PUC 5-1

Request:

Referencing PUC 2-8, please add a column to show the net present value calculation that results in a direct benefit from the program of approximately $4 million. Please provide the discount rate and the interest rate used. Please also plot that new column as a new line on the graph from PUC 2-8.

Response:

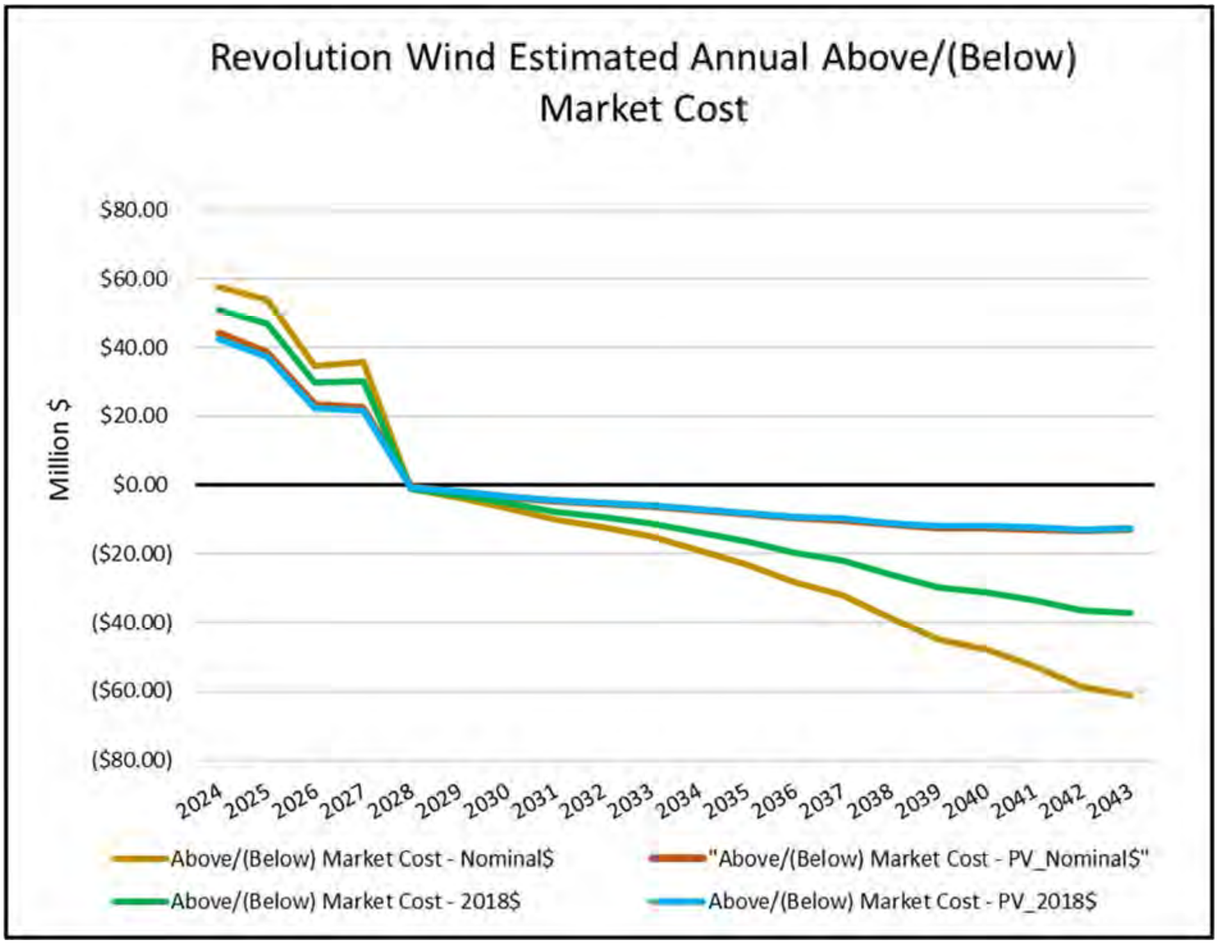
The table and graph summarize data provided in Attachment Schedule NG-5-A (Confidential).

Year	Annual Above/(Below) Market Cost *Nominal$*	Annual Above/(Below) Market Cost *NPV - Nominal$* π	Annual Above/(Below) Market Cost *2018$* †	Annual Above/(Below) Market Cost *NPV - 2018$* ‡
2024	$57,672,871	$44,014,809	$51,211,859	$42,305,914
2025	$54,121,903	$38,606,205	$47,116,373	$37,107,357
2026	$34,754,872	$23,171,629	$29,662,949	$22,272,047
2027	$35,933,439	$22,392,185	$30,067,494	$21,522,894
2028	($1,144,678)	($666,712)	($939,035)	($640,830)
2029	($3,716,752)	($2,023,368)	($2,989,246)	($1,944,824)
2030	($6,638,100)	($3,377,629)	($5,234,097)	($3,246,520)
2031	($9,839,613)	($4,679,538)	($7,606,341)	($4,497,900)
2032	($12,054,760)	($5,358,464)	($9,136,001)	($5,150,481)
2033	($14,779,002)	($6,140,216)	($10,981,016)	($5,901,899)
2034	($18,898,720)	($7,338,846)	($13,766,694)	($7,054,017)
2035	($23,013,051)	($8,352,690)	($16,435,059)	($8,028,525)
2036	($28,265,069)	($9,588,685)	($19,790,053)	($9,216,565)
2037	($31,892,998)	($10,112,561)	($21,892,335)	($9,720,125)
2038	($38,611,307)	($11,442,927)	($25,984,302)	($10,998,880)
2039	($45,091,309)	($12,490,283)	($29,750,156)	($12,005,611)
2040	($48,139,376)	($12,463,405)	($31,138,427)	($11,979,794)
2041	($52,668,779)	($12,745,190)	($33,400,218)	($12,250,664)
2042	($58,835,053)	($13,307,180)	($36,579,017)	($12,790,867)
2043	($61,257,454)	($12,949,877)	($37,338,301)	($12,447,442)
		($4,852,741)		**($4,666,733)**

π The quantitative evaluation was for the period 2021-2045 with the Net Present Value calculated to the year prior. The Annual Present Values are calculated to the year 2020, at a discount rate of 6.99%.

† The energy market models assume all financial parameters to be in real 2018 dollars and are indexed to that based on a 2% rate of inflation.

‡ The quantitative evaluation was for the period 2021-2045 with the Net Present Value calculated to the year prior. The Annual Present Values are calculated to the year 2020, at a real discount rate of 4.892%.



Note: The projected annual above/below market costs are based on the total net direct benefits, or the annual contract costs compared to a market forecast for energy and RECs. This does not include the expected reduction in electric supply costs.

PUC 5-2

Request:

Referencing the footnote on PUC 2-9, please provide the calculation for each year of the PPA of the projected reduction in electric supply costs and explain where they will be reflected on bills and/or realized by customers.

Response:

Year	Annual (Reduction)/Increase in Electric Supply Cost [Indirect Benefit] *Nominal$*
2024	($10,288,908)
2025	($9,096,317)
2026	($7,266,169)
2027	($7,175,280)
2028	($11,194,213)
2029	($8,563,199)
2030	($10,563,312)
2031	($11,040,632)
2032	($9,480,073)
2033	($9,153,435)
2034	($14,002,850)
2035	($14,860,224)
2036	($19,851,217)
2037	($17,590,110)
2038	($17,109,092)
2039	($12,353,279)
2040	($3,109,352)
2041	($8,583,186)
2042	$1,100,779
2043	($3,162,515)

The projected reduction in energy supply costs will be realized by customers through reduced Standard Offer Service (SOS) charges or non-regulated power producer (NPP) supply charges in the Supply Services section of the bill.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

The calculations of the indirect benefits for each year of the PPA are provided in the TCR workbook tab 'Proposal_Quant_Metrics', in Schedule NG-5-A (Confidential).

PUC 5-3

Request:

Referencing Exhibit D of the PPA on Bates page 114, is the mathematical result of the language related to negative pricing such that, during periods of negative locational marginal price (LMP) at the Delivery point, ratepayers would have, after paying the contract cost and energy market sales cost, a net cost rate of $98.425/megawatt-hour (i.e., the exact contract price assuming there is no Adjusted Price in effect)?

Response:

Yes. During periods of negative locational marginal price (LMP) at the Delivery point, the net effect to customers will be equal to the contract price of $98.425 per megawatt-hour.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

PUC 5-4

Request:

Please provide the above- and below-market cost projections for each year of the PPA with and without remuneration and provide a unitized amount per kWh across all distribution customers.

Response:

Annual Above/(Below) Market Cost - Without Remuneration

Year	Projected Above/(Below) Market Cost *Nominal$*	Forecasted kilowatt-hours (FkWhx) † *kWh*	Annual Unitized Amount per kWh *$/kWh*
	(A)	(B)	(C = A / B)
2024	$57,672,871	6,653,198,620	$0.00867
2025	$54,121,903	6,653,198,620	$0.00813
2026	$34,754,872	6,653,198,620	$0.00522
2027	$35,933,439	6,653,198,620	$0.00540
2028	($1,144,678)	6,653,198,620	($0.00017)
2029	($3,716,752)	6,653,198,620	($0.00056)
2030	($6,638,100)	6,653,198,620	($0.00100)
2031	($9,839,613)	6,653,198,620	($0.00148)
2032	($12,054,760)	6,653,198,620	($0.00181)
2033	($14,779,002)	6,653,198,620	($0.00222)
2034	($18,898,720)	6,653,198,620	($0.00284)
2035	($23,013,051)	6,653,198,620	($0.00346)
2036	($28,265,069)	6,653,198,620	($0.00425)
2037	($31,892,998)	6,653,198,620	($0.00479)
2038	($38,611,307)	6,653,198,620	($0.00580)
2039	($45,091,309)	6,653,198,620	($0.00678)
2040	($48,139,376)	6,653,198,620	($0.00724)
2041	($52,668,779)	6,653,198,620	($0.00792)
2042	($58,835,053)	6,653,198,620	($0.00884)
2043	($61,257,454)	6,653,198,620	($0.00921)

† Forecasted kWh per Company forecast - CY 2024.

Note: The projected annual above/below market costs are based on the total net direct benefits, or the annual contract costs compared to a market forecast for energy and RECs. This does not include the expected reduction in electric supply costs.

Annual Above/(Below) Market Cost - With Remuneration

Year	Projected Above/(Below) Market Cost *Nominal$*	Remuneration *Nominal$*	Forecasted kilowatt-hours (FkWhx) † *kWh*	Annual Unitized Amount per kWh *$/kWh*
	(A)	(B)	(C)	(D = (A + B) /C)
2024	$57,672,871	$4,440,824	6,653,198,620	$0.00934
2025	$54,121,903	$4,413,470	6,653,198,620	$0.00880
2026	$34,754,872	$4,402,132	6,653,198,620	$0.00589
2027	$35,933,439	$4,372,362	6,653,198,620	$0.00606
2028	($1,144,678)	$4,418,537	6,653,198,620	$0.00049
2029	($3,716,752)	$4,412,302	6,653,198,620	$0.00010
2030	($6,638,100)	$4,421,213	6,653,198,620	($0.00033)
2031	($9,839,613)	$4,413,470	6,653,198,620	($0.00082)
2032	($12,054,760)	$4,388,928	6,653,198,620	($0.00115)
2033	($14,779,002)	$4,390,708	6,653,198,620	($0.00156)
2034	($18,898,720)	$4,411,440	6,653,198,620	($0.00218)
2035	($23,013,051)	$4,412,302	6,653,198,620	($0.00280)
2036	($28,265,069)	$4,428,291	6,653,198,620	($0.00358)
2037	($31,892,998)	$4,402,132	6,653,198,620	($0.00413)
2038	($38,611,307)	$4,372,362	6,653,198,620	($0.00515)
2039	($45,091,309)	$4,390,708	6,653,198,620	($0.00612)
2040	($48,139,376)	$4,423,328	6,653,198,620	($0.00657)
2041	($52,668,779)	$4,421,213	6,653,198,620	($0.00725)
2042	($58,835,053)	$4,413,470	6,653,198,620	($0.00818)
2043	($61,257,454)	$4,402,131	6,653,198,620	($0.00855)

† Forecasted kWh per Company forecast - CY 2024.

Note: The projected annual above/below market costs are based on the total net direct benefits, or the annual contract costs compared to a market forecast for energy and RECs. This does not include the expected reduction in electric supply costs.

PUC 5-5

Request:

Please provide the above- and below-market cost projections for each year of the PPA with and without remuneration and convert it to a fixed monthly charge for each year for each customer class using the allocators approved in the Docket 4770 distribution rate case (consistent with the REGrowth methodology).

Response:

Annual Above/(Below) Market Cost - Without Remuneration

Year	Projected Above/(Below) Market Cost *Nominal$*	Fixed Monthly Charge *$ per bill/luminaire*					
		Residential	Small C&I	General C&I	Large Demand	Streetlighing	Propulsion
Rate		A-16/A-60	C-06	G-02	B-32/G-32	SL	X-01
Distribution Revenue Allocator (A)		55.6%	11.1%	15.4%	15.1%	2.7%	0.1%
Forecasted Number of Bills/Luminaires (B)		5,356,217	636,111	104,358	13,063	1,227,828	12
	(C)	(D = (C x A)/B)	(E = (C x A)/B)	(F = (C x A)/B)	(G = (C x A)/B)	(H = (C x A)/B)	(I = (C x A)/B)
2024	$57,672,871	$5.98	$10.06	$85.10	$666.66	$1.26	$4,806.07
2025	$54,121,903	$5.61	$9.44	$79.86	$625.61	$1.19	$4,510.15
2026	$34,754,872	$3.60	$6.06	$51.28	$401.74	$0.76	$2,896.23
2027	$35,933,439	$3.73	$6.27	$53.02	$415.36	$0.79	$2,994.45
2028	($1,144,678)	($0.11)	($0.19)	($1.68)	($13.23)	($0.02)	($95.38)
2029	($3,716,752)	($0.38)	($0.64)	($5.48)	($42.96)	($0.08)	($309.72)
2030	($6,638,100)	($0.68)	($1.15)	($9.79)	($76.73)	($0.14)	($553.17)
2031	($9,839,613)	($1.02)	($1.71)	($14.52)	($113.73)	($0.21)	($819.96)
2032	($12,054,760)	($1.25)	($2.10)	($17.78)	($139.34)	($0.26)	($1,004.56)
2033	($14,779,002)	($1.53)	($2.57)	($21.80)	($170.83)	($0.32)	($1,231.58)
2034	($18,898,720)	($1.96)	($3.29)	($27.88)	($218.45)	($0.41)	($1,574.89)
2035	($23,013,051)	($2.38)	($4.01)	($33.96)	($266.01)	($0.50)	($1,917.75)
2036	($28,265,069)	($2.93)	($4.93)	($41.71)	($326.72)	($0.62)	($2,355.42)
2037	($31,892,998)	($3.31)	($5.56)	($47.06)	($368.66)	($0.70)	($2,657.74)
2038	($38,611,307)	($4.00)	($6.73)	($56.97)	($446.32)	($0.84)	($3,217.60)
2039	($45,091,309)	($4.68)	($7.86)	($66.54)	($521.22)	($0.99)	($3,757.60)
2040	($48,139,376)	($4.99)	($8.40)	($71.03)	($556.46)	($1.05)	($4,011.61)
2041	($52,668,779)	($5.46)	($9.19)	($77.72)	($608.81)	($1.15)	($4,389.06)
2042	($58,835,053)	($6.10)	($10.26)	($86.82)	($680.09)	($1.29)	($4,902.92)
2043	($61,257,454)	($6.35)	($10.68)	($90.39)	($708.09)	($1.34)	($5,104.78)

(A) RIPUC Docket Nos. 4770/4780 Compliance Attachment 8 Schedule 3 Page 3 line 53.

(B) Forecasted Bills per Company forecast for customers - CY 2024, luminaires based on active luminaires as of December 31, 2018, used for all years.

Annual Above/(Below) Market Cost - With Remuneration

Year	Projected Above/(Below) Market Cost, including Remuneration *Nominal$*	Fixed Monthly Charge per Bill/Luminaire *$ per bill/luminaire*					
		Residential	Small C&I	General C&I	Large Demand	Streetlighing	Propulsion
Rate		A-16/A-60	C-06	G-02	B-32/G-32	SL	X-01
Distribution Revenue Allocator	(A)	55.6%	11.1%	15.4%	15.1%	2.7%	0.1%
Forecasted Number of Bills/Luminaires	(B)	5,356,217	636,111	104,358	13,063	1,227,828	12
	(C)	(D = (C x A)/B)	(E = (C x A)/B)	(F = (C x A)/B)	(G = (C x A)/B)	(H = (C x A)/B)	(I = (C x A)/B)
2024	$62,113,695	$6.44	$10.83	$91.66	$717.99	$1.36	$5,176.14
2025	$58,535,372	$6.07	$10.21	$86.38	$676.63	$1.28	$4,877.94
2026	$39,157,004	$4.06	$6.83	$57.78	$452.63	$0.86	$3,263.08
2027	$40,305,801	$4.18	$7.03	$59.47	$465.90	$0.88	$3,358.81
2028	$3,273,859	$0.33	$0.57	$4.83	$37.84	$0.07	$272.82
2029	$695,550	$0.07	$0.12	$1.02	$8.04	$0.01	$57.96
2030	($2,216,887)	($0.23)	($0.38)	($3.27)	($25.62)	($0.04)	($184.74)
2031	($5,426,143)	($0.56)	($0.94)	($8.00)	($62.72)	($0.11)	($452.17)
2032	($7,665,831)	($0.79)	($1.33)	($11.31)	($88.61)	($0.16)	($638.81)
2033	($10,388,295)	($1.07)	($1.81)	($15.32)	($120.08)	($0.22)	($865.69)
2034	($14,487,280)	($1.50)	($2.52)	($21.37)	($167.46)	($0.31)	($1,207.27)
2035	($18,600,749)	($1.93)	($3.24)	($27.44)	($215.01)	($0.40)	($1,550.06)
2036	($23,836,778)	($2.47)	($4.15)	($35.17)	($275.53)	($0.52)	($1,986.39)
2037	($27,490,867)	($2.85)	($4.79)	($40.56)	($317.77)	($0.60)	($2,290.90)
2038	($34,238,945)	($3.55)	($5.97)	($50.52)	($395.78)	($0.75)	($2,853.24)
2039	($40,700,602)	($4.22)	($7.10)	($60.06)	($470.47)	($0.89)	($3,391.71)
2040	($43,716,048)	($4.53)	($7.62)	($64.51)	($505.32)	($0.96)	($3,643.00)
2041	($48,247,566)	($5.00)	($8.41)	($71.19)	($557.71)	($1.06)	($4,020.63)
2042	($54,421,583)	($5.64)	($9.49)	($80.30)	($629.07)	($1.19)	($4,535.13)
2043	($56,855,323)	($5.90)	($9.92)	($83.90)	($657.21)	($1.25)	($4,737.94)

(A) RIPUC Docket Nos. 4770/4780 Compliance Attachment 8 Schedule 3 Page 3 line 53.

(B) Forecasted Bills per Company forecast for customers - CY 2024, luminaires based on active luminaires as of December 31, 2018, used for all years.

Note:
The projected annual above/below market costs are based on the total net direct benefits, or the annual contract costs compared to a market forecast for energy and RECs. This does not include the expected reduction in electric supply costs.

PUC 5-6

Request:

Using the historical information for the period 1998-2017 located at: https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/ (2018 Forecast Data), please use any relevant adjustments National Grid believes necessary (or none), and explain any adjustments.

a. Please use a solid black line to plot a graph of the actual summer peak load for New England from 1998 to present.

b. On the same graph, please plot the appropriate ISO New England CELT Report summer peak forecast for each CELT Report using a different color line for the forecast in each CELT Report. Please identify the peak data used (e.g., net of PV).

c. Please provide a table with the data depicted in the graph.

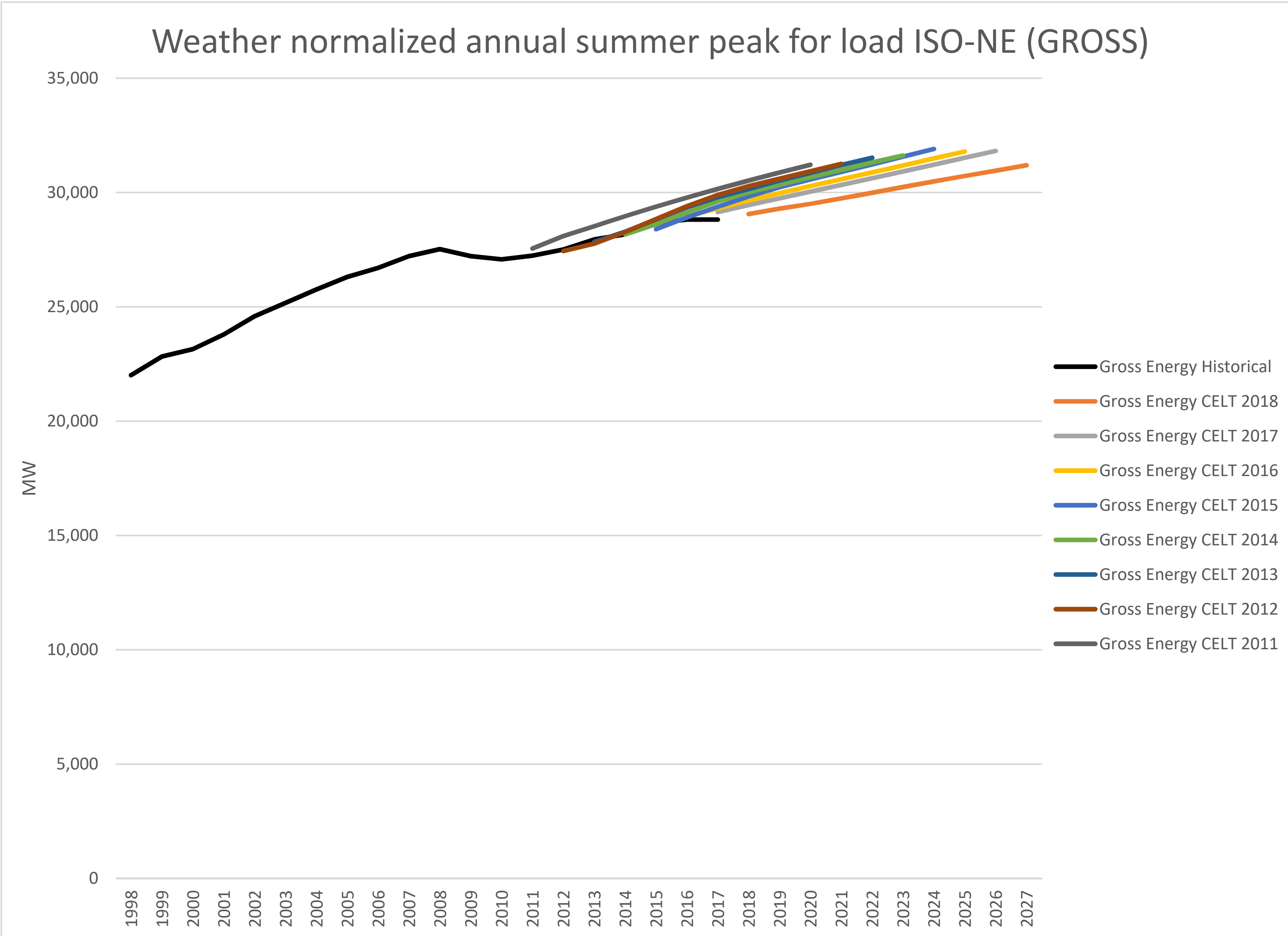
Response:

a. Please refer to Attachment PUC 5-6 for the requested graphs and data tables for historic and forecasted weather normalized summer peak data. National Grid has not made any adjustments. This includes:
   - Weather normalized annual summer peak for load ISO-NE (Gross) in tabs '1Ch Sum Peak (Gross)' and '1 Sum Peak (Gross); and
   - Weather normalized annual summer peak for load ISO-NE (Net of PV and PDR) in tabs '2Ch Sum Peak (Net)' and '2 Sum Peak (Net).

b. Please refer to the response to part a, above.

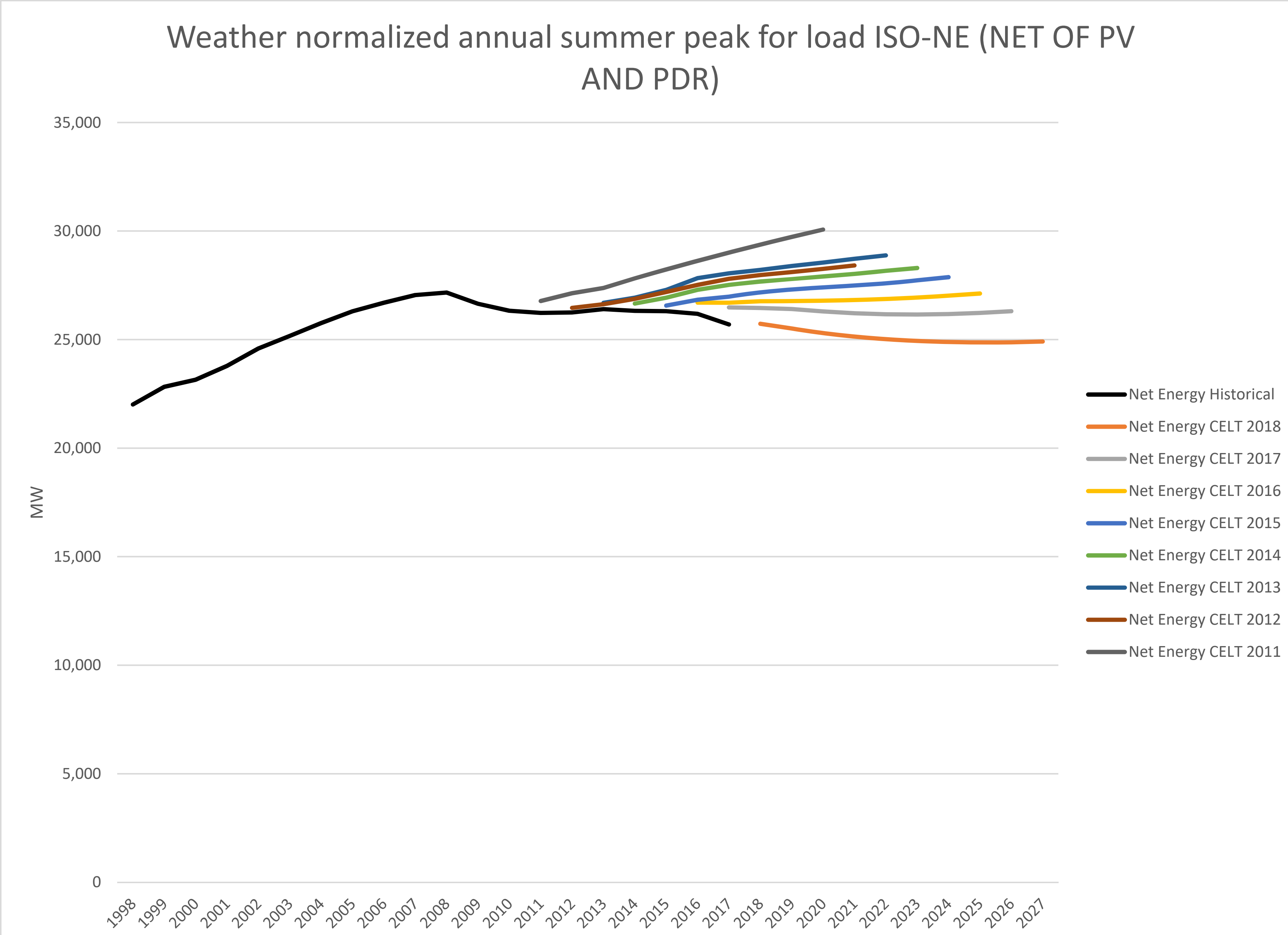
c. Please refer to the response to part a, above.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico


Weather normalized annual summer peak for load ISO-NE (GROSS)
MW
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
Gross Energy Historical
Gross Energy CELT 2018
Gross Energy CELT 2017
Gross Energy CELT 2016
Gross Energy CELT 2015
Gross Energy CELT 2014
Gross Energy CELT 2013
Gross Energy CELT 2012
Gross Energy CELT 2011

Weather normalized annual summer peak for load ISO-NE (GROSS)

MW	Gross Energy								
	Historical	CELT 2018	CELT 2017	CELT 2016	CELT 2015	CELT 2014	CELT 2013	CELT 2012	CELT 2011
1998	22,010								
1999	22,825								
2000	23,150								
2001	23,790								
2002	24,590								
2003	25,170								
2004	25,760								
2005	26,305								
2006	26,700								
2007	27,220								
2008	27,525								
2009	27,220								
2010	27,075								
2011	27,240								27550
2012	27,507							27440	28095
2013	27,952						27840	27765	28525
2014	28,171					28165	28290	28275	28970
2015	28,660				28395	28615	28825	28840	29380
2016	28,815			28966	28910	29130	29350	29400	29775
2017	28,817		29,146	29307	29375	29610	29790	29895	30155
2018		29,060	29,454	29652	29825	30005	30155	30275	30525
2019		29,298	29,753	29975	30230	30335	30525	30605	30875
2020		29,504	30,039	30276	30575	30675	30860	30930	31215
2021		29,744	30,327	30578	30900	30990	31205	31255	
2022		29,994	30,623	30883	31230	31315	31520		
2023		30,245	30,923	31190	31570	31620			
2024		30,486	31,223	31493	31905				
2025		30,721	31,521	31794					
2026		30,957	31,820						
2027		31,192							


Weather normalized annual summer peak for load ISO-NE (NET OF PV AND PDR)
MW
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
Net Energy Historical
Net Energy CELT 2018
Net Energy CELT 2017
Net Energy CELT 2016
Net Energy CELT 2015
Net Energy CELT 2014
Net Energy CELT 2013
Net Energy CELT 2012
Net Energy CELT 2011

Weather normalized annual summer peak for load ISO-NE (NET OF PV AND PDR)

MW	Net Energy								
	Historical	CELT 2018	CELT 2017	CELT 2016	CELT 2015	CELT 2014	CELT 2013	CELT 2012	CELT 2011
1998	22,010								
1999	22,825								
2000	23,150								
2001	23,790								
2002	24,590								
2003	25,170								
2004	25,760								
2005	26,305								
2006	26,700								
2007	27,053								
2008	27,167								
2009	26,650								
2010	26,327								
2011	26,229								26,776
2012	26,248							26,462	27,135
2013	26,405						26,690	26,629	27,377
2014	26,324					26,658	26,929	26,877	27,822
2015	26,310				26,565	26,930	27,290	27,193	28,232
2016	26,185			26,704	26,835	27,291	27,830	27,520	28,627
2017	25,698		26,482	26,698	26,976	27,521	28,053	27,797	29,007
2018		25,729	26,458	26,764	27,178	27,677	28,213	27,973	29,377
2019		25,512	26,409	26,782	27,310	27,782	28,391	28,111	29,727
2020		25,298	26,298	26,788	27,399	27,911	28,546	28,257	30,067
2021		25,136	26,213	26,817	27,487	28,028	28,721	28,414	
2022		25,021	26,167	26,870	27,598	28,167	28,878		
2023		24,942	26,155	26,942	27,733	28,298			
2024		24,889	26,176	27,026	27,875				
2025		24,864	26,228	27,122					
2026		24,874	26,310						
2027		24,912							

PUC 5-8

Request:

R.I. Gen. Laws § 39-31-1(4) states that one of the purposes of the Affordable Clean Energy and Security Act (ACES) is the increased use of no- and low-carbon energy resources that diversify our energy supply portfolio. R.I. Gen. Laws § 39-31-7(a)(4) contemplates the possibility of the PUC addressing changes to standard offer procurements related to projects approved under ACES. Since the PPA is purported to be below market for most of the years of operation and the PUC will be considering a last resort procurement plan prior to the commercial operation date of the Facility, please explain why the Company has not proposed to consider this PPA as part of a last resort service portfolio.

Response:

R.I. Gen. Laws § 39-1-27.3(c) requires the Company to "arrange for a last-resort power supply for customers who have left the standard offer for any reason and are not otherwise receiving electric service from nonregulated power producers." Currently, almost half of the Company's distribution load receives its supply from nonregulated power producers (NPPs).

Using any fixed price Power Purchase Agreement (PPA), whether it is above- or below-market, in the Company's Last Resort Service (LRS) portfolio will distort the competitive retail markets and disrupt customer choice. Including the contract prices of these PPAs in LRS rates will not reflect actual market conditions. In reaction, customers could migrate to or from LRS, depending on the switching rules and which option (LRS or NPPs) provides the lowest electric supply rates. If LRS rates include above-market contract prices, then more customers may migrate to NPPs, leaving a smaller number of customers on LRS rates to shoulder the above-market costs. Stranded costs may arise if all customers switch. If LRS rates include below-market contract prices, then more customers will migrate to LRS, which may result in some NPPs leaving the market and reducing overall customer choice. Including the net market difference between the contract price and the resale of energy to the ISO-NE back through the LTCRER to all distribution customers as proposed ensures all distribution customers share in the benefit or costs of the fixed price contracts and will not create a false price signal between LRS and competitive retail markets. Using the fixed price contracts in the LRS would most likely impact the retail customer choice market in a negative way.

Prepared by or under the supervision of: Timothy J. Brennan and Corinne M. DiDomenico

---

PUC 5-9

Request:

Please explain why, instead of positive-only remuneration calculated on the cost of the PPA, the Company did not propose something more like the shared incentive proposal in National Grid's Proposal to Bid Capacity of Customer-Owned Distributed Generation Facilities Into the Forward Capacity Market, Docket No. 4676.

Response:

The Company is not proposing remuneration as an incentive. The purpose of remuneration is to minimize any harm to the Company as a result of accepting the financial obligation of this long-term contract in furtherance of the State of Rhode Island's clean energy goals, and to help Rhode Island customers and the region achieve the identified benefits associated with the long-term contract.

The purpose of National Grid's proposal to receive a shared percentage of net Forward Capacity Market proceeds associated with bidding the capacity of certain non-residential distributed generation facilities was to align the interests of the Company with customers by incenting the Company to maximize the value of the Forward Capacity Market portfolio, on an ongoing basis. The Narragansett Electric Company, Docket No. 4676, Report and Order at 5-6 (2018). To maximize the value of Forward Capacity Market proceeds for customers, the Company proposed to assume a Capacity Supply Obligation, which would include both Performance Incentive payments and penalties. Id. at 3-4. To minimize the risk of penalties, the Company proposed to take certain actions, including qualifying resources as "Summer Only" Intermittent Generating Resources, conducting a full review of a facility's projected and/or historic performance to appropriately size the Capacity Supply Obligation, and monitoring the facility for underperformance after receiving a Capacity Supply Obligation. Id. at 4-5. The shared incentive structure was proposed to encourage the Company to execute these voluntary administrative functions effectively on an ongoing basis to maximize Forward Capacity Market revenues for the benefit of customers.

In the case of the proposed long-term contract with DWW, the Company is providing value to customers by enabling cost-effective financing for the project that would not be obtainable without the use of the Company's balance sheet. As explained in Mr. Hevert's initial testimony, remuneration of 2.75 percent will: (1) compensate the Company for strategically utilizing its balance sheet and strong credit profile to advance the public interest objectives of the Affordable Clean Energy Security (ACES) Act; (2) mitigate the financial risks to the Company associated with the long-term, fixed financial obligations under the Contract, thereby supporting the Company's financial flexibility and strong credit profile, which are required to efficiently fund its ongoing utility operations and to enter into long-term renewable energy contracts; and (3) enable significant net benefits to its customers after consideration of the remuneration payments, while advancing the public policy objectives that the ACES Act intends to achieve. (Initial Filing at Bates page 381). The remuneration rate therefore has two objectives: (1) maximize the total value created by the Project (by enabling its cost-effective financing); and (2) minimize the financial harm associated with large, fixed financial obligations.

Unlike the Company's proposal to monetize capacity from non-residential distributed generation facilities in the Forward Capacity Market in Docket No. 4676, it is not within the Company's control to maximize the net benefits of the DWW contract over the 20-year term. In addition, remuneration is not intended to influence the Company's future behavior or management of the PPA. It is intended to provide compensation for the use of the Company's balance sheet, which in turn relies on the capital supplied by investors. Because the purpose of the Company's proposal is different in this case than in Docket No. 4676, it is reasonable that the compensation structure is also different.