy of Schedule A-1 showing the REC sales can be seen under HJR Testimony Exhibit #6.** When Reconciling the ENE Forecast to the Actual cost through September, we were under budget by $78,005 and the MWH purchased were under budget by 843MWH. **Please see Schedule D Line 32D and 32G in Testimony Exhibit HJR-6-5.**

Using ENE's 2018 Power Assumptions for October, November and December, we estimate the cumulative under collection will be ($44,084) at the end of 2018 which is the net of ($173,865) Standard Offer Service, $42,982 Transition, and $86,799 Transmission. The estimated sales to customers for 2019 are 55,268 MWH which is calculated using a three-year average for January – October and a two-year average for November and December of this year plus the actual consumption from 2016 and 2017. We have also factored in a negative growth factor of (.00989%) for 2019. The District expects to have growth of 108 MW from new homes which is offset by a reduction of (660) MW due to the energy efficiency projects that the school department will complete at the end of 2018. This will result in a reduction of (552) MW. **Please see Schedule E Line 146 J and Schedule F-2, Line 112 O in Book 2.**

- The forecasted Transition cost for 2019 is $132,000 minus the estimated over collection of $42,982 divided by 55,268 MWH equals $1.61 per MWH or $0.00161 per kWh. This will result in an increase of 0.00121 in the Transition Rate.
- The forecasted 2019 Transmission cost is $1,850,825 minus the estimated over collection of $86,799 divided by 55,268 MWH equals $31.92 per MWH or $0.03192 per kWh, an increase of $0.00219 to the Transmission rate.
- The forecasted Standard offer cost for 2019 is $4,151,814 plus the estimated under-collection of $173,865 divided by 55,268 MWH equals $78.27 per MWH or $0.07827per kWh an increase of $0.00661 to the Standard Offer rate.

- The District is also proposing to decrease the Purchase Power Restricted Fund Credit (PPRFC) from $266,167 to $156,356 this would decrease the flow back of PPRFC to ($0.00283) which would result in an increase of $0.00186.
- The net result of the Transmission, Transition, Standard Offer, and PPRFC will be an increase of $0.01187 per kWh or an increase of 7.9%. A 500-Kilowatt Hour per month Residential Customer will see their bill increase from $75.31 to s $81.24, or an increase of $5.93. ***Please see Testimony Exhibit HJR-2.***

Other factors that contributed to the under-collection to the standard offer component was the fact that Pascoag only received 2,150,800 interruptible kilowatt-hours (kWh) from the two New York Power Authority (NYPA) entitlements for the previous three quarters ending in September 2018, this was a reduction of 2,764,200 kwh compared to the same time period last year. The average cost per kWh for January through September in 2017 was $0.0226/kWh, the average has increased to $0.032/kWh for Niagara and St Lawrence went from $0.0295 cents/kWh in 2017 to $0.0288/per kWh in 2018.

The District estimate in the addendum filing last year showed that we would have 48,016 MW in sales through the month of October, 2018. The actual sales through October are only 47,281 MW, an under collection of (735) MW. The District is feeling the effects of energy conservation measures being implemented by the Demand Side Management Program that is directly affecting consumption. This is one of the biggest reasons for the under collection to the Standard Offer in 2018. **Please see Testimony Exhibit HJR 10.**

The Transition Charge in is estimated to have an over collection of $42,982. The revenue is expected to exceed the expense in all twelve month. The cost of Transition will rise from $9,000 in 2018 to $132,000 in 2019. This will be the last year for transition charges which were associated with Project 6/ Seabrook. This will end the required payments under the PSAs and PPAs for the debt service portion of the Seabrook rates to MMWEC as of December 31, 2019.

The Transmission Charge is estimated to have an over-collection of $86,799 at the end of 2018. Revenue exceeded expenses in five of the 9 months and expenses exceeded revenue in 4 of the nine months. ENE estimates for 2018 were used to calculate October – December. ENE forecasted a cost of $1,393,127 through September and the actual bills through September are $1,289,233 a difference of $103,904 less than the budget. **Please see Testimony Exhibit HJR-11**

The District flowed back $266,797.98 of the 2017/2018 Surplus funds for MMWEC for the period January through June of 2018. The large return of surplus funds last year was the result of excess funds in the bond reserve account that were returned after the bond principal and interest payments were made on July 1, 2017. **Please see Testimony Exhibit HJR 6-1.** We received a check for $30,656.52 in August of 2018 which was divided by 11 months and is being used to reduce the Purchase Power bills by $13,934.82 from August - December 2018. The remaining $16,630.70 will be flowed back in 2019 with a credit each month of $2,786.05 from January – June of 2019. **Please see Testimony Exhibit HJR 6-2.** In 2019, the surplus funds are estimated at $13,400. The District also received other credits from Project 6 in January and October of 2018 for a total of $27,543.08. Please see **Testimony Exhibit HJR-6-3.**

- **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, 2018. The District will be able to provide actual expenses and revenue for October shortly after that date. The District will provide an 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 2019**

A6. The District, working with it consultants at Energy New England ("ENE"), has submitted the 2019 forecast total of $6,134,639 which is an increase of $228,992 from the 2018 Budget of $5,905,647.

Table #6: ENE Forecast	**2019**
Energy/ Transition	$4,283,813
Transmission	$1,850,825
Total	**$6,134,639**

ENE has provided a summary sheet of the 2019 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 $22.83/kw and surplus funds being applied $1,200 for Jan- June 2018 and $13,400 for the period Aug-Dec 2019. The cost will increase by $187,280. ENE forecast the net adjustments for Seabrook which will be a reduction to $5.36 per MWH for a ($2,164) adjustment and the Transmission was decreased ($27) based on the projection. The estimated net increase was $185,090;
2. The NYPA projections are based on Historical deliveries and cost. ENE increased the transmission cost based on 3-year historical actuals with a 5% increase; applied a deduction of 15% for Jan through Dec 2018 due to the lower entitlement in St. Lawrence. The net increase for NYPA was $15,800;
3. ENE updated the Capacity projections to reflect the auction pricing, bilateral, and payments by the Lead Participants. The FMC payments by Lead Participants will be ($117,599). The ISO FCM cost will increase by $223,037. The net adjustments to the capacity cost is $105,437;
4. ENE Updated NextEra Rise Call Options which increased the fixed cost by $ 3,240 and they updated the Energy to include the price lock of 6/30/16 with an increase of $4,579. The net increase was $7,819;
5. The Bilateral Transactions includes a contract extension for Miller Hydro (now Brown Bear Hydro) with a reduction of ($614), a place holder for REC sales on Spruce Mountain of $10/RECforsale at an increase of $11,194 and a contract with Canton Wind which includes placeholders for $10/REC for sale and an increase of $3,578 and an increase of $169,068 to the NextEra Bilateral. ENE projected a decrease of ($252,873) Energy costs for PSEG due to a lower contracted price of $45.75/MWH. The net decrease to the Bilateral Transactions is ($69,647);
6. A change from resales to purchases with ISO –NE resulting in a decrease of ($4,824);
7. The adjustments to ENE charges increased from $7,100 to $7,150 per month resulted in an increase of $600;
8. The Adjustments to estimated ISO expense saw no changes to the annual fee, a decrease of ($1,909) to the load base charges to account for reduced expenses for winter reliability. The scheduled charges increase by $9,215 and the transmission charges decreased by ($6,042). The net increase to Adjustments for estimated ISO Expenses was $1,263;
9. National Grid's Network Transmission Charges were increased based on historical data.
10. ENE adjustments to the DAF Sub-transmission charges by ($1,680);
11. For the Hydro Quebec Transmission Charges, the Use Right Values were decreased by ($11,404) and the FCM Credit was increased $536. The net adjustment was ($10,868).

The total adjustments for all categories resulted in increase of $228,992 to the 2019 budget. The estimated Forecasted Budget from ENE is $6,134,639 for 2019.

- **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 $75.31. Under the proposed rates, that customer would see his monthly bill increased to $81.24, an increase of $5.93. 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 $156,356 of the estimated over collection that was mentioned earlier in this testimony.

Table 7: Factor	**Current (2018)**	**Proposed (2019)**	**Difference**
Standard Offer	$0.07166	$0.07827	0.00661
Transition	$0.00040	$0.00161	0.00121
Transmission	$0.02973	$0.03192	0.00219
PPRFC	($0.00469)	($0.00283)	0.00186
Total	**$.09710**	**$0.10897**	**$0.01187**

- **Q8. Is Pascoag using any growth factors in its calculations for 2019?**

A8. Yes, we are using a negative load growth factor of (0.00989) %. The District is experiencing some growth in the village of Pascoag. We expect to have growth of 108 MWh when an additional 16 units at Greenridge Village come on service in 2019 along with new homes currently being constructed but this will be off-set by energy efficiency measures which are being currently installed by the School Department which will reduce their consumption by 660 MWh. The total will be a reduction in MWh sales of (552).

- **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 is at $33,975. 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
2017	$33,323
2018	$31,995 Estimate

Q10. Does this conclude your testimony?

Q10A. Yes, it does.

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

Testimony
Exhibit HSR - 1

Pascoag Utility District

Revision: 17192

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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	49581	09/26/2018	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	4,742.68	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	49,543.69	353,520	180 DAVIS DR	3	1	20		Pascoag Utility District

BILLING HISTORY

	Oct 18	Sep 18	Aug 18	Jul 18	Jun 18	May 18	Apr 18	Mar 18	Feb 18	Jan 18	Dec 17	Nov 17
Rev:	3459.60	4290.22	4909.10	2360.27	4029.63	3695.76	3353.74	3565.47	3834.81	3569.80	4214.48	4351.47
Dmd:	1361.20	1418.60	1418.60	1418.60	1418.60	1418.60	1418.60	1418.60	1418.60	1418.60	1418.60	1418.60
Dvc:	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.56	0.56
PCA:	-154.21	-192.48	-220.99	-103.56	-180.47	-165.09	-149.33	-159.08	-171.84	-160.96	-271.60	-280.67
Rev Tot:	4667.06	5516.81	6107.18	3675.78	5268.23	4949.74	4623.48	4825.46	5082.04	4827.91	5362.04	5489.96
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:	75.62	94.39	108.38	50.78	88.50	80.96	73.23	78.02	84.27	78.94	93.66	96.78
Total:	4742.68	5611.20	6215.56	3726.56	5356.73	5030.70	4696.71	4903.48	5166.31	4906.85	5455.70	5586.74
Pymnt:	-5611.20	-6215.56	-3726.56	-5356.73	-5030.70	-4696.71	-4903.48	-5166.31	-4906.85	-5455.70	-5586.74	-5725.50
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:	45,634.35	Total Dmd:	16,965.80	Total Dvc:	5.82	Total PCA:	-2,210.28
Avg Rev:	3,802.86	Avg Dmd Rev:	1,413.82	Avg Reporting Rev:	5,216.68	Total Payment:	-62,382.04

USAGE HISTORY

	Oct 18	Sep 18	Aug 18	Jul 18	Jun 18	May 18	Apr 18	Mar 18	Feb 18	Jan 18	Dec 17	Nov 17
Usage:	32880	41040	47120	22080	38480	35200	31840	33920	36640	34320	40720	42080
Kw Dmd:	81.840	98.400	132.000	120.800	119.200	111.200	110.400	116.000	116.800	115.200	124.000	132.800
Bill Dmd:	132.800	138.400	138.400	138.400	138.400	138.400	138.400	138.400	138.400	138.400	138.400	138.400

Total Usage:	436,320	Total Kw Dmd:	1378.640	Total Bill Dmd:	1655.200
Avg Usage:	36,360	Avg Kw Dmd:	114.887	Avg Bill Dmd:	137.933

Average demand 2016/2017 123.113
average demand 2017/2018 114.887
down 9.000 Kw

10/11/2018 1:58:16 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	49581	09/26/2018	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	4,742.68	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	49,543.69	353,520	180 DAVIS DR	3	1	20		Pascoag Utility District

BILLING HISTORY

	Oct 17	Sep 17	Aug 17	Jul 17	Jun 17	May 17	Apr 17	Mar 17	Feb 17	Jan 17	Dec 16	Nov 16
Rev:	4496.52	4335.35	4029.13	4303.12	3964.67	3513.39	3610.10	3392.52	3692.62	3707.12	3692.02	3941.21
Dmd:	1418.60	1394.00	1418.60	1418.60	1418.60	1418.60	1418.60	1418.60	1418.60	1418.60	1418.60	1418.60
Dvc:	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.60	0.60
PCA:	-290.28	-279.61	-259.33	-277.47	-255.06	-225.18	-231.58	-217.18	-239.05	-253.99	-84.18	-90.04
Rev Tot:	5625.40	5450.30	5188.96	5444.81	5128.77	4707.37	4797.68	4594.50	4872.73	4872.29	5027.04	5270.37
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:	100.10	96.42	89.42	95.68	87.95	77.65	79.86	74.89	82.43	87.58	87.22	93.29
Total:	5725.50	5546.72	5278.38	5540.49	5216.72	4785.02	4877.54	4669.39	4955.16	4959.87	5114.26	5363.66
Pymnt:	-5546.72	-5278.38	-5540.49	-5216.72	-4711.86	-4950.70	-4669.39	-4955.16	-4959.87	-5114.26	-5363.66	-5484.58
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:	46,677.77	Total Dmd:	16,998.60	Total Dvc:	6.80	Total PCA:	-2,702.95
Avg Rev:	3,889.81	Avg Dmd Rev:	1,416.55	Avg Reporting Rev:	5,306.36	Total Payment:	-61,791.79

USAGE HISTORY

	Oct 17	Sep 17	Aug 17	Jul 17	Jun 17	May 17	Apr 17	Mar 17	Feb 17	Jan 17	Dec 16	Nov 16
Usage:	43520	41920	38880	41600	38240	33760	34720	32560	35840	38080	37920	40560
Kw Dmd:	138.400	134.400	85.360	133.600	131.200	120.000	116.000	116.800	120.800	121.600	124.800	134.400
Bill Dmd:	138.400	136.000	138.400	138.400	138.400	138.400	138.400	138.400	138.400	138.400	138.400	138.400

Total Usage:	457,600	Total Kw Dmd:	1477.360	Total Bill Dmd:	1658.400
Avg Usage:	38,133	Avg Kw Dmd:	123.113	Avg Bill Dmd:	138.200

10/11/2018 2:02:57 pm

ACCOUNT 10524001 RECONCILIATION

Account	Name	Address	Home Phone	Work Phone	Mobile Phone	Cyc
10524001	DANIELE INTERNATIONAL INC	PO BOX 106 PASCOAG, RI 02859	0-	(401)568-6228	0-	1

Meter	Rdg	Rdg Dt	Rate	Dvc Type	# of Dvc	Mem Nbr
E5125	69576	09/26/2018	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	28,004.22	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	290,796.35	2,324,880	105 DAVIS DR B	3		20		Pascoag Utility District

BILLING HISTORY

	Oct 18	Sep 18	Aug 18	Jul 18	Jun 18	May 18	Apr 18	Mar 18	Feb 18	Jan 18	Dec 17	Nov 17
Rev:	22099.39	23858.31	28109.08	29281.69	27083.02	22832.28	19827.44	19754.14	21250.52	23393.47	27382.38	29703.19
Dmd:	6420.60	6420.60	6420.60	6420.60	6420.60	6420.60	6420.60	6420.60	6420.60	6420.60	6420.60	6863.40
Dvc:	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.56	0.56
PCA:	-1013.04	-1094.08	-1289.94	-1343.97	-1242.66	-1046.81	-908.36	-904.98	-975.90	-1083.95	-1805.70	-1959.38
Rev Tot:	27507.42	29185.30	33240.21	34358.79	32261.43	28206.54	25340.15	25270.23	26695.69	28730.59	31997.84	34607.77
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:	496.80	536.54	632.59	659.09	609.41	513.36	445.46	443.81	478.58	531.58	622.66	675.65
Total:	28004.22	29721.84	33872.80	35017.88	32870.84	28719.90	25785.61	25714.04	27174.27	29262.17	32620.50	35283.42
Pymnt:	-29721.84	-33872.80	-35017.88	-32870.84	-28719.90	-25785.61	-25714.04	-27174.27	-29262.17	-32620.50	-35283.42	-32924.52
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:	294,574.91	Total Dmd:	77,490.00	Total Dvc:	5.82	Total PCA:	-14,668.77
Avg Rev:	24,547.91	Avg Dmd Rev:	6,457.50	Avg Reporting Rev:	31,005.41	Total Payment:	-368,967.79

USAGE HISTORY

	Oct 18	Sep 18	Aug 18	Jul 18	Jun 18	May 18	Apr 18	Mar 18	Feb 18	Jan 18	Dec 17	Nov 17
Usage:	216000	233280	275040	286560	264960	223200	193680	192960	208080	231120	270720	293760
Kw Dmd:	49.680	496.800	511.200	626.400	612.000	576.000	453.600	453.600	511.200	511.200	576.000	590.400
Bill Dmd:	626.400	626.400	626.400	626.400	626.400	626.400	626.400	626.400	626.400	626.400	626.400	669.600

Total Usage:	2,889,360	Total Kw Dmd:	5968.080	Total Bill Dmd:	7560.000
Avg Usage:	240,780	Avg Kw Dmd:	497.340	Avg Bill Dmd:	630.000

average demand 2016|2017 578.400
average demand 2017|2018 497.340
down 81.06 KW

10/11/2018 2:02:39 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	()-	1

Meter	Rdg	Rdg Dt	Rate	Dvc Type	# of Dvc	Mem Nbr
E5125	69576	09/26/2018	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	28,004.22	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	290,796.35	2,324,880	105 DAVIS DR B	3		20		Pascoag Utility District

BILLING HISTORY

	Oct 17	Sep 17	Aug 17	Jul 17	Jun 17	May 17	Apr 17	Mar 17	Feb 17	Jan 17	Dec 16	Nov 16
Rev:	27237.32	31298.76	28035.11	30283.40	25931.86	23030.84	21000.12	23393.47	20824.83	22335.93	28112.60	27432.99
Dmd:	6863.40	7084.80	7084.80	7084.80	7084.80	7084.80	7084.80	7084.80	7084.80	7084.80	7084.80	7084.80
Dvc:	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.60	0.60
PCA:	-1796.10	-2065.03	-1848.92	-1997.80	-1709.65	-1517.56	-1383.09	-1541.57	-1383.09	-1570.38	-658.54	-642.56
Rev Tot:	32305.18	36319.09	33271.55	35370.96	31307.57	28598.64	26702.39	28937.26	26527.10	27850.91	34539.46	33875.83
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:	619.34	712.08	637.56	688.90	589.54	523.30	476.93	531.58	476.93	541.51	682.27	665.71
Total:	32924.52	37031.17	33909.11	36059.86	31897.11	29121.94	27179.32	29468.84	27004.03	28392.42	35221.73	34541.54
Pymnt:	-37031.17	-33909.11	-36059.86	-60172.02	-29147.24	-28026.35	-29468.84	-27004.03	-28392.42	-35578.69	-69180.49	0.00
NSF:	0.00	0.00	0.00	29147.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Total Rev:	308,917.23	Total Dmd:	84,796.20	Total Dvc:	6.80	Total PCA:	-18,114.29
Avg Rev:	25,743.10	Avg Dmd Rev:	7,066.35	Avg Reporting Rev:	32,809.45	Total Payment:	-413,970.22

USAGE HISTORY

	Oct 17	Sep 17	Aug 17	Jul 17	Jun 17	May 17	Apr 17	Mar 17	Feb 17	Jan 17	Dec 16	Nov 16
Usage:	269280	309600	277200	299520	256320	227520	207360	231120	207360	235440	296640	289440
Kw Dmd:	604.800	619.200	626.400	619.200	576.000	540.000	504.000	489.600	489.600	532.800	669.600	669.600
Bill Dmd:	669.600	691.200	691.200	691.200	691.200	691.200	691.200	691.200	691.200	691.200	691.200	691.200

Total Usage:	3,106,800	Total Kw Dmd:	6940.800	Total Bill Dmd:	8272.800
Avg Usage:	258,900	Avg Kw Dmd:	578.400	Avg Bill Dmd:	689.400

10/11/2018 2:06:01 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	()-	1

Meter	Rdg	Rdg Dt	Rate	Dvc Type	# of Dvc	Mem Nbr
E1096	64266	09/26/2018	PA-I	240 Watt LED Flood	4	

Dep Type	Prov	Srv Loc Nbr	Dep Amt	Dep Dt	Use

Provider	Cur AR	30 Day AR	60 Day AR	90 Day AR
EPUD	23,744.48	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	262,807.02	2,101,064	105 DAVIS DR M	3	1	20		Pascoag Utility District

BILLING HISTORY

	Oct 18	Sep 18	Aug 18	Jul 18	Jun 18	May 18	Apr 18	Mar 18	Feb 18	Jan 18	Dec 17	Nov 17
Rev:	19053.83	20047.30	24314.33	24762.22	21594.52	22221.54	20780.20	21960.96	19925.85	19751.07	25319.43	24578.05
Dmd:	5084.00	5182.40	5608.80	5977.80	5977.80	5977.80	5977.80	5977.80	5977.80	5977.80	5977.80	5977.80
Dvc:	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.39	51.48	51.48
PCA:	-872.72	-918.49	-1115.09	-1135.73	-989.78	-1018.67	-952.26	-1006.66	-914.74	-914.36	-1669.10	-1620.01
Rev Tot:	23316.50	24362.60	28859.43	29655.68	26633.93	27232.06	25857.13	26983.49	25040.30	24865.90	29679.61	28987.32
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:	427.98	450.43	546.85	556.97	485.39	499.56	466.99	493.67	448.59	448.41	575.55	558.62
Total:	23744.48	24813.03	29406.28	30212.65	27119.32	27731.62	26324.12	27477.16	25488.89	25314.31	30255.16	29545.94
Pymnt:	-24813.03	-29406.28	-30212.65	-27119.32	-27731.62	-26324.12	-27477.16	-25488.89	-25314.31	-30255.16	-29545.94	-30049.78
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:	264,309.30	Total Dmd:	69,675.40	Total Dvc:	616.86	Total PCA:	-13,127.61
Avg Rev:	22,025.78	Avg Dmd Rev:	5,806.28	Avg Reporting Rev:	27,832.06	Total Payment:	-333,738.26

USAGE HISTORY

	Oct 18	Sep 18	Aug 18	Jul 18	Jun 18	May 18	Apr 18	Mar 18	Feb 18	Jan 18	Dec 17	Nov 17
Usage:	186080	195840	237760	242160	211040	217200	203040	214640	195040	194960	250240	242880
Kw Dmd:	401.120	408.800	444.800	477.600	473.600	434.400	431.200	424.000	410.400	448.000	496.000	479.200
Bill Dmd:	496.000	505.600	547.200	583.200	583.200	583.200	583.200	583.200	583.200	583.200	583.200	583.200

Total Usage:	2,590,880	Total Kw Dmd:	5329.120	Total Bill Dmd:	6797.600
Avg Usage:	215,907	Avg Kw Dmd:	444.093	Avg Bill Dmd:	566.467

Average demand 2016/2017 529.600
Average demand 2017/2018 444.093
down 85.507 KW

10/11/2018 2:06:21 pm

ACCOUNT 10524003 RECONCILIATION

Account	Name	Address	Home Phone	Work Phone	Mobile Phone	Cyc
10524003	DANIELE INTERNATIONAL INC	PO BOX 106 PASCOAG, RI 02859	0-	(401)568-6228	0-	1

Meter	Rdg	Rdg Dt	Rate	Dvc Type	# of Dvc	Mem Nbr
E1096	64266	09/26/2018	PA-I	240 Watt LED Flood	4	

Dep Type	Prov	Srv Loc Nbr	Dep Amt	Dep Dt	Use

Provider	Cur AR	30 Day AR	60 Day AR	90 Day AR
EPUD	23,744.48	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	262,807.02	2,101,064	105 DAVIS DR M	3	1	20		Pascoag Utility District

BILLING HISTORY

	Oct 17	Sep 17	Aug 17	Jul 17	Jun 17	May 17	Apr 17	Mar 17	Feb 17	Jan 17	Dec 16	Nov 16
Rev:	24787.57	30565.44	25794.87	27100.33	24489.41	24328.24	23683.57	24384.65	22934.40	24110.46	29668.15	28497.71
Dmd:	6281.20	6551.80	6551.80	6551.80	6551.80	6551.80	6551.80	6551.80	6551.80	6551.80	6551.80	6551.80
Dvc:	51.48	51.48	51.48	51.48	51.48	51.48	76.25	76.25	76.25	79.26	79.30	79.30
PCA:	-1633.88	-2016.47	-1700.58	-1787.03	-1614.14	-1603.47	-1560.78	-1607.20	-1523.96	-1695.78	-695.13	-667.60
Rev Tot:	29486.37	35152.25	30697.57	31916.58	29478.55	29328.05	28750.84	29405.50	28038.49	29045.74	35604.12	34461.21
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:	563.41	695.34	586.41	616.22	556.60	552.92	538.20	554.21	525.50	584.75	720.18	691.66
Total:	30049.78	35847.59	31283.98	32532.80	30035.15	29880.97	29289.04	29959.71	28563.99	29630.49	36324.30	35152.87
Pymnt:	-35847.59	-31283.98	-32532.80	-59916.12	-29880.97	-29289.04	-29959.71	-28563.99	-29630.49	-37026.94	-70110.08	0.00
NSF:	0.00	0.00	0.00	29880.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Total Rev:	310,344.80	Total Dmd:	78,351.00	Total Dvc:	775.49	Total PCA:	-18,106.02
Avg Rev:	25,862.07	Avg Dmd Rev:	6,529.25	Avg Reporting Rev:	32,391.32	Total Payment:	-414,041.71

USAGE HISTORY

	Oct 17	Sep 17	Aug 17	Jul 17	Jun 17	May 17	Apr 17	Mar 17	Feb 17	Jan 17	Dec 16	Nov 16
Usage:	244960	302320	254960	267920	242000	240400	234000	240960	228480	254240	313120	300720
Kw Dmd:	505.600	547.200	583.200	517.600	513.600	492.800	482.400	472.000	492.000	556.000	580.000	612.800
Bill Dmd:	612.800	639.200	639.200	639.200	639.200	639.200	639.200	639.200	639.200	639.200	639.200	639.200

Total Usage:	3,124,080	Total Kw Dmd:	6355.200	Total Bill Dmd:	7644.000
Avg Usage:	260,340	Avg Kw Dmd:	529.600	Avg Bill Dmd:	637.000

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-2

2019 Forecasted Rates & Comparison of Requested Rates to Current Rates

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

Column 1 Approved Rate December 2017 (For 2018)			Column 2 Rate Requested December 2018 (For 2019)		
	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	$ 0.00040	$ 0.20	Transition	$ 0.00161	$ 0.81
Standard Offer	$ 0.07166	$ 35.83	Standard Offer	$ 0.07827	$ 39.13
Transmission	$ 0.02973	$ 14.87	Transmission	$ 0.03192	$ 15.96
DSM/ Renewables	$ 0.00230	$ 1.15	DSM/Renewables	$ 0.00230	$ 1.15
PPRFC	$ (0.00469)	$ (2.35)	PPRFC	$ (0.00283)	$ (1.41)
Total		$ 75.31	Total		$ 81.24
Net Increase/(Decrease)		$ 2.01	Net Increase/(Decrease)		$ 5.93
Percent Increase/(Decrease)		2.3%	Percent Increase/(Decrease)		7.9%

Transition	$ 0.00040	Transition	$ 0.00161	
				Increase/(decrease
SOS	$ 0.07166	SOS	$ 0.07827	$ 0.00661
PPRFC	$ (0.00469)	PPRFC	$ (0.00283)	$ 0.00186
Transmission	$ 0.02973	Transmission	$ 0.03192	$ 0.00219
Total	$ 0.09710	Total	0.10897	$ 0.01187

Schedule H-1

Schedule H

Forecast Rates

Transition Cost Calculations:				
Estimated Sales (MWH) to customers			55,268	See Schedule F-2, Line 114
Forecast Transition Cost			$132,000	See Schedule F-2, line 70
Historic Transistion Revenue			($66,433)	See Schedule A-3, Line 155
Historic Transition Expense		$	9,000	See Schedule A-2, Line 78
Carry over from prior period (12/31/2017)			$14,451	See Schedule C-3, Line 162
	Total		$89,018	
Cost Per MWH		**$**	**1.61**	**Transition Charge**
Transmission Cost Calculations:				
Estimated Sales (MWH) to customers			55,268	See Schedule F-2, Line 114
Forecast Transmission Cost			$1,850,825	See Schedule F-2, line 76
Historic Transmission Revenue			($1,679,067)	See Schedule A-3, Line 157
Historic Transmission Expense		$	1,750,272	See Schedule A-2, Line 85
Carry over from prior period (12/31/2017)			($158,004)	See Schedule C-4, Line 157
	Total		$1,764,027	
Cost per MWH		**$**	**31.92**	**Transmission Charge**
Standard Offer Calculation:				
Estimated Sales (MWH) to customers			55,268	See Schedule F-2, Line 114
Forecast Standard Offer			$4,151,814	See Schedule F-2, line 101
Historic SOS Revenue			($3,963,788)	See Schedule A-3, Line 156
Historic SOS Expense		$	4,068,370	See Schedule A-2, Line 123
Carry over from prior period (12/31/2017)			$69,282	See Schedule C-2, Line 161
-	Total		$4,325,678	
Cost per MWH		**$**	**78.27**	**Standard OfferService**
(1) This is the net amount including any over/(under) recovery				
Purchase Power Reserve Fund Credit				
Estmated Sale (MWH) to customers			55,268	See Schedule F-2, Line 116
Total Flow back for 2018		$	(156,356.00)	
Cost Per MWH		**$**	**(2.83)**	**Purchase Power Reserve Fund Credit**
(2) this is the net amount including the PPRFC				
Total				**$ 108.97**

Revenue/Expense Proof:

Forecast Transition Cost	$	132,000	See Schedule F-2, line 72		
Over/Under Collection at period end	$	(42,982)	Schedule C-3, Line 183		
	$	89,018	$		1.61
Forecast Transmission Cost	$	1,850,825	See Schedule F-2, line 76		
Over/Under Collection at period end	$	(86,799)	Schedule C-4, Line 176		
	$	1,764,027	$		31.92
Forecast SOS Cost	$	4,151,814	See Schedule F-2, line 101		
Over/Under Collection at period end		$173,865	Schedule C-2, Line 181		
	$	4,325,679	$		78.27
Purchase Power Reserve Fund Credit	$	(156,356.00)	$		(2.83)
			$		**108.97**

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-3

Proposed Purchase Power Restricted Fund Credit

Testimony Exhibit -3

DPI Estimated Overcollection for 2018

Purchase Power Bank account balance Sept 31, 2018	$596,764
Estimated deposit for Oct 2018 - Dec 2018	$32,987
PPRF withdrawals $22,180.58 x3 months	($66,542)
Estimated Bank balance 12-31-18	$563,208
Allowable PP Balance per the RIPUC	($550,000)
Estimated overcollection at the end of 2018	$13,208
Estimated GIO Overcollection for 2019 Act 10686001	$16,023
Esimated DPI Overcollection for 2019 Act 10524001	$70,733
Estimated DPI Overcollection for 2019 Act 10524003	$56,392
Estimated Overcollection to Flow back in 2019	$156,356
Flow back	$156,356

Billing Period	Cycle	Adj...	Pres Rdg Dt	Pres Rdg Ti...	Account	Reading KW	Billed KW	Provider	Service	Mtr
Sep 2018	1		08/29/2018	12:00am	10524001	496.800	626.400	EPUD	ELEC	
Aug 2018	1		07/30/2018	12:00am	10524001	511.200	626.400	EPUD	ELEC	
Jul 2018	1		06/27/2018	12:00am	10524001	626.400	626.400	EPUD	ELEC	
Jun 2018	1		05/25/2018	12:00am	10524001	612.000	626.400	EPUD	ELEC	
May 2018	1		04/26/2018	12:00am	10524001	576.000	626.400	EPUD	ELEC	
Apr 2018	1		03/27/2018	12:00am	10524001	453.600	626.400	EPUD	ELEC	
Mar 2018	1		02/26/2018	12:00am	10524001	453.600	626.400	EPUD	ELEC	
Feb 2018	1		01/26/2018	12:00am	10524001	511.200	626.400	EPUD	ELEC	
Jan 2018	1		12/26/2017	12:00am	10524001	511.200	626.400	EPUD	ELEC	
Dec 2017	1		11/27/2017	12:00am	10524001	576.000	626.400	EPUD	ELEC	
Nov 2017	1		10/27/2017	12:00am	10524001	590.400	669.600	EPUD	ELEC	
Oct 2017	1		09/26/2017	12:00am	10524001	604.800	669.600	EPUD	ELEC	
Sep 2017	1		08/28/2017	12:00am	10524001	619.200	691.200	EPUD	ELEC	
Aug 2017	1		07/26/2017	12:00am	10524001	626.400	691.200	EPUD	ELEC	

	Estimated Damand	Demand x Rate 10.25	Cutomer Charge $112.75	
18-Oct	626.4	6420.6	$ 112.75	
Nov-18	626.4	6420.6	$ 112.75	
Dec-18	626.4	6420.6	$ 112.75	
Total	1252.8	$ 12,841.20	$ 338.25	$ 13,179.45

	Estimated Damand	Demand x Rate 10.25	Cutomer Charge $112.75	
Jan-19	626.4	$ 6,420.60	$ 125.75	
Feb-19	626.4	$ 6,420.60	$ 125.75	
Mar-19	626.4	$ 6,420.60	$ 125.75	
Apr-19	626.4	$ 6,420.60	$ 125.75	
May-19	626.4	$ 6,420.60	$ 125.75	
Jun-19	626.4	$ 6,420.60	$ 125.75	
Jul-19	511.2	$ 5,239.80	$ 125.75	
Aug-19	496.8	$ 5,092.20	$ 125.75	
Sep-19	496.8	$ 5,092.20	$ 125.75	
Oct-19	496.8	$ 5,092.20	$ 125.75	
Nov-19	496.8	$ 5,092.20	$ 125.75	
Dec-19	496.8	$ 5,092.20	$ 125.75	
		$ 69,224.40	$ 1,509.00	$ 70,733.40

Consumption History

Billing Period	Cycle	Adj...	Pres Rdg Dt	Pres Rdg Ti...	Account	Reading KW	Billed KW	Provider	Ser...
Sep 2018	1		08/29/2018	12:00am	10524003	408.800	505.600	EPUD	ELEC
Aug 2018	1		07/30/2018	12:00am	10524003	444.800	547.200	EPUD	ELEC
Jul 2018	1		06/27/2018	12:00am	10524003	477.600	583.200	EPUD	ELEC
Jun 2018	1		05/25/2018	12:00am	10524003	473.600	583.200	EPUD	ELEC
May 2018	1		04/26/2018	12:00am	10524003	434.400	583.200	EPUD	ELEC
Apr 2018	1		03/27/2018	12:00am	10524003	431.200	583.200	EPUD	ELEC
Mar 2018	1		02/26/2018	12:00am	10524003	424.000	583.200	EPUD	ELEC
Feb 2018	1		01/26/2018	12:00am	10524003	410.400	583.200	EPUD	ELEC
Jan 2018	1		12/26/2017	12:00am	10524003	448.000	583.200	EPUD	ELEC
Dec 2017	1		11/27/2017	12:00am	10524003	496.000	583.200	EPUD	ELEC
Nov 2017	1		10/27/2017	12:00am	10524003	479.200	583.200	EPUD	ELEC
Oct 2017	1		09/26/2017	12:00am	10524003	505.600	612.800	EPUD	ELEC
Sep 2017	1		08/28/2017	12:00am	10524003	547.200	630.200	EPUD	ELEC
Aug 2017	1		07/26/2017	12:00am	10524003	583.200	639.200	EPUD	ELEC

	Estimated Damand	Demand x Rate 10.25	Cutomer Charge $112.75	
18-Oct	496	5084	$ 112.75	
Nov-18	496	5084	$ 112.75	
Dec-18	477.6	4895.4	$ 112.75	
Total	973.6	$ 15,063.40	$ 338.25	$ 15,401.65

	Estimated Damand	Demand x Rate 10.25	Cutomer Charge $112.75	
Jan-19	477.6	$ 4,895.40	$ 125.75	
Feb-19	477.6	$ 4,895.40	$ 125.75	
Mar-19	477.6	$ 4,895.40	$ 125.75	
Apr-19	477.6	$ 4,895.40	$ 125.75	
May-19	477.6	$ 4,895.40	$ 125.75	
Jun-19	477.6	$ 4,895.40	$ 125.75	
Jul-19	444.8	$ 4,559.20	$ 125.75	
Aug-19	408.8	$ 4,190.20	$ 125.75	
Sep-19	408.8	$ 4,190.20	$ 125.75	
Oct-19	408.8	$ 4,190.20	$ 125.75	
Nov-19	408.8	$ 4,190.20	$ 125.75	
Dec-19	408.8	$ 4,190.20	$ 125.75	
		$ 54,882.60	$ 1,509.00	$ 56,391.60

Consumption History

Billing Period	Cycle	Adj...	Pres Rdg Dt	Pres Rdg Ti...	Account	Reading KW	Billed KW	Provider	Ser...
Sep 2018	1		08/29/2018	12:00am	10686001	98.400	138.400	EPUD	ELEC
Aug 2018	1		07/30/2018	12:00am	10686001	132.000	138.400	EPUD	ELEC
Jul 2018	1		06/27/2018	12:00am	10686001	120.800	138.400	EPUD	ELEC
Jun 2018	1		05/25/2018	12:00am	10686001	119.200	138.400	EPUD	ELEC
May 2018	1		04/26/2018	12:00am	10686001	111.200	138.400	EPUD	ELEC
Apr 2018	1		03/27/2018	12:00am	10686001	110.400	138.400	EPUD	ELEC
Mar 2018	1		02/26/2018	12:00am	10686001	116.000	138.400	EPUD	ELEC
Feb 2018	1		01/26/2018	12:00am	10686001	116.800	138.400	EPUD	ELEC
Jan 2018	1		12/26/2017	12:00am	10686001	115.200	138.400	EPUD	ELEC
Dec 2017	1		11/27/2017	12:00am	10686001	124.000	138.400	EPUD	ELEC
Nov 2017	1		10/27/2017	12:00am	10686001	132.800	138.400	EPUD	ELEC
Oct 2017	1		09/26/2017	12:00am	10686001	138.400	138.400	EPUD	ELEC

	Estimated I	Demand x Rate 10.25	Cutomer Charge $112.75	
18-Oct	132.8	1361.2	$ 112.75	
Nov-18	132	1353	$ 112.75	
Dec-18	132	1353	$ 112.75	
Total	264	$ 4,067.20	$ 338.25	$ 4,405.45

	Estimated I	Demand x Rate 10.25	Cutomer Charge $112.75	
Jan-19	132	$ 1,353.00	$ 125.75	
Feb-19	132	$ 1,353.00	$ 125.75	
Mar-19	132	$ 1,353.00	$ 125.75	
Apr-19	132	$ 1,353.00	$ 125.75	
May-19	132	$ 1,353.00	$ 125.75	
Jun-19	132	$ 1,353.00	$ 125.75	
Jul-19	132	$ 1,353.00	$ 125.75	
Aug-19	98.4	$ 1,008.60	$ 125.75	
Sep-19	98.4	$ 1,008.60	$ 125.75	
Oct-19	98.4	$ 1,008.60	$ 125.75	
Nov-19	98.4	$ 1,008.60	$ 125.75	
Dec-19	98.4	$ 1,008.60	$ 125.75	
		$ 14,514.00	$ 1,509.00	$ 16,023.00

Summary of Activity - Rate Stabilization Fund

2018		
RSF	$	266,167.00
Interest	$	-
Total	$	266,167.00

Monthly transfer: $ 22,180.58

Date	RSF Transfer From PPRF	Credit to OP Cash	RSF
	0		
01/01/18	$ 22,180.62	$ (22,180.62)	$ 243,986.38
02/01/18	$ 22,180.58	$ (22,180.58)	$ 221,805.80
03/01/18	$ 22,180.58	$ (22,180.58)	$ 199,625.22
04/01/18	$ 22,180.58	$ (22,180.58)	$ 177,444.64
05/01/18	$ 22,180.58	$ (22,180.58)	$ 155,264.06
06/01/18	$ 22,180.58	$ (22,180.58)	$ 133,083.48
07/01/18	$ 22,180.58	$ (22,180.58)	$ 110,902.90
08/01/18	$ 22,180.58	$ (22,180.58)	$ 88,722.32
09/01/18	$ 22,180.58	$ (22,180.58)	$ 66,541.74
10/01/18	$ 22,180.58	$ (22,180.58)	$ 44,361.16
11/01/18			
12/01/18			
Total	$ 221,805.84	$ (221,805.84)	

Date	Tranfer From PP To Checking	Refunded thru Billing Credit to Customers	
01/01/18	$ 22,180.62	$ (24,733.15)	$ (2,552.53)
02/01/18	$ 22,180.58	$ (23,182.58)	$ (3,554.53)
03/01/18	$ 22,180.58	$ (20,347.37)	$ (1,721.32)
04/01/18	$ 22,180.58	$ (20,486.66)	$ (27.40)
05/01/18	$ 22,180.58	$ (18,247.53)	$ 3,905.65
06/01/18	$ 22,180.58	$ (18,941.03)	$ 7,145.20
07/01/18	$ 22,180.58	$ (23,510.43)	$ 5,815.35
08/01/18	$ 22,180.58	$ (27,072.27)	$ 923.66
09/01/18	$ 22,180.58	$ (25,482.12)	$ (2,377.88)
10/01/18	$ 22,180.58	$ (19,682.39)	$ 120.31
11/01/18			$
12/01/18			
Total	$ 221,805.84	$ (221,685.53)	$ 120.31
		$ -	

Journal Entry to Record:

		Debit	Credit
132.09	RSF	$ 22,180.58	
131.02	Op Cash		$ 22,180.58
131.02	Operating Cash	$ 22,180.58	
132.09	RSF		$ 22,180.58

This entry will be done once a month to transfer money from the Rate Stabilizaiton Account to the Operating Account
RIPUC Docket 4762

Under Terms of the Rate Case (RIPUC #4762) Pascoag will use money from its PPRF account as a Rate Stabilization Fund, and will transfer that money to its operating account over a 12-month period beginning January 2018.

Testimony exhibit HJR - 3

Proposed Purchase Power Restricted Fund Credit ("PPRFC")
If approved by Division the District proposes to flow back $156,356 of the overcollection back to customers through a PPRFC of 2.89 mills per kilowatt hour reduction ($0.00289)

Date	Transfer	Balance to refund
		$ 156,356.00
1/1/2019	$ 13,029.66	$ 143,326.34
2/1/2019	$ 13,029.66	$ 130,296.68
3/1/2019	$ 13,029.66	$ 117,267.02
4/1/2019	$ 13,029.66	$ 104,237.36
5/1/2019	$ 13,029.66	$ 91,207.70
6/1/2019	$ 13,029.66	$ 78,178.04
7/1/2019	$ 13,029.66	$ 65,148.38
8/1/2019	$ 13,029.66	$ 52,118.72
9/1/2019	$ 13,029.66	$ 39,089.06
10/1/2019	$ 13,029.66	$ 26,059.40
11/1/2019	$ 13,029.66	$ 13,029.74
12/1/2019	$ 13,029.74	$ (0.00)
Total $ Transferred	**$ 156,356.00**	

Journal Entry to Record:

	Debit	Credit
Operating Cash	$ 13,029.66	
PPRF		$ 13,029.66

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.

Testimony Exhibt 3

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-4

Summary of Cash Flow

Summary of Cash Flow -Jan 2018

Operating Cash balance forward	$277,155	
Projected Purchased Power Expense:		
ENE	($138,530)	
Project 6 (MMWEC & HQ)	($29,591)	
NYPA	($29,088)	
ENE/ISO	($285,445)	
Deferred PP Credit	$22,181	
		($460,473)
Customer Payments	$898,500	
Transfer from MR deposit	$7,342	
NSF Checks	($528)	
Payroll, benefits	($180,302)	
Ecumber RF Capital-From DEC	($25,500)	
Transfer to RF Capital- Jan	$25,000	
Encumbered RF Capital- Feb	($25,500)	
Transfer from RF Capital	$ 12,952.00	(1)
Transfer from PPRF to Rate Stabilization fund	($2,173)	
DPI transfer to PPRF	($14,155)	DPI Base rate - for Dec
Misc. vendor payments	($207,295)	
Encumber for PP - from DEC	$700,000	
Encumber for PP - for Feb	($700,000)	
	$305,023	

Other Financial Information:

Accounts Payable Balance	$0	Month End
Accounts Receivable Balance	$575,099	
2018 AR Write Offs		
2018 Misc. Receivable Write Offs		
Summary of Savings/Investments: (Not Restricted)		
Contingency/Emergency	$10,000	
Storm Fund ˜	$85,494	
Working Cash Reserve	$1,179	
Dedicated DSM Fund	$37,894	
Total Savings/Investment (NR)	$134,567	
Year-End Reconciliation Account	$74,271	(Year to-date over collection)
Restricted Account(Debt/Capital)	$572,467	
Rate Stabilization fund (RSF) Bal. left to refund in 2018	$243,986	
Restricted Account (Purchase Pwr)	$659,960	
Net All Saving/Investment		$1,685,252

Misc. Accounts:

Customer Deposit Holding Account GL235.0	$363,258
Working Capital - on Deposit w/ ENE GL165.06	$171,439
Working Capital - on Deposit w/MMWEC GL165.02	$2,280
Deffered Credit GL253	$266,798

Restricted Fund 2018 Goal			$306,000				
	Jan	$ 25,500					
	Feb						
	Mar						
	Apr						
	May						
	Jun						
	Jul						
	Aug						
	Sep						
	Oct						
	Nov	$ -					
	Dec	$ -		Annual		%	Funding
Total Transfer		$ 25,500		Funding Level		Complete	Requirement
					$306,000	8%	$280,500
Storm Fund - 2017 Goal			$20,000				
Q/E 3/18							
Q/E 6/18							
Q/E 9/18							
Q/E 12/18				Annual		%	Funding
Total Transfer		$ -		Funding Level		Complete	Requirement
					$20,000	0%	$20,000

(1) Capital Item

Bill's Jeep	$ 41,921.00
	$ 41,921.00

Summary of Cash Flow -FEB 2018

Operating Cash balance forward	$305,023		
Projected Purchased Power Expense:			
ENE	($150,112)	Jan Power Bills Pd in FEB	
Project 6 (MMWEC & HQ)	($37,992)		
NYPA	($50,153)		
ENE/ISO	($214,634)		
ENE/ Constant Energy Capital	($35,694)		
Deferred PP Credit	$44,466		
			($444,119)
Customer Payments	$748,307		
Transfer from MR deposit	$0		
NSF Checks	($365)		
Payroll, benefits	($138,393)		
Encumber RF Capital-From Jan	($25,500)		
Transfer to RF Capital- Feb	$25,000		
Encumbered RF Capital- March	($25,500)		
Transfer from RF Capital	$ 190.00		(1)
Transfer from PPRF to Rate Stabilization fund	$22,181		
DPI transfer to PPRF/ RSF TRUE UP	($14,152)	DPI Base rate - for Feb	
Misc. vendor payments	($156,597)		
Encumber for PP - from Jan	$700,000		
Encumber for PP - for March	($700,000)		
	$296,074		

Other Financial Information:			
Accounts Payable Balance	$0	Month End	
Accounts Receivable Balance	$577,525		
2018 AR Write Offs			
2018 Misc. Receivable Write Offs			
Summary of Savings/Investments: (Not Restricted)			
Contingency/Emergency	$10,000		
Storm Fund	$65,851		
Working Cash Reserve	$20,870		
Dedicated DSM Fund	$55,966		
Total Savings/Investment (NR)	$152,686		
Year-End Reconciliation Account	$157,710	(Year to-date over collection)	
Restricted Account(Debt/Capital)	$572,467		
Rate Stabilization fund (RSF) Bal. left to refund in 2018	$221,806		
Restricted Account (Purchase Power)	$654,105		
Net All Saving/Investment			$1,758,774

Misc. Accounts:	
Customer Deposit Holding Account GL235.0	$366,133
Working Capital - on Deposit w/ ENE GL165.06	$171,953
Working Capital - on Deposit w/MMWEC GL165.02	$2,283
Differed Credit GL253	$177,865

Restricted Fund 2017 Goal			$306,000				
	Jan	$ 25,500					
	Feb	$ 25,500					
	Mar						
	Apr						
	May						
	Jun						
	Jul						
	Aug						
	Sep						
	Oct						
	Nov	$ -					
	Dec	$ -		Annual		%	Funding
Total Transfer		$ 51,000		Funding Level		Complete	Requirement
					$306,000	17%	$255,000

Storm Fund - 2018 Goal		$20,000				
Q/E 3/18						
Q/E 6/18						
Q/E 9/18						
Q/E 12/18			Annual		%	Funding
Total Transfer	$ -		Funding Level		Complete	Requirement
				$20,000	0%	$20,000

(1) Capital Item	
Bill's Jeep- Lettering	$ 190.00
	$ 190.00

Summary of Cash Flow -March 2018

Operating Cash balance forward	$296,974		
Projected Purchased Power Expense:			
ENE	($197,387)	FEB Power Bills Pd in FEB	
Project 6 (MMWEC & HQ)	($39,013)		
NYPA	($62,283)		
ENE/ISO	($214,634)		
ENE/ Constant Energy Capital	($10,462)		
Deferred PP Credit	$44,466		
			($479,313)
Customer Payments	$913,058		
Transfer from MR deposit	$0		
NSF Checks	($751)		
Payroll, benefits	($166,415)		
Encumber RF Capital-From FEB	($25,500)		
Transfer to RF Capital-March	$25,000		
Encumbered RF Capital- April	($25,500)		
Transfer from RF Capital	$ 3,639.85		(1)
Transfer from PPRF to Rate Stabilization fund	$22,181		
DPI transfer to PPRF/ RSF TRUE UP	($14,155)	DPI Base rate - for Feb	
Misc. vendor payments	($96,361)		
Encumber for PP - from Jan	$700,000		
Encumber for PP - for March	($700,000)		
	$452,867		

Other Financial Information:

Accounts Payable Balance	$81,914	Month End	
Accounts Receivable Balance	$475,654		
2018 AR Write Offs			
2018 Misc. Receivable Write Offs			
Summary of Savings/Investments: (Not Restricted)			
Contingency/Emergency	$10,000		
Storm Fund	$70,851		
Working Cash Reserve	$15,991		
Dedicated DSM Fund	$61,836		
Total Savings/Investment (NR)	$158,678		
Year-End Reconciliation Account	$223,674	(Year to-date over collection)	
Restricted Account(Debt/Capital)	$603,217		
Rate Stabilization fund (RSF) Bal. left to refund in 2018	$199,625		
Restricted Account (Purchase Power)	$646,079		
Net All Saving/Investment			$1,831,273

Misc. Accounts:

Customer Deposit Holding Account GL235.0	$368,683
Working Capital - on Deposit w/ ENE GL165.06	$172,218
Working Capital - on Deposit w/MMWEC GL165.02	$2,283
Differed Credit GL253	$133,399

Restricted Fund 2017 Goal			$306,000				
	Jan	$ 25,500					
	Feb	$ 25,500					
	Mar	$ 25,500					
	Apr						
	May						
	Jun						
	Jul						
	Aug						
	Sep						
	Oct						
	Nov	$ -					
	Dec	$ -		Annual		%	Funding
Total Transfer		$ 76,500		Funding Level		Complete	Requirement
					$306,000	25%	$229,500
Storm Fund - 2018 Goal			$20,000				
Q/E 3/18		$ 5,000.00					
Q/E 6/18							
Q/E 9/18							
Q/E 12/18				Annual		%	Funding
Total Transfer		$ 5,000		Funding Level		Complete	Requirement
					$20,000	25%	$15,000

(1) Capital Item

Bill's Jeep- Assessories	$ 2,396.95
Glue for Linemans Floor	$ 1,243.00
	$ 3,639.95

Summary of Cash Flow -April 2018

Operating Cash balance forward	$449,387		
Projected Purchased Power Expense:			
ENE	($166,360)	March Power Bills Pd In April	
Project 6 (MMWEC & HQ)	($38,827)		
NYPA	($14,701)		
ENE/ISO	($196,115)		
ENE/ Constant Energy Capital	($10,329)		
Deferred PP Credit	$44,466		
			($381,866)
Customer Payments	$704,898		
Transfer from MR deposit	$0		
NSF Checks	($542)		
Payroll, benefits	($130,720)		
Encumber RF Capital-From March	($25,500)		
Transfer to RF Capital-April	$25,000		
Encumbered RF Capital- May	($25,500)		
Transfer from RF Capital	$ -		(1)
Transfer from PPRF to Rate Stabilization fund	$22,181		
DPI transfer to PPRF/ RSF TRUE UP	($14,155)	DPI Base rate - for April	
Misc. vendor payments	($182,199)		
Encumber for PP - from March	$700,000		
Encumber for PP - for May	($700,000)		
Encumbered to DSM	($64,984)		
	$376,000		

Other Financial Information:			
Accounts Payable Balance	$62,176	Month End	
Accounts Receivable Balance	$512,413		
2018 AR Write Offs			
2018 Misc. Receivable Write Offs			
Summary of Savings/Investments: (Not Restricted)			
Contingency/Emergency	$10,000		
Storm Fund	$70,851		
Working Cash Reserve	$15,991		
Dedicated DSM Fund	$64,984		
Total Savings/Investment (NR)	$161,825		
Year-End Reconciliation Account	$256,195	(Year to-date over collection)	
Restricted Account(Debt/Capital)	$628,717		
Rate Stabilization fund (RSF) Bal. left to refund in 2018	$177,445		
Restricted Account (Purchase Power)	$638,054		
Net All Saving/Investment			$1,862,236

Misc. Accounts:	
Customer Deposit Holding Account GL235.0	$370,133
Working Capital - on Deposit w/ ENE GL165.06	$172,218
Working Capital - on Deposit w/MMWEC GL165.02	$2,283
Differed Credit GL253	$133,399

Restricted Fund 2017 Goal			$306,000				
	Jan	$ 25,500					
	Feb	$ 25,500					
	Mar	$ 25,500					
	Apr	$ 25,500					
	May						
	Jun						
	Jul						
	Aug						
	Sep						
	Oct						
	Nov	$ -					
	Dec	$ -		Annual		%	Funding
Total Transfer		$ 102,000		Funding Level		Complete	Requirement
					$306,000	33%	$204,000

Storm Fund - 2018 Goal		$20,000					
Q/E 3/18	$ 5,000.00						
Q/E 6/18							
Q/E 9/18							
Q/E 12/18			Annual		%	Funding	
Total Transfer	$ 5,000		Funding Level		Complete	Requirement	
				$20,000	25%	$15,000	

(1) Capital Item

$ -

Summary of Cash Flow -May 2018

Operating Cash balance forward	$440,984		
Projected Purchased Power Expense:			
ENE	($140,647)	April Power Bills Pd in May	
Project 6 (MMWEC & HQ)	($38,119)		
NYPA	($24,205)		
ENE/ISO	($193,096)		
ENE/ Constant Energy Capital	($12,099)		
Deferred PP Credit	$44,466		
MMWEC Reconciling CM and Constant Energy Credits	17905.97		($345,793)
Customer Payments	$753,666		
Transfer from MR deposit	$0		
NSF Checks	($1,339)		
Payroll, benefits	($135,896)		
Encumber RF Capital-From April	($25,500)		
Transfer to RF Capital-May	$25,000		
Encumbered RF Capital- June	($25,500)		
Transfer from RF Capital	$ 1,019		(1)
Transfer from PPRF to Rate Stabilization fund	$22,181		
DPI transfer to PPRF/ RSF TRUE UP	($14,155)	DPI Base rate - for May	
Misc. vendor payments	($217,537)		
Encumber for PP - from April	$700,000		
Encumber for PP - for June	($700,000)		
Encumbered to DSM	($66,222)		
	$410,905		
Other Financial Information:			
Accounts Payable Balance	$238	Month End	
Accounts Receivable Balance	$404,285		
2018 AR Write Offs			
2018 Misc. Receivable Write Offs			
Summary of Savings/Investments: (Not Restricted)			
Contingency/Emergency	$10,000		
Storm Fund	$40,909		
Working Cash Reserve	$45,985		
Dedicated DSM Fund	$66,222		
Total Savings/Investment (NR)	$163,116		
Year-End Reconciliation Account	$326,987	(Year to-date over collection as of April)	
Restricted Account(Debt/Capital)	$653,197		
Rate Stabilization fund (RSF) Bal. left to refund in 2018	$155,264		
Restricted Account (Purchase Power)	$630,029		
Net All Saving/Investment			**$1,928,593**
Misc. Accounts:			
Customer Deposit Holding Account GL235.0	$370,683		
Working Capital - on Deposit w/ ENE GL165.06	$172,809		
Working Capital - on Deposit w/MMWEC GL165.02	$2,286		
Differed Credit GL253	$88,932		

Restricted Fund 2017 Goal **$306,000**

	Month	Amount				
	Jan	$ 25,500				
	Feb	$ 25,500				
	Mar	$ 25,500				
	Apr	$ 25,500				
	May	$ 25,500				
	Jun					
	Jul					
	Aug					
	Sep					
	Oct					
	Nov	$ -				
	Dec	$ -	Annual		%	Funding
Total Transfer		**$ 127,500**	Funding Level		Complete	Requirement
				$306,000	42%	$178,500

Storm Fund - 2018 Goal **$20,000**

Q/E 3/18	$ 5,000.00				
Q/E 6/18					
Q/E 9/18					
Q/E 12/18		Annual		%	Funding
Total Transfer	**$ 5,000**	Funding Level		Complete	Requirement
			$20,000	25%	$15,000

(1) Capital Item $ 1,019.00 Meter Cable

$ 1,019.00

Summary of Cash Flow -June 2018

Operating Cash balance forward	$477,127		
Projected Purchased Power Expense:			
ENE	($133,172)	May Power Bills Pd in June	
Project 6 (MMWEC & HQ)	($38,312)		
NYPA	($23,756)		
ENE/ISO	($183,301)		
ENE/ Constant Energy Capital	($10,554)		
Deferred PP Credit	$44,466		
MMWEC Reconciling CM and Constant Energy Credits	17905.97		($326,723)
Customer Payments	$840,145		
Transfer from MR deposit	$0		
NSF Checks	($979)		
Payroll, benefits	($126,978)		
Encumber RF Capital-From May	$25,500		
Transfer to RF Capital-June & July	($51,000)		
Encumbered RF Capital- july	$0		
Transfer from RF Capital	$ 84,127		(1)
Transfer from PPRF to Rate Stabilization fund	$22,181		
DPI transfer to PPRF/ RSF TRUE UP	($14,155)	DPI Base rate - for June	
Misc. vendor payments	($253,677)		
Encumber for PP - from May	$700,000		
Encumber for PP - for July	($700,000)		
Encumbered to DSM	($71,744)		
	$403,823		

Other Financial Information:			
Accounts Payable Balance	$100	Month End	
Accounts Receivable Balance	$432,112		
2018 AR Write Offs			
2018 Misc. Receivable Write Offs			
Summary of Savings/Investments: (Not Restricted)			
Contingency/Emergency	$10,000		
Storm Fund	$40,909		
Working Cash Reserve	$41,076		
Dedicated DSM Fund	$71,744		
Total Savings/Investment (NR)	$163,729		
Year-End Reconciliation Account	$267,702	(Year to-date over collection as of June)	
Restricted Account(Debt/Capital)	$620,070		
Rate Stabilization fund (RSF) Bal. left to refund in 2018	$133,083		
Restricted Account (Purchase Power)	$622,004		
Net All Saving/Investment			$1,806,589
Misc. Accounts:			
Customer Deposit Holding Account GL235.0	$373,183		
Working Capital - on Deposit w/ ENE GL165.06	$173,132		
Working Capital - on Deposit w/MMWEC GL165.02	$2,287		
Differed Credit GL253	$0		

Restricted Fund 2017 Goal			**$306,000**
	Jan	$ 25,500	
	Feb	$ 25,500	
	Mar	$ 25,500	
	Apr	$ 25,500	
	May	$ 25,500	
	Jun	$ 25,500	
	Jul	$ 25,500	
	Aug		
	Sep		
	Oct		
	Nov	$ -	
	Dec	$ -	
Total Transfer		$ 178,500	

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

Storm Fund - 2018 Goal		**$20,000**
Q/E 3/18	$ 5,000.00	
Q/E 6/18	$ 5,000.00	
Q/E 9/18		
Q/E 12/18		
Total Transfer	$ 10,000	

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

(1) Capital Item	$ 3,905.00	Datto Service & Cloud Backup
	$ 6,010.00	LED Flood Lights
	$ 3,802.00	15 KV Switch
	$ 70,410.00	Parking Lot Paving
	$ 84,127.00	

Summary of Cash Flow -July 2018

Operating Cash balance forward		$475,567		
Projected Purchased Power Expense:				
ENE		($134,193)	June Power Bills Pd in July	
Project 6 (MMWEC & HQ)		($44,820)		
NYPA		($24,186)		
ENE/ISO		($280,539)		
ENE/ Constant Energy Capital		($9,328)		
Deferred PP Credit		$44,466		
MMWEC Reconciling CM and Constant Energy Credits				($448,599)
Customer Payments		$707,980		
Transfer from MR deposit		$0		
NSF Checks		($312)		
Payroll, benefits		($126,888)		
Encumber RF Capital-From June		$0		
Transfer to RF Capital-June & July		$0		
Encumbered RF Capital-Aug		($25,500)		
Transfer from RF Capital	$ -			(1)
Transfer from PPRF to Rate Stabilization fund		$22,181		
DPI transfer to PPRF/ RSF TRUE UP		($14,155)	DPI Base rate - for July	
Misc. vendor payments		($129,996)		
Encumber for PP - from June		$700,000		
Encumber for PP - for Aug		($700,000)		
		$460,277		
Encumber to DSM		($55,200)		
		$405,077		

Other Financial Information:			
Accounts Payable Balance	$100	Month End	
Accounts Receivable Balance	$509,253		
2018 AR Write Offs			
2018 Misc. Receivable Write Offs			
Summary of Savings/Investments: (Not Restricted)			
Contingency/Emergency	$10,000		
Storm Fund	$40,909		
Working Cash Reserve	$41,125		
Dedicated DSM Fund	$55,200		
Total Savings/Investment (NR)	$147,234		
Year-End Reconciliation Account	$202,923	(Year to-date over collection as of July)	
Restricted Account(Debt/Capital)	$620,070		
Rate Stabilization fund (RSF) Bal. left to refund in 2018	$110,903		
Restricted Account (Purchase Power)	$613,979		
Net All Saving/Investment			$1,695,109
Misc. Accounts:			
Customer Deposit Holding Account GL235.0	$374,978		
Working Capital - on Deposit w/ ENE GL165.06	$173,455		
Working Capital - on Deposit w/MMWEC GL165.02	$2,288		
Differed Credit GL253	$0		

Restricted Fund 2017 Goal		$306,000				
Jan	$ 25,500					
Feb	$ 25,500					
Mar	$ 25,500					
Apr	$ 25,500					
May	$ 25,500					
Jun	$ 25,500					
Jul	$ 25,500					
Aug						
Sep						
Oct						
Nov	$ -					
Dec	$ -		Annual		%	Funding
Total Transfer	$ 178,500		Funding Level		Complete	Requirement
				$306,000	58%	$127,500
Storm Fund - 2018 Goal		$20,000				
Q/E 3/18	$ 5,000.00					
Q/E 6/18	$ 5,000.00					
Q/E 9/18						
Q/E 12/18			Annual		%	Funding
Total Transfer	$ 10,000		Funding Level		Complete	Requirement
				$20,000	50%	$10,000

(1) Capital Item

$ -

Summary of Cash Flow -August 2018

Operating Cash balance forward	$460,276		
Projected Purchased Power Expense:			
ENE	($196,445)	July Power Bills Pd in Aug	
Project 6 (MMWEC & HQ)	($40,828)		
NYPA	($25,164)		
ENE/ISO	($301,002)		
ENE/ Constant Energy Capital	($3,752)		
Deferred PP Credit	$0		
MMWEC Reconciling CM and Constant Energy Credits			($567,191)
Customer Payments	$806,405		
NSF Checks	($1,411)		
Payroll, benefits	($166,352)		
Encumber RF Capital-From July	$25,500		
Transfer to RF Capital-Aug	($25,500)		
Encumbered RF Capital-Sept	($25,500)		
Transfer from RF Capital	$ -		(1)
Transfer from PPRF to Rate Stabilization fund	$22,181		
DPI transfer to PPRF/ RSF TRUE UP	($13,786)	DPI Base rate - for August	
Misc. vendor payments	($107,702)		
Encumber for PP - from June	$700,000		
Encumber for PP - for Aug	($700,000)		
	$406,920		
Encumbered to DSM	($67,479)		
	$339,441		

Other Financial Information:

Accounts Payable Balance	$100	Month End
Accounts Receivable Balance	$558,427	
2018 AR Write Offs		
2018 Misc. Receivable Write Offs		
Summary of Savings/Investments: (Not Restricted)		
Contingency/Emergency	$10,000	
Storm Fund	$40,909	
Working Cash Reserve	$41,174	
Dedicated DSM Fund	$67,479	
Total Savings/Investment (NR)	$159,562	
Year-End Reconciliation Account	$202,923	(Year to-date over collection as of July)
Restricted Account(Debt/Capital)	$645,570	
Rate Stabilization fund (RSF) Bal. left to refund in 2018	$88,722	
Restricted Account (Purchase Power)	$605,584	
Net All Saving/Investment		**$1,702,362**

Misc. Accounts:

Customer Deposit Holding Account GL235.0	$379,408
Working Capital - on Deposit w/ ENE GL165.06	$173,785
Working Capital - on Deposit w/MMWEC GL165.02	$2,289
Differed Credit GL253	$27,870

Restricted Fund 2017 Goal			$306,000				
	Jan	$ 25,500					
	Feb	$ 25,500					
	Mar	$ 25,500					
	Apr	$ 25,500					
	May	$ 25,500					
	Jun	$ 25,500					
	Jul	$ 25,500					
	Aug	$ 25,500					
	Sep						
	Oct						
	Nov	$ -					
	Dec	$ -		Annual		%	Funding
Total Transfer		$ 204,000		Funding Level		Complete	Requirement
					$306,000	67%	$102,000
Storm Fund - 2018 Goal			$20,000				
Q/E 3/18		$ 5,000.00					
Q/E 6/18		$ 5,000.00					
Q/E 9/18							
Q/E 12/18				Annual		%	Funding
Total Transfer		$ 10,000		Funding Level		Complete	Requirement
					$20,000	50%	$10,000

(1) Capital Item

$ -

Summary of Cash Flow -SEPT 2018

Operating Cash balance forward	$406,920		
Projected Purchased Power Expense:			
ENE	($190,552)	Aug Power Bills Pd in Sept	
Project 6 (MMWEC & HQ)	($6,911)		
NYPA	($20,754)		
ENE/ISO	($326,533)		
ENE/ Constant Energy Capital	($13,633)		
Deferred PP Credit	$2,787		
NYPA Settlement FMC	$14,620		
Project 6 Settlement FMC	$19,549		
			($521,427)
Customer Payments	$799,308		
NSF Checks	($537)		
Payroll, benefits	($149,095)		
Encumber RF Capital-From Aug	$25,500		
Transfer to RF Capital-Sept	($25,500)		
Encumbered RF Capital-Oct	($25,500)		
Transfer from RF Capital	$ 8,560		(1)
Transfer from PPRF to Rate Stabilization fund	$22,181		
DPI transfer to PPRF/ RSF TRUE UP	($13,360)	DPI Base rate - for August	
Misc. vendor payments	($133,017)		
Encumber for PP - from Aug	$700,000		
Encumber for PP - for Oct	($700,000)		
	$394,033		
Encumbered to DSM	($67,991)		
	$326,042		

Other Financial Information:			
Accounts Payable Balance	$33,737	Month End	
Accounts Receivable Balance	$615,256		
2018 AR Write Offs			
2018 Misc. Receivable Write Offs			
Summary of Savings/Investments: (Not Restricted)			
Contingency/Emergency	$10,000		
Storm Fund	$50,909		
Working Cash Reserve	$36,222		
Dedicated DSM Fund	$67,991		
Total Savings/Investment (NR)	$165,122		
Year-End Reconciliation Account	$187,943	(Year to-date over collection as of Aug)	
Restricted Account(Debt/Capital)	$662,510		
Rate Stabilization fund (RSF) Bal. left to refund in 2018	$66,542		
Restricted Account (Purchase Power)	$596,764		
Net All Saving/Investment			$1,678,880

Misc. Accounts:	
Customer Deposit Holding Account GL235.0	$379,483
Working Capital - on Deposit w/ ENE GL165.06	$174,130
Working Capital - on Deposit w/MMWEC GL165.02	$2,289
Differed Credit GL253	$27,870

Restricted Fund 2017 Goal			$306,000				
	Jan	$ 25,500					
	Feb	$ 25,500					
	Mar	$ 25,500					
	Apr	$ 25,500					
	May	$ 25,500					
	Jun	$ 25,500					
	Jul	$ 25,500					
	Aug	$ 25,500					
	Sep	$ 25,500					
	Oct						
	Nov	$ -					
	Dec	$ -		Annual		%	Funding
Total Transfer		$ 229,500		Funding Level		Complete	Requirement
					$306,000	75%	$76,500

Storm Fund - 2018 Goal		$20,000				
Q/E 3/18	$ 5,000.00					
Q/E 6/18	$ 5,000.00					
Q/E 9/18	$ 5,000.00					
Q/E 12/18			Annual		%	Funding
Total Transfer	$ 15,000		Funding Level		Complete	Requirement
				$20,000	75%	$5,000

(1) Capital Item	
Substation Meeting	$ 535.00
1Step Voltage Regulator	$ 8,035.00
	$ 8,570.00

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-5

AR/AP Summary

Summary of Accounts Payable (1)

	1 - 30 Days	31 - 60 Days	61 - 90 Days	Over 90 Days	Balance
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
Sep-16	$ -				$ -
Oct-16	$ 1,300				$ 1,300
Nov-16	$ 28				$ 28
Dec-16	$ 30,630				$ 30,630
Jan-17	$ 33,817				$ 33,817
Feb-17	$ 37,052				$ 37,052
Mar-17	$ 6,196				$ 6,196
Apr-17	$ (490)				$ (490)
May-17	$ 26,465				$ 26,465
Jun-17	$ 34,769				$ 34,769
Jul-17	$ 65,306				$ 65,306
Aug-17	$ 15,180				$ 15,180
Sep-17	$ 11,354				$ 11,354
Oct-17	$ 29,742				$ 29,742
Nov-17	$ -				$ -
Dec-17	$ -				$ -
Jan-18	$ -				$ -
Feb-18	$ -				$ -
Mar-18	$ 81,914				$ 81,914
Apr-18	62176				$ 62,176
May-18	$ 238				$ 238
Jun-18	$ 100				$ 100
Jul-18	$ 100				$ 100
Aug-18	$ 100				$ 100
Sep-18	$ 33,737				$ 33,737
Oct-18					
Nov-18					
Dec-18					

Summary of Accounts Receivable

	1 - 30 Days	31 - 60 Days	61 - 90 Days	Over 90 Days	Balance	
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	w/o $31,777
Dec 2014	$ 353,903	$ 108,526	$ 41,145	$ 89,572	$ 593,146	
Jan-15	$ 506,348	$ 90,604	$ 45,009	$ 103,859	$ 745,820	
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	
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	w/o $28,875 for 2015
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	
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	$ 413,725	$ 85,409	$ 19,031	$ 57,092	$ 575,258	w/o $39,195 for 2016
Nov-16	$ 316,297	$ 65,001	$ 34,738	$ 64,795	$ 480,831	
Dec-16	$ 315,924	$ 60,281	$ 28,533	$ 82,998	$ 487,736	
Jan-17	$ 370,583	$ 70,627	$ 26,027	$ 87,386	$ 554,623	
Feb-17	$ 378,579	$ 88,384	$ 29,792	$ 86,042	$ 582,797	
Mar-17	$ 309,061	$ 70,895	$ 30,170	$ 88,455	$ 498,581	
Apr-17	$ 349,380	$ 69,511	$ 29,794	$ 92,760	$ 541,445	
May-17	$ 253,000	$ 69,410	$ 25,196	$ 94,810	$ 442,416	
Jun-17	$ 288,081	$ 54,686	$ 25,112	$ 100,225	$ 468,104	
Jul-17	$ 385,255	$ 61,499	$ 21,962	$ 104,393	$ 573,109	
Aug-17	$ 406,031	$ 71,162	$ 17,304	$ 95,296	$ 589,793	
Sep-17	$ 343,792	$ 91,211	$ 23,221	$ 95,821	$ 554,045	
Oct-17	$ 324,383	$ 58,839	$ 15,931	$ 97,678	$ 496,831	w/o $53,514 for 2017
Nov-17	$ 238,660	$ 63,059	$ 18,255	$ 68,506	$ 388,480	
Dec-17	$ 370,359	$ 63,649	$ 27,644	$ 74,036	$ 535,688	
Jan-18	$ 400,920	$ 68,980	$ 23,202	$ 81,997	$ 575,099	
Feb-18	$ 387,499	$ 85,491	$ 25,289	$ 79,246	$ 577,525	
Mar-18	$ 298,000	$ 67,528	$ 29,483	$ 79,743	$ 474,754	
Apr-18	$ 346,579	$ 56,381	$ 24,204	$ 85,248	$ 512,412	
Jun-18	$ 257,305	$ 48,934	$ 14,968	$ 83,077	$ 404,284	
Jul-18	$ 377,958	$ 38,821	$ 12,439	$ 80,035	$ 509,253	
Aug-18	$ 420,942	$ 46,576	$ 13,071	$ 77,838	$ 558,427	
Sep-18	$ 423,411	$ 97,292	$ 14,027	$ 80,526	$ 615,256	
Oct-18	$ 292,281	$ 65,532	$ 14,196	$ 81,816	$ 453,826	2018 W/O Estimate $31,995.05
Nov-18						
Dec-18						

PASCOAG
UTILITY DISTRICT

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P.O. Box 107
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Testimony Exhibits HJR-6

Surplus Fund Check/ Other Credits

MASSACHUSETTS MUNICIPAL
WHOLESALE ELECTRIC CO.

6-1

Vendor Number	Vendor Name	Check No.	Check Date
1150	Pascoag Utility District	149235	8/17/2017

Reference	Invoice Date	Invoice Number	Invoice Amount	Discount	Net Check Amount
Invoice Summary	8/16/2017	08162017	489,129.72		489,129.72
			489,129.72		489,129.72

2017/2018 surplus funds
applied Aug 2017 - June 2018
44,466.42 Aug 2017
44,466.33 Sept - June 2018

2018 amount

Bank of America
52-153-112

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

Check No.	Check Date	Vendor No.
149235	8/17/2017	1150

Pay FOUR HUNDRED EIGHTY NINE THOUSAND ONE HUNDRED TWENTY NINE AND 72/100*****************

Check Amount
$***489,129.72

Not Valid After 365 Days

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

Two signatures required over $25,000.00

⑈00149235⑈ ⑆011201539⑆ 000080242607⑈

6-1

MMWEC
MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY
Public Energy Partners

TO: Project Participants

FROM: Marjorie L. Freshour, Senior Accountant

DATE: August 21, 2017

SUBJECT: Surplus Funds

The enclosed billing includes the return of Surplus Funds, either via enclosed check or credit applied to your Project Bills, per your election.

Systems who elected to transfer funds into their Working Capital, Reserve Trust or OPEB Trust accounts will find charges for the transfer on their ISO settlement or in a separate billing. The charges correspond with credits on the Project Bills for the Surplus Funds. The charges and corresponding credits facilitates the transfer of funds within MMWEC.

Please feel free to contact Carol Martucci at cmartucci@mmwec.org or (413) 308-1375 with any questions.

MASSACHUSETTS MUNICIPAL
WHOLESALE ELECTRIC CO.

Testimony Exhibit 6-2

Vendor Number	Vendor Name	Check No.	Check Date
1150	Pascoag Utility District	152135	8/30/2018

Reference	Invoice Date	Invoice Number	Invoice Amount	Discount	Net Check Amount
Invoice Summary	8/27/2018	08272018	30,656.52		30,656.52
			30,656.52		30,656.52

253.0 deferred credit

2018/2019 surplus funds

rnal: 2018006967 Date: Sep 5, 2018
: 0 Time: 11:12:09

plus funds 2018
Miscellaneous Activity 30656.52

plus $15709.91 RNE Revenue $14946.61

Total To-Be-Paid: 30656.52
152135 Check: 30656.52

Change Due: 0.00

52 pscgcsh2 1 29

Aug 2018 1 @ 2787.02
Sept 2018 10 @ 2786.95
June 2019

Bank of America
52-153-112

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

Check No.	Check Date	Vendor No.
152135	8/30/2018	1150

Check Amount
$****30,656.52
Not Valid After 365 Days

Pay THIRTY THOUSAND SIX HUNDRED FIFTY SIX AND 52/100**

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

Two signatures required over $25,000.00

⑈00152135⑈ ⑆011201539⑆ 000080242607⑈

Date:	August 27, 2018
Amount ($):	$ 30,656.52
To:	Pascoag Utility District
Street:	253 Pascoag-Main Street, PO Box 107
City, State :	Pascoag, RI — Zip Code: 01867

Surplus funds - 2018 $15,709.91

RNS Revenues -$14,946.61

Town	Nuclear Project 6	2018 Total Surplus	RNS Revenues	Surplus with Other Items
Pascoag	$ 15,709.91	$ 15,709.91	$ 14,946.61	$ 30,656.52

Oct - other Credit

Massachusetts Municipal Wholesale Electric Company
327 Moody Street
PO Box 426
Ludlow, Massachusetts 01056

MMWEC Public Energy Partners

Pascoag Utility District
253 Pascoag-Main Street
PO Box 107
Pascoag, RI 02859
CUST ID# 1150

Participant Prepaid Balance Summary Report
Project Name: Project Six
Beginning Balance ($414.80) December - 2017

2018	Billing (Budget)	KWH Generation	Capacity	Fuel	Transmission	Ending Balance	Surplus Funds and Other Credits
January	$37,389.50	993,394	$31,174.45	$5,880.89	$73.66	($154.30)	$8,779.53
February	36,821.83	897,469	31,204.72	5,313.02	43.39	$106.40	0.00
March	37,129.99	992,080	31,187.65	5,873.11	60.46	$115.17	0.00
April	36,934.24	961,702	31,186.26	5,693.27	61.85	$108.03	0.00
May	37,122.22	994,094	31,228.64	5,885.04	19.47	$97.10	0.00
June	36,942.40	961,312	31,183.93	5,690.97	64.19	$100.41	0.00
July	38,312.16	992,686	32,381.20	5,876.70	52.68	$101.99	0.00
August	38,304.17	990,417	32,374.58	5,863.27	59.31	$109.00	0.00
September	38,125.79	941,498	32,340.09	5,573.67	93.79	$227.24	0.00
October	18,763.55	0	0.00	0.00	0.00	$18,990.79	18,763.55
November	0.00	0	0.00	0.00	0.00	$18,990.79	0.00
December	0.00	0	0.00	0.00	0.00	$18,990.79	0.00
TOTAL	$355,845.85	8,724,652	$284,261.52	$51,649.94	$528.80		$27,543.08

Debit 165.03 18,763.55

Credit 555 18,763.35

mmwec other Credit

Testimony
Hgh exhibit 6-3

(Oct)

Testimony
HJR - exhibit 6-4

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1							Pascoag Utility District - Electric Department											
2							Summary of Purchase Power Costs (1)											
3												Estimate	Estimate	Estimate				
4			Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total			
5	Purchased Energy (kWhrs)																	
6		NYPA	1,032,000	1,141,000	995,000	834,000	879,000	890,000	990,000	1,053,000	1,182,000	902,000	873,000	902,000	11,673,000			
7		Project 6 /Seabrook	993,394	897,469	992,080	961,702	994,094	961,312	992,686	990,417	941,498	31,000	940,000	973,000	10,668,652			
8		Miller Hydro Group/ Brown Bear	152,917	141,510	163,878	201,061	154,955	58,912	68,813	81,144	53,454	100,000	109,000	142,000	1,427,644			
9		Spruce Mnt	189,566	152,881	154,889	110,265	126,916	106,988	94,164	76,854	82,900	149,000	167,000	150,000	1,561,423			
10		Spruce Mnt REC Sales													0			
11		PSEG Settlement	(256,104)	(842)	0	0	29,273	0	0	0		0	0	0	(227,673)			
12		PSEG Energy	2,560,662	1,795,534	1,918,673	1,315,633	1,456,069	1,849,284	3,231,155	3,297,510	2,069,078	2,704,000	1,936,000	2,564,000	26,697,598			
13		NextEra Energy	868,000	784,000	867,500	840,000	868,000	840,000	868,000	868,000	840,000	868,000	840,000	868,000	10,219,500			
14		ISO Interchange													0			
15		NextEra UCAP													0			
16		Canton Mntn Wind	155,302	120,947	173,765	105,609	96,702	81,155	51,208	50,782	58,029	122,000	126,000	148,000	1,289,499			
17		ISO Monthly Charges													0			
18		ISO Weekly Activity	(299,258)	(417,807)	(240,539)	(7,143)	(132,547)	(85,718)	(81,639)	(227,630)	(260,614)	(157,000)	(114,000)	(266,000)	(2,289,895)			
19		Constant Energy Capital	170,709	17,323	22,965	30,264	23,900	4,020	7,219	32,598	28,035			0	337,032			
20		Net Meter Customers												0	0			
21	Total Kwhrs		5,567,188	4,632,015	5,048,211	4,391,391	4,496,362	4,705,953	6,221,606	6,222,675	4,994,380	4,719,000	4,877,000	5,481,000	61,356,780	(A3, Line 183)		
22													Kwhr Proof		61,356,780	(Schedule D,Line F32)		
23	Purchased Power Expense																	
24		NYPA	$ 11,996.44	$ 12,532.72	$ (7,663.80)	$ 11,080.08	$ 11,301.49	$ 11,355.60	$ 12,376.64	$ 12,158.30	$ 12,792.25	$ 11,357.34	$ 11,214.16	$ 11,357.34	$ 121,858.56			
25		Seabrook	$ 37,055.34	$ 36,517.74	$ 37,060.76	$ 36,879.53	$ 37,113.68	$ 36,874.90	$ 38,257.90	$ 38,237.85	$ 37,913.76	$ 18,791.11	$ 38,259.50	$ 38,432.40	$ 431,394.47			
26		Seabrook Surplus Credit	$ (53,245.86)	$ (44,466.33)	$ (44,466.33)	$ (44,466.33)	$ (44,466.33)	$ (44,466.33)		$ (2,787.02)	$ (22,336.31)	$ (2,787.02)	$ (2,786.95)	$ (2,786.95)	$ (309,061.76)			
27		MMWEC Admin Fee	$ 93.08	$ 249.82	$ 106.59	$ 111.16	$ 217.33	$ 262.62	$ 214.65	$ 146.99	$ 205.04	$ 100.00	$ 100.00	$ 100.00	$ 1,907.28			
28		NYPA 1995 True Up		$ (4,441.17)	$ (12,952.18)	$ (12,160.00)	$ 3,628.51	$ 5,087.97	$ (15,004.27)	$ (15,000.82)	$ (14,620.23)			$ -	$ (65,462.19)			
29		Consulting Serv. Canton Mtn													$ -			
30		Energy Purchase Canton Mtn Win	$ 15,328.07	$ 12,155.14	$ 17,286.53	$ 10,613.71	$ 9,714.74	$ 8,156.00	$ 5,144.35	$ 5,103.63	$ 5,831.96	$ 12,273.88	$ 8,196.73	$ 14,916.44	$ 124,721.18			
31		ISO Interchange													$ -			
32		Net Meter Customers												$ -	$ -			
33		ISO Scheduled Charges													$ -			
34		FMC Payment by Spruce Mnt													$ -			
35		Brown Bear Hydo II	$ 7,486.84	$ 6,928.33	$ 8,023.46	$ 9,843.96	$ 7,586.62	$ 2,942.07	$ 3,436.54	$ 4,052.36	$ 2,669.47	$ 4,917.54	$ 5,322.93	$ 6,957.41	$ 70,167.53			
36		Spruce Mnt	$ 18,814.45	$ 15,173.48	$ 15,372.77	$ 10,943.77	$ 12,596.43	$ 10,618.59	$ 9,345.74	$ 7,627.71	$ 8,227.86	$ 14,768.40	$ 10,785.96	$ 14,916.08	$ 149,191.24			
37		Spruce Mnt REC Sales/maint fee	$ -	$ (2,880.00)		$ -	$ (1,245.00)		$ -	$ (2,490.00)		$ -	$ -	$ -	$ (6,615.00)			
38		Spruce Mnt REC Fee		$ -		$ -				$ -	$ -	$ -	$ -	$ -	$ -			
39		Sprue Mntn wind FMC Credit	$ (1,643.74)	$ (1,643.74)	$ (1,643.74)	$ (1,649.38)	$ (1,649.38)	$ (1,649.38)	$ (588.32)	$ (585.50)	$ (585.50)		$ -		$ (11,638.68)			
40		Worumbo Rec Sales to EDF											$ -		$ -			
41		ENE All Requirements	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,100.00	$ 7,100.00	$ 7,100.00	$ 88,647.00			
42		PSEG Settlement/NextEra	$ (46,414.63)	$ (28.76)	$ -	$ -	$ 976.24	$ (9,541.00)	$ (8,759.56)	$ (2,115.17)	$ (922.55)	$ -	$ -	$ -	$ (66,805.43)			
43		PSEG Energy	$ 117,150.29	$ 82,145.68	$ 87,779.29	$ 60,190.21	$ 66,615.16	$ 84,604.75	$ 147,825.34	$ 150,861.08	$ 94,660.32	$ 123,720.17	$ 88,580.05	$ 117,290.96	$ 1,221,423.30			
44		NextEra Energy	$ 33,157.72	$ 29,948.91	$ 33,138.22	$ 32,088.12	$ 33,157.72	$ 32,417.19	$ 33,497.76	$ 33,497.76	$ 32,417.19	$ 33,497.76	$ 32,417.19	$ 33,497.76	$ 392,733.30			
45		NextEra Mthly Fixed	$ 6,480.00	$ 6,480.00	$ 6,480.00	$ 6,480.00	$ 6,480.00	$ 6,960.00	$ 6,960.00	$ 6,960.00	$ 6,960.00	$ 6,960.00	$ 6,960.00	$ 6,960.00	$ 81,120.00			
46		NextEra Rise Capacity Purchase	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 30,120.00			
47		Canton Mnt Rec Sales/ FMC Credit	$ -	$ -	$ -		$ (580.00)			$ (2,250.00)	$ (153.07)			$ -	$ (2,983.07)			
48		ISO Monthly Charges	$ 106,562.56	$ 110,577.65	$ 107,307.04	$ 106,045.15	$ 106,519.72	$ 206,670.04	$ 207,881.34	$ 215,333.45	$ 215,362.10	$ 183,116.27	$ 182,132.84	$ 189,544.19	$ 1,937,052.35			
49		Financial Settlement Next Era	$ -							$ (9,541.00)	$ (9,541.00)				$ (19,082.00)			
50		HQ Use Right/HQICC	$ (2,756.85)	$ (2,663.71)	$ (2,586.80)	$ (2,661.79)	$ (2,636.58)	$ (2,825.10)	$ (2,926.76)	$ (3,078.49)	$ (3,055.84)	$ (1,957.80)	$ (1,957.80)	$ (1,957.80)	$ (31,065.32)			
51		ISO Weekly Activity	$ 983.67	$ (7,131.95)	$ 8,590.62	$ 9,083.83	$ (818.48)	$ (2,473.98)	$ (3,149.08)	$ (603.47)	$ (2,670.09)	$ (36,570.37)	$ (36,050.57)	$ (44,949.22)	$ (115,759.09)			
52		ISO Annual Fee	$ 5,509.43							$ -					$ 5,509.43			
53		Brown Bear Rec Sales	$ -	$ -	$ -	$ -	$ (354.00)	$ -	$ -	$ -	$ -				$ (354.00)			
54		Constant Energy Capital (CEC)	$ 35,693.87	$ 1,111.02	$ 1,023.03	$ 2,777.85	$ 1,237.14	$ 152.20	$ 1,358.98	$ 4,644.67	$ 8,010.67				$ 56,009.43			
55		CEC Energy Charge True up				$ (5,658.17)									$ (5,658.17)			
56		Transmission	$ 146,756.17	$ 176,467.63	$ 146,286.35	$ 134,580.77	$ 137,703.35	$ 118,348.56	$ 129,438.55	$ 152,577.54	$ 147,063.89	$ 162,350.52	$ 148,717.18	$ 149,981.54	$ 1,750,272.05			
57	Total Expense		$ 448,999.85	$ 437,025.46	$ 409,134.81	$ 374,115.47	$ 393,091.36	$ 473,487.70	$ 575,302.80	$ 602,742.87	$ 528,222.92	$ 540,147.80	$ 501,501.22	$ 543,870.15	$ 5,827,642.41	(A2, Line 125)		
58													Revenue Proof:		$ 5,827,642.41			
59																		
60	*Market Value is based on the aggregate amount of Pascoag's required payments under the PSA's and PPA's, exclusive of the Reserve and Contingency Fund billings,*																	
61	*to MMWEC at December 31, 2016.. These amounts are from Pascoag's audited financial statements page 37, $9000*														-			
62																		
63																		
64	2018 aggregate amount		$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$9,000			
65	Cumulative carry over - 12/2017*		($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($14,451)	(Schedule C-3, Line 162)		
66	Monthly Transition Exp.		($454)	($454)	($454)	($454)	($454)	($454)	($454)	($454)	($454)	($454)	($454)	($454)	($5,451)			
67		**Cumulative Carry Over - See Schedule C-3, Line 158*											Revenue Proof:		($5,451)			
68	(1) Information on Schedule A-1 is from Pascoag's Summary of Purchased Power Invoices, submitted under separate cover as "Book 3"																A-1	

Testimony HJK
exhibit 6-5

Reconciliation of Forecast to Actual

	A	B	C	D	E	F	G	H	I	J
4	Month	Budget	Actual	Difference	Energy (MWH)	Energy (MWH)	Difference	Actual Cost	Budget Cost	
5					Budget	Actual	(Energy)	MWH	MWH	
6		(1)			(1)	(2)				
8	Jan 2018	$469,194	$449,000	($20,194)	5,579	5,567	(12)	$80.65	$84.10	
10	Feb 2018	$461,831	$437,025	($24,805)	5,052	4,632	(420)	$94.35	$91.42	
12	March 2018	$468,952	$409,135	($59,818)	5,157	5,048	(109)	$81.05	$90.94	
14	April 2018	$413,937	$374,115	($39,822)	4,450	4,391	(59)	$85.19	$93.02	
16	May 2018	$405,344	$393,091	($12,252)	4,627	4,496	(131)	$87.42	$87.60	
18	June 2018	$471,426	$473,488	$2,062	5,051	4,706	(345)	$100.61	$93.33	
20	July 2018	$551,104	$575,303	$24,199	6,091	6,222	131	$92.47	$90.48	
22	August 2018	$561,290	$602,743	$41,453	5,986	6,223	237	$96.86	$93.77	
24	September 2018	$517,049	$528,223	$11,174	5,129	4,994	(135)	$105.76	$100.81	
26	October 2018 Estimate	$540,148	$540,148	$0	4,720	4,719	(1)	$114.46	$114.44	
28	November 2018 Estimate	$501,501	$501,501	$0	4,877	4,877	0	$102.83	$102.83	
30	December 2018 Estimate	$543,870	$543,870	$0	5,481	5,481	0	$99.23	$99.23	
32	Total	$5,905,647	$5,827,642	($78,005)	62,200	61,357	(843)	$94.98	$94.95	
34						"Average" MWH cost		$94.98	$94.95	
35	(1) From ENE Forecast 12/2017 for 2018 (Schedule F)									
38										D
39	(2) See A1, Line 21									

Schedule D

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-7

ENE Bulk Power Cost Projections for 2019

Bulk Power Cost Projections
Pascoag Utility District
January 2019 through December 2019

			FIXED COSTS			ENERGY VARIABLE COSTS			TRANS. COSTS	TOTAL COSTS			
System Peak Demand (KW)			13,293										
System Energy Requirements (MWH)			62,041										62,201
RESOURCES		(KW)	Budget ($/KW-MO)	($)	CF (%)	MWH	Budget ($/MWH)	($)	Budget ($)	Budget ($)	($/MWH)		Fixe 2017
NYPA Firm	17.12%	1,600	4.07	78,144	75	10,512	4.92	51,719	223,000	352,863	33.57	$	78,144
Seabrook (Project 6)	18.47%	1,331	18.29	292,060	98	11,459	5.19	59,441	694	352,195	30.74	$	104,780
	24,338												
SUBTOTAL - BASE		2,931		370,204		21,971		111,160	223,694	705,058	64.30	$	182,924
FCM Payments by LP				-353,268		0		0	0	-353,268		$	(235,669)
ISO FCM Costs				1,920,254		0		0	0	1,920,254		$	1,697,218
NextEra Rise Capacity Purchase				30,120		0		0	0	30,120		$	30,120
NextEra Rise Energy Purchase				84,360		5,840	38.79	226,512	0	310,872	53.23	$	81,120
Miller Hydro Purchase	2.40%			0		1,492	49.94	74,512	0	74,512	49.94	$	-
Spruce Mtn Purchase	2.68%			0		1,665	89.25	148,609	0	148,609	89.25	$	-
PSEG "Bal Power" Purchase	35.31%			0		21,904	45.75	1,002,125	0	1,002,125	45.75	$	-
Canton Wind Purchase	2.18%			0		1,351	95.20	128,580	0	128,580	95.20	$	-
NextEra Purchase				0		8,760	38.80	339,888	0	339,888	38.80	$	-
Conlant Energy Capital				0		0		0	0	0		$	-
SUBTOTAL - INTERMEDIATE		0		1,681,466		41,012		1,920,226	0	3,601,692	87.82	$	1,572,789
NYPA Peak		100	4.07	4,884	13	110	4.92	539	4,800	10,223	93.36	$	4,884
SUBTOTAL - PEAKING		100		4,884		110		539	4,800	10,223	93.36	$	4,884
ISO Energy Net Interchange	-1.69%					-1,051	45.92	-48,259	0	-48,259	45.92	$	-
Service Billing				1,200		0		0	0	1,200	0.02	$	1,200
Hydro Quebec I		934		-22,766		0		0	-3,553	-26,319	-0.42	$	(23,302)
ENE All Req/Short Supply				85,800		0		0	0	85,800	1.38	$	85,200
ISO Annual Fee				5,417		0		0	0	5,417	0.09	$	5,417
ISO Load Based Charges				76,859		0		0	0	76,859	1.24	$	78,768
ISO Scheduled Charges				97,085		0		0	0	97,085	1.56	$	87,870
NEPOOL OATT Charge				0		0		0	1,270,980	1,270,980	20.49	$	-
Network Transmission Service (NGRID)				0		0		0	282,005	282,005	4.55	$	-
DAF (Subtransmission Ch)				0		0		0	72,900	72,900	1.18	$	-
SUBTOTAL - OTHER CHARGES		934		243,595		0		0	1,622,331	1,865,926	30.08	$	235,153
TOTAL		3,965		2,300,148		62,041 MWH	31.97	1,983,665	1,850,825	6,134,639	98.88	$	1,995,750

4,283,813

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

RESOURCES	d Variance	Energy 2017	Variance	Trans 2017	Variance	Total 2016	Variance
NYPA Firm	$ -	$ 51,719	$ -	$ 207,200	$ 15,800	$ 337,063	$ 15,800
Seabrook (Project 6)	$ 187,280	$ 61,605	$ (2,164)	$ 721	$ (27)	$ 167,105	$ 185,090
SUBTOTAL - BASE	$ 187,280	$ 113,324	$ (2,164)	$ 207,921	$ 15,773	$ 504,168	$ 200,890
FCM Payments by LP	$ (117,599)	$ -	$ -	$ -	$ -	$ (235,669)	$ (117,599)
ISO FCM Costs	$ 223,037	$ -	$ -	$ -	$ -	$ 1,697,218	$ 223,037
NextEra Rise Capacity Purchase	$ -	$ -	$ -	$ -	$ -	$ 30,120	$ -
NextEra Rise Energy Purchase	$ 3,240	$ 221,933	$ 4,579	$ -	$ -	$ 303,053	$ 7,819
Miller Hydro Purchase	$ -	$ 75,126	$ (614)	$ -	$ -	$ 75,126	$ (614)
Spruce Mtn Purchase	$ -	$ 137,415	$ 11,194	$ -	$ -	$ 137,415	$ 11,194
PSEG "Bal Power" Purchase	$ -	$ 1,254,997	$ (252,873)	$ -	$ -	$ 1,254,997	$ (252,873)
Canton Wind Purchase	$ -	$ 125,002	$ 3,578	$ -	$ -	$ 125,002	$ 3,578
NextEra Purchase	$ -	$ 170,820	$ 169,068	$ -	$ -	$ 170,820	$ 169,068
Contant Energy Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL - INTERMEDIATE	$ 108,677	$ 1,985,293	$ (65,067)	$ -	$ -	$ 3,558,082	$ 43,610
NYPA Peak	$ -	$ 539	$ -	$ 4,800	$ -	$ 10,223	$ -
SUBTOTAL - PEAKING	$ -	$ 539	$ -	$ 4,800	$ -	$ 10,223	$ -
ISO Energy Net Interchange	$ -	$ (43,435)	$ (4,824)	$ -	$ -	$ (43,435)	$ (4,824)
Service Billing	$ -	$ -	$ -	$ -	$ -	$ 1,200	$ -
Hydro Quebec I	$ 536	$ -	$ -	$ 7,850	$ (11,404)	$ (15,451)	$ (10,868)
ENE All Req/Short Supply	$ 600	$ -	$ -	$ -	$ -	$ 85,200	$ 600
ISO Annual Fee	$ -	$ -	$ -	$ -	$ -	$ 5,417	$ -
ISO Load Based Charges	$ (1,909)	$ -	$ -	$ -	$ -	$ 78,768	$ (1,909)
ISO Scheduled Charges	$ 9,215	$ -	$ -	$ -	$ -	$ 87,870	$ 9,215
NEPOOL OATT Charge	$ -	$ -	$ -	$ 1,277,022	$ (6,042)	$ 1,277,022	$ (6,042)
Network Transmission Service (NGRID)	$ -	$ -	$ -	$ 282,004	$ 1	$ 282,004	$ 1
DAF (Subtransmission Ch)	$ -	$ -	$ -	$ 74,580	$ (1,680)	$ 74,580	$ (1,680)
SUBTOTAL - OTHER CHARGES	$ 8,441	$ -	$ -	$ 1,641,456	$ (19,125)	$ 1,876,609	$ (10,683)
TOTAL	$ 304,399	$ 2,055,721	$ (72,055)	$ 1,854,177	$ (3,352)	$ 5,905,647	$ 228,992
	15.3%	-3.51%			-0.18%		

PASCOAG
UTILITY DISTRICT

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

.scoag Electric • Pascoag Water

Testimony Exhibits HJR-8

ENE Budget Assumptions for 2019

2019 Budget Assumptions

MWH			Total Costs		$/MWH
62,201	2018 Budget	$	5,905,647	$	94.94
62,041	2019 Budget	$	6,134,639	$	98.88
(160)	Total Increase (+) /Decrease (-) of	$	228,992	$	(3.94)

Details of Increase:

			Adj:		Total Adj of :
1 Seabrook Projections - Updated to reflect 3/28/18 Budget					
	Fixed Cost - reduced to $22.83/kw, and applied Surplus Credit of $1,200 for January through June, and $13,400 for August through December	$	187,280		
	Energy - reduced to $5.36/MWH	$	(2,164)		
	Transmission - decreased based on projections	$	(27)	$	185,090
2 NYPA Projections based on historical deliveries and costs					
	Fixed Costs - changed entitlement from 2300kw to 1700kw for Jan through April 2018	$	-		
	Energy - Capacity Factor set at 75%, lower purchases due to the entitlement reduction	$	-		
	Transmission - based on 3 year historical actuals with a 5% increase; applied a reduction of 15% for Jan through Dec 2018 due to the lower entitlement	$	15,800	$	15,800
3 Capacity - Updated Projection to reflect auction pricing, bilaterals, and payments by LP					
	FCM Payments by LP	$	(117,599)		
	ISO FCM Costs	$	223,037		
	FCM Bilateral Costs* Price Reduction	$	-	$	105,437
4 Updated NextEra Rise Call Option					
	Fixed Cost - Applied Capacity cost against ISO credit in item#3	$	3,240		
	Energy - Updated to include the Price Lock on 6/30/16	$	4,579	$	7,819
5 Bilateral Transactions					
	Energy - Miller Hydro - update projection to include contract extension	$	(614)		
	Energy - Spruce Mtn - update projects based on historical deliveries includes placeholder for $10/REC for Sales	$	11,194		
	Canton Wind projection based on data included in contract includes placeholder for $10/REC for Sales	$	3,578		
	NextEra Bilateral	$	169,068		
	Energy - PSEG 100% LF less Fixed Volumes; forecasted MWH of 21,904 at contracted price of $45.75 is lower than the 2018 projected MWH of 27,432	$	(252,873)	$	(69,647)
6 Change from resales to purchases from the ISO-NE for Power				$	(4,824)
7 ENE All Req/Short Supply					
	Estimated Increase from $7,100/mo to $7,150/mo			$	600
8 Adjustments to Estimated ISO Expenses					
	Annual Fee	$	-		
	Load Based Charges to account for reduced expenses for Winter Reliability	$	(1,909)		
	Scheduled Charges	$	9,215		
	Transmission projections by ISO decreased	$	(6,042)	$	1,263
9 NGRID Network Transmission Charges					
Jan - Dec	Left forecast at $282K based on historical invoices 7/16-6/17 was $265K, 7/17-6/18 was $269K			$	1
10 DAF Subtransmission Charges					
Jan-Dec	Adjusted Project to $6,075 based on Increased % from $5,920 to $5,991			$	(1,680)
11 HQ Transmission Charges					
	Include the Use Rights and FCM Credit associated with the HQ ICC transfer				
Jan - Dec	Use Rights Value	$	(11,404)		
	FCM Credit	$	536	$	(10,868)
			Total Adjustment	**$**	**228,992**
			Variance	$	0

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

Testimony Exhibits HJR-9

ENE Budget Assumptions for October - December 2018

	A	B	C	D	E	F	G	H	I	J
676										
677		Pascoag Utility District - Expense by Rate Component								
678				October 2018 Estimated						
679	Energy Component	Kwhrs		Standard Offer		Transmission		Total	Average	
680										
681	**MMWEC - Project 6**									
682	Project 6	31,000		$ 18,791.11		$ 60.06		$ 18,851.17		
683	Credit			$ (2,787.02)				$ (2,787.02)		
684	**Total MMWEC-Project 6**	31,000		$ 16,004.09		$ 60.06		$ 16,064.15	$ 0.5182	
685										
686	**MMWEC Non-PSA**									
687	Admin Exp			$ 100.00				$ 100.00		
688	HQI			$ (1,957.80)		$ 639.81		$ (1,317.99)		
689	HQII							$ -		
690	HQIII							$ -		
691	NYPA Billing correction									
692	**Total MMWEC Non PSA**			$ (1,857.80)		$ 639.81		$ (1,217.99)		
693										
694	**NYPA - Niagara & St Lawrence**									
695	Demand	9,000		$ 452.76				$ 452.76		
696	Energy	893,000		$ 10,904.58				$ 10,904.58		
697	NYISO Ancillary					$ 400.00		$ 400.00		
698	TUC Charges					$ 11,200.00		$ 11,200.00		
699	ISO True up Charges/credits							$ -		
700	**Total - Niagara & ST LAWRENCE**	902,000		$ 11,357.34		$ 11,600.00		$ 22,957.34	$ 0.0255	
701										
702										
703	**National Grid**									
704	Direct Assignment Facilities (DAF)					$ 6,215.00		$ 6,215.00		
705	LNS - NGrid					$ 18,124.00		$ 18,124.00		
706	**Total National Grid**					$ 24,339.00		$ 24,339.00		
707										
708	**Energy New England**									
709	All Requirements/ST Power Sply			$ 7,100.00				$ 7,100.00		
710	Spruce Mountain	149,000		$ 14,768.40				$ 14,768.40	$ 0.0991	
711	Spruce Mountain - REC Sales							$ -		
712	Spruce Mountain - FCM Credit							$ -		
713	Brown Bear II/Hydro group	100,000		$ 4,917.54				$ 4,917.54	$ 0.0492	
714	Energy Purchase PSEG	2,704,000		$ 123,720.17				$ 123,720.17	$ 0.0458	
715	Financial Settlement PSEG							$ -	#DIV/0!	
716	HQ Administrative Fee							$ -	#DIV/0!	
717	HQ Use Right Payment							$ -		
718	HQ HQICC Payment							$ -		
719	Financial Settlement - Exelon							$ -	#DIV/0!	
720	Energy Purchase- NextEra	372,000		$ 14,508.00				$ 14,508.00	$ 0.0390	
721	Option Energy Purchase NextEra	496,000		$ 18,989.76						
722	Option Mthly Fixed Cost-NextEra			$ 6,960.00				$ 6,960.00	#DIV/0!	
723	UCAP PURHASES -NEXTERA			$ 2,510.00				$ 2,510.00		
724	Energy Purchase Canton Mntn	122,000		$ 12,273.88				$ 12,273.88		
725										
726	**ENE/ ISO**							$ -		
727	ISO Monthly Charges			$ 183,116.27		$ 125,711.65		$ 308,827.92		
728	Weekly Sales/Purchases	-157,000		$ (36,570.37)				$ (36,570.37)	$ 0.2329	
729	Annual ISO Membership Fees							$ -		
730	MH CM Credit							$ -		
731	**ENE/Constant Energy Capital**									
732	Pascoag Power House - Energy							$ -		
733	Pascoag Power House -Transmission							$ -		
734	**Total -Energy New England**	3,786,000		$ 352,293.65		$ 125,711.65		$ 478,005.30		
735										
736	**Power Cost - October 2018**	4,719,000	0	377,797.28		$ 162,360.52		$ 540,147.80	$ 0.1145	
737										
738	**NYPA Interruptible Kwhrs:**			Month		Y-T-D				
739	Niagara					610,000				
740	St Lawrence					1,540,800				
741				-		2,150,800				

Bulk Power Cost Projections
Pascoag Utility District
October-18

FCA9

System Peak Demand (KW) 8,709

System Energy Requirements (MWH) 4,720

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	1,600	4.07	\$ 6,512.00	75	893	4.92	\$ 4,392.58	\$ 11,200.00	\$ 22,104.58	24.76
Seabrook (Project 6)	1,331	\$ 12.72	\$ 15,838.09	3.2	31	\$ 5.29	\$ 166.00	\$ 60.06	\$ 16,064.15	511.76
SUBTOTAL - BASE	2,931		\$ 22,350.09		924		\$ 4,558.57	\$ 11,260.06	\$ 38,168.72	41.30
FCM Payments by LP			\$ (32,683.52)						\$ (32,683.52)	N/A
ISO FCM Costs			\$171,355.27						\$171,355.27	N/A
NextEra Rise Capacity Purchase			\$ 2,510.00						\$ 2,510.00	N/A
NextEra Rise Energy Purchase	1,000		\$ 6,960.00		496	38.29	\$ 18,989.76		\$ 25,949.76	52.32
Miller Hydro Purchase					100	48.96	\$ 4,917.54		\$ 4,917.54	48.96
Spruce Mtn Purchase					149	99.25	\$ 14,768.40		\$ 14,768.40	99.25
PSEG "Bal Power" Purchase					2,704	45.75	\$123,720.17		\$123,720.17	45.75
Canton Wind Purchase					122	100.50	\$ 12,273.88		\$ 12,273.88	100.50
NextEra Purchase					372	39.00	\$ 14,508.00		\$ 14,508.00	39.00
									\$ -	
SUBTOTAL - INTERMEDIATE	1,000		\$148,141.75		3,944		\$189,177.75	\$ -	\$337,319.50	85.54
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					-157	24.69	\$ (3,886.85)	\$ -	\$ (3,886.85)	24.69
Service Billing			\$ 100.00		0	0.00	\$ -	\$ -	\$ 100.00	0.02
Hydro Quebec I	934	0	\$ (1,957.80)	0	0	0	\$ -	\$ 639.81	\$ (1,317.98)	-0.28
ENE All Req/Short Supply			\$ 7,100.00			0.00	\$ -	\$ -	\$ 7,100.00	1.50
ISO Annual Fee									\$ -	0.00
ISO Load Based Charges			\$ 3,816.74						\$ 3,816.74	0.81
ISO Scheduled Charges			\$ 7,944.26						\$ 7,944.26	1.68
NEPOOL OATT Charge			\$ -		0	0.00	\$ -	\$ 125,711.65	\$125,711.65	26.64
Network Transmission Service (NGRID)			\$ -		0	0.00	\$ -	\$ 18,124.00	\$ 18,124.00	3.84
DAF (Subtransmission Ch)			\$ -		0	0.00	\$ -	\$ 6,215.00	\$ 6,215.00	1.32
SUBTOTAL - OTHER CHARGE	934		\$ 17,003.20		0		\$ -	\$ 150,690.47	\$167,693.67	35.53
TOTAL	2,034		\$187,902.04		4,720		\$189,895.23	\$ 162,350.53	\$540,147.80	114.45

E= 377797.27

	A	B	C	D	E	F	G	H	I
743	Pascoag Utility District - Expense by Rate Component								
744	November 2018 -Estimated								
745	Energy Component	Kwhrs		Standard Offer		Transmission		Total	Average
746									
747	MMWEC - Project 6								
748	Project 6 SeaBrook	940,000		$ 38,259.50		$ 60.06		$ 38,319.56	
749	Credit			$ (2,786.95)				$ (2,786.95)	
750	Total MMWEC-Project 6	940,000		$ 35,472.55		$ 60.06		$ 35,532.61	$ 0.0378
751									
752	MMWEC Non-PSA								
753	Admin Exp			$ 100.00				$ 100.00	
754	HQI			$ (1,957.80)		$ 664.34		$ (1,293.46)	
755	HQII							$ -	
756	HQIII							$ -	
757	NYPA Billing correction								
758	Total MMWEC Non PSA			$ (1,857.80)		$ 664.34		$ (1,193.46)	
759									
760	NYPA - Niagara & St Lawrence								
761	Demand	9,000		$ 451.28		$ 400.00		$ 851.28	
762	Energy	864,000		$ 10,762.88		$ 19,200.00		$ 29,962.88	
763	NYISO Ancillary							$ -	
764	TUC Charges							$ -	
765	ISO True up Charges/credits							$ -	
766	Total - Niagara	873,000		$ 11,214.16		$ 19,600.00		$ 30,814.16	$ 0.0353
767									
768									
769	National Grid								
770	Direct Assignment Facilities (DAR)					$ 6,215.00		$ 6,215.00	
771	LNS - NGrid					$ 32,464.00		$ 32,464.00	
772	Total National Grid					$ 38,679.00		$ 38,679.00	
773									
774	Energy New England								
775	All Requirements/ST Power Sply			$ 7,100.00				$ 7,100.00	
776	Spruce Mountain	167,000		$ 10,785.96				$ 10,785.96	$ 0.0646
777	Spruce Mountain - REC Sales							$ -	
778	Spruce Mountain - FCM Credit							$ -	
779	Spruce Mnt Management fee							$ -	
780	Class 1 Worumbo Rec Sales to EDF							$ -	
781	Brown Bear II /Hydo Miller	109,000		$ 5,322.93				$ 5,322.93	$ 0.0488
782	Energy Purchase PSEG	1,936,000		$ 88,580.05				$ 88,580.05	$ 0.0458
783	Financial Settlement PSEG							$ -	#DIV/0!
784	HQ Administrative Fee							$ -	#DIV/0!
785	HQ Use Right Payment							$ -	
786	HQ HQICC Payment							$ -	
787	Financial Settlement - Exelon							$ -	#DIV/0!
788	Energy Purchase - NextEra	480,000		$ 18,377.19				$ 18,377.19	$ 0.0383
789	Option Energy Purchase NextEra	360,000		$ 14,040.00				$ 14,040.00	$ 0.0390
790	option mnthly fixed cost			$ 6,960.00					
791	UCAP PURHASES -NEXTERA			$ 2,510.00				$ 2,510.00	
792	Energy Purchase Canton Mntn Wind	126,000		$ 8,196.73				$ 8,196.73	
793	FCM Payments by LP							$ -	
794	ENE/ISO							$ -	
795	ISO Monthly Charges			$ 182,132.84		$ 89,713.78		$ 271,846.62	#DIV/0!
796	Weely Sales/Purchases	-114,000		$ (36,050.57)				$ (36,050.57)	$ 0.3162
797	Annual ISO Membership Fees							$ -	
798	MC CM Credit							$ -	#DIV/0!
799	ENE/Constant Energy Captital								
800	Pascoag Power House-Energy								
801	Pascoag Power House-Transmission							$ -	
802								$ -	
803	Total Energy New England	3,064,000		$ 307,955.13		$ 89,713.78		$ 397,668.91	
804									
805	Power Cost November 2018	4,877,000	0	352,784.04		$ 148,717.18		$ 501,501.22	$ 0.1028
806									
807	NYPA Interruptible Kwhrs:			Month		Y-T-D			
808	Niagara					610,000			
809	St Lawrence					1,540,800			
810						2,150,800			

Bulk Power Cost Projections
Pascoag Utility District
November-18

FCA9

System Peak Demand (KW) 9,841

System Energy Requirements (MWH) 4,877

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	1,600	4.07	\$ 6,512.00	75	864	4.92	\$ 4,250.88	\$ 19,200.00	\$ 29,962.88	34.68
Seabrook (Project 6)	1,331	\$ 23.74	\$ 30,499.89	98.1	940	\$ 5.29	\$ 4,972.66	\$ 60.06	\$ 35,532.61	37.79
SUBTOTAL - BASE	2,931		\$ 37,011.89		1,804		\$ 9,223.54	\$ 19,260.06	\$ 65,495.49	36.30
FCM Payments by LP			\$ (32,683.52)						\$ (32,683.52)	N/A
ISO FCM Costs			\$ 171,355.27						\$ 171,355.27	N/A
NextEra Rise Capacity Purchase			\$ 2,510.00						\$ 2,510.00	N/A
NextEra Rise Energy Purchase	1,000		\$ 6,960.00		480	38.29	\$ 18,377.19		\$ 25,337.19	52.79
Miller Hydro Purchase					109	48.96	\$ 5,322.93		\$ 5,322.93	48.96
Spruce Mtn Purchase					167	99.25	\$ 10,785.96		\$ 10,785.96	64.57
PSEG "Bal Power" Purchase					1,936	45.75	\$ 88,580.05		\$ 88,580.05	45.75
Canton Wind Purchase					126	100.50	\$ 8,196.73		\$ 8,196.73	65.08
NextEra Purchase					360	39.00	\$ 14,040.00		\$ 14,040.00	39.00
									\$ -	
SUBTOTAL - INTERMEDIATE	1,000		\$ 148,141.75		3,178		\$ 145,302.87	\$ -	\$ 293,444.61	92.34
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					-114	29.43	\$ (3,367.05)	\$ -	\$ (3,367.05)	29.43
Service Billing			\$ 100.00		0	0.00	\$ -	\$ -	\$ 100.00	0.02
Hydro Quebec I	934	0	\$ (1,957.80)	0	0	0	\$ -	\$ 664.34	\$ (1,293.46)	-0.27
ENE All Req/Short Supply			\$ 7,100.00			0.00	\$ -	\$ -	\$ 7,100.00	1.46
ISO Annual Fee									\$ -	0.00
ISO Load Based Charges			\$ 3,582.23						\$ 3,582.23	0.73
ISO Scheduled Charges			\$ 7,195.34						\$ 7,195.34	1.48
NEPOOL OATT Charge			\$ -		0	0.00	\$ -	\$ 89,713.78	\$ 89,713.78	18.40
Network Transmission Service (NGRID)			\$ -		0	0.00	\$ -	\$ 32,464.00	\$ 32,464.00	6.66
DAF (Subtransmission Ch)			\$ -		0	0.00	\$ -	\$ 6,215.00	\$ 6,215.00	1.27
SUBTOTAL - OTHER CHARGE	934		\$ 16,019.77		0		\$ -	\$ 129,057.11	\$ 145,076.89	29.75
TOTAL	2,034		\$ 201,580.41		4,877		\$ 151,203.64	\$ 148,717.18	\$ 501,501.22	102.83

•E = 352,784.05

T

	A	B	C	D	E	F	G	H	I
812				Pascoag Utility District - Expense by Rate Component					
813				December 2018 -Estimated					
814	Energy Component	Kwhrs		Standard Offer		Transmission		Total	Average
815									
816	MMWEC - Project 6								
817	Project 6	973,000		$ 38,432.40		$ 60.06		$ 38,492.46	
818	Credit			$ (2,786.95)				$ (2,786.95)	
819	Total MMWEC-Project 6	973,000		$ 35,645.45		$ 60.06		$ 35,705.51	$ 0.0367
820									
821	MMWEC Non-PSA								
822	Admin Exp			$ 100.00				$ 100.00	
823	HQI			$ (1,957.80)		$ 639.81		$ (1,317.99)	
824	HQII							$ -	
825	HQIII							$ -	
826	NYPA Billing correction								
827	Total MMWEC Non PSA			$ (1,857.80)		$ 639.81		$ (1,217.99)	
828									
829	NYPA - Niagara								
830	Demand	9,000		$ 452.76				$ 452.76	
831	Energy	893,000		$ 10,904.58				$ 10,904.58	
832	NYISO Ancillary					$ 400.00		$ 400.00	
833	TUC Charges					$ 16,000.00		$ 16,000.00	
834	ISO True up Charges/credits							$ -	
835	Total - Niagara	902,000		$ 11,357.34		$ 16,400.00		$ 27,757.34	$ 0.0308
836									
837	NYPA - St Lawrence							$ 44,157.34	
838	Demand							$ 87,914.68	
839	Energy							$ 159,829.36	
840	NYISO Ancillary							$ 319,658.72	
841	TUC Charges							$ 611,560.10	
842	ISO True up Charges/credits							$ 1,223,120.20	
843	Total - Lawrence	0		$ -		$ -		$ 2,402,083.06	
844									
845	National Grid							$ 4,236,763.36	
846	Direct Assignment Facilities (DAR)					$ 6,215.00		$ 6,215.00	
847	LNS - NGrid					$ 25,290.00		$ 25,290.00	
848	Total National Grid					$ 31,505.00		$ 31,505.00	
849									
850	Energy New England								
851	All Requirements/ST Power Sply			$ 7,100.00				$ 7,100.00	
852	Spruce Mountain	150,000		$ 14,916.08				$ 14,916.08	$ 0.0994
853	Spruce Mountain - REC Sales							$ -	
854	Spruce Mountain - management fee							$ -	
855	Brown Bear II Hydo	142,000		$ 6,957.41				$ 6,957.41	$ 0.0490
856	Energy Purchase PSCG	2,564,000		$ 117,290.96				$ 117,290.96	$ 0.0457
857	Financial Settlement PSCG							$ -	#DIV/0!
858	HQ Administrative Fee							$ -	#DIV/0!
859	HQ Use Right Payment							$ -	
860	HQ HQICC Payment							$ -	
861	Financial Settlement - Exelon							$ -	#DIV/0!
862	Energy Purchase -NextEra	372,000		$ 14,508.00					
863	Option Energy Purchase NextEra	496,000		$ 18,989.76				$ 18,989.76	0.038285806
864	Option Mthly Fixed Cost NextEra			$ 6,960.00				$ 6,960.00	#DIV/0!
865	UCAP PURHASES -NEXTERA			$ 2,510.00				$ 2,510.00	
866	2017 Vintage ME Rec Sales Next Era							$ -	
867	Energy Purchase Canton Mnt Wind	148,000		$ 14,916.44				$ 14,916.44	
868	ENE/ISO								
869	ISO Monthly Charges			$ 189,544.19		$ 101,376.67		$ 290,920.86	#DIV/0!
870	Weekly Sales/Purchases	-266,000		$ (44,949.22)				$ (44,949.22)	
871	Annual ISO Membership Fee							$ -	
872	MH CM Credit							$ -	
873	ISO weekly Charges							$ -	
874	ENE/Constant Energy Capital								
875	Pascoag Power House-Energy							$ -	#DIV/0!
876	Pascoag Power House-Transmission							$ -	
877	Total Energy New England	3,606,000		$ 348,743.82		$ 101,376.67		$ 435,612.29	
878									
879	Net Metering Customers	0		$ -		$ -		$ -	#DIV/0!
880									
881	Power Cost - December 2018	5,481,000		$ 393,888.61		$ 149,981.54		$ 543,870.15	$ 0.0992
882									
883	NYPA Interruptible Kwhrs:			Month		Y-T-D			
884	Niagara					610,000			
885	St Lawrence					1,540,800			
886						2,150,800			

Bulk Power Cost Projections
Pascoag Utility District
December-18

FCA9

System Peak Demand (KW)	10,366
System Energy Requirements (MWH)	5,481

RESOURCES	(KW)	FIXED COSTS Budget (\$/KW-MO)	FIXED COSTS ($)	CF (%)	ENERGY VARIABLE COSTS MWH	ENERGY VARIABLE COSTS Budget (\$/MWH)	ENERGY VARIABLE COSTS ($)	TRANS. COSTS Budget ($)	TOTAL COSTS Budget ($)	TOTAL COSTS (\$/MWH)
NYPA Firm	1,600	4.07	$ 6,512.00	75	893	4.92	$ 4,392.58	$ 16,000.00	$ 26,904.58	30.14
Seabrook (Project 6)	1,331	$ 23.74	$ 30,499.90	98.3	973	$ 5.29	$ 5,145.55	$ 60.06	$ 35,705.52	36.69
SUBTOTAL - BASE	2,931		$ 37,011.90		1,866		$ 9,538.12	$ 16,060.06	$ 62,610.09	33.56
FCM Payments by LP			$ (32,683.52)						$ (32,683.52)	N/A
ISO FCM Costs			$ 171,355.27						$ 171,355.27	N/A
NextEra Rise Capacity Purchase			$ 2,510.00						$ 2,510.00	N/A
NextEra Rise Energy Purchase	1,000		$ 6,960.00		496	38.29	$ 18,989.76		$ 25,949.76	52.32
Miller Hydro Purchase					142	48.96	$ 6,957.41		$ 6,957.41	48.96
Spruce Mtn Purchase					150	99.25	$ 14,916.08		$ 14,916.08	99.25
PSEG "Bal Power" Purchase					2,564	45.75	$ 117,290.96		$ 117,290.96	45.75
Canton Wind Purchase					148	100.50	$ 14,916.44		$ 14,916.44	100.50
NextEra Purchase					372	39.00	$ 14,508.00		$ 14,508.00	39.00
									$ -	
SUBTOTAL - INTERMEDIATE	1,000		$ 148,141.75		3,873		$ 187,578.65	$ -	$ 335,720.40	86.69
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					-266	46.07	$ (12,265.70)	$ -	$ (12,265.70)	46.07
Service Billing			$ 100.00		0	0.00	$ -	$ -	$ 100.00	0.02
Hydro Quebec I	934	0	$ (1,957.80)	0	0	0	$ -	$ 639.81	$ (1,317.98)	-0.24
ENE All Req/Short Supply			$ 7,100.00			0.00	$ -	$ -	$ 7,100.00	1.30
ISO Annual Fee									$ -	0.00
ISO Load Based Charges			$ 10,605.47						$ 10,605.47	1.93
ISO Scheduled Charges			$ 7,583.45						$ 7,583.45	1.38
NEPOOL OATT Charge			$ -		0	0.00	$ -	$ 101,376.67	$ 101,376.67	18.49
Network Transmission Service (NGRID)			$ -		0	0.00	$ -	$ 25,290.00	$ 25,290.00	4.61
DAF (Subtransmission Ch)			$ -		0	0.00	$ -	$ 6,215.00	$ 6,215.00	1.13
SUBTOTAL - OTHER CHARGE	934		$ 23,431.11		0		$ -	$ 133,521.49	$ 156,952.60	28.63
TOTAL	2,034		$ 208,991.77		5,481		$ 184,896.83	$ 149,981.55	$ 543,870.15	99.22

e = 393,888.60

2018 Budget Assumptions

MWH			Total Costs		$/MWH
59,767	2017 Budget	$	5,990,958	$	100.24
62,201	2018 Budget	$	5,905,647	$	94.94
2,433	Total Increase (+) /Decrease (-) of	$	(85,311)	$	5.29

Details of Increase:

			Adj:		Total Adj of :
1 Seabrook Projections - Updated to reflect 3/29/17 Budget					
	Fixed Cost - reduced to $23.74/kw, and applied Surplus Credit of $42,375 for January through June, and $1,099 for August through December	$	(249,507)		
	Energy - reduced to $5.86/MWH	$	(3,119)		
	Transmission - decreased based on projections	$	(88)	$	(252,714)
2 NYPA Projections based on historical deliveries and costs					
	Fixed Costs - changed entitlement from 2300kw to 1700kw for Jan through April 2018	$	(9,768)		
	Energy - Capacity Factor set at 75%, lower purchases due to the entitlement reduction	$	(6,376)		
	Transmission - based on 3 year historical actuals with a 5% increase; applied a reduction of 15% for Jan through Dec 2018 due to the lower entitlement	$	(85,670)	$	(101,814)
3 Capacity - Updated Projection to reflect auction pricing, bilaterals, and payments by LP					
	FCM Payments by LP	$	(223,342)		
	ISO FCM Costs	$	828,337		
	FCM Bilateral Costs* Price Reduction	$	-	$	604,995
4 Updated NextEra Rise Call Option					
	Fixed Cost - Applied Capacity cost against ISO credit in item#3	$	4,510		
	Energy - Updated to include the Price Lock on 6/30/16	$	3,096	$	7,606
5 Bilateral Transactions					
	Energy - Miller Hydro - update projection to include contract extension	$	(1,106)		
	Energy - Spruce Mtn - update projects based on historical deliveries includes placeholder for $15/REC for Sales	$	33,521		
	Canton Wind projection based on data included in contract includes placeholder for $15/REC for Sales	$	125,002		
	NextEra Bilateral	$	170,820		
	Energy - PSEG 100% LF less Fixed Volumes; forecasted MWH of 27,010 at contracted price of $45.75 is lower than last year's transaction of 26,873MWH at $70.30	$	(634,185)	$	(305,948)
6 Change from resales to purchases from the ISO-NE for Power				$	(34,247)
7 ENE All Req/Short Supply					
	Estimated increase from $7,050/mo to $7,100/mo			$	600
8 Adjustments to Estimated ISO Expenses					
	Annual Fee	$	-		
	Load Based Charges to account for reduced expenses for Winter Reliability	$	(9,389)		
	Scheduled Charges	$	7,058		
	Transmission Increase effective 6/1/17 & 6/1/18	$	93,568	$	91,237
9 NGRID Network Transmission Charges					
Jan - Dec	Decrease forecast from $330K to $282K based on historical invoices 7/16-6/17 was $265K, 6/15-5/16 was $300K			$	(83,996)
10 DAF Subtransmission Charges					
Jan-Dec	Left at $6,215 based Invoices from 7/16-6/17 ave cost of $5,920			$	-
11 HQ Transmission Charges					
	Include the Use Rights and FCM Credit associated with the HQ ICC transfer				
Jan - Dec	Use Rights Value	$	2,909		
	FCM Credit	$	(13,940)	$	(11,031)
			Total Adjustment	**$**	**(85,311)**
			Variance	$	(0)

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-10

Forecasted to Actual MW Sales to Customers through October 2018

Forcasted to Actual MW in Sales to Customers

Testimony Exhibit 10

	PUD's Forecast MW for 2018	Actual MW
Jan-18	5,265	5,274
Feb-18	5,066	4,945
Mar-18	4,497	4,339
Apr-18	4,798	4,371
May-18	4,010	3,892
Jun-18	4,125	4,039
Jul-18	4,759	5,015
Aug-18	5,091	5,774
Sep-18	5,414	5,435
Oct-18	4,991	4,197
	48,016	47,281

48,016	Forecast
47,281	Actual
735	**MW less than Forecasted**

Forecasted MW

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
64			(T)	Indicates Transmission Charges												
65								Pascoag Utility District								
66								Restated Forecast Purchased Power Costs								
67																
68			Jan 2018	Feb 2018	Mar 2018	Apr 2018	May 2018	Jun 2018	Jul 2018	Aug 2018	Sept 2018	Oct 2018	Nov 2018	Dec 2018	Period Total	
69	Annual Identified MMWEC Cost (3)		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast		
70	Monthly Assessment		750	750	750	750	750	750	750	750	750	750	750	750	9,000	
71	Less Cumulative Carry Over		$648	$648	$648	$648	$648	$648	$648	$648	$648	$648	$648	$648	7,779	(C3,Line 162)
72	Restated Transition Cost		1,398	1,398	1,398	1,398	1,398	1,398	1,398	1,398	1,398	1,398	1,398	1,398	16,779	
73																
74	Transmission															
75		Transmission	158,323	170,096	174,294	154,785	145,295	143,966	138,562	162,619	145,188	162,351	148,717	149,982	1,854,177	
76	Net Transmission		158,323	170,096	174,294	154,785	145,295	143,966	138,562	162,619	145,188	162,351	148,717	149,982	1,854,177	
77																
78	Restated Costs (Dollars) - Standard Offer															
79		NYPA Firm	10,905	10,479	10,905	10,763	10,905	10,763	10,905	10,905	10,763	10,905	10,763	10,905	129,863	
80		NYPA - Peak	452	448	453	451	453	451	453	453	451	453	451	453	5,422	
81		Miller Hydro	6,994	5,791	7,686	8,672	8,560	6,944	5,355	4,225	3,701	4,918	5,323	6,957	75,126	
82		NextEra RISE Energy Purchase	25,130	23,325	25,130	24,528	25,130	25,337	25,950	25,950	25,337	25,950	25,337	25,950	303,053	
83		FCM Payments by LP	(1,377)	($1,377)	($1,377)	($1,377)	($1,377)	($32,684)	($32,684)	($32,684)	($32,684)	($32,684)	($32,684)	($32,684)	($235,669)	
84		ISO FCM Costs	99,546	99,546	99,546	99,546	99,546	171,355	171,355	171,355	171,355	171,355	171,355	171,355	$1,697,218	
85		Spruce Mnt.	16,319	10,043	16,171	14,864	4,897	11,577	9,304	2,408	11,362	14,768	10,786	14,916	137,415	
86		REC Quarterly credit		-	-	-	-	-	-	-	-	-	-	-	-	
87		HQ Fixed Cost	(1,919)	(1,919)	(1,919)	(1,919)	(1,919)	(1,958)	(1,958)	(1,958)	(1,958)	(1,958)	(1,958)	(1,957)	(23,301)	
88		NextEra RISE Capacity Purchase	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	30,120	
89		PAEG "Bal Power"	113,129	103,273	94,876	61,596	74,306	97,773	142,966	135,871	101,617	123,720	88,580	117,291	$1,254,997	
90		Project 6 (total billing)	(4,949)	(5,513)	(4,942)	(5,137)	(4,949)	(5,137)	37,425	36,327	36,139	16,004	35,473	35,645	$166,384	
91		Service Billing	100	100	100	100	100	100	100	100	100	100	100	100	1,200	
92		ISO Energy Net Interchange	(6,488)	(5,381)	(5,069)	150	(3,231)	(2,098)	(1,654)	469	(613)	(3,887)	(3,367)	(12,266)	(43,435)	
93		ISO Annual Fee	5,417	-	-	-	-	-	-	-	-	-	-	-	5,417	
94		ISO Load Based Charges	4,879	8,300	8,207	3,694	6,909	5,354	5,984	12,074	5,364	3,817	3,582	10,605	78,768	
95		ISO Scheduled Charges	3,376	8,596	7,295	7,858	6,945	7,518	7,337	7,798	8,423	7,944	7,195	7,583	87,870	
96		Canton Wind Purchase	15,240	13,310	13,479	11,714	9,658	8,514	7,586	1,260	8,853	12,274	8,197	14,916	125,002	
97		NextEra Purchase	14,508	13,104	14,508	14,040	14,508	14,040	14,508	14,508	14,040	14,508	14,040	14,508	170,820	
98		ENE Expenses	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	7,100	85,200	
99		Sub-Total	310,871	291,735	294,658	259,152	260,048	327,460	412,542	398,671	371,862	377,797	352,784	393,889	4,051,471	
100	Less Identified Project 6 Transition		(750)	(750)	(750)	(750)	(750)	(750)	(750)	(750)	(750)	(750)	(750)	(750)	(9,000)	
101	Restated Costs - Standard Offer		310,121	290,985	293,908	258,402	259,298	326,710	411,792	397,921	371,112	377,047	352,034	393,139	4,042,471	
102																
103	Restated Costs:															
104	Transition		750	750	750	750	750	750	750	750	750	750	750	750	9,000	
105	Transmission		158,323	170,096	174,294	154,785	145,295	143,966	138,562	162,619	145,188	162,351	148,717	149,982	1,854,177	
106	Standard Offer		310,121	290,985	293,908	258,402	259,298	326,710	411,792	397,921	371,112	377,047	352,034	393,139	4,042,471	
107	Total Restated Costs		469,193	461,831	468,952	413,937	405,344	471,426	551,104	561,290	517,049	540,148	501,501	543,871	5,905,648	
108																
109			Jan 2017	Feb 2017	Mar 2017	Apr 2017	May 2017	Jun 2017	Jul 2017	Aug 2017	Sept 2017	Oct 2017	Nov 2017	Dec 2017		
110			3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	2 Yr-Avg	2 Yr-Avg	2 Yr-Avg		
111	Actual Sales Previous Period (4)		5,226	5,028	4,463	4,762	3,980	4,094	4,724	5,054	5,374	4,954	4,338	4,545	56,542	
112	.75% Growth Factor		39	38	33	36	30	31	35	38	40	37	33	34	424	
113															-	
114	Estimated Sales (5)		5,265	5,066	4,497	4,798	4,010	4,125	4,759	5,091	5,414	4,991	4,370	4,579	56,966	48,0 16 through oct
115																
116		Transition	0.14	0.15	0.17	0.16	0.19	0.18	0.16	0.15	0.14	0.15	0.17	0.16	0.16	S
117		Transmission	30.07	33.58	38.76	32.26	36.24	34.90	29.11	31.94	26.81	32.53	34.03	32.75	32.55	c
118		Standard Offer	58.90	57.44	65.36	53.86	64.67	79.21	86.52	78.15	68.54	75.54	80.55	85.86	70.96	h
119		Total	89.12	91.16	104.28	86.27	101.09	114.29	115.80	110.24	95.49	108.22	114.75	118.77	103.67	e
120																d
121	(3)	From Pascoag's Audited Financial Statements, FY ending 12/31/2016; Contingent Liability - MMWEC Footnote, Page 37. For 2017, the total annual cost is $9,000														l
122	(4)	From Schedule E - three-year average (Except where noted: October - December uses a two-year average)														e
123												Purchases	62,201			
124	(T)	Indicates Transmission Charges										Sales	56,966			F-2
125													5,235			
126											Equates to line losses		8%			

	A	B	C	D	E	F	G	H	I	J	K
97											
98			**Summary of Energy Sales to Customers Fiscal Year 2016**								Schedule E
99			**2016**		**2015**		**2014**			**3-Year Average**	
100	January		5,279		5,487		5,614			5,460	
101	February		4,840		4,788		5,252			4,960	
102	March		4,150		5,015		4,465			4,543	
103	April		4,760		4,188		4,399			4,449	
104	May		3,880		3,979		4,308			4,056	
105	June		4,087		4,196		4,164			4,149	
106	July		4,908		4,494		4,652			4,685	
107	August		5,739		5,562		5,395			5,565	
108	September		5,761		5,452		4,765			5,326	
109	October		4,456		4,521		4,339			4,439	
110	November		4,155		4,342		4,468			4,322	
111	December		4,748		4,042		4,249			4,346	
112					56,065		56,069			56,299	
113											
114			**Summary of Energy Sales to Customers Fiscal Year 2017**								
115			**2017**		**2016**		**2015**			**3-Year Average**	
116	January		4,911		5,279		5,487			5,226	
117	February		4,758		4,840		5,487			5,028	
118	March		4,452		4,150		4,788			4,463	
119	April		4,513		4,760		5,015			4,763	
120	May		3,872		3,880		4,188			3,980	
121	June		4,216		4,087		3,979			4,094	
122	July		5,068		4,908		4,196			4,724	
123	August		4,928		5,739		4,494			5,054	
124	September		4,799		5,761		5,562			5,374	
125	October		4,377		4,456		5,452			4,762	
126	November		4,126		4,155		4,521			4,267	
127	December		4,682		4,748		4,342			4,591	Divided By 3
128			54,702		58,779		57,510			56,325	
129	Growth Factor of 0.75% was used									424	
130										56,749	
131			**Summary of Energy Sales to Customers Fiscal Year 2018**								
132			**2018**		**2017**		**2016**			**3-Year Average**	
133	January		5,274		4,911		5,279			5,155	
134	February		4,945		4,758		4,840			4,848	
135	March		4,339		4,452		4,150			4,314	
136	April		4,371		4,513		4,760			4,548	
137	May		3,892		3,872		3,880			3,881	
138	June		4,039		4,216		4,087			4,114	
139	July		5,015		5,068		4,766			4,950	
140	August		5,774		4,928		5,739			5,480	
141	September		5,435		4,799		5,761			5,332	
142	October		4,197		4,377		4,456			4,343	
143	November				4,126		4,155			4,141	divided by 2
144	December				4,682		4,748			4,715	"
145			47,280		54,702		56,621			55,820	
146	Negative Growth Factor									-552	
147										55,268	

actual
MW sales
through Oct

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-11

Forecasted to Actual SOS, Transition, & Transmission

Testimony exhibit
HJR - 11

Forecast to Actual Comparison for Standard Offer, Transition, & Transmission

	Forecasted	Actual		
Standard Offer				
Through Dec 2018	$ 4,042,471	$ 4,068,370		
minus Dec	$ (393,139)	$ (393,139) Estimate		
Minus Nov	$ (352,034)	$ (352,034) Estimate		
Minus Oct	$ (377,047)	$ (377,047) Estimate		
	$ 2,920,251	$ 2,946,150	$ (25,899)	Actual though September were over budget by 26,199
Transition				
Through Dec 2018	$ 9,000	$ 9,000		
minus Dec	$ (750)	$ (750) Estimate		
Minus Nov	$ (750)	$ (750) Estimate		
Minus Oct	$ (750)	$ (750) Estimate		
	$ 6,750	$ 6,750	$ -	Actuals though September were right on Budget
Transmission				
Through Dec 2018	$ 1,854,177	$ 1,750,272		
minus Dec	$ (149,982)	$ (149,982) Estimate		
Minus Nov	$ (148,717)	$ (148,717) Estimate		
Minus Oct	$ (162,351)	$ (162,351) Estimate		
	$ 1,393,127	$ 1,289,223	$ 103,904	Actual Through September were Under-budget
			$ 78,005	under budget

2018 Forecast

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
64			(T)	Indicates Transmission Charges												
65								Pascoag Utility District								
66								Restated Forecast Purchased Power Costs								
67																
68			Jan 2018	Feb 2018	Mar 2018	Apr 2018	May 2018	Jun 2018	Jul 2018	Aug 2018	Sept 2018	Oct 2018	Nov 2018	Dec 2018	Period Total	
69	Annual Identified MMWEC Cost (3)		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast		
70	Monthly Assessment		$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 9,000	
71	Less Cumulative Carry Over		$648	$648	$648	$648	$648	$648	$648	$648	$648	$648	$648	$648	$ 7,779	(C3,Line 162)
72	Restated Transition Cost		1,398	1,398	1,398	1,398	1,398	1,398	1,398	1,398	1,398	1,398	1,398	1,398	$ 16,779	
73																
74	Transmission															
75		Transmission	$ 158,323	$ 170,096	$ 174,294	$ 154,785	$ 145,295	$ 143,966	$ 138,562	$ 162,619	$ 145,188	$ 162,351	$ 148,717	$ 149,982	$ 1,854,177	
76	Net Transmission		$ 158,323	$ 170,096	$ 174,294	$ 154,785	$ 145,295	$ 143,966	$ 138,562	$ 162,619	$ 145,188	$ 162,351	$ 148,717	$ 149,982	$ 1,854,177	
77																
78	Restated Costs (Dollars) - Standard Offer															
79		NYPA Firm	$ 10,905	$ 10,479	$ 10,905	$ 10,763	$ 10,905	$ 10,763	$ 10,905	$ 10,905	$ 10,763	$ 10,905	$ 10,763	$ 10,905	$ 129,863	
80		NYPA - Peak	$ 452	$ 448	$ 453	$ 451	$ 453	$ 451	$ 453	$ 453	$ 451	$ 453	$ 451	$ 453	$ 5,422	
81		Miller Hydro	$ 6,994	$ 5,791	$ 7,686	$ 8,672	$ 8,560	$ 6,944	$ 5,355	$ 4,225	$ 3,701	$ 4,918	$ 5,323	$ 6,957	$ 75,128	
82		NextEra RISE Energy Purchase	$ 25,130	$ 23,325	$ 25,130	$ 24,528	$ 25,130	$ 25,337	$ 25,950	$ 25,950	$ 25,337	$ 25,950	$ 25,337	$ 25,950	$ 303,053	
83		FCM Payments by LP	$ (1,377)	($1,377)	($1,377)	($1,377)	($1,377)	($32,684)	($32,684)	($32,684)	($32,684)	($32,684)	($32,684)	($32,684)	($235,669)	
84		ISO FCM Costs	$ 99,546	$ 99,546	$ 99,546	$ 99,546	$ 99,546	$ 171,355	$ 171,355	$ 171,355	$ 171,355	$ 171,355	$ 171,355	$ 171,355	$1,697,218	
85		Spruce Mnt.	$ 16,319	$ 10,043	$ 16,171	$ 14,864	$ 4,897	$ 11,577	$ 9,304	$ 2,408	$ 11,362	$ 14,768	$ 10,786	$ 14,916	$ 137,415	
86		REC Quarterly credit		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
87		HQ Fixed Cost	$ (1,919)	$ (1,919)	$ (1,919)	$ (1,919)	$ (1,919)	$ (1,958)	$ (1,958)	$ (1,958)	$ (1,958)	$ (1,958)	$ (1,958)	$ (1,957)	$ (23,301)	
88		NextEra RISE Capacity Purchase	$ 2,510	$ 2,510	$ 2,510	$ 2,510	$ 2,510	$ 2,510	$ 2,510	$ 2,510	$ 2,510	$ 2,510	$ 2,510	$ 2,510	$ 30,120	
89		PAEG "Bal Power"	$ 113,129	$ 103,273	$ 94,876	$ 61,596	$ 74,306	$ 97,773	$ 142,966	$ 135,871	$ 101,617	$ 123,720	$ 88,580	$ 117,291	$1,254,997	
90		Project 6 (total billing)	$ (4,949)	$ (5,513)	$ (4,942)	$ (5,137)	$ (4,949)	$ (5,137)	$ 37,425	$ 36,327	$ 35,139	$ 16,004	$ 35,473	$ 35,645	$166,384	
91		Service Billing	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 1,200	
92		ISO Energy Net Interchange	$ (6,488)	$ (5,381)	$ (5,069)	$ 150	$ (3,231)	$ (2,098)	$ (1,654)	$ 469	$ (613)	$ (3,887)	$ (3,367)	$ (12,266)	$ (43,435)	
93		ISO Annual Fee	$ 5,417	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,417	
94		ISO Load Based Charges	$ 4,879	$ 8,300	$ 8,207	$ 3,694	$ 6,909	$ 5,354	$ 5,984	$ 12,074	$ 5,364	$ 3,817	$ 3,582	$ 10,605	$ 78,768	
95		ISO Scheduled Charges	$ 3,376	$ 8,596	$ 7,295	$ 7,858	$ 6,945	$ 7,518	$ 7,337	$ 7,798	$ 8,423	$ 7,944	$ 7,195	$ 7,583	$ 87,870	
96		Canton Wind Purchase	$ 15,240	$ 13,310	$ 13,479	$ 11,714	$ 9,658	$ 8,514	$ 7,586	$ 1,260	$ 8,853	$ 12,274	$ 8,197	$ 14,918	$ 125,002	
97		NextEra Purchase	$ 14,508	$ 13,104	$ 14,508	$ 14,040	$ 14,508	$ 14,040	$ 14,508	$ 14,508	$ 14,040	$ 14,508	$ 14,040	$ 14,508	$ 170,820	
98		ENE Expenses	$ 7,100	$ 7,100	$ 7,100	$ 7,100	$ 7,100	$ 7,100	$ 7,100	$ 7,100	$ 7,100	$ 7,100	$ 7,100	$ 7,100	$ 85,200	
99		Sub-Total	$ 310,871	$ 291,735	$ 294,658	$ 259,152	$ 260,048	$ 327,460	$ 412,542	$ 398,671	$ 371,862	$ 377,797	$ 352,784	$ 393,889	$ 4,051,471	
100	Less Identified Project 6 Transition		$ (750)	$ (750)	$ (750)	$ (750)	$ (750)	$ (750)	$ (750)	$ (750)	$ (750)	$ (750)	$ (750)	$ (750)	$ (9,000)	
101	Restated Costs - Standard Offer		$ 310,121	$ 290,985	$ 293,908	$ 258,402	$ 259,298	$ 326,710	$ 411,792	$ 397,921	$ 371,112	$ 377,047	$ 352,034	$ 393,139	$ 4,042,471	
102																
103	Restated Costs:															
104	Transition		$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 750	$ 9,000	
105	Transmission		$ 158,323	$ 170,096	$ 174,294	$ 154,785	$ 145,295	$ 143,966	$ 138,562	$ 162,619	$ 145,188	$ 162,351	$ 148,717	$ 149,982	$ 1,854,177	
106	Standard Offer		$ 310,121	290,985	$ 293,908	$ 258,402	$ 259,298	$ 326,710	$ 411,792	$ 397,921	$ 371,112	$ 377,047	$ 352,034	$ 393,139	$ 4,042,471	
107	Total Restated Costs		$ 469,193	$ 461,831	$ 468,952	$ 413,937	$ 405,344	$ 471,426	$ 551,104	$ 561,290	$ 517,049	$ 540,148	$ 501,501	$ 543,871	$ 5,905,648	
108																
109			Jan 2017	Feb 2017	Mar 2017	Apr 2017	May 2017	Jun 2017	Jul 2017	Aug 2017	Sept 2017	Oct 2017	Nov 2017	Dec 2017		
110			3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	3 Yr-Avg	2 Yr-Avg	2 Yr-Avg	2 Yr-Avg		
111	Actual Sales Previous Period (4)		5,226	5,028	4,463	4,762	3,980	4,094	4,724	5,054	5,374	4,954	4,338	4,545	56,542	
112	.75% Growth Factor		39	38	33	36	30	31	35	38	40	37	33	34	424	
113															-	
114	Estimated Sales (5)		5,265	5,066	4,497	4,798	4,010	4,125	4,759	5,091	5,414	4,991	4,370	4,579	56,966	
115																
116		Transition	$ 0.14	$ 0.15	$ 0.17	$ 0.16	$ 0.19	$ 0.18	$ 0.18	$ 0.15	$ 0.14	$ 0.15	$ 0.17	$ 0.16	$ 0.16	
117		Transmission	$ 30.07	$ 33.58	$ 38.76	$ 32.26	$ 36.24	$ 34.90	$ 29.11	$ 31.94	$ 26.81	$ 32.53	$ 34.03	$ 32.75	$ 32.55	
118		Standard Offer	$ 58.90	$ 57.44	$ 65.36	$ 53.86	$ 64.67	$ 79.21	$ 86.52	$ 78.15	$ 68.54	$ 75.54	$ 80.55	$ 85.86	$ 70.96	
119		Total	$ 89.12	$ 91.16	$ 104.28	$ 86.27	$ 101.09	$ 114.29	$ 115.80	$ 110.24	$ 95.49	$ 108.22	114.75	118.77	$ 103.67	
120																
121	(3)	From Pascoag's Audited Financial Statements, FY ending 12/31/2016; Contingent Liability - MMWEC Footnote, Page 37. For 2017, the total annual cost is $9,000														
122	(4)	From Schedule E - three-year average (Except where noted: October - December uses a two-year average)														
123												Purchases	62,201			
124	(T)	Indicates Transmission Charges										Sales	56,966			
125													5,235			
126											Equates to line losses		8%			

Schedule F-2

Forecast

Through Sept

$6750
$1,393,127
$2920251

Ac al Cost Throug Sept

Oct - Dec is estimated

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
69																		
70							Restated Purchase Power Costs											
71																		
72																		
73			Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total			
74						ACTUAL	ACTUAL	ACTUAL	ACTUAL	ACTUAL	ACTUAL	Estimated	Estimated	Estimated				
75							Restated Costs (Dollars) -											
76		Transition:													$ -			
77	Monthly Transition Charge		$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$9,000			
78			($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($1,204)	($14,451)			
79	Restated Transition Cost		($454)	($454)	($454)	($454)	($454)	($454)	($454)	($454)	($454)	($454)	($454)	($454)	$ (5,451)			
80																		
81																		
82																		
83		Transmission	$ 146,756.17	$ 176,467.63	$ 146,286.35	$ 134,580.77	$ 137,703.35	$ 118,348.56	$ 129,438.55	$ 152,577.54	$ 147,063.89	$ 162,350.52	$ 148,717.18	$ 149,981.54	$ 1,750,272.05			
84																		
85	Net Transmission		$ 146,756.17	$ 176,467.63	$ 146,286.35	$ 134,580.77	$ 137,703.35	$ 118,348.56	$ 129,438.55	$ 152,577.54	$ 147,063.89	$ 162,350.52	$ 148,717.18	$ 149,981.54	$ 1,750,272.05			
86																		
87		Restated Costs (Dollars) Standard Offer																
88		NYPA	$ 11,996.44	$ 12,532.72	$ (7,663.80)	$ 11,080.08	$ 11,301.49	$ 11,355.60	$ 12,376.64	$ 12,158.30	$ 12,792.25	$ 11,357.34	$ 11,214.16	$ 11,357.34	$ 121,858.56			
89		Seabrook	$ 37,055.34	$ 36,517.74	$ 37,060.76	$ 36,879.53	$ 37,113.68	$ 36,874.90	$ 38,257.90	$ 38,237.85	$ 37,913.76	$ 18,791.11	$ 38,259.50	$ 38,432.40	$ 431,394.47			
90		Seabrook Surplus Credit	$ (53,245.86)	$ (44,466.33)	$ (44,466.33)	$ (44,466.33)	$ (44,466.33)	$ (44,466.33)	$ -	$ (2,787.02)	$ (22,336.31)	$ (2,787.02)	$ (2,786.95)	$ (2,786.95)	$ (309,061.76)			
91		MMWEC Admin Fee	$ 93.08	$ 249.82	$ 106.59	$ 111.16	$ 217.33	$ 262.62	$ 214.65	$ 146.99	$ 205.04	$ 100.00	$ 100.00	$ 100.00	$ 1,907.28			
92		MMWEC Other Charges/Credits		$ (4,441.17)	$ (12,952.18)	$ (12,160.00)	$ 3,628.51	$ 5,087.97	$ (15,004.27)	$ (15,000.82)	$ (14,620.23)			$ -	$ (65,462.19)			
93		ISO FCM Cost										$ -	$ -	$ -	$ -			
94		Energy Purchase Canton Mntn	$ 15,328.07	$ 12,155.14	$ 17,286.53	$ 10,613.71	$ 9,714.74	$ 8,156.00	$ 5,144.35	$ 5,103.63	$ 5,831.96	$ 12,273.88	$ 8,196.73	$ 14,916.44	$ 124,721.18			
95		ISO Interchange										$ -	$ -		$ -			
96		Net Meter Customers										$ -	$ -	$ -	$ -			
97		ISO Scheduled Charges										$ -	$ -	$ -	$ -			
98		FMC Payment by LP										$ -	$ -	$ -	$ -			
99		MMWEC FCM Credit			$ -										$ -			
100		Miller Hydro Group	$ 7,486.84	$ 6,928.33	$ 8,023.46	$ 9,843.96	$ 7,586.62	$ 2,942.07	$ 3,436.54	$ 4,052.36	$ 2,669.47	$ 4,917.54	$ 5,322.93	$ 6,957.41	$ 70,167.53			
101		Spruce Mnt	$ 18,814.45	$ 15,173.48	$ 15,372.77	$ 10,943.77	$ 12,596.43	$ 10,618.59	$ 9,345.74	$ 7,627.71	$ 8,227.86	$ 14,768.40	$ 10,785.96	$ 14,916.08	$ 149,191.24			
102		Spruce Mnt REC Sales	$ -	$ (2,880.00)	$ -	$ -	$ (1,245.00)	$ -	$ -	$ (2,490.00)	$ -	$ -	$ -	$ -	$ (6,615.00)			
103		Spruce Mnt REC Fee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
104		Spruce MNT Wind FMC Credit	$ (1,643.74)	$ (1,643.74)	$ (1,643.74)	$ (1,649.38)	$ (1,649.38)	$ (1,649.38)	$ (588.32)	$ (585.50)	$ (585.50)	$ -	$ -	$ -	$ (11,638.68)			
105		Worsumbo Rec Sales to EDF											$ -		$ -			
106		ENE All Requirements	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,483.00	$ 7,100.00	$ 7,100.00	$ 7,100.00	$ 88,647.00			
107		TransCanada Settlement	$ (46,414.63)	$ (29)	$ -	$ -	$ 976	$ (9,541)	$ (8,760)	$ (2,115)	$ (923)	$ -	$ -	$ -	$ (66,805.43)			
108		PSCG Energy	$ 117,150.29	$ 82,145.68	$ 87,779	$ 60,190.21	$ 66,615	$ 84,605	$ 147,825	$ 150,861	$ 94,660	$ 123,720	$ 88,580	$ 117,291	$ 1,221,423.30			
109		NextEra Energy	$ 33,157.72	$ 29,948.91	$ 33,138.22	$ 32,088.12	$ 33,157.72	$ 32,417.19	$ 33,497.76	$ 33,497.76	$ 32,417.19	$ 33,497.76	$ 32,417.19	$ 33,497.76	$ 392,733.30			
110		NextEra Mthly Fixed	$ 6,480.00	$ 6,480.00	$ 6,480.00	$ 6,480.00	$ 6,480.00	$ 6,960.00	$ 6,960.00	$ 6,960.00	$ 6,960.00	$ 6,960.00	$ 6,960.00	$ 6,960.00	$ 81,120.00			
111		NextEra Rise Capacity Purchases	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 2,510.00	$ 30,120.00			
112		2017 Vintage ME Rec Sales NextEr	$ -	$ -	$ -	$ -	$ (580)	$ -	$ -	$ (2,250)	$ (153)	$ -	$ -	$ -	$ (2,983.07)			
113		ISO Monthly Charges	$ 106,562.56	$ 110,577.65	$ 107,307.04	$ 106,045.15	$ 106,519.72	$ 206,670.04	$ 207,881.34	$ 215,333.45	$ 215,362.10	$ 183,116.27	$ 182,132.84	$ 189,544.19	$ 1,937,052.35			
114		HQ Use Right/HQICC	$ (2,756.85)	$ (2,663.71)	$ (2,587)	$ (2,661.79)	$ -		$ (2,926.76)	$ (3,078.49)	$ (3,055.84)	$ (1,957.80)	$ (1,957.80)	$ (1,957.80)	$ (25,603.64)			
115		HQ Admin Fee (ENE)	$ -				$ (2,637)	$ (2,825)	$ -	$ (9,541)	$ (9,541)	$ -			$ (24,543.68)			
116		ISO Weekly Activity	$ 983.67	$ (7,131.95)	$ 8,591	$ 9,083.83	$ (818)	$ (2,474)	$ (3,149)	$ (603)	$ (2,670)	$ (36,570)	$ (36,051)	$ (44,949)	$ (115,759.09)			
117		ISO Annual Fee	$ 5,509.43	$ -	$ -	$ -	$ -	$ -	$ -						$ 5,509.43			
118		Long Term Seabrook Setup	$ -	$ -	$ -	$ -	$ (354)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (354.00)			
119		Constant Energy Capital	$ 35,693.87	$ 1,111.02	$ 1,023	$ 2,777.85	$ 1,237	$ 152	$ 1,359	$ 4,645	$ 8,011			$ -	$ 56,009.43			
120		CEC Energy True up				$ (5,658.17)									$ (5,658.17)			
121	Sub-Total		$ 302,243.68	$ 260,557.83	$ 262,848.46	$ 239,534.70	$ 255,388.01	$ 355,139.14	$ 445,864.25	$ 450,165.33	$ 381,159.03	$ 377,797.28	$ 352,784.04	$ 393,888.61	$ 4,077,370.36			
122	Market Value (Transition)		($750)	($750)	($750)	($750)	($750)	($750)	($750)	($750)	($750)	($750)	($750)	($750)	$ (9,000.00)			
123	Restated Cost - SOS		$ 301,493.68	$ 259,807.83	$ 262,098.46	$ 238,784.70	$ 254,638.01	$ 354,389.14	$ 445,114.25	$ 449,415.33	$ 380,409.03	$ 377,047.28	$ 352,034.04	$ 393,138.61	$ 4,068,370.36			
124																		
125	Restated Power Costs		$ 448,999.85	$ 437,025.46	$ 409,134.81	$ 374,115.47	$ 393,091.36	$ 473,487.70	$ 575,302.80	$ 602,742.87	$ 528,222.92	$ 540,147.80	$ 501,501.22	$ 543,870.15	$ 5,827,642.41	(A1, Line 57)		
126													Revenue Proof:		$ 5,827,642.41			
127																		
128																		
129																		
130																		
131																		
132																		
133																		
134																	A-2	
135																		
136																		
137																		

Actual Cost through Sept
$ 6,750

Actual Through Sept
$1,289,223

Actual through sept
$ 2946,150.43