nationalgrid

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February 10, 2021

VIA E-FILING and COURIER

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

Re: In Re: Commission's Review of the Benefits and Costs of Net Metering Credit Calculation Pursuant to R.I. Gen. Laws § 39-26.4-3: Docket No. 5010

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid (the Company), enclosed for filing with the Rhode Island Public Utilities Commission (the Commission) please find the Company's complete response to PUC 8-1, which was issued by the Commission on January 26, 2021. In making its filing on February 5, 2021, the Company inadvertently omitted Attachment 8-1 from its response. Enclosed here is the filing again, with the attachment included, in Excel and in PDF.

Consistent with the instructions issued by the Commission on March 16, 2020, and updated on October 2, 2020, this filing is being made electronically. Five (5) hard copies of this filing will be submitted to the Commission on Thursday, February 11, 2021, with two (2) hard copies being three-hole punched.

If you have any questions, please contact me at: 781-907-2126. Thank you for your time and attention to this matter.

Very truly yours,

Laura C. Bickel
RI Bar # 10055

Enclosures

cc: Docket No. 5010 Service List

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Docket No. 5010 Service List as of 9/10/2020

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PUC 8-1

Request:

In PUC 6-4 in Docket No. 5010, the Commission asked National Grid to provide a table with historic MDC values and "an explanation of how National Grid estimated that MDC rate, using what data." With this data request, the Commission sought to understand how National Grid calculates MDC values. While National Grid did clarify that the MDC values are calculated using a spreadsheet tool developed by ICF International, Inc., it did not explain how that tool works or what specific data it uses. To respond to the Commission's original request, please submit the following:

(a) A copy of the ICF International spreadsheet tool used by National Grid to calculate MDC values.

(b) Either within the spreadsheet tool or in a separate document, note where in the spreadsheet tool each of the "Company-specific inputs of historic and projected capital expenditures and loads, as well as a carrying charge calculated from applicable tax rates and FERC Form 1 accounting data" are input into the tool, and explain the specific origins of that data.

Response:

a) Please find attached the ICF International spreadsheet tool used by National Grid to calculate MDC values.
b) The below table summarizes the source of inputs requested by the PUC. The tool and attached PDF documentation has more detailed information, including formulas and sources.

Topic	**Tab**	**Cell**	**Source**
Historic Capital Expenditures	Summary Schedule 1	D14	NECO FORM 1 P206 L75c
Projected Capital Expenditures	Summary Schedule 1	E14	NECO FORM 1 P206 L75c
Historic Incremental Load	Summary Schedule 1	D24	2017 Company Specific Forecast Data. Peak forecast data used should be consistent with the company planning policy (for example if transmission investment is based on extreme weather expectations, the extreme weather peak forecast should be used. For consistency with the historical data, the forecast should be at the generation level.
Projected Incremental Load	Summary Schedule 1	E24	Forecast Peak MWs from NE PEAK 2015 Report, Appendix A

Prepared by or under the supervision of: Christopher Porter, John Richards, Jessica Darling

Historical Carrying Charge	Summary Schedule 1	D19	See "Carrying Charge Schedule 3 (DS)" with individual sources listed for formula components.
Projected Carrying Charge	Summary Schedule 1	E19	Equal to Historical Carrying Charge.

With respect to the historic and projected incremental load values, the AESC 2018 study recommended that the marginal distribution cost calculations conducted by National Grid should use a peak forecast inclusive of energy efficiency's impacts on peak demand.[1] When that recommendation was tested in the avoided T&D tool, the resulting calculation of avoided marginal distribution cost was more than $1000 per kW. The peak forecast omitting energy efficiency impacts was therefore used in the calculation. While this was not the recommendation of the AESC 2018 study, it provides a more conservative value for the calculation of the benefits of energy efficiency measures that impact peak demand in the absence of investment forecasts that account for the higher investment required in a counterfactual without energy efficiency.

Functionally this modeling choice accounts for the way that the T&D tool takes into account five years of historical and five years of projected peak loads in the calculation. The historical and forecasted peak demand data used account for the cumulative impact of past energy efficiency installations' impact on peak demand. Therefore, when the input forecast includes the impact of energy efficiency, the future peaks are reduced due to the cumulative effect of energy efficiency relative to the past. When forecasted investments in distribution infrastructure are divided by those lower peak forecasts the resulting marginal per-unit values are significantly higher than when the forecast of peak demand that does not account for energy efficiency is used. This treatment of investments and peak demand forecasts was used in both the Rhode Island and Massachusetts benefit cost analyses for the most recent energy efficiency program plans. These calculations and assumptions will be revisited as the AESC 2021 study concludes in Q2 2021 in advance of the 2022 Annual Energy Efficiency Plan development.

[1] AESC 2018, Section 10.2 page 208, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf provides helpful discussion of the considerations of the historical and forecasted distribution investment and peak demand data.

Topic	**Tab**	**Cell**	**Source**
Historic Capital Expenditures	Summary Schedule 1	D14	NECO FORM 1 P206 L75c
Projected Capitial Expenditures	Summary Schedule 1	E14	NECO FORM 1 P206 L75c
Historic Incremental Load	Summary Schedule 1	D24	2017 Company Specific Forecast Data. Peak forecast data used should be consistent with the company planning policy (for example if transmission investment is based on extreme weather expectations, the extreme weather peak forecast should be used. For consistency with the historical data, the forecast should be at the generation level.
Projected Incremental Load	Summary Schedule 1	E24	Forecast peak MWs from NE PEAK 2015 Report, Appendix A
Historical Carrying Charge	Summary Schedule 1	D19	See "Carrying Charge Schedule 3 (DS)" with individual sources listed for formula components.
Projected Carrying Charge	Summary Schedule 1	E19	Equal to Historical Carrying Charge.

Summary Schedule 1

Purpose: Assuming detailed data on incremental transmission investments are available to participants as they assess avoided Transmission and Distribution (transmission) expenses, this workbook provides a methodology for calculating marginal avoided costs. Schedule 1 performs that calculation using outputs from subordinate Schedules 2 through 4.

Inputs are Shaded in Green

Line	Description	Units	Historical	Forecast	Avoided Capacity Costs - Weighted	Avoided Capacity Costs - No Weighting	Source
1	Incremental Investments in transmission systems caused by load growth	US$000	$1,143,034	$948,245			Line 3 from Schedule 2
1Meco	Incremental Investments in distribution systems caused by load growth	US$	$136,697,216	$239,967,745			Line 3 from Schedule 2
1Neco	Incremental Investments in distribution systems caused by load growth	US$	$48,182,631	$94,020,216			Line 3 from Schedule 2
2	Annual carrying charge of transmission capital investments	%/yr	10.1%	10.1%			Line 8 from Schedule 3 (TR)
2Meco	Annual carrying charge of distribution capital investments	%/yr	23.1%	23.1%			Line 8 from Schedule 3 (DS)
2Neco	Annual carrying charge of distribution capital investments	%/yr	16.5%	16.5%			
3	Incremental growth in peak demand	MW	359	628			Line 1 from Schedule 4
3Meco		MW	255	439			
3Neco		MW	123	189			
4	Marginal cost of transmission capacity - component	$/kW-yr	$321.82	$152.62			Line 1 * Line 2 / Line 3
4Meco	Marginal cost of distribution capacity - component	$/kW-yr	$124.03	$126.48			Line 1 * Line 2 / Line 3
4Neco		$/kW-yr	$64.76	$82.24			

IN CASE OF ERRORS USERS SHOULD VERIFY VALUES. TOTAL ERRORS FOUND: 4

ALTERNATIVE CALCULATIONS OF MDC AND MTC
For 2009, we choose option (A). It is preferred over option (b) because we only have five years of historic data, which is too limited for application of weightings
Option (C) was used in prior years when we made a distinction between Res and C&I classes (primary/secondary equipment ownership), especially for RI where the utility cost test was used
However, in 2009, RI will be using the TRC test. The distinction between C&I and Res classes is no longer relevant.

A) UNWEIGHTED TOTAL MDC AND MTC. Uses the entire time period (Total column) for estimating marginal costs to reduce the effects of lumpiness in the investment cycle. Best if only limited investment data is available.
As a guideline, less than 4 years of forecast data or less than 8 years or total data should be considered limited data.
Since we only have five years of forecast data, we combine this with five years of historic data

Line	Description	Units		BASE YEAR =	2016	
6	Marginal cost of transmission capacity - total	$/kW-yr		ALL -MTC	$214.16	Σ (Line 4 * Line 5) for Components or Line 1*Line 2/ Line 3 for Total
6Meco	Marginal cost of distribution capacity - total	$/kW-yr		MA -MDC	$125.58	Σ (Line 4a * Line 5) for Components or Line 1a*Line 2a/ Line 3 for Total
6Neco		$/kW-yr		RI -MDC	$80.24	

B) WEIGHTED MDC AND MTC. Uses weighhting factors applied to historic data and forecast data. Weighting Factors are used to allow for component periods to be given greater or lesser importance in determining the marginal costs.
Component periods should only be used in cases where adequate investment occurs in the component periods or in cases where the quality of the data for either component is unreliable.

Line	Description	Units	Historical	Forecast		
5	Weighting of component costs	%	50%	50%	BASE YEAR =	2016
	Marginal cost of transmission capacity - total					$237.22
6Meco	Marginal cost of distribution capacity - total					$125.25
6Neco						$73.50

C) SPLIT BETWEEN PRIMARY AND SECONDARY: uses old MDC ratios and peak load data to split MDC into Res & C&I components

					BASE YEAR =	2016	
	OLD MDC --->	Res	C&I	Ratio	RES	C&I	
7Meco		114.571	77.9864	1.469115128	$154.12	104.91	MA -MDC
7Neco		87.944	60.3411	1.457447743	$99.23	68.09	RI -MDC
	CLASS PEAK LOAD SHARE --->	Res	C&I		$214.16	$214.16	ALL -MTC
7Meco		42%	58%				
7Neco		39%	61%				

Transmission Investment Schedule 2

Purpose: This schedule tracks capital investments made on transmission systems over a specific historical or future time period. (The same time period peak growth was tracked for Schedule 4.) The time period requires a duration over which a reasonable amount of investment occurred or is projected to occur; recommended is 25 years in length:- 15 historical years and 10 forecast years.

** Could not remove PTF - so using the $94 value from the 2018 AESC Study

Need to adjust BASE YEAR every year and correct real $ equation every year. BASE YEAR = 2016

Because available forecast is only 5 years, but 1st FY of forecast is already halfway over, National Grid has adopted practice of 5 historic/6 future. We need to adjust periods in Lines 1, 1a, and 1b every year

Inputs are Shaded in Green (previously used), New/Needed Inputs are Shaded in Yellow

Line	Description	Units	NEP TRANSMISSION Nominal$ (1) (2) (3)	NEP TRANSMISSION Real$	Mass. (MECO + NANT) DISTRIBUTION Nominal$	Mass. (MECO + NANT) DISTRIBUTION Real$	NECO FORM 1 P206 L75c DISTRIBUTION Nominal$	NECO DISTRIBUTION Real$	GSECO Nominal$	GSECO Real$	Source	
1	Incremental Investments into transmission systems - Historical	US$000	1,547,244	1,632,906	998,556,206	1,051,517,049	304,248,718	321,217,538	-	-	Sum of 5 most recent 5 historic years	
1a	Incremental Investments into transmission systems - Forecast	US$000	1,395,411	1,354,636	1,901,467,494	1,845,905,731	645,668,165	626,801,442	-	-	Sum of 6 most recent forecast years	
1b	Incremental Investments into transmission systems - Total	US$000	2,942,654	2,987,542	2,900,023,700	2,897,422,781	949,916,883	948,018,979	-	-	Sum of the above (5 hist.+ 6 frct. years)	
c	Capital Investment: Year 1 (Historical) 1993	US$000	17,822	35,252	0	0	26,410,521	52,239,965				1993
d	Capital Investment: Year 2 (Historical) 1994	US$000	75,906	145,755	0	0	43,015,253	82,597,899				1994
e	Capital Investment: Year 3 (Historical) 1995	US$000	26456	49,316	0	0	42273840	78,802,288				1995
f	Capital Investment: Year 4 (Historical) 1996	US$000	39,928	72,255	0	0	26,692,971	48,304,174				1996
g	Capital Investment: Year 5 (Historical) 1997	US$000	53,373	93,763	86150425	151,344,199	24625546	43,260,768				1997
h	Capital Investment: Year 6 (Historical) 1998	US$000	41,039	69,989	75644292	129,004,581	25722104	43,866,750				1998
i	Capital Investment: Year 7 (Historical) 1999	US$000	54,624	90,434	77,155,499	127,736,928	19,555,018	32,374,853				1999
j	Capital Investment: Year 8 (Historical) 2000	US$000	34,395	55,280	85,185,624	136,910,420	34,997,102	56,247,377				2000
k	Capital Investment: Year 9 (Historical) 2001	US$000	71,494	111,548	84,125,734	131,256,154	33,979,551	53,016,181				2001
l	Capital Investment: Year 10 (Historical) 2002	US$000	37,018	56,069	87,832,291	133,034,913	34,383,487	52,078,844				2002
m	Capital Investment: Year 11 (Historical) 2003	US$000	56,375	82,893	119,599,897	175,858,287	41,859,256	61,549,360				2003
n	Capital Investment: Year 12 (Historical) 2004	US$000	72,100	102,917	114,225,180	163,047,633	32,605,299	46,541,549				2004
o	Capital Investment: Year 13 (Historical) 2005	US$000	67,676	93,780	133,159,165	184,520,372	47,043,894	65,189,331				2005
p	Capital Investment: Year 14 (Historical) 2006	US$000	112,154	150,872	138,814,935	186,736,866	46,988,796	63,210,349				2006
q	Capital Investment: Year 15 (Historical) 2007	US$000	156,951	204,964	157,943,112	206,260,077	47,892,648	62,543,666				2007
r	Capital Investment: Year 16 (Historical) 2008	US$000	99,414	126,032	158,598,930	201,064,478	67,688,304	85,812,139				2008
s	Capital Investment: Year 17 (Historical) 2009	US$000	181,033	222,799	160,244,980	197,215,091	50,501,487	62,152,682				2009
t	Capital Investment: Year 18 (Historical) 2010	US$000	166,265	198,645	156,785,385	187,319,030	50,710,050	60,585,732				2010
u	Capital Investment: Year 19 (Historical) 2011	US$000	147,326	170,874	169,954,744	197,119,790	40,245,646	46,678,387				2011
v	Capital Investment: Year 20 (Historical) 2012	US$000	262,799	295,898	151,724,143	170,833,187	50,832,585	57,234,744				2012
w	Capital Investment: Year 21 (Historical) 2013	US$000	253,071	276,618	144,261,322	157,684,160	39,112,499	42,751,733				2013
x	Capital Investment: Year 22 (Historical) 2014	US$000	296,450	314,565	202,738,799	215,127,358	74,615,506	79,174,962				2014
y	Capital Investment: Year 23 (Historical) 2015	US$000	362,190	373,092	267,123,015	275,163,418	78,670,122	81,038,093				2015
z	Capital Investment: Year 24 (Historical) 2016	US$000	372,733	372,733	232,708,927	232,708,927	61,018,006	61,018,006				2016
aa	Capital Investment: Year 25 (Forecast) 2017	US$000	241,015	233,972	279,459,197	271,293,270	91,884,613	89,199,702				2017
ab	Capital Investment: Year 26 (Forecast) 2018	US$000	220,813	214,361	346,008,297	335,897,774	111,511,650	108,253,228				2018
ac	Capital Investment: Year 27 (Forecast) 2019	US$000	246,947	239,731	327,000,000	317,444,908	106,972,149	103,846,373				2019
ad	Capital Investment: Year 28 (Forecast) 2020	US$000	250,695	243,369	305,000,000	296,087,758	108,300,015	105,135,438				2020
ae	Capital Investment: Year 28 (Forecast) 2021	US$000	222,358	215,861	319,000,000	309,678,672	110,999,605	107,756,145				
af	Capital Investment: Year 28 (Forecast) 2022	US$000	213,582	207,341	325,000,000	315,503,349	116,000,133	112,610,555				

Source:

Nominal$, (historical) from FERC Form 1, P206, Line 75 (c) "TOTAL Distribution Plant"

Real$ column, historical investment costs are inflated to last historic year (Baseline Year) using the historical escalation rate. The historical escalation rate is an average of 10-year rolling averages of Transmission Plant Cost Index from the Handy Whitman Index for the 2002-2012 period.

Real$ column, forecast investment costs are deflated to last historic year (Baseline Year) using the forecast escalation rate. The forecast escalation rate is based on an average of 10-year rolling averages of Transmission Plant Cost Index from the Handy Whitman Index for the 1991-2004 period and is adjusted for general inflation calculated for the same time period. Forecast investments were given to us in 2013 dollars so they

Three Company Summed Data for NEP Transmission (column D)

PAGE 206 LINE 58 c for the calc of inputs in table to right

	NEP	MECo/NANT	NECo	GSECO	TOTAL for NEP
2006	108,642,257	2,872,872	638,517	0	112,153,646
2007	145,551,971	2,895,005	8,503,766	0	156,950,742
2008	64,974,859	2,650,421	31,788,587	0	99,413,867
2009	172,120,526	1,038,392	7,873,872	0	181,032,790
2010	113,851,898	872,440	51,541,108	0	166,265,446
2011	113,719,158	1,497,060	32,109,852	0	147,326,070
2012	118,757,910	1,570,380	142,471,000	0	262,799,290
2013	165,060,713	5,925,148	82,085,000	0	253,070,861
2014	263,633,313	5,430,399	27,386,526	0	296,450,238
2015	187,218,340	8,134,702	166,836,922	0	362,189,964
2016	255,628,603	1,094,072	116,010,494	0	372,733,169

Historical Escalation Rate	%	3.01%	Handy Whitman for 2008-2017
Forecast Escalation Rate	%	3.01%	Handy Whitman for 2008-2017

Line			Transmission	MECo	NECo	
2	Percentage Assumed to be Related to Increasing Load	%	70%	13%	15%	The percentage due to load growth would be between 26% in Massachusetts and 35% in Rhode Island from Glen DiConza, 5/23/17

	MECo	NECo	
load growth	26%	35%	
above number, X$% of abover number)	13.0%	15.0%	Represents the amount with new business removed

Line	Description	Units	Transmission	MECo	NECo	GSECO	Source
3	Incremental Investments in Transmission Systems caused by Load Growth - Historical	US$	1,143,034.13	136,697,216.43	48,182,630.66	-	Line 1 times Line 2
3a	Incremental Investments in Transmission Systems caused by Load Growth - Forecast	US$	948,245.21	239,967,745	94,020,216.25	-	Line 1a times Line 2
3b	Incremental Investments in Transmission Systems caused by Load Growth - Total	US$	2,091,279.34	376,664,961.52	142,202,846.90	-	Line 1b times Line 2

(1) FERC FORM 1 NEW ENGLAND POWER COMPANY, PAGE 206 L58 (L53 prior to 2003) Total Additions to Transmission Plant
(2) FERC FORM 1 MASSACHUSETTS ELECTRIC COMPANY, PAGE 206, L58 Total Additions to Transmission Plant
(3) FERC FORM 1 NARRAGANSETT ELECTRIC COMPANY, PAGE 206, L58 (c) Total Additions to Transmission Plant

DISTRIBUTION CAPITAL BUDGET - updated 2017	FY2013	FY2014	FY2015	FY2016	FY2017	FY2018	FY2019	FY2020	FY2021	FY2022	FY2023
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
CAPEX By jurisdiction											
Massachusetts (MECO+NANT) - "MA Electric Capex - Total"	$ 170,000.00	$ 205,419.00	$ 242,100.00	$ 292,140.00	$ 279,459.20	$ 346,008.30	$ 327,000.00	$ 305,000.00	$ 319,000.00	$ 325,000.00	$ 313,000.00
Narragansett Electric Company (NECO) - "Narr Electric Capex - Subtotal" "17-18 are actuals"	$ 50,250.00	$ 78,000.00	$ 72,590.00	$ 83,655.00	$ 91,884.61	$ 111,511.65	$ 106,972.15	$ 108,300.02	$ 110,999.61	$ 116,000.13	$ 115,699.58
Distribution Capex Additions - Totals	220,250	283,419	314,690	375,795	371,344	457,520	433,972	413,300	430,000	441,000	428,700

TRANSMISSION CAPITAL BUDGET	Converting from FY to Calendar Year			
	Fisc Year	$million NEP+MECO+NECO	Cal Yr $million	Calendar Year
US Transmission				
NEP Capex Spend from 2015 budget in $,	FY13 -hist	260.0	$232.81	2013
	FY14 - hist	223.8	$291.45	2014
	FY15 -hist	314.0	$312.98	2015
	FY16 - hist	312.6	$282.89	2016
	FY17 -fcst	273.0	$241.01	2017
Assume level funding from year previous if no data for final year.	FY18 -fcst	230.4	$220.81	2018
	FY19 -fcst	217.6	$246.95	2019
	FY20 -fcst	256.7	$250.69	2020
	FY21 -fcst	248.7	$222.36	2021
	FY22 -fcst	213.6	$213.58	2022

Company ID	PTF FY19	Non-PTF FY19	Total FY19 Capex
5310 MECO-T	1,001	2,121	3,123
5360 NECO-T	26,899	40,387	67,286
5410 NEP	109,609	64,740	174,349

Status:

DISTRIBUTION CAPITAL BUDGET - updated 2017	Updated	Actual	Fcast	Fcast	Fcast	Fcast	Fcast
CAPEX By jurisdiction	FY2017 $000	FY2018 $000	FY2019 $000	FY2020 $000	FY2021 $000	FY2022 $000	FY2023 $000
Massachusetts (MECO+NANT) - "MA Electric Capex - Total"	279,459.197	346,008.297	327,000.000	305,000.000	319,000.000	325,000.000	313,000.000
Narragansett Electric Company (NECO) - "Narr Electric Capex - Subtotal" "17-18 are actuals"	91,884.613	111,511.650	106,972.149	108,300.015	110,999.605	116,000.133	115,699.580
Distribution Capex Additions - Totals	371,343.810	457,519.947	433,972.149	413,300.015	429,999.605	441,000.133	428,699.580

Carrying Charge Schedule 3 - Transmission

Purpose: Schedule 1 tracks large long-termed investments in transmission systems. This Schedule calculates the factor used to determine the annual cost of those investments. Annual costs include obligations to debt holders and shareholders for those long-term investments, as well as taxes, insurance, and other recurring expenses. In calculating an annual charge we can get from $/kW reductions to $/kW-yr reductions, valuing DSM programs over their useful life.

Data source - Use most recent FERC Form 1 form for NEP.

Inputs are Shaded in Green (previously used), New/Needed Inputs are Shaded in Yellow

Line	Description	Units	Source		Source / Notes	
1	**Real After Tax Cost of Financing (WACC)**	**%**	Formula	**4.0%**	**[(1-Line 1a)*(Line 1c)]+[(Line 1a)*(Line 1b)*(1-Line 1f)]**	
a	Share of project financed through debt	%	NA	**50%**		
b	Real Interest Rate on Debt	%	NA	**0%**	**(1+ Line 1b1) / (1+Line 9) -1**	
b1	Nominal Interest Rate on Debt	%	NA	**2%**	Nominal value only is available, the value should be converted to real using the inflation rate	
c	Expected After Tax Real Return on Equity	%	NA	**8%**		
c1	Expected After Tax Nominal Return on Equity	%	NA	**10%**	**(1+Line 1c1) / (1+Line 9)-1**	
d	State Income Tax Rate	%	NA	**6.93%**		
e	Federal Income Tax Rate	%	NA	**21%**	(will state in FERC form 1 (can find on page 450.2)	
f	**Effective State and Federal Income Tax Rate**	**%**	**Formula**	**26%**	**Line 1d + Line 1e * (1-1d)**	
2	**Property Taxes Expense**	**%**	Formula	**1.1%**	**Line 2a / Line 2b**	
a	Total Plant Annual Property Taxes	MM$	NEP FERC Form 1 Taxes Accrued, Prepaid and Charged During the Year (pg 263 column i, municipal -transmission) where available, else Form 1 Electric Operation and Maintenance Expenses (pg 323 line 164)	**28.53**	Line 2b must be consistent with data entered for Line 2a. For line 2b, use (value from FERC form)/10^6	2012 NEP page 263. Sum lines for MA, NH, RI, VT
b	Net Book Value of Total Plant	MM$	Form 1 Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion - Net utility plant (pg 200 line 15)	**2,553.69**		2016 NEP page 200
				\		
3	**Insurance Expense**	**%**	Formula	**0.0%**	**Line 3a / Line 3b**	
a	Total Plant Annual Insurance Costs	MM$	Form 1 Electric Operation and Maintenance Expenses (pg 323 line 185) "property insurance" current year	**1.04**	use number from Form 1 in this formula =(Value)/10^6	2016 NEP
b	Net Book Value of Total Plant	MM$	Form 1 Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion (pg 200 line 15)	**2,553.69**		2016 NEP page 200
4	**Depreciation Expense (using Sinking Fund Factor Approach)**	**%**	Formula	0.83%	**Line 1/ ((1+ Line 1) ^ Line 4a -1)**	
a	**Depreciation Life of Transmission Plant**	**Yr**		**45**		
5	**Operation and Maintenance Expense**	**%**	Formula	**3.2%**	**Line 5a / Line 5b**	
a	Annual Transmission Operation and Maintenance Expenses	MM$	NEP FERC Form 1 Electric Operation and Maintenance Expenses as per Appendix 1	58.49		
b	Net Book Value of Distribution Plant	MM$	Formula	1,833.12	**Line 5c - Line 5d**	
c	Electric Plant in Service	$	NEP page 207 L58 end of yr. *Old: Form 1 Electric Plant in Service (pg 207 line 75 for D; line 58, col g, for T)*	**2,276,550,274**		2016 NEP page 207 L58 end of yr
d	Accumulated Depreciation	$	Accumulated Provision for Depreciation of Electric Utility Plant (pg 219 line 26 for D, line 25 for T)	**443,428,297**		2016 NEP page 219 L25
7	**Income Taxes Expense**	**%**	Formula	**0.936%**	**(Line 1f / Line 6a)*(Line 1+Line 4-1/Line 4a)*(1-Line 1a*Line 1b / Line 1)**	
a	Gross up factor for taxes	%	Formula	74%	**1 - Line 1f**	
8	**Annual Real Carrying Charge of Capital Investments**	**%**	Formula	**10.1%**	**(Line 1+Line 2+Line 3+Line 4+Line 5+Line 6)**	
9	General Inflation	%	Input	**1.86%**	**Set to 2019 Plan value inflation rate**	
					before 2013, we used this: based on Consumer Price Index - July'12 (the change in the CPI from a year earlier. So compare Jan 2015 to Jan 2014. use the CPI index for all urban customers)	
					-0.1	

Form 1 line	FERC Form 1 page 262-63 column (i) municipal - trans		
	Municipal - Transmission		
10	MA		24,657,699
17	NH		2,788,702
23	VT		1,080,853
26	ME		
28	RI		
31	CT		
	NY		
35	RI		146,854
	PA		
		TOTAL	**28,674,108**
	minus NH		25,885,406
	minus vt		27,593,255
	minus ri		28,527,254

Could the "Total Plant Annual Property Taxes" (line 2a) be the Municipal - transmission tax for electric of just MA, NH, VT but not RI (FERC Form 1pg 262-3)?

2012 NEP page 263. Sum lines for MA, NH, RI, VT

Carrying Charge Schedule 3 - Distribution

You are correct, our federal rate for all companies is now at 21%. NECO state tax rate remains at zero. MECO remains at 8%. For NEP, we are currently using a state blended rate of 6.93%. Let me know if you need anything else.

1,871

Purpose: Schedule 1 tracks large long-termed investments in transmission systems. This Schedule calculates the factor used to determine the annual cost of those investments. Annual costs include obligations to debt holders and shareholders for those long-term investments, as well as taxes, insurance, and other recurring expenses. In calculating an annual charge we can get from $/kW reductions to $/kW-yr reductions, valuing DSM programs over their useful life.

MECO, NECO, and GSECO have been updated at different time intervals because of the different planning periods at National Grid.

Inputs are Shaded in Green (previously used/ no alternation required), New/Needed Inputs are Shaded in Yellow

Line	Description	Units	Source	2016 Form 1 MECO	2016Form 1 NECO	2006 Form 1 GSECO	Source / Notes	Recent Notes:
1	**After Tax Cost of Financing (WACC)**	%	Formula	6.4%	6.2%		[(1-Line 1a)*(Line 1c)]+[(Line 1a)*(Line 1b)*(1-Line 1f)]	
a	Share of project financed through debt	%	NA	50%	50%			
b	Real Interest Rate on Debt	%	NA	4%	3%		(1+ Line 1b1) / (1+Line 9) -1 Nominal value only is available, the value should be converted to real using the inflation rate	
b1	Nominal Interest Rate on Debt	%	NA	5.8%	5.1%			
c	Expected After Tax Real Return on Equity	%	NA	10%	10%		(1+Line 1c1) / (1+Line 9)-1	
c1	Expected After Tax Nominal Return on Equity	%	NA	12%	12%			
d	State Income Tax Rate	%	NA	8%	0%		MECO – 6.5% state rate until March 31, 2014, 8% state rate from April 1, 2014 forward.	
e	Federal Income Tax Rate	%	NA	21%	21%			
f	Effective State and Federal Income Tax Rate	%	Formula	27%	21%		Line 1d + Line 1e * (1-1d)	
2	**Property Taxes Expense**	%	Formula	4.0%	0.9%		Line 2a / Line 2b	
a	Total Plant Annual Property (Real Estate) Taxes	MM$	Form 1 Taxes Accrued, Prepaid and Charged During the Year, Under Distribution of taxes charged "electric" (line 11 I, p.263) *OLD: (pg 263 column i distribution share) where available, else Form 1 Electric Operation and Maintenance Expenses (pg 323 line 164)*	87.11	20.20		Line 2b must be consistent with data entered for Line 2a. NECO/MECO 2016 used page 322 Line 164 since there was no tax information on page 263	
b	Net Book Value of Total Plant	MM$	If Taxes Accrued schedule identified for distribution only in Line 2a, then enter value as per Line 5b. If Operation and Maintenance Expenses Schedule is used, enter value as per line 3b	2,195.12	2,277.23			
3	**Insurance Expense**	%	Formula	1.3%	0.4%		Line 3a / Line 3b	
a	Total Plant Annual Insurance Costs	MM$	Form 1 Electric Operation and Maintenance Expenses (pg 323 line 185)	49.74	8.03		NECO FERC Form 1 2016 page 323 L185	
b	Net Book Value of Total Plant	MM$	Form 1 Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion (pg 200 line 15 c)	3,727.12	2,277.23		NECO FERC Form 1 2016 page 200 L15c	
4	**Depreciation Expense (using Sinking Fund Factor Approach)**	%	Formula	1.60%	1.51%		Line 1/ ((1+ Line 1) ^ Line 4a -1)	
a	**Depreciation Life of Distribution Plant**	Yr		26	27			
5	**Operation and Maintenance Expense**	%	Formula	8.3%	6.5%		Line 5a / Line 5b	
a	Annual Distribution Operation and Maintenance Expenses	MM$	Form 1 Electric Operation and Maintenance Expenses as per Appendix 1	182.21	50.22			
b	Net Book Value of Distribution Plant	MM$	Formula	2,195.12	776.21		Line 5c - Line 5d	
c	Electric Plant in Service	$	Form 1 Electric Plant in Service (pg 207 line 75)	3,775,362,613	1,401,914,307		NECO FERC Form 1 2016 page 207 L75g	
d	Accumulated Depreciation	$	Accumulated Provision for Depreciation of Electric Utility Plant, balances and changes during the year, "distribution" (pg 219 line 26 c or 19)	1,580,246,219	625,699,916		NECO FERC Form 1 2016 page 219 L26b	
6	**Income Taxes Expense**	%	Formula	1.554%	1.075%		(Line 1f / Line 6a)*(Line 1+Line 4-1/Line 4a)*(1-Line 1a*Line 1b / Line 1)	
a	Gross up factor for taxes	%	Formula	73%	79%		1 - Line 1f	
7	**Annual Real Carrying Charge of Capital Investments**	%	Formula	23.1%	16.5%		(Line 1+Line 2+Line 3+Line 4+Line 5+Line 6)	
8	General Inflation	%	Input	1.86%	1.86%			
			2006 CC	11.7%	11.9%			

Appendix 1: Transmission and Distribution Operation and Maintenance Cost Avoidable Expenses

Inputs are Shaded in Green

		NEP 2016	MECO 2013	NECO 2016	GSECO 2009			NEP 2016	MECO 2013	NECO 2016	GSECO 2009	
	Category	**FERC Form 1 Operation and Maintenance Expenses page 321**				**Share Avoidable**	**Share Not Avoidable**	**Avoidable Costs ($)**				**Notes**
Source:		**Enter Value in $ Directly from Form 1**				**Assumption**	**Assumption**	**Calculation**				
TRANSMISSION EXPENSES - OPERATION												
Operation	(560) Operation Supervision and Engineering	644,817	29,699	1,124,230		0%	100%	-	-	-	-	
Operation	(561) Load Dispatching	8,044,207	18,010,749	6,465,395		0%	100%	-	-	-	-	
Operation	(562) Station Expenses	1,044,022	1,285,859	606,595		10%	90%	104,402	128,586	60,660	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Operation	(563) Overhead Lines Expenses	1,934,102	1,046,451	404,856		20%	80%	386,820	209,290	80,971	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Operation	(564) Underground Lines Expenses	0	36,938	0		20%	80%	-	7,388	-	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Operation	(565) Transmission of Electricity by Others	9,925,870	369,137,595	27,000,069		20%	80%	1,985,174	73,827,519	5,400,014	-	Share will vary considerable based on situation of individual companies and purpose of the transmission investment
Operation	(566) Miscellaneous Transmission Expenses	5,411,837	901,851	2,971,259		50%	50%	2,705,919	450,926	1,485,630	-	Items included in this category may be vary from company to company or year to year and may span variable and fixed costs. A 50% split is used as a proxy.
Operation	(567) Rents	3,956,072	31,505	103,987		0%	100%	-	-	-	-	Rents are considered fixed
	Total (as a check for correct entry)	30,960,927	390,480,647	38,676,391								
TRANSMISSION EXPENSES - MAINTENANCE												
Maintenance	(568) Maintenance Supervision and Engineering	812,683	136,287	67,964		0%	100%	-	-	-	-	
Maintenance	(569) Maintenance of Structures	61,653	28,573	83,948		20%	80%	12,331	5,715	16,790	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(570) Maintenance of Station Equipment	4,495,046	685,875	862,890		20%	80%	899,009	137,175	172,578	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(571) Maintenance of Overhead Lines	21,648,474	1,093,190	1,450,492		20%	80%	4,329,695	218,638	290,098	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(572) Maintenance of Underground Lines	123,018	48,162	747,878		20%	80%	24,604	9,632	149,576	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(573) Maintenance of Miscellaneous Transmission Pla	383,294	162,527	16,071		50%	50%	191,647	81,264	8,036	-	Items included in this category may be vary from company to company or year to year and may span variable and fixed costs. A 50% split is used as a proxy.
	Total (as a check for correct entry)	27,524,168	2,154,614	3,229,243								
AVOIDABLE TRANSMISSION O&M		58,485,095	392,635,261	41,905,634				10,639,600	75,076,132	7,664,351	-	
DISTRIBUTION EXPENSES - OPERATION												
Operation	(580) Operation Supervision and Engineering	0	2,709,725	1,739,133		0%	100%	-			-	
Operation	(581) Load Dispatching	0	4,167,739	2,244,001		0%	100%	-			-	
Operation	(582) Station Expenses	0	2,403,644	1,149,970		10%	90%	-	240,364	114,997	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Operation	(583) Overhead Line Expenses	0	5,528,073	3,283,676		20%	80%	-	1,105,615	656,735	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Operation	(584) Underground Line Expenses	0	2,151,062	357,037		20%	80%	-	430,212	71,407	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Operation	(585) Street Lighting and Signal	0	3,078,089	218,107		0%	100%	-	-	-	-	
Operation	(586) Meter Expenses	0	13,199,155	2,050,886		0%	100%	-	-	-	-	
Operation	(587) Customer Installations Expenses	0	3,742,382	99,166		0%	100%	-	-	-	-	
Operation	(588) Miscellaneous Expenses	40,336	29,953,231	6,901,716		50%	50%	20,168	14,976,616	3,450,858	-	Items included in this category may be vary from company to company or year to year and may span variable and fixed costs. A 50% split is used as a proxy.
Operation	(589) Rents	0	438,600	342,898		0%	100%	-	-	-	-	
	Total (as a check for correct entry)	40,336	67,371,700	18,386,590					-	-	-	
DISTRIBUTION EXPENSES - MAINTENANCE									-	-	-	
Maintenance	(590) Maintenance Supervision and Engineering	0	27,396	455,954		0%	100%	-	-	-	-	
Maintenance	(591) Maintenance of Structures	0	390,321	59,096		20%	80%	-	78,064	11,819	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(592) Maintenance of Station Equipment	-9	7,465,323	1,336,120		10%	90%	(1)	746,532	133,612	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(593) Maintenance of Overhead Lines	0	95,789,728	25,241,880		20%	80%	-	19,157,946	5,048,376	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(594) Maintenance of Underground Lines	0	5,041,347	2,390,497		20%	80%	-	1,008,269	478,099	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(595) Maintenance of Line Transformers	0	530,567	431,001		20%	80%	-	106,113	86,200	-	Majority of expenses will be considered fixed and will not be affected by normal new investment in equipment.
Maintenance	(596) Maintenance of Street Lighting and Signal	0	4,628,414	1,013,628		0%	100%	-	-	-	-	
Maintenance	(597) Maintenance of Meters	0	144,098	77,721		0%	100%	-	-	-	-	
Maintenance	(598) Maintenance of Miscellaneous Distribution Plant	0	817,711	827,645		50%	50%	-	408,856	413,823	-	Items included in this category may be vary from company to company or year to year and may span variable and fixed costs. A 50% split is used as a proxy.
	Total (as a check for correct entry)	-9	114,834,905	31,833,542								
AVOIDABLE DISTRIBUTION O&M		40,327	182,206,605	50,220,132				20,167	38,258,587	10,465,927	-	

Shares are based on expert judgment unless noted.

*** Use these total values in the carrying charge

Peak Growth Schedule 4

Purpose: This schedule tracks peak demand growth over a specific historical or future time period. (The same time period transmission investment was tracked for Schedule 2 except that the starting year is a year prior to the transmission investment.) The time period requires a duration over which a reasonable amount of investment occurred or is projected to occur; recommended is 25 years in length: 15 historical years and 10 forecast years. Please note: Peak demand can vary widely from year to year, as seasonal temperatures affect consumption during peak periods. If historical information is used for this analysis, please ensure that the starting and ending points are relatively weather normal.

Because available forecast is only 5 years, but 1st FY of forecast is already halfway over, National Grid has adopted practice of 5 historic/6 future. We need to adjust periods in Lines 1, 1a, and 1b every year

Because the distribution peaks are PSA loads at the power substation interfaces between the transmission and distribution systems, the distribution load differences are grossed up by the transmission loss factor of 2%. This puts all loads at the generation level for consistency in application of loss factors. No adjustments are made to Tx loads

Inputs are Shaded in Green (previously used/ no alternation required), New/Needed Inputs are Shaded in Yellow

Transmission loss factor 2%

Line	Description	Units	NEP updated 2017	MECo + NANT updtd 2017	NECo updtd 2017	Source					
1	**Incremental growth in peak demand - Historical**	**MW**	359	255	123	**Maximum Value of most recent 5 year historical - the year before historical time period (6 years behind)**					
1a	**Incremental growth in peak demand - Forecast**	**MW**	628	439	189	**Maximum Value of 6 most recent forecasted years minus most recent historical year**					
1b	**Incremental growth in peak demand - Total**	**MW**	987	694	293	**Maximum Value of 5 historic years and 6 forecast years minus historical value of year before that set of numbers**					
c	Peak Demand: Year 0 (Historical) 1992	MW	3,964				1992				
d	Peak Demand: Year 1 (Historical) 1993	MW	4,075				1993				
e	Peak Demand: Year 2 (Historical) 1994	MW	4,370				1994				
f	Peak Demand: Year 3 (Historical) 1995	MW	4,341				1995				
g	Peak Demand: Year 4 (Historical) 1996	MW	4,632	3,370	1,261		1996				
h	Peak Demand: Year 5 (Historical) 1997	MW	4,981	3,588	1,394	Historicals from Form 1	1997				
i	Peak Demand: Year 6 (Historical) 1998	MW	5,210	3,791	1,418	_____(pg 401 Monthly Peaks	1998				
j	Peak Demand: Year 7 (Historical) 1999	MW	5,532	4,022	1,511	and Output, line highest of lines	1999	includes EUA pre-merger, from 2005 PSA forecast document			
k	Peak Demand: Year 8 (Historical) 2000	MW	5,355	3,879	1,475	29-40)	2000				
l	Peak Demand: Year 9 (Historical) 2001	MW	6,077	4,413	1,663		2001				
m	Peak Demand: Year 10 (Historical) 2002	MW	6,269	4,582	1,687		2002	NEP Page 400 max col. E			
n	Peak Demand: Year 11 (Historical) 2003	MW	6,048	4,412	1,636		2003				
o	Peak Demand: Year 12 (Historical) 2004	MW	5,915	4,314	1,602		2004				
p	Peak Demand: Year 13 (Historical) 2005	MW	6,673	4,885	1,788		2005				
q	Peak Demand: Year 14 (Historical) 2006	MW	7,038	5,106	1,932		2006				
r	Peak Demand: Year 15 (Historical) 2007	MW	6,450	4,690	1,760		2007				
s	Peak Demand: Year 16 (Historical) 2008	MW	6,487	4,706	1,781	Company Specific Forecast	2008				
t	Peak Demand: Year 17 (Historical) 2009	MW	6,110	4,434	1,676	Data. Peak forecast data used	2009				
u	Peak Demand: Year 18 (Historical) 2010	MW	6,716	4,892	1,824	should be consistent with the	2010				
v	Peak Demand: Year 19 (Historical) 2011	MW	6,920	4,985	1,935	company planning policy (for	2011				FERC Form 1
w	Peak Demand: Year 20 (Historical) 2012	MW	7,072	5,128	1,944	example if transmission	2012		4,749	1,892	FERC Form 1
x	Peak Demand: Year 21 (Historical) 2013	MW	7,154	5,174	1,980	investment is based on extreme	2013		4,982	1,954	FERC Form 1
y	Peak Demand: Year 22 (Historical) 2014	MW	7,006	5,074	1,932	weather expectations, the	2014		4,387	1,653	FERC Form 1
z	Peak Demand: Year 23 (Historical) 2015	MW	7,268	5,210	2,058	extreme weather peak forecast	2015		4,375	1,738	FERC Form 1
aa	**Peak Demand: Year 24 (Historical) 2016**	MW	7,279	5,240	2,039	should be used. For	2016		4,541	1,802	FERC Form 1
						consistency with the historical					
						data, the forecast should be at					
ab	Peak Demand: Year 25 (Forecast) 2017	MW	7,469	5,376	2,093	the generation level.	2017				
ac	Peak Demand: Year 26 (Forecast) 2018	MW	7,585	5,460	2,125		2018				
ad	Peak Demand: Year 27 (Forecast) 2019	MW	7,674	5,525	2,149		2019				
ae	Peak Demand: Year 28 (Forecast) 2020	MW	7,748	5,575	2,173	2014 onward, forecast values	2020				
ef	Peak Demand: Year 29 (Forecast) 2021	MW	7,826	5,626	2,200	(MECO + NANT) updated from	2021				
ag	Peak Demand: Year 30 (Forecast) 2022	MW	7,907	5,679	2,228	NE Peak report. See appendix	2022				
ah	Peak Demand: Year 31 (Forecast) 2023	MW	7,988	5,733	2,255	A. They are Peak MW	2023				
ai	Peak Demand: Year 32 (Forecast) 2024	MW	8,068	5,787	2,281	forecasts from a 50/50	2024				
aj	Peak Demand: Year 33 (Forecast) 2025	MW	8,149	5,842	2,307	scenario. Use numbers that	2025				
ak	Peak Demand: Year 34 (Forecast) 2026	MW	8,228	5,896	2,332	include EE savings (Decision	2026				
al	Peak Demand: Year 35 (Forecast) 2027	MW	-	-	-	made after AESC study 2018)	2027				
am	Peak Demand: Year 36 (Forecast) 2028	MW	-	-	-		2028				
an	Peak Demand: Year 37 (Forecast) 2029	MW	-	-	-		2029				

2017 UPDATE

Forecast PEAK MWs from NE PEAK 2015 Report appendix A
Peak without EE (Forecast based on 50/50 scenario)

		MA (without EE and PV)	NECO (without EE and PV)
	2012	5,128	1,944
	2013	5,174	1,980
Actuals	2014	5,074	1,932
	2015	5,210	2,058
	2016	5,240	2,039
	2017	5,376	2,093
	2018	5,460	2,125
	2019	5,525	2,149
	2020	5,575	2,173
	2021	5,626	2,200
Forecast	2022	5,679	2,228
normal	2023	5,733	2,255
50/50	2024	5,787	2,281
(without all	2025	5,842	2,307
EE and PV)	2026	5,896	2,332
in MW			

Method changed in 2018 from Synapse AESC update Now use forecast with EE savings included.

	MA (includes EE and PV)	NECO (Includes EE and PV)
2012	4,749	1,892
2013	4,982	1,954
2014	4,387	1,653
2015	4,375	1,738
2016	4,541	1,802
2017	4,419	1,793
2018	4,386	1,783
2019	4,378	1,780
2020	4,361	1,780
2021	4,348	1,786
2022	4,341	1,794
2023	4,338	1,804
2024	4,337	1,812
2025	4,340	1,821
2026	4,345	1,830