Raquel J. Webster
Senior Counsel

March 8, 2019

BY HAND DELIVERY AND ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4930 - 2019 Annual Retail Rate Filing
Responses to Division Data Requests – Set 1

Dear Ms. Massaro:

I have enclosed ten (10) copies of National Grid's[1] responses to the Division's First Set of Data Requests in the above-referenced docket.

Thank you for your attention to this filing. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosures

cc: Docket 4930 Service List
John Bell, Division
Al Mancini, Division
Leo Wold, Esq.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

40 Sylvan Road, Waltham, MA 02451
T: 781-907-2121 ■ raquel.webster@nationalgrid.com ■ www.nationalgrid.com

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

____
Joanne M. Scanlon

March 8, 2019
Date

National Grid – 2019 Annual Retail Rate Filing - Docket No. 4930
Service List Updated 2/27/2019

Name/Address	**E-mail Distribution**	**Phone**
Raquel Webster, Esq. National Grid. 280 Melrose St. Providence, RI 02907	Raquel.webster@nationalgrid.com; Celia.obrien@nationalgrid.com; Joanne.scanlon@nationalgrid.com; Adam.crary@nationalgrid.com; Tiffany.Forsyth@nationalgrid.com; Robin.Pieri@nationalgrid.com;	781-907-2121
Christy Hetherington, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Chetherington@riag.ri.gov; John.bell@dpuc.ri.gov; Al.mancini@dpuc.ri.gov; Jonathan.Schrag@dpuc.ri.gov; dmacrae@riag.ri.gov; Mfolcarelli@riag.ri.gov;	401-222-2424
Richard Hahn Matt Loiacono Daymark Energy Advisors	rhahn@daymarkea.com; mloiacono@daymarkea.com;	617-778-2467
File an original & 9 copies w/: Luly E. Massaro, Commission Clerk Margaret Hogan, Commission Counsel Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov; Margaret.hogan@puc.ri.gov; Emma.Rodvien@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov;	401-780-2017
Office of Energy Resources Nicholas Ucci Christopher Kearns	Nicholas.ucci@energy.ri.gov; Christopher.Kearns@energy.ri.gov;	

Division 1-1

Request:

Please refer to file "NECO_Recs_SOS_2018.div.puc", and answer the following:

(a) Refer to tab "REP-2-SOS-P1 (Total)".
   i. Explain the change from a net over-recovery of $989 in Docket 4805 to a net over-recovery of $3.7 million in this Filing.

(b) Refer to tab "REP-2-SOS-P2-P3-P4 (CLASS)".
   i. Explain why the residential group continues to be over-recovered.
   ii. Explain the change from a net under-recovery of $97,481 to a net under-recovery of $378,383 for the industrial group.

(c) Refer to tab "Input-SOS Expenses".
   i. Explain the discrepancy and its impact of total expenses noted in cell AE22.
   ii. Further explain the differences and their impact of the values noted in Column AB of Table D (Compare to Invoice Total).

(d) Refer to tab "Input-Spot Mkt Alloc".
   i. Explain what monthly values from the ISO Bill go into Column B Spot Market Purchases.

(e) Refer to tab "REP-2-SOS-P5 (REV)".
   i. Explain what the "Check of Prorate" value means in cell W21, including if it should be equal to zero.

Response:

(a) REP-2-SOS-P1 (Total):

Each year's net over or under-recovery is separate from the last. There is no relationship between the net over-recovery of $989 in Docket No. 4805 and the net over-recovery of $3.7 million in this filing. The $3.7 million over-recovery results exclusively from the revenue billed and expense incurred during calendar year 2018 as well as the revenue adjustment to account for the recovery deferred during the months October 2018 through December 2018 from the October 2018 through March 2019 pricing period. The $3.7 million over-recovery in this filing is made up of the following: (1) an over-recovery of $5.6 million in the Residential customer group, (2) an under-recovery of $1.6 million in the Commercial customer group, and (3) an under-recovery of $0.4 million in the Industrial customer group.

Excluding the $8.2 million revenue adjustment made in the reconciliation, the reconciliation balance would have been an under-recovery of $4.4 million as

Division 1-1, page 2

follows: (1) a $1.6 million under-recovery for the Residential customer group, (2) a $2.5 million under-recovery for the Commercial customer group, and (3) a $0.3 million under-recovery for the Industrial customer group.

For the Residential and Commercial customer groups, the reason for the under-recovery (prior to the revenue adjustments) was higher-than-forecasted kWh deliveries during months where the cost per kWh of Standard Offer Service (SOS) was higher than the SOS rate billed. Specifically, the Residential customer group had higher-than-forecasted kWh in November and December 2018, and the Commercial customer group had higher-than-forecasted kWh in July through August 2018. For the Industrial customer group, the $0.4 million under-recovery is about 1.7% of the annual costs and is attributable to timing differences.

(b) REP-2-SOS-P2-P3-P4 (CLASS):

i. The Residential customer group has an over-recovery for calendar year 2018 due to the revenue adjustment of $7.2 million included in October 2018 through January 2019. As explained in the testimony, this revenue adjustment was made to account for the deferral of revenue from the October 2018 through March 2019 pricing period to the upcoming April through September 2019 pricing period. Had the Company not included this adjustment, the Residential customer group would have had an under-recovery of approximately $1.6 million that would have been recovered through the Standard Offer Service Adjustment Factor rather than the SOS rate during April through September 2019 pricing period. Please see the response to part (a) above for the driver of the $1.6 million under-recovery.

ii. There is no relationship between the net under-recovery in Docket No. 4805 to the net under-recovery of $378,383 in this filing. The $378,383 under-recovery is approximately 1.7% of the total annual expenses and it attributable to timing differences.

(c) Input-SOS Expenses:

i. The amount shown in cell AE22 is due to a variance between internal documents that summarize each month's supplier invoices and the individual received invoices. A resettlement for SOS kWh in April 2018 by a supplier for Industrial SOS, which was received in August 2018, resulted in a credit to the Company totaling $63,287. This amount was not included in the accompanying summary that is used to verify inputs into the reconciliation. Consequently, the variance for that amount is shown

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Division 1-1, page 3

in cell AE22. This variance has no effect on the reconciliation, as the resettlement amount of ($63,287) is included in the resettlement expense amounts received in August 2018, as shown in cell R95 of the "Input-SOS Expenses" tab.

ii. Column AB of Table D is an internal check which shows the variances between the summarized SOS expense by month, shown in column AA, and the actual individual invoiced expenses received each month. This internal check is similar that what was described in the previous response. Similarly, to the previous response, these variances do not reflect an error in the reconciliation, as the (these variances are only reflected in the check. The actual resettlement credits were correctly included in each appropriate month's SOS expenses. A revised version of the reconciliation has been included with this response that should illuminate this more clearly.

(d) Input-Spot Mkt Alloc:

The amounts shown in column B Spot Market purchase on the Input-Spot Mkt Alloc tab are the company expenses related to real-time, day-ahead, real time Schedule 2, related ancillary expenses, and capacity payments related to the Company's purchase of spot market energy for 20% of the Company's Standard Offer Service load for each month.

(e) REP-2-SOS-P5 (REV):

The check of prorates value in cell W21 should be equal to zero. The formula had not been updated with the appropriate amount of pro-rated January 2018 revenue from the Revised ASC-2 Schedule filed in Docket No. 4805. Upon updating the formula, the Company realized that the prorate included in the filing was off by the amount of HVM in Schedule ASC-2 in Docket No. 4805, or $2,099. This error has been corrected in the attached version of the file. The change is not large enough to have an effect on any rates calculated in the filing.

Prepared by or under the supervision of: Robin E. Pieri

Division 1-2

Request:

Please refer to Schedule REP-3, page 3, and explain the increase in the current rate for customer deposits.

Response:

Per the Company's electric Terms and Condition for Distribution Service, RIPUC No. 2217, paragraph 16 the customer deposit rate is adjusted every year effective March 1. The customer deposit rate is determined using the average rate for the previous calendar year of the 10-year constant maturity Treasury Bonds as reported by the Federal Reserve. Please see Attachment Division 1-2 for the Company's filings containing the customer deposit rates of 2.33% effective March 1, 2018 and 2.91% effective March 1, 2019.

Prepared by or under the supervision of: Robin E. Pieri

Jennifer Brooks Hutchinson
Senior Counsel

January 8, 2018

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Customer Deposits Filing

Dear Ms. Massaro:

I write to report National Grid's[1] interest rate on customer deposits applicable to its electric and gas customers pursuant to the Company's electric Terms and Conditions for Distribution Service, RIPUC No. 2130, Paragraph 16, and its gas Terms and Conditions for Distribution Service, RIPUC NG-Gas No. 101 Section 1, Schedule A, Paragraph 4.0. The current interest rate on customer deposits will be 2.33%, effective March 1, 2018.

National Grid is required to pay interest on customer deposits based on the average rate over the prior calendar year for 10-year Constant Maturity Treasury Bonds, as reported by the Federal Reserve Board. The rate of interest is adjusted annually on March 1. I have enclosed the Federal Reserve statistical release used in support of this interest rate.

Thank you for your attention to this filing. Please contact me if you have any questions concerning this matter at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

Luly Massaro, Commission Clerk
Customer Deposits Filing 2018
January 8, 2018
Page 2 of 2

Series Description	H.15 Selected Interest Rates for Jan 03, 2018
Series Description	Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on investment basis
Unit:	Percent:_Per_Year
Multiplier:	1
Currency:	NA
Unique Identifier:	H15/H15/RIFLGFCY10_N.M
Time Period	RIFLGFCY10_N.M
2017-01	2.43
2017-02	2.42
2017-03	2.48
2017-04	2.30
2017-05	2.30
2017-06	2.19
2017-07	2.32
2017-08	2.21
2017-09	2.20
2017-10	2.36
2017-11	2.35
2017-12	2.40
2017 average	2.33

nationalgrid

Raquel J. Webster
Senior Counsel

January 8, 2019

BY HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Customer Deposits Filing

Dear Ms. Massaro:

I write to report National Grid's[1] interest rate on customer deposits applicable to its electric and gas customers pursuant to the Company's electric Terms and Conditions for Distribution Service, RIPUC No. 2196, Paragraph 16, and its gas Terms and Conditions for Distribution Service, RIPUC NG-Gas No. 101 Section 1, Schedule A. The current interest rate on customer deposits will be 2.91%, effective March 1, 2019.

National Grid is required to pay interest on customer deposits based on the average rate over the prior calendar year for 10-year Constant Maturity Treasury Bonds, as reported by the Federal Reserve Board. The rate of interest is adjusted annually on March 1. I have enclosed the Federal Reserve statistical release used in support of this interest rate.

Thanks for your attention to this matter. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

cc: John Bell, Division
Christy Hetherington, Esq.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

Series Description	H.15 Selected Interest Rates for Jan 07, 2019
Series Description	Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on investment basis
Unit:	Percent:_Per_Year
Multiplier:	1
Currency:	NA
Unique Identifier:	H15/H15/RIFLGFCY10_N.M
Time Period	RIFLGFCY10_N.M
2018-01	2.58
2018-02	2.86
2018-03	2.84
2018-04	2.87
2018-05	2.98
2018-06	2.91
2018-07	2.89
2018-08	2.89
2018-09	3.00
2018-10	3.15
2018-11	3.12
2018-12	2.83
2018 average	2.91

Division 1-3

Request:

Please refer to the Direct Testimony of Robin Pieri, page 27, lines 4-11, and file "NECO_Recs_Transmission_2018.div.pic", tab "2018 & 2011 6-17 CP". Explain how the 2017 Test Year (July 2016 through June 2017) Contributions to 1CP and Class NCP were utilized in the analysis to develop class load factors.

Response:

Page 2 of Schedule REP-11 shows the three 12-month periods used to develop the class load factors for the coincident peak allocator. In its August 22, 2018 order in Docket No. 4805, the PUC directed the Company to use a more recent set of years to develop the allocators for assigning transmission costs to each rate class. The previous calculation used the test years of 2008 and 2011 from the Company's previous two rate cases in Docket Nos. 4065 and 4323, respectively. Accordingly, Company has added a more recent year in the calculation of the coincident peak allocation - the test year ending June 2017, which was used in Docket No. 4770. The calculation now includes the test years from the Company's last three general rate cases with each year receiving a one third weight. Therefore, the final allocation of costs on Page 1 of REP-11 is based on the weighted average of the three years.

Division 1-4

Request:

Please refer to file "NECO_Recs_Transmission_2018.div.pic", and answer the following:

(a) Refer to tab "REP-12-Transm P1".

  i. Explain why the Company has continued to over-collect transmission service charges to the point that with interest, the Base Transmission Reconciliation Balance is now $20,821,511, which is an increase from $3,852,203 from Docket 4805.
  ii. Explain what caused the transmission expense to be higher than the revenue in May 2018.

(b) Refer to tabs "REP-12-Transm P4" and "Input-Expenses".

  i. Explain the December Restoration value of $59,878 in cells P33 and H38, respectively, including why no other months have any restoration costs associated with them.

(c) Refer to tab "Input-Expenses", cell C35 for the September 2018 Non-PTF Expense, and provide further explanation and calculations, if available, behind the credit that month. The explanation states "due to a large revenue credit for regional revenues collected from the ISO that were related to higher than prior months load (August)".

Response:

(a)

  i. The Company re-sets customers' transmission service charges on an annual basis based on a forecast any over or under-recovery in a given year is a result of variances from the expense or revenue forecasts. In the Company's 2018 forecast of transmission expenses, the Company inadvertently only included a partial impact of the lower federal tax reform. As a result, actual transmission costs through November plus forecasted December expenses in 2018 equaled $191.8M which was $16M lower than the forecasted expenses of $208M. The remaining over-recovery in 2018 is due to higher revenues based on higher kWh deliveries than forecasted.

  ii. The revenues represent monthly actual customer volumes multiplied by the annual transmission service rate, when the expenses represent the actual payments for transmission service paid to the ISO-NE and New England Power Company (NEP).

Prepared by or under the supervision of: Tiffany M. Forsyth and Robin E. Pieri

In May, the transmission expenses were overstated by $4.4M due to a billing error in the monthly NEP-billed charge under the Local Network Service. The error was fixed through a billing adjustment in the June billing. Please refer to page 7 of Attachment DIV 1-5_C_from the response to the data request DIV 1-5 for a copy of June customer detail showing the billing adjustment.

(b) ISO-NE Blackstart Service, also known as System Restoration and Planning Service from Generators, is necessary to ensure the continued reliable operation of the New England transmission system. This service allows for the designation of generators with the capability of supplying load and ability to start without an outside electrical supply to re-energize the transmission system following a system-wide blackout. The charges are assessed by the ISO-NE based on payments to the designated resources providing Blackstart service and allocated to Narragansett based on its proportionate share of the Regional Network Load to ISO-NE's total Regional Network Load.

Consistent with past filing, the Company has set the estimate for December 2018 expenses based on the previous years' December actuals as a proxy. The categorization of the estimated expenses is based on the previous year's actuals. The $59,878 associated with Restoration charges should have been included in column G under Schedule 16 charges, and $99,496 should have been included in column O under Schedule 2 charges.

(c) Please refer to Page 1 of Attachment DIV 1-4 for a copy of the monthly invoice for September 2018 that reconciles to cell C35 of the "Input-Expenses" tab. Page 2 of the attachment shows the monthly Non-PTF[1] customer detail to support the revenue credit amount in the monthly bill calculation. The large revenue credit in the amount of $46,558,160 associated with collections under the Regional rates is reflected at the bottom of Page 2 to Attachment DIV 1-4. It is the primary driver of the negative total amount of the invoice.

NEP calculates its total transmission revenue requirement for PTF and Non-PTF pursuant to the FERC-approved formula included in Attachment RR to Schedule 21 – NEP of the ISO/RTO Tariff. When the total revenue requirement is calculated, NEP credits the regional revenues collected by ISO-NE for PTF through the Regional Network Service Rate against the total revenue requirement to determine the net amount to be collected through NEP's local rates. Local Network Service charges are billed monthly to local network load (which includes Narragansett) on a load ratio share basis.

[1] PTF means pooled transmission facilities.

DATE 22-Oct-18

THE NARRAGANSETT ELECTRIC COMPANY
280 MELROSE STREET
PROVIDENCE, RI 02901

CLA010-25.16-19.135
INVOICE# **Journal Entry**
NETWORK TRANSMISSION SERVICE
September-18

DO NOT MAIL - INFORMATIONAL PURPOSES ONLY

COINCIDENT NETWORK LOAD - PTF	1,724,340	**KW**
COINCIDENT NETWORK LOAD - NON-PTF	1,724,340	**KW**
LOAD RATIO SHARE - PTF	0.2512700	
LOAD RATIO SHARE - NON-PTF	0.2790946	
TOTAL MONTHLY TRANSMISSION SYSTEM EXPENSE - PTF	-$13,241,405.38	
TOTAL MONTHLY TRANSMISSION SYSTEM EXPENSE - NON-PTF	$10,559,136.98	

MONTHLY DEMAND CHARGE						
PTF	-$13,241,405.38		X	0.2512700	=	-$3,327,167.65
NON-PTF	$10,559,136.98		X	0.2790946	=	$2,946,998.51
TRANSFORMER SURCHARGE						
	2,592	KW	X	$0.370	=	$959.04
METER SURCHARGE						
	20		X	$65.28	=	$1,305.60
OTHER SURCHARGES APPLIED:			(PTF LOAD RATIO)			
ADJUSTMENT						-$24,679.49
LOAD DISPATCH CHG						-$25,794.47
INTEREST REFUND						$0.00
LOAD RATIO REBILL ADJ.						-$288.51
3RD PARTY SUPPORT PAYMENTS						$0.00
TOTAL TRANSMISSION CHARGE						-$428,666.97
Total Bill						**-$428,666.97**

PEAK LOAD FOR BILLING MONTH: **09/6/2018 4:00:00 PM**

PAYMENT SHOULD BE MADE AS FOLLOWS:
PAYMENT IS TO BE RECEIVED BY THE TWENTY - FIFTH DAY FROM THE ABOVE INVOICE DATE.

PAYMENT BY FED WIRE:
JP Morgan Chase
ABA # [redacted]
ACCOUNT: [redacted]
Credit: National Grid USA

PAYMENT BY CHECK:
New England Power Co.
Post Office - Brooklyn, P.O. Box 29803
New York, NY 10087-9803

QUESTIONS SHOULD BE ADDRESSED TO JOSEPH MURPHY (781)907-2007, TRANSMISSION COMMERCIAL

New England Power Company
Network Transmission Revenue Requirement

ACTUALfor the month of September 2018

Monthly Demand Charge (PTF):

	PTF Transmission Rate	$30,423,031
	Less: NEPOOL RNS revenue received	-43,664,436
	Monthly Demand Charge (PTF)	**-$13,241,405**

Monthly Non-PTF Demand Charge:

A	Return and Associated Income Taxes (see detail below)	$14,248,120
B	Transmission Depreciation Expense	5,197,859
C	Transmission-Related Amortization of Loss on Reacquired Debt	0
D	Transmission-Related Amortization of Investment Tax Credits	-23,374
E	Transmission-Related Amortization of FAS 109	0
F	Transmission-Related Municipal Tax Expense	3,997,793
G	Transmission Operation and Maintenance Expense	6,897,750
H	Transmission-Related Administrative and General Expense	0
I	Transmission-Related Integrated Facilities Credit	13,554,002
J	Transmission Revenue Credit	-33,316,754
K	Distribution-Related Integrated Facilities Credit	0
L	Billing Adjustments	0
M	Reactive Power Expense	0
N	Bad Debt Expense	3,741
	Monthly Non-PTF Demand Charge	**$10,559,137**

Detail - Return and Associated Income Taxes:

Transmission Investment Base	$1,617,572,762
Weighted cost of capital	10.570% *
Return and Associated Income Taxes - Annual	$170,977,441
Return and Associated Income Taxes - Month	$14,248,120
Total Monthly Revenue Credit	-$46,558,160

* The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014

Division 1-5

Request:

Please refer to file "TMF.NECO Forecast 2019.div.puc", and answer the following:

(a) Refer to tab "PTF Rate -TMF-3".

i. In Line 2, the Total Estimated PTO Plant Additions of $983,000,000 is explained in the footnote to be the Forecasted Plant Additions 2019 from the PTO Forecast RWG Presentation August 7-8, 2018. Explain where in the presentation the value comes from and how it is calculated.

ii. In Line 3, the Estimated Carrying Charge is explained in the footnote to be the Forecasted Revenue Requirement 2019 from the PTO Forecast RWG Presentation August 7-8, 2018 divided by the Total Estimated PTO Plant Additions. Explain where in the presentation the value of 131000000 comes from and how it is calculated.

(b) Refer to tab "NEP Sched 21-RR TMF-6".

i. Provide a summary of the Company's Non-PTF Additions in 2019 by Project that supports the Line 4 value of $85,214,439.

(c) Refer to tab "NEP Sched 21-RR TMF-6".

i. Provide a copy of the NEP Schedule 21 Billing that supports Lines 7-9 and 11.

Response:

(a)

i. The source of the $983,000,000 in forecasted PTO additions included on Line 2 of Exhibit TMF-3 is documentation presented by the Rates Working Group (RWG) of the New England Transmission Owners (NETOs) for review at the annual Summer Meeting of the NEPOOL Reliability Committee/Transmission Committee held on August 7-8, 2018. At the annual Summer Meeting the RWG presents an indicative RNS rate trend for the next five years based on the forecasted PTO PTF-related additions. The forecasted PTO PTF-related additions represent an aggregate total of estimated PTF-related capital additions of all NETOs based on the data available at the time of the Summer Meeting. Please refer to Line 1 in Column B of Attachment DIV 1-5_A for the source of the $983,000,000.

Division 1-5, page 2

ii. Please refer to Line 2 in Column B of Attachment DIV 1-5_A for the source of the $131,000,000 in forecasted 2019 revenue requirement from the Summer Meeting Presentation. The forecasted revenue requirement is calculated by aggregating the revenue requirement for all PTO's associated with the $983,000,000.

(b)

i. Please refer to Attachment DIV 1-5_B for summary of the Company's Non-PTF Additions in 2019 by Project that supports the total on Line 4 of Exhibit TMF-6.

(c)

i. Please refer to Attachment DIV 1-5-C for support of the totals reported on Lines 7-9 and 11 of Exhibit TMF-6. Page 1 summarizes the total that reconcile to the Exhibit TMF-6. Page 2 through 13 reflect the actual monthly Schedule-21 revenue requirement calculations.

Prepared by or under the supervision of: Tiffany M. Forsyth

2019 - 2022 Forecast - Summary

	(A)	(B) 2019	(C) 2020	(D) 2021	(E) 2022
(1)	Estimated Additions In-Service and CWIP ($ in Millions)	$ 983	$ 853	$ 786	$ 803
(2)	Forecasted Revenue Requirement ($ in Millions)	$ 131	$ 120	$ 110	$ 118
(3)	Estimated RNS Rate Impact ($/kW-Yr)	$ 7	$ 6	$ 6	$ 6
(4)	Estimated RNS Rate Forecast ($/kW-Yr)	$ 117	$ 123	$ 129	$ 135
(5)	Estimated RNS Rate Forecast ($/kWh) Assumes a 57.7%[1] Load Factor	$ 0.023	$ 0.024	$ 0.026	$ 0.027

[1] 2018 Forecast Data CELT Report May 1, 2018

Forecast is preliminary and for illustrative purposes only. Estimates are consistent with the March 2018 RSP and do not reflect revised ISO forecasts.
Figures may differ slightly due to rounding.

National Grid Plant Additions
Non-Pooled Transmission Plant
Calendar Year 2019

Non-PTF	CY2019 (in Millions)
Massachusetts	42.73
Rhode Island	40.31
New Hampshire	2.11
Vermont	0.07
Total	85.21

State	Project Description	Amount (In Thousands)
	Old Boston Rd. T-Sub	5,327.47
	North Grafton Replace transformer	4,478.10
	S9 ACR (Shieldwire	3,917.17
	C3 ACR (Shieldwire)	3,485.63
	Spare 345/115 Auto Transformer NEP	3,255.86
	O&M Storage Bldg Spare Transformers	2,250.00
	Spare 230/115 Auto Transformer NEP	2,079.53
	New Mobile D-ZZ NEP	1,992.23
	Old Boston Road - Transmission Line	1,619.99
	Mobile 3V0 Protection - NEP	1,176.71
	Replace HMIs - NEP	1,094.86
	RelayReplacementStrategyCo10	1,042.16
	O42 Tap ACR	1,036.57
	Tx Asset D/F Blanket Sub Co5410.	1,018.89
	LT NEP Protection Circuit Migration	912.50
	E Weymouth CRSW Replacement	854.05
	Spare 115/69 Auto Transformer	767.44
	ST NEP Protection Circuit Migration	750.00
	Replace Read Street transformer	651.94
	2377N ACR	645.61
	Substation Monitoring Ph II NEP	562.50
	Tx I&M Repair Prgm Line Co5410.	525.00
	Substation Monitoring Nashua Str#25	500.00
	Everett #37 Transformer Upgrades	473.71
	PLC Upgrades - NEP	393.19
	Ckt Switcher trailer asset replace	262.50
	Everett 37 115kV Transformer Replac	239.48
	Sandy Pond Asset Condition	166.78
	Tx Asset D/F Blanket Line Co5410	125.00
	N14 and O15S Kibbe Rd Switch Rfb	119.00
	Tx Asset Rplmt Blanket Line Co5410	100.00
	Adams - Install 115 kV Breakers	93.51
	LSDP 12 LLC DG Pratt Cor Rd	91.14
	18716149-S-SolarPM-Westminster-Ells	77.20
	V148S/F184 Line Tap Read St T4 TX	74.75
MA	21192247-S-BLUEWAVE CAP WESTPORT MA	67.80
	Tx Plan PS&I Blanket Line Co5410	63.28
	Z1-Y2 Somerset-Hathaway ACR	63.25
	O42-4 Tap CCR Repairs	60.20
	Tx I&M Repair Prgm Line Co5310	52.50
	Conductor Clearance - NEP Program	43.62
	Relocate E131 and Q117 at Adams	40.97
	Gilbert St - Asset Issues	36.58
	B154S/N192 Relay Reconfig	35.50
	17164016-17164155-S-WestminsterSLR	35.00
	Mid Weymouth TRF #2 D/F	29.70
	Tx Asset Rplmt Blanket Line Co5310	25.00
	Tx Asset D/F Blanket Sub/Line Co5310.	25.00
	IHC Capital Small Tools Co5410	25.00
	BatterRplStrategyCo10TxT	24.98
	Tx Asset Rplmt Blanket Sub Co5410	21.88
	I-35 T-Line Decommision	21.61
	Tx Storm D/F Blanket Line Co5410	18.75
	Vernon Hill #8 Replace #2 XFMR	18.38
	Tewksbury-Scobie line	18.25
	G7 ACR (Shieldwire)	12.50
	Melrose#2 Rebuild 115/23kV Sub	11.25
	Field St #4 Transformer Repairs	10.25
	New Meadowbrook Sub 115/13.2kV	8.50
	Brayton Point - Plant Retirement	6.00
	Tx Asset Rplmt Blanket Sub Co5310	5.00
	IHC Capital Small Tools Co5310	5.00
	Tx Asset PS&I Blanket Sub Co5310	2.50
	Tx Plan PS&I Blanket Line Co5310	2.50
	Tx Asset PS&I Blanket Line Co5310	2.50
	NE SMART FCI PILOT	2.50
	King St 18 Positron System Replacement	1.25
	Harrison Blvd #75 Substation Addition	0.56
	Peabody Ipswich River Study	(7.88)
	Salem Harbor Retirement	(222.07)
	Sub-Total MA	**42,728.08**
	R144 D/F River Crossing Relocation	13,191.70
	Woonsocket Station Rebuild	11,480.23

RI	Woonsocket Sub T Line Reconfig	4,092.23
	D/F Terminations - Franklin Sq Sub	2,023.74
	Seawall at South Street Sub	1,814.97
	South Street Substation Rebuild	1,680.52
	3308 ACR	1,017.50
	Southeast Sub Tap Line	671.32
	3311 ACR	637.28
	IntrMeterInvestmentPrgmCo49	637.22
	B23 ACR	625.00
	T1/T2/T3 Circuits Rebuild	609.75
	W. Kingston #62 34.5 kV Breaker Rep	435.69
	Substation Monitoring Ph II NECO	300.00
	ST NEC Protection Circuit Migration	237.50
	Substation Monitoring Kent County	167.00
	Tx Storm D/F Blanket Line Co5360	118.75
	LT NEC Protection Circuit Migration	99.99
	T1/T2/T3 Circuits Rebuild (Frln SQ)	79.50
	Flood Contingency Plan NEC - T	70.00
	22989422-T-N_Kingstown-PV-Hamilton	63.75
	Tx Asset Rplmt Blanket Sub Co5360	61.63
	Tx I&M Repair Prgm Line Co5360.	52.50
	New London Ave - Tap T-172S	36.25
	New London WaveTrap	25.75
	Tx Asset Rplmt Blanket Line Co5360	25.00
	Tx Asset PS&I Blanket Sub Co5360	12.50
	Instrument TRF ARP - RI	10.25
	Tx Plan PS&I Blanket Line Co5360	7.75
	IHC Capital Small Tools Co5360	7.50
	New England RAPR replacements Co:49	6.75
	Conductor Clearance - NEC Program	6.30
	New Chase Hill Substation RI	0.19
	Sub-Total RI	**40,306.00**
NH	Comerford #18 Unmetered Load	725.59
	Spare 230/34.5 Transformer NEP	625.93
	Sub Monitoring Monroe AC Terminal	500.00
	Charlestown 4401 TLine Installation	157.50
	Pelham - Inst 2nd xfmr & inline bkr	52.31
	PLC Upgrades - NEP	31.95
	Tewksbury-Scobie line	12.17
	3314 ACR	1.13
	Sub-Total NH	**2,106.58**
VT	Circuit Breaker ARP NEP	60.75
	Land-Vernon #13 Substa Relo	7.50
	3314 ACR	5.13
	Bellows Falls Rebuild	0.41
	Sub-Total VT	**73.78**
	Total	**85,214.44**
	Adjusted Total (in Actuals)	**85,214,439**

Attachment DIV 1-5_C
New England Power Company
Schedule 21 - NEP Revenue Requirement

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.	**Month**	**Monthly Demand Charge (PTF)**	**Monthly Non-PTF Demand Charge**	**Less Adjustment***	**Net Total = (C+D-E) Line 7 TMF-6**	**Revenue Credit**	**Total Revenue Credit = (G+C) - Line 8 TMF-6**	**Total Transmission Integrated Facilities Credit - Line 9 TMF-6**	**Transmission Plant - Line 11 TMF-6**	**Page Reference**
1	Jan-2018	(6,374,829)	10,551,694		4,176,865	(34,595,333)	(40,970,162)	13,111,392		Page 2 of 14
2	Feb-2018	(4,323,160)	11,443,802		7,120,642	(35,085,336)	(39,408,495)	13,528,523		Page 3 of 14
3	Mar-2018	663,235	11,530,891		12,194,126	(36,638,995)	(35,975,759)	15,002,301		Page 4 of 14
4	Apr-2018	1,239,569	10,864,479	261,344	11,842,705	(33,946,037)	(32,706,468)	13,213,428		Page 5 of 14
5	May 2018 revised'	3,698,744	11,078,708		14,777,452	(34,872,176)	(31,173,432)	15,284,295		Page 6 of 14
6	Jun-2018	(5,197,606)	8,940,846	(4,400,278)	8,143,519	(28,792,317)	(33,989,922)	11,810,149		Page 7 of 14
7	Jul-2018	(7,574,473)	10,056,213		2,481,739	(31,460,282)	(39,034,756)	8,288,560		Page 8 of 14
8	Aug-2018	(6,378,764)	12,085,401		5,706,637	(38,445,212)	(44,823,976)	18,523,234		Page 9 of 14
9	Sep-2018	(13,241,405)	10,559,137		(2,682,268)	(33,316,754)	(46,558,160)	13,554,002		Page 10 of 14
10	Oct-2018	(8,928,904)	11,226,682		2,297,778	(35,740,898)	(44,669,802)	14,382,283		Page 11 of 14
11	Nov-2018	362,421	11,846,504		12,208,926	(35,415,637)	(35,053,215)	13,954,000		Page 12 of 14
12	Dec-2018	555,955	11,910,555		12,466,510	(33,612,651)	(33,056,696)	14,470,686	2,750,114,173	Page 13 &14 of 14
13										
14	**Grand Total**	**(45,499,216)**	**132,094,913**	**(4,138,935)**	**90,734,632**	**(411,921,627)**	**(457,420,844)**	**165,122,855**	**2,750,114,173**	

Detail for One-time Adjustments not expected to impact 2019 RR

April	261,344	Pension deferral account, Plant Adjustment, and other misc adjustments
June	(4,400,278)	May 2018 RR was revised and adjustment was included in June 2018 Billing (May 2019 above reflects the revised amount)

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New England Power Company
Network Transmission Revenue Requirement

ACTUALfor the month of January 2018

Monthly Demand Charge (PTF):

	PTF Transmission Rate	$29,231,198
	Less: NEPOOL RNS revenue received	-35,606,027
	Monthly Demand Charge (PTF)	**-$6,374,829**

Monthly Non-PTF Demand Charge:

	A	Return and Associated Income Taxes (see detail below)	$13,776,477
	B	Transmission Depreciation Expense	5,102,383
	C	Transmission-Related Amortization of Loss on Reacquired Debt	0
	D	Transmission-Related Amortization of Investment Tax Credits	-24,116
	E	Transmission-Related Amortization of FAS 109	0
	F	Transmission-Related Municipal Tax Expense	4,781,889
	G	Transmission Operation and Maintenance Expense	8,398,566
	H	Transmission-Related Administrative and General Expense	0
	I	Transmission-Related Integrated Facilities Credit	13,111,392
	J	Transmission Revenue Credit	-34,595,333
	K	Distribution-Related Integrated Facilities Credit	0
*	L	Billing Adjustments	0
	M	Reactive Power Expense	0
	N	Bad Debt Expense	436
		Monthly Non-PTF Demand Charge	**$10,551,694**

Detail - Return and Associated Income Taxes:

Transmission Investment Base	$1,652,185,913	
Weighted cost of capital	10.006%	**
Return and Associated Income Taxes - Annual	$165,317,722	
Return and Associated Income Taxes - Month	$13,776,477	

** The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014
* Biling adjustment for O & M, Annual FAS-109 true up, ADIT adjustment, & ROE adjustment

New England Power Company
Network Transmission Revenue Requirement

ACTUALfor the month of February 2018

Monthly Demand Charge (PTF):

	PTF Transmission Rate	$31,681,302
	Less: NEPOOL RNS revenue received	-36,004,462
	Monthly Demand Charge (PTF)	**-$4,323,160**

Monthly Non-PTF Demand Charge:

	A	Return and Associated Income Taxes (see detail below)	$13,825,810
	B	Transmission Depreciation Expense	5,132,153
	C	Transmission-Related Amortization of Loss on Reacquired Debt	0
	D	Transmission-Related Amortization of Investment Tax Credits	-23,374
	E	Transmission-Related Amortization of FAS 109	0
	F	Transmission-Related Municipal Tax Expense	4,291,188
	G	Transmission Operation and Maintenance Expense	9,774,857
	H	Transmission-Related Administrative and General Expense	0
	I	Transmission-Related Integrated Facilities Credit	13,528,523
	J	Transmission Revenue Credit	-35,085,336
	K	Distribution-Related Integrated Facilities Credit	0
*	L	Billing Adjustments	0
	M	Reactive Power Expense	0
	N	Bad Debt Expense	-20
		Monthly Non-PTF Demand Charge	**$11,443,802**

Detail - Return and Associated Income Taxes:

Transmission Investment Base	$1,657,605,291	
Weighted cost of capital	10.009%	**
Return and Associated Income Taxes - Annual	$165,909,714	
Return and Associated Income Taxes - Month	$13,825,810	

** The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014
* Biling adjustment for O & M, Annual FAS-109 true up, ADIT adjustment, & ROE adjustment

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New England Power Company
Network Transmission Revenue Requirement

ACTUALfor the month of March 2018

Monthly Demand Charge (PTF):

	PTF Transmission Rate	$31,943,714
	Less: NEPOOL RNS revenue received	-31,280,479
	Monthly Demand Charge (PTF)	**$663,235**

Monthly Non-PTF Demand Charge:

	A	Return and Associated Income Taxes (see detail below)	$14,368,789
	B	Transmission Depreciation Expense	5,144,044
	C	Transmission-Related Amortization of Loss on Reacquired Debt	0
	D	Transmission-Related Amortization of Investment Tax Credits	-23,374
	E	Transmission-Related Amortization of FAS 109	0
	F	Transmission-Related Municipal Tax Expense	3,975,514
	G	Transmission Operation and Maintenance Expense	9,702,610
	H	Transmission-Related Administrative and General Expense	0
	I	Transmission-Related Integrated Facilities Credit	15,002,301
	J	Transmission Revenue Credit	-36,638,995
	K	Distribution-Related Integrated Facilities Credit	0
*	L	Billing Adjustments	0
	M	Reactive Power Expense	0
	N	Bad Debt Expense	0
		Monthly Non-PTF Demand Charge	**$11,530,891**

Detail - Return and Associated Income Taxes:

Transmission Investment Base	$1,661,291,772	
Weighted cost of capital	10.379%	**
Return and Associated Income Taxes - Annual	$172,425,473	
Return and Associated Income Taxes - Month	$14,368,789	

** The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014
* Biling adjustment for O & M, Annual FAS-109 true up, ADIT adjustment, & ROE adjustment

New England Power Company
Network Transmission Revenue Requirement

ACTUALfor the month of April 2018

Monthly Demand Charge (PTF):

	PTF Transmission Rate	$30,085,962
	Less: NEPOOL RNS revenue received	-28,846,393
	Monthly Demand Charge (PTF)	**$1,239,569**

Monthly Non-PTF Demand Charge:

	A	Return and Associated Income Taxes (see detail below)	$14,351,725
	B	Transmission Depreciation Expense	5,150,801
	C	Transmission-Related Amortization of Loss on Reacquired Debt	0
	D	Transmission-Related Amortization of Investment Tax Credits	0
	E	Transmission-Related Amortization of FAS 109	0
	F	Transmission-Related Municipal Tax Expense	4,034,259
	G	Transmission Operation and Maintenance Expense	7,831,247
	H	Transmission-Related Administrative and General Expense	0
	I	Transmission-Related Integrated Facilities Credit	13,213,428
	J	Transmission Revenue Credit	-33,946,037
	K	Distribution-Related Integrated Facilities Credit	0
*	L	Billing Adjustments	229,056
	M	Reactive Power Expense	0
	N	Bad Debt Expense	0
		Monthly Non-PTF Demand Charge	**$10,864,479**

Detail - Return and Associated Income Taxes:

Transmission Investment Base	$1,645,368,279	
Weighted cost of capital	10.467%	**
Return and Associated Income Taxes - Annual	$172,220,698	
Return and Associated Income Taxes - Month	$14,351,725	

** The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014
* Biling adjustment for O & M, Annual FAS-109 true up, ADIT adjustment, & ROE adjustment

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New England Power Company

Network Transmission Revenue Requirement

ACTUALfor the month of May 2018

Monthly Demand Charge (PTF):

	PTF Transmission Rate	$30,733,102
	Less: NEPOOL RNS revenue received	-27,034,358
	Monthly Demand Charge (PTF)	**$3,698,744**

Monthly Non-PTF Demand Charge:

	A	Return and Associated Income Taxes (see detail below)	$14,306,107
	B	Transmission Depreciation Expense	5,149,414
	C	Transmission-Related Amortization of Loss on Reacquired Debt	0
	D	Transmission-Related Amortization of Investment Tax Credits	-46,748
	E	Transmission-Related Amortization of FAS 109	0
	F	Transmission-Related Municipal Tax Expense	3,917,962
	G	Transmission Operation and Maintenance Expense	7,339,855
	H	Transmission-Related Administrative and General Expense	0
	I	Transmission-Related Integrated Facilities Credit	15,284,295
	J	Transmission Revenue Credit	-34,872,176
	K	Distribution-Related Integrated Facilities Credit	0
*	L	Billing Adjustments	0
	M	Reactive Power Expense	0
	N	Bad Debt Expense	0
		Monthly Non-PTF Demand Charge	**$11,078,708**

Detail - Return and Associated Income Taxes:

Transmission Investment Base	$1,643,121,020	
Weighted cost of capital	10.448%	**
Return and Associated Income Taxes - Annual	$171,673,284	
Return and Associated Income Taxes - Month	$14,306,107	

** The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014

* Biling adjustment for O & M, Annual FAS-109 true up, ADIT adjustment, & ROE adjustment

New England Power Company
Network Transmission Revenue Requirement

ACTUALfor the month of June 2018

Monthly Demand Charge (PTF):

		PTF Transmission Rate	$24,821,902
		Less: NEPOOL RNS revenue received	-30,019,508
		Monthly Demand Charge (PTF)	**-$5,197,606**

Monthly Non-PTF Demand Charge:

	A	Return and Associated Income Taxes (see detail below)	$14,378,676
	B	Transmission Depreciation Expense	5,162,472
	C	Transmission-Related Amortization of Loss on Reacquired Debt	0
	D	Transmission-Related Amortization of Investment Tax Credits	-23,374
	E	Transmission-Related Amortization of FAS 109	0
	F	Transmission-Related Municipal Tax Expense	3,971,741
	G	Transmission Operation and Maintenance Expense	6,828,785
	H	Transmission-Related Administrative and General Expense	0
	I	Transmission-Related Integrated Facilities Credit	11,810,149
	J	Transmission Revenue Credit	-28,792,317
	K	Distribution-Related Integrated Facilities Credit	0
*	L	Billing Adjustments	-4,400,278
	M	Reactive Power Expense	0
	N	Bad Debt Expense	4,992
		Monthly Non-PTF Demand Charge	**$8,940,846**

Detail - Return and Associated Income Taxes:

Transmission Investment Base	$1,649,088,299	
Weighted cost of capital	10.463%	**
Return and Associated Income Taxes - Annual	$172,544,109	
Return and Associated Income Taxes - Month	$14,378,676	

** The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014
* Biling adjustment for O & M, Annual FAS-109 true up, ADIT adjustment, & ROE adjustment

New England Power Company
Network Transmission Revenue Requirement

ACTUALfor the month of July 2018

Monthly Demand Charge (PTF):

	PTF Transmission Rate	$27,900,798
	Less: NEPOOL RNS revenue received	-35,475,271
	Monthly Demand Charge (PTF)	**-$7,574,473**

Monthly Non-PTF Demand Charge:

	A	Return and Associated Income Taxes (see detail below)	$14,428,201
	B	Transmission Depreciation Expense	5,180,704
	C	Transmission-Related Amortization of Loss on Reacquired Debt	0
	D	Transmission-Related Amortization of Investment Tax Credits	-23,374
	E	Transmission-Related Amortization of FAS 109	0
	F	Transmission-Related Municipal Tax Expense	3,958,836
	G	Transmission Operation and Maintenance Expense	8,520,247
	H	Transmission-Related Administrative and General Expense	0
	I	Transmission-Related Integrated Facilities Credit	8,288,560
	J	Transmission Revenue Credit	-31,460,282
	K	Distribution-Related Integrated Facilities Credit	0
*	L	Billing Adjustments	1,139,854
	M	Reactive Power Expense	0
	N	Bad Debt Expense	23,466
		Monthly Non-PTF Demand Charge	**$10,056,213**

Detail - Return and Associated Income Taxes:

Transmission Investment Base	$1,652,084,084	
Weighted cost of capital	10.480%	**
Return and Associated Income Taxes - Annual	$173,138,412	
Return and Associated Income Taxes - Month	$14,428,201	

** The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014
* Billing adjustment to Net Benefit Costs for prior quarter

New England Power Company
Network Transmission Revenue Requirement

ACTUALfor the month of August 2018

Monthly Demand Charge (PTF):		
	PTF Transmission Rate	$34,728,474
	Less: NEPOOL RNS revenue received	-41,107,238
	Monthly Demand Charge (PTF)	**-$6,378,764**
Monthly Non-PTF Demand Charge:		
A	Return and Associated Income Taxes (see detail below)	$14,340,447
B	Transmission Depreciation Expense	5,191,732
C	Transmission-Related Amortization of Loss on Reacquired Debt	0
D	Transmission-Related Amortization of Investment Tax Credits	-23,374
E	Transmission-Related Amortization of FAS 109	0
F	Transmission-Related Municipal Tax Expense	4,039,337
G	Transmission Operation and Maintenance Expense	8,459,236
H	Transmission-Related Administrative and General Expense	0
I	Transmission-Related Integrated Facilities Credit	18,523,234
J	Transmission Revenue Credit	-38,445,212
K	Distribution-Related Integrated Facilities Credit	0
L	Billing Adjustments	0
M	Reactive Power Expense	0
N	Bad Debt Expense	0
	Monthly Non-PTF Demand Charge	**$12,085,401**

Detail - Return and Associated Income Taxes:

Transmission Investment Base	$1,633,928,672
Weighted cost of capital	10.532% *
Return and Associated Income Taxes - Annual	$172,085,368
Return and Associated Income Taxes - Month	$14,340,447

* The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014

New England Power Company
Network Transmission Revenue Requirement

ACTUALfor the month of September 2018

Monthly Demand Charge (PTF):		
	PTF Transmission Rate	$30,423,031
	Less: NEPOOL RNS revenue received	-43,664,436
	Monthly Demand Charge (PTF)	**-$13,241,405**

Monthly Non-PTF Demand Charge:		
A	Return and Associated Income Taxes (see detail below)	$14,248,120
B	Transmission Depreciation Expense	5,197,859
C	Transmission-Related Amortization of Loss on Reacquired Debt	0
D	Transmission-Related Amortization of Investment Tax Credits	-23,374
E	Transmission-Related Amortization of FAS 109	0
F	Transmission-Related Municipal Tax Expense	3,997,793
G	Transmission Operation and Maintenance Expense	6,897,750
H	Transmission-Related Administrative and General Expense	0
I	Transmission-Related Integrated Facilities Credit	13,554,002
J	Transmission Revenue Credit	-33,316,754
K	Distribution-Related Integrated Facilities Credit	0
L	Billing Adjustments	0
M	Reactive Power Expense	0
N	Bad Debt Expense	3,741
	Monthly Non-PTF Demand Charge	**$10,559,137**

Detail - Return and Associated Income Taxes:

Transmission Investment Base	$1,617,572,762
Weighted cost of capital	10.570% *
Return and Associated Income Taxes - Annual	$170,977,441
Return and Associated Income Taxes - Month	$14,248,120

* The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014

New Enland Power Company
Network Transmission Revenue Requirement
Actual for the Month of Oct 2018

Line	Description		Amount
	Monthly Demand Charge (PTF)		
1	PTF Transmission Rate		32,292,982
2	Less: NEPOOL RNS revenue received		(41,221,886)
3	**Monthly Demand Charge (PTF)**		**(8,928,904)**
	Monthly Non-PTF Demand Charge		
4	Return and Associated Income Taxes		14,104,543
5	Transmission Depreciation Expense		5,201,459
6	Transmission-Related Amortization of Loss on Reacquired Debt		-
7	Transmission-Related Amortization of Investment Tax Credits		(23,374)
8	Transmission-Related Amortization of FAS 109		-
9	Transmission-Related Municipal Tax Expense		3,985,986
10	Transmission Operation and Maintenance Expense		5,333,386
11	Transmission-Related Administration and General Expense		3,971,532
12	Transmission-Related Integrated Facilities Credit		14,382,283
13	Transmission Revenue Credit		(35,740,898)
14	Distribution-Related Integrated Facilities Credit		-
15	Billing Adjustments		-
16	Reactive Power Expense		-
17	Bad Debt Expense		11,766
18	**Monthly Non-PTF Demand Charge**		**$ 11,226,682**
	Detail - Return and Associated Income Taxes:		
19	Transmission Investment Base		1,630,253,019
20	Weighted cost of capital	(a)	10.3821%
21	Return and Associated Income Taxes - Annual		169,254,511
22	Return and Associated Income Taxes - Month		14,104,543

Notes

The billing for November 2018 includes an additional charge to true-up the Load Dispatch Surcharge fees to the costs reported on the September 2018 FERC Form 3Q filed report. A corresponding credit will be included in the December 2018 Transmission Revenue Credit line on the monthly Revenue Requirement.

(a) The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014

New Enland Power Company
Network Transmission Revenue Requirement
Actual for the Month of Nov 2018

Line	Description		Amount
	Monthly Demand Charge (PTF)		
1	PTF Transmission Rate		30,783,289
2	Less: NEPOOL RNS revenue received		(30,420,868)
3	**Monthly Demand Charge (PTF)**		**362,421**
	Monthly Non-PTF Demand Charge		
4	Return and Associated Income Taxes		14,428,877
5	Transmission Depreciation Expense		5,210,216
6	Transmission-Related Amortization of Loss on Reacquired Debt		-
7	Transmission-Related Amortization of Investment Tax Credits		(23,374)
8	Transmission-Related Amortization of FAS 109		-
9	Transmission-Related Municipal Tax Expense		4,077,210
10	Transmission Operation and Maintenance Expense		4,972,561
11	Transmission-Related Administration and General Expense		4,341,135
12	Transmission-Related Integrated Facilities Credit		13,954,000
13	Transmission Revenue Credit		(35,415,637)
14	Distribution-Related Integrated Facilities Credit		-
15	Billing Adjustments		301,469
16	Reactive Power Expense		-
17	Bad Debt Expense		48
18	**Monthly Non-PTF Demand Charge**		**$ 11,846,504**
	Detail - Return and Associated Income Taxes:		
19	Transmission Investment Base		1,631,670,416
20	Weighted cost of capital	(a)	10.6116%
21	Return and Associated Income Taxes - Annual		173,146,522
22	Return and Associated Income Taxes - Month		14,428,877

(a) The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014

New Enland Power Company
Network Transmission Revenue Requirement
Actual for the Month of Dec 2018

Line	Description		Amount
	Monthly Demand Charge (PTF)		
1	PTF Transmission Rate		31,065,597
2	Less: NEPOOL RNS revenue received		(30,509,642)
3	**Monthly Demand Charge (PTF)**		**555,955**
	Monthly Non-PTF Demand Charge		
4	Return and Associated Income Taxes		13,754,487
5	Transmission Depreciation Expense		5,222,717
6	Transmission-Related Amortization of Loss on Reacquired Debt		-
7	Transmission-Related Amortization of Investment Tax Credits		(23,175)
8	Transmission-Related Amortization of FAS 109		-
9	Transmission-Related Municipal Tax Expense		4,311,547
10	Transmission Operation and Maintenance Expense		3,516,897
11	Transmission-Related Administration and General Expense		3,958,881
12	Transmission-Related Integrated Facilities Credit		14,470,686
13	Transmission Revenue Credit		(33,612,651)
14	Distribution-Related Integrated Facilities Credit		-
15	Billing Adjustments		(11,924)
16	Reactive Power Expense		-
17	Bad Debt Expense		323,090
18	**Monthly Non-PTF Demand Charge**		**$ 11,910,555**
	Detail - Return and Associated Income Taxes:		
19	Transmission Investment Base		1,616,854,497
20	Weighted cost of capital	(a)	10.2083%
21	Return and Associated Income Taxes - Annual		165,053,844
22	Return and Associated Income Taxes - Month		13,754,487

(a) The Weighted Cost of Capital is based on FERC Opinion No. 531-A issued on 10/16/2014

New England Power Company
Local Network Service
Investment Base Detail
Worksheet 3
For Costs in the Month of Dec 2018

Input Cells are Shaded Yellow

Line No.	Description	FERC Account No.	(A) Transmission	(B) Reference	(C) Attachment RR Reference
	Transmission Plant				
1	Total Investment in Transmission Plant	350-359	2,765,991,871	Attachment 7a	I.A.1.a.
2	Total Investment in Distribution Plant	360-374	7,916,790	Attachment 7a	I.A.1.a.
3	Less: Capital Leases in Hydro Quebec DC facilities (HQ leases)	350-359	(23,794,487)	Attachment 4	I.A.1.a.
4	Total Transmission Plant		2,750,114,173	Sum Lines 1 thru 3	I.A.1.a.
5	Investment in PTF Transmission Plant	350-359	2,039,077,686	Data input tab, Line 10+Line 11	I.A.1.a.
6	Investment in Stepdown Transformers beyond NEP's Point of Delivery, including associated equipment		161,453,402	Attachment 5	I.A.1.a.
7	Investment in Wholesale Meters, including associated equipment		2,419,019	Line 2 * W/S 5, Line 12(A)	I.A.1.a.
	Transmission-Related General Plant				
8	Investment in General Plant	389-399	4,882,268	Attachment 7a	I.A.1.b.
9	Less: General Plant related to NEP's generation facilities as specifically identified in NEP's CTC	389-399	-	N/A	I.A.1.b.
10	Total Transmission-Related General Plant		4,882,268	Line 8 - Line 9	I.A.1.b.
	Transmission Plant Held For Future Use				
11	Transmission Plant Held For Future Use	105	1,026,919	Attachment 7b	I.A.1.c.
	Transmission-Related Construction Work in Progress				
12	Investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders	107	-	Attachment 6	I.A.1.d.
	Transmission-Related Depreciation Reserve				
13	Total Depreciation Reserve	108	(525,467,079)	Attachment 7c	I.A.1.e.
14	Less: Generation-related depreciation reserve associated with assets identified in NEP's CTC	108	-	N/A	I.A.1.e.
15	Total Transmission-Related Depreciation Reserve		(525,467,079)	Line 13 - Line 14	
	Transmission-Related Accumulated Deferred Taxes				
16	Accumulated Deferred Income Taxes	281-283, 190	(626,930,815)	Attachment 15	I.A.1.f.
17	Less: Accumulated Deferred Taxes associated with non-utility assets or generation facilities as identified in the CTC	190	-	Attachment 15	I.A.1.f.
18	Total Transmission-Related Accumulated Deferred Income Taxes		(626,930,815)	Line 16 - Line 17	I.A.1.f.
	Transmission-Related Loss on Reacquired Debt				
19	Transmission-Related Loss on Reacquired Debt	189	-	Attachment 8b	I.A.1.g.
20	Less: Losses associated with NEP Generation as specifically identified in the CTC	189	-	N/A	I.A.1.g.
21	Less: Generation-related losses associated with pollution control bonds	189	-	N/A	I.A.1.g.
22	Total Transmission-Related Loss on Reacquired Debt		-	Line 19 - 20 - 21	I.A.1.g.
	Other Regulatory Assets				
23	FAS 109 Regulatory Asset	182.3	-	Attachment 13	I.A.1.h.
24	FAS 109 Regulatory Liability	254	-	Attachment 13	I.A.1.h.
25	Less: FAS 109 balances associated with NEP Generation as specifically identified in the CTC	182.3/254	-	Attachment 13	I.A.1.h.
26	Total Other Regulatory Assets		-	Line 23 + 24 - 25	I.A.1.h.
	Allowance for Funds Used During Construction (AFUDC) Regulatory Liability				
27	Unamortized balance of the capitalized AFUDC booked on NEP's Transmission-related projects as recorded in FERC Account 254 consistent with Commission orders	254	(1,795,506)	Attachment 14	I.A.1.i.
	Transmission Prepayments				
28	Prepayments	165	2,102,365	Attachment 8b	I.A.1.j.
29	Less: Prepayments related to NEP's ongoing generation-related activities	165	-	N/A	I.A.1.j.
30	Total Transmission Prepayments		2,102,365	Line 28 - Line 29	I.A.1.j.
	Transmission Materials and Supplies				
31	Transmission-related Materials and Supplies	154	1,708,503	Attachment 8b	I.A.1.k.
	Transmission-Related Cash Working Capital				
32	Transmission Operation & Maintenance Expense		3,516,897	W/S 1, Line 21(A)	I.A.1.l.
33	Transmission-Related Admin & General Expense		3,958,881	W/S 1, Line 22(A)	I.A.1.l.
34	Transmission Related Expenses		7,475,778	Line 32 + Line 33	I.A.1.l.
35	45 Days / 360 Days		1.500	45 Days / 360 Days * 12 months	I.A.1.l.
36	Transmission-Related Cash Working Capital		11,213,667	Line 34 x Line 35	I.A.1.l.
37	**Transmission Investment Base**		**1,616,854,497**	Line 4+10+11+12+15+18+22+26+27+30+31+36	

Division 1-6

Request:

Please refer to the CTC Reconciliation Reports filed in January 2018 and 2019, and answer the following:

(a) Provide a copy of the January 2019 CTC Reconciliation Report.

(b) Explain how the Phase III and IV litigation proceeds by unit will be returned to wholesale customers and how this amount changed from the January 2018 CTC Reconciliation Report.

Response:

(a) Please see Attachment DIV 1-6-1 for a copy of Narragansett Electric Company's 2018 CTC Reconciliation filed in January 2019.

Please see Attachment DIV 1-6-2 for a copy of Blackstone Valley Electric Company and Newport Electric Corporation's 2018 CTC Reconciliation filed in January 2019.

(b) Customers receive the full benefit of litigation proceeds, either directly via the CTC reconciliation, or indirectly via NEP and Montaup's share of the Yankees' reduced nuclear decommissioning and other post shut-down costs. Each of the three Yankees must obtain FERC approval for their proposed distributions of proceeds.

Phase III

Below are excerpts from the calendar year 2016 annual reports of Connecticut Yankee, Maine Yankee, and Yankee Atomic (MA) which describe the Phase III litigation and disposition of litigation proceeds.

Connecticut Yankee:

On July 18, 2016, the DOE's right to appeal the Judgment in the Company's Phase III Litigation expired and the Judgment became final. The damages awarded to the Company for Phase III Litigation were $32.6 million. In July 2016, the Department of Justice submitted the required paperwork to the United States Treasury to initiate payment to the Company. The Company recorded the receivable in July 2016 when the period for appeals passed and it became likely that such damages would be paid. The damage proceeds of $32.6 million were received on October 14, 2016. In accordance with the Company's October 2016 Informational FERC Filing, **$18.4 million of the proceeds were returned to the Company's wholesale customers on December 15, 2016. In addition, $.6 million of proceeds were deposited in the Company's irrevocable external trust to fund Post Retirement Benefits Other Than Pension "PBOP," and $.4 million of proceeds were used to pay the associated taxes. The remaining proceeds were deposited into the Decommissioning Trust Fund to fund long-term ISFSI operations and decommissioning costs.** [Emphasis added]

Maine Yankee:

On July 18, 2016, the DOE's right to appeal the Judgment in the Company's Phase III Litigation expired and the Judgment became final. The damages awarded to the Company for Phase III Litigation were $24.6 million. In July 2016, the Department of Justice submitted the required paperwork to the United States Treasury to initiate payment to the Company. The Company recorded the receivable in July 2016 when the period for appeals passed and it became likely that such damages would be paid. The damage proceeds of $24.6 million were received on October 14, 2016. In accordance with the Company's October 2016 Informational FERC Filing, **$3.6 million of the proceeds were returned to the Company's wholesale customers on December 15, 2016. The remaining proceeds were deposited into the Decommissioning Trust Fund to fund long-term ISFSI operations and decommissioning costs.** [Emphasis added]

Yankee Atomic:

On July 18, 2016, the DOE's right to appeal the Judgment in the Company's Phase III Litigation expired and the Judgment became final. The damages awarded to the Company for Phase III Litigation were $19.6 million. In July 2016, the Department of Justice submitted the required paperwork to the United States Treasury to initiate payment to the Company. The Company recorded the receivable in July 2016 when the period for appeals passed and it became likely that such damages would be paid. The damage proceeds of $19.6 million were received on October 14, 2016 and in accordance with the Company's October 2016 Informational FERC Filing, **the proceeds were deposited in the Decommissioning Trust to fund long-term ISFSI operations and decommissioning costs.** [Emphasis added]

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NEP received $14.8 million and Montaup received $3.2 million for their shares of the Phase III proceeds in December 2016, which were credited to customers through the 2017 CTC reconciliation filed in January 2018.

Phase IV

On February 21, 2019, U.S. Court of Federal Claims Judge Nancy Firestone issued her decision on a motion for partial summary judgment filed in July 2018 by Connecticut Yankee Atomic Power Company, Yankee Atomic Electric Company, and Maine Yankee Atomic Power Company awarding the three companies approximately $103.2 million in undisputed damages for costs related to the federal government's continuing failure to honor its contractual obligations to remove spent nuclear fuel and Greater than Class C waste from the three sites for the period January 1, 2013 through December 31, 2016. The federal government has 60 days (until April 22, 2019) to appeal the decision. In her decision Judge Firestone awarded CYAPCO approximately $40.7 million, YAEC $28.1 million and MYAPCO $34.4 million.

Once the Judgment becomes final, the customers will again receive the full benefit of the litigation proceeds either directly or indirectly, as described above.

Prepared by or under the supervision of: Kathleen M. Hammer

Division 1-7

Request:

Please refer to file "NECO_Recs_LTCRER_and_NM_2018.div.puc", and answer the following:

(a) Refer to tabs "REP-18-Expense Summary" and "Input-Expense (LTC_DG)".

  i. Explain the inclusion of Forward Capacity Gross Revenues and Net Forward Capacity Revenues.
  ii. Explain the calculation of Net Forward Capacity Revenues.

(b) Explain how the Phase III and IV litigation proceeds by unit will be returned to wholesale customers and how this amount changed from the January 2018 CTC Reconciliation Report.

(c) Refer to tab "REP-18-Expense Summary".

  i. Explain the administration expenses for July 2018.

Response:

(a) Refer to tabs "REP-18-Expense Summary" and "Input-Expense (LTC_DG)".

  i. In accordance with the Long Term Contracting for Renewable Energy Recovery Reconciliation Provision, R.I.P.U.C. No. 2175, the cost to be recovered from customers shall include actual payments made during the Reconciliation Period under the individual approved Long-term Contracts and Distributed Generation Standard Contracts less (i) any proceeds received by the Company resulting from the sale of the Contract Products and (ii) actual Customer Share of Net Forward Capacity Market Proceeds. Customer Share of Net Forward Capacity Market Proceeds is defined as 90% of the proceeds received from or fees, charges, or penalties assessed by ISO-NE as a result of the Company's bidding the capacity of qualified customer-owned Distributed Generation Facilities into the ISO-NE Forward Capacity Market. Gross Forward Capacity Revenues presented in column (e) of page 4 of Schedule REP-18 are shown for informational purposes only. Customer Share Net Forward Capacity Revenues (90% of Gross Forward Capacity Revenues) in column (f) are subtracted from the net payment to the generator which reduces the amount of costs to be recovered from customers.

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ii. Net Forward Capacity Revenues are calculated as 90% of Gross Forward Capacity Revenues.

(b) Please see the Company's response to DIV 1-6 (b)

(c) Refer to tab "REP-18-Expense Summary".

i. July 2018 included an expense of $37,102.50 representing an invoice from a Company consultant, Antares Group, Inc., as well as some employee labor cost. In responding to this data request, the Company determined that this consultant expense was related to bidding the capacity of the RE Growth Program's distributed generation units into the Forward Capacity Market during 2018, not bidding capacity of Long Term Contracting renewable energy resources. The Company has removed this expense from the reconciliation and noted that there was no change in the calculated factor of $0.00678. In addition, the Company proposes to include the cost in the RE Growth Program's reconciliation in January 2019.