STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY :
d/b/a NATIONAL GRID – ELECTRIC AND GAS : DOCKET NO. 4780
DISTRIBUTION RATE FILING :

COMMISSION'S FIRST SET OF DATA REQUESTS
DIRECTED TO NATIONAL GRID
(Issued May 4, 2018)

Performance Incentive Mechanisms and PST

1-1. Niagara Mohawk agreed to a metric designed to provide an incentive for the Company to reduce the number of residential service terminations for non-payment while decreasing, or maintaining, the level of bad debt from residential accounts based on a five-year average.

a. Please explain the mechanisms available in New York which would enable the Company to meet the metric.
b. Are those mechanisms available in Rhode Island?
c. What are the differences in New York regulations and Rhode Island regulations that would affect (positively or negatively) the ability of Narragansett Electric or Narragansett Gas to work toward meeting such a metric?

Response can be found on Bates page(s) 1-2.

1-2. Please complete the following table for the years 2012-2017, where the example below is the for year 2012 only, and provide the data in a machine-readable file. Further:

- please be sure to indicate where National Grid believes the entries are not applicable, unknown, or zero;
- for all monetary values, please use nominal dollars;
- for each year requested, please use the program year that overlapped the most with the calendar year, and indicate which program years were used in the response (e.g., for year 2018, use ISR FY2017;
- for "company earnings" related to incentives, please use the (nominal dollar) value National Grid collected for the program year achievement, whether it was concurrent with or after the program year; and
- for "company earnings" related to capital investment, please use the (nominal dollar) value of earnings included in the revenue requirement that was calculated after any applicable annual reconciliations.

Response can be found on Bates page(s) 3-16.

Table to accompany PUC-1-2

	2012									
	Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost	Company Earnings
Energy Efficiency										
System Reliability Procurement										
Infrastructure, Safety, Reliability (e.g. VVO/CVR)										
Renewable Energy Growth										
Long-term Contracts										
DG Contracts										
Net Metering										
Renewable Energy Standard										

1-3. For each year in the response to 1-4, please provide the following:

a. The minimum, maximum, and average Program Cost for each Outcome Category for that year;
b. The minimum, maximum, and average Company Earnings for each Outcome Category for that year.

Response can be found on Bates page(s) 17–29.

1-4. Please complete the table above for all programs and sub-programs proposed by National Grid in Docket 4780 that are associated with a performance incentive in Chapter 9, Section 3. For each program or subprogram, highlight (color or bold font) the metric National Grid has proposed at the metric for determining performance and related incentives. Please use the target achievement and incentive for this table.

Response can be found on Bates page(s) 30-33.

1-5. For all programs and sub-programs proposed by National Grid in Docket 4780 that are associated with a performance incentive in Chapter 9, Section3, and that propose a range of achievement levels and associated incentives:

a. Provide the $/metric value for each proposed achievement level;
b. For any responses in part a that do not have a uniform $/metric value for all achievement levels, please provide a justification for the variation.
c. For any proposed $/metric value in part b that is above of the ranges identified in PUC 1-3.b for 2016 and 2017, please provide a justification for the value being above the range.

Response can be found on Bates page(s) 34-35.

1-6. What is the Company's current expectation of the cost of RGGI allowances and Renewable Energy Certificates (RECs) over the next three years?

Response can be found on Bates page(s) 36.

1-7. How much CO_2 does company expect is abated by purchase of a single RGGI allowance and REC?

Response can be found on Bates page(s) 37.

1-8. Is the Company's expected cost/tonCO_2 for RGGI allowances or RECs less than the Company's estimate of the value of a ton of CO_2?

Response can be found on Bates page(s) 38.

1-9. Is the Company's expected cost/tonCO_2 for RGGI allowances or RECs less than any of the Company's expected cost/tonCO_2 in the Company's Electric Heat Initiative?

Response can be found on Bates page(s) 39-40.

1-10. Was the voluntary purchase of RECs and RGGI when the price of each is below a certain price, such as the company's benchmark for CO_2, considered for meeting the Company's GHG reduction targets?

Response can be found on Bates page(s) 41.

1-11. Please provide the expected or target rebate, per month, that would be paid to participant in the EV Off-Peak Charging Rebate program. Please indicate which months are summer which months are winter rebate months. Please provide the number of hours participants are expected to charge their vehicles per month during on- and off-peak hours. Please reference or include supporting material, and indicate which are Rhode Island-specific data.

Response can be found on Bates page(s) 42-49.

1-12. In National Grid's response to Sierra Club 1-16 in Docket No. 4780, National Grid states, "As part of the EV Off-Peak Charging Rebate, the Company will evaluate the technical capability of Level 2 electric vehicle supply equipment to function as residential revenue-grade meters.

a. In what way will this evaluation be similar to the streetlight metering pilot conducted as part of Docket No. 4513? In what ways will it be similar?
b. Why does National Grid believe the results of the proposed study will be different from the results of the study conducted in Docket No. 4513?

Response can be found on Bates page(s) 50.

1-13. Regarding the proposal to electrify portions of National Grid's fleet:

a. Where will these vehicles be housed, recharged, and registered?

b. Will the vehicles be used in other jurisdictions? If so, will some of the costs of these vehicles be paid for by ratepayers in other jurisdictions?

Response can be found on Bates page(s) 51.

1-14. In National Grid's response to Sierra Club 1-24 in Docket No. 4780, National Grid states, "Although funding for the beneficial heat electrification will originate from both the EE and PST programs, most part of the implementation and delivery… will be undertaken by the same internal staff."

a. How will employees understand when they are working on EE versus PST initiatives?
b. How will these employees' time be tracked and accounted for appropriately in the different programs' administrative costs.
c. For electric heating activities that are identical in the EE and PST programs, would National Grid's metric achievement measurement and incentive structure identical for these activities? If not, why not?

Response can be found on Bates page(s) 52-53.

1-15. For any PST program or subprogram described as a "pilot" or "demonstration" by the National Grid

a. Please confirm that the primary objective of the activity is to learn.
b. For each activity that also would count toward a proposed incentive and <u>is</u> supported by capital spending, please explain why an incentive beyond the return on investment is justified.
c. For each activity that also would count toward a proposed incentive and <u>is not</u> supported by capital spending, please confirm that no existing program incentive or proposed program incentive could apply to the activity in the case that the Company's pilot or demonstration leads to a full-fledged program deployment.

Response can be found on Bates page(s) 54-56.

1-16. Regarding National Grid's proposed increase to the Residential customer charge:

a. What, increase to National Grid proposed to the Residential distribution charge would be necessary to achieve the proposed revenue requirement if the customer charge remained at $5/customer-bill?
b. What would be the average annual value of such an increase to existing residential net metering customers? Please provide the number of existing residential net metering customers and their annual kWh generation used to respond to this data request.

Response can be found on Bates page(s) 57-58.

1-17. In National Grid's response to Division 8-12 in Docket No. 4770 (Division 2-12 in Docket No. 4780), National Grid describes the undepreciated costs associated with existing meters that are replaced by AMI meters as "sunk costs and, therefore, should not be factored into the benefit-cost analysis." For simplicity, assume book life is equal to useful life, and meters are replaced when they are fully depreciated.

Regarding costs, in both the case that AMI are installed, and the case they are not installed, customers cannot avoid paying the undepreciated cost for the existing meters, and in that sense the undepreciated cost for the meters appear to be sunk costs, and thus should not be included as a cost category of the benefit-cost analysis.

Turning to benefits, if AMI are installed, customers will lose the value of the remaining metering life of the existing meters. However, if AMI are not installed, customers will get to use the remaining metering life of the existing meters—thus customers can avoid losing the value of the remaining metering life. Please explain why the different outcomes related to this (negative) benefit category (i.e., the remaining value to customers in existing meters) is not considered in National Grid's cost-benefit analysis.

Response can be found on Bates page(s) 59-61.

PUC 1-1

Request:

Niagara Mohawk agreed to a metric designed to provide an incentive for the Company to reduce the number of residential service terminations for non-payment while decreasing, or maintaining, the level of bad debt from residential accounts based on a five-year average.

a. Please explain the mechanisms available in New York which would enable the Company to meet the metric.

b. Are those mechanisms available in Rhode Island?

c. What are the differences in New York regulations and Rhode Island regulations that would affect (positively or negatively) the ability of Narragansett Electric or Narragansett Gas to work toward meeting such a metric?

Response:

a. The Joint Proposal[1] in the Niagara Mohawk rate case (Cases 17-E-0238 and 17G-0239), the terms of which were adopted by the New York Public Service Commission in its *Order Adopting the Terms of Joint Proposal and Establishing Electric and Gas Rate Plans* (issued and effective March 15, 2018), includes a Termination and Uncollectible Expense metric and incentive. The metric is designed to provide an incentive for Niagara Mohawk to reduce the number of residential service terminations for non-payment while decreasing, or maintaining, the level of bad debt from residential accounts. The metric measures the number of annual residential terminations and the total annual uncollectible expense (i.e., write offs) for the combined electric and gas segments.

Niagara Mohawk has the ability to manage the volume of service terminations by controlling the number of termination orders that are issued to the field. The degree to which controlled dispatching will control termination volumes adequately depends on the volatility of the effectiveness of the field. In recent years, the field effectiveness rate has been stable.

Niagara Mohawk has less ability to influence the second component of the metric, which captures the level of bad debt from residential accounts. Bad debt results when an account closes with outstanding arrears. It is strongly influenced by fluctuations in

[1] On January 19, 2018, Niagara Mohawk Power Corporation (Niagara Mohawk), the New York Department of Public Service Staff, and the other parties in the case entered into a Joint Proposal that memorializes the settlement agreement among the parties.

commodity prices, weather, economic health, and consumer behavior. When terminations are limited by Niagara Mohawk, one should expect a modest immediate corresponding drop in write-off rates. This is because bad debt write-off occurs after an account is closed (whether voluntarily or as a result of service termination). In the long term, however, reduced termination rates would be expected to lead to a rise in bad debt. This is because lower terminations ultimately lead to higher account balances. Thus, a temporary drop in bad debt write-off is likely to be followed by a long term rise in bad debt above current levels.

b. The mechanisms described in the response to part a. above would operate similarly in Rhode Island.

c. The regulatory differences between New York and Rhode Island would not be expected to have a large effect on the mechanisms described above, or on the ability of Narragansett Electric or Narragansett Gas to work toward meeting such a metric. That said, for Rhode Island, the Company suggests that development of a performance incentive focused on outcomes for income eligible customers be evaluated following implementation of the Company's proposals affecting income eligible customers.

(This response is identical to the Company's response to PUC 9-25 in Docket No. 4770.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

PUC 1-2

Request:

Please complete the following table for the years 2012-2017, where the example below is the for year 2012 only, and provide the data in a machine-readable file. Further:

a. please be sure to indicate where National Grid believes the entries are not applicable, unknown, or zero;

b. for all monetary values, please use nominal dollars;

c. for each year requested, please use the program year that overlapped the most with the calendar year, and indicate which program years were used in the response (e.g., for year 2018, use ISR FY2017;

d. for "company earnings" related to incentives, please use the (nominal dollar) value National Grid collected for the program year achievement, whether it was concurrent with or after the program year; and

e. for "company earnings" related to capital investment, please use the (nominal dollar) value of earnings included in the revenue requirement that was calculated after any applicable annual reconciliations.

Response:

Please see Attachment PUC 1-2-1, which provides the information requested in the table below, and Attachment PUC 1-2-2, which provides supporting calculations for the estimated earnings from VVO/CVR. With respect to the Infrastructure, Safety, and Reliability (ISR) Plan, the Company interpreted this question as seeking earnings and impact information for the Company's VVO/CVR Pilot and Expansion programs under the Company's ISR Plan, rather than the ISR Plan overall.

(This response is identical to the Company's response to PUC 9-26 in Docket No. 4770.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

2012												
	Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
Energy Efficiency	N/A	119,666,157	N/A	19,947	N/A	56,243	201,351	119,666,157	0	$ 49,869,528	$ 2,469,411
System Reliability Procurement	N/A	132,000	N/A	N/A	42	N/A	107	224600	0	$ 133,400	$ -
ISR -- VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$0	$ -	$ -
Renewable Energy Growth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Long-term Contracts	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 581,777	$ -
DG Contracts	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ -	$ -
Net Metering	6	N/A	N/A	N/A	N/A	N/A	61	N/A	N/A	$ 329,386	N/A
Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 12,803,595	N/A

Notes:

CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"

Program costs for Long-term Contracts represents administrative costs associated with PPA negotiation

For Net Metering and ReGrowth, number of kW and participants provided based on date authroity to interconnect was given i.e. CY2012

Nameplate capacity for Long-term Contracts and DG Contracts is cumulative

The Company does not have estimates of generation from net metering and REGrowth

2013											
	Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
Energy Efficiency	N/A	157,121,309	N/A	26,427	N/A	73847.02	493,271	157,121,309		$ 63,145,737	$ 2,997,681
System Reliability Procurement	N/A	790,000	N/A	N/A	266	N/A	321	653000		$ 672,400	$ -
ISR -- VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 139
FY 14									$56,889	$ -	$ 139
FY 13									-	-	$ -
Renewable Energy Growth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Long-term Contracts	36	81,666,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 2,204,145	$ 146,297
DG Contracts	11	4,490,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 416,028	$ 20,238
Net Metering	1	N/A	N/A	N/A	N/A	N/A	60	N/A	N/A	$ 51,554	N/A
Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 18,964,816	N/A

Notes:
CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"
For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2013
Nameplate capacity for Long-term Contracts and DG Contracts is cumulative
The Company does not have estimates of generation from net metering and REGrowth

2014											
	Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
Energy Efficiency	N/A	268,468,226	N/A	38,693	N/A	126,180	551,882	268,468,226	N/A	$ 85,348,093	$ 4,223,321
System Reliability Procurement	N/A	455,000	N/A	N/A	120	N/A	197	464,000	N/A	$ 569,300	$ -
ISR -- VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 14,522
FY 15									$ 2,014,587	$ -	$ 13,947
FY 14									-	$ -	$ 574
FY 13									-	-	$ -
Renewable Energy Growth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 77,121	$ -
Long-term Contracts	36	234,392,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 4,642,891	$ 757,319
DG Contracts	16	18,108,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 2,649,080	$ 119,283
Net Metering	1	N/A	N/A	N/A	N/A	N/A	88	N/A	N/A	$ 125,526	N/A
Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 17,899,440	N/A

Notes:
CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"
For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2014
Nameplate capacity for Long-term Contracts and DG Contracts is cumulative
The Company does not have estimates of generation from net metering and REGrowth

2015											
	Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
Energy Efficiency	N/A	222,822,045	N/A	33335.385	N/A	104726.4	622822.4271	222822044.5	N/A	$ 87,430,831	$ 4,533,360
System Reliability Procurement	N/A	685,000	N/A	N/A	144	N/A	267	251700	N/A	$ 1,029,400	$ -
ISR -- VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 45,848
FY 16									$ 2,212,462	$ -	$ 18,761
FY 15									-	-	$ 26,612
FY 14									-	-	$ 475
FY 13									-	-	$ -
Renewable Energy Growth	3	N/A	N/A	N/A	N/A	N/A	438	N/A	N/A	$ 675,133	$ 103
Long-term Contracts	36	238,276,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 7,150,901	$ 792,715
DG Contracts	19	22,784,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 3,516,629	$ 141,560
Net Metering	3	N/A	N/A	N/A	N/A	N/A	330	N/A	N/A	$ 551,915	N/A
Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 13,958,024	N/A

Notes:

CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"

For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2015

Nameplate capacity for Long-term Contracts and DG Contracts is cumulative

The Company does not have estimates of generation from net metering and REGrowth

2016											
	Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
Energy Efficiency	N/A	214,328,549	N/A	30,530	N/A	100734.4	758,284	214,328,549	N/A	$ 78,402,087	$ 4,128,034
System Reliability Procurement	N/A	550,000	N/A	N/A	96	N/A	155	(158,500)	N/A	$ 989,700	$ -
ISR -- VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 70,175
FY 17									$ 1,573,303	$ -	$ 9,353
FY 16											$ 36,364
FY 15											$ 24,080
FY 14											$ 377
FY 13											$ -
Renewable Energy Growth	12	N/A	N/A	N/A	N/A	N/A	906	N/A	N/A	$ 1,797,768	$ 16,843
Long-term Contracts	66	235,107,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 14,654,577	$ 812,217
DG Contracts	23	26,695,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 4,228,911	$ 168,717
Net Metering	13	N/A	N/A	N/A	N/A	N/A	677	N/A	N/A	$ 1,713,779	N/A
Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 8,968,717	N/A

Notes:

CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"

For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2016

Nameplate capacity for Long-term Contracts and DG Contracts is cumulative

The Company does not have estimates of generation from net metering and REGrowth

The annual impacts of VVO/CVR are not available. During 2016, the pilot was in M&V and undergoing commissioning efforts, resulting in many "off" days.

2017											
	Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
Energy Efficiency	N/A	232,023,450	N/A	29,363	N/A	109,051	687,141	232,023,450		$ 94,841,567	$ 4,829,847
System Reliability Procurement	N/A	718,000	N/A	N/A	352	N/A	120	63,000		$ 1,349,400	$ -
ISR -- VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 86,750
FY 18									$ 1,393,536	$ 60,000	$ 12,970
FY 17									-	-	$ 17,786
FY 16									-	-	$ 34,142
FY 15									-	-	$ 21,579
FY 14									-	-	$ 274
FY 13									-	-	$ -
Renewable Energy Growth	13	N/A	N/A	N/A	N/A	N/A	922	N/A		$ 7,040,636	$ 120,473
Long-term Contracts	69	332,488,731	N/A	N/A	N/A	N/A	N/A	N/A		$ 37,154,188	$ 1,480,355
DG Contracts	23	27,979,500	N/A	N/A	N/A	N/A	N/A	N/A		$ 4,890,691	$ 171,131
Net Metering	13	N/A	N/A	N/A	N/A	N/A	512	N/A		$ 3,149,512	N/A
Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		$ 3,753,535	N/A

Notes:
CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"
For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2017
Nameplate capacity for Long-term Contracts and DG Contracts is cumulative
The Company does not have estimates of generation from net metering and REGrowth
ReGrowth program costs and earnings are preliminary and have not yet been filed
Renewable Energy Standard obligation year is not yet complete.
2017 kWh values for Long-term and DG Contracts are estimates
The annual impacts of VVO/CVR are not available. During 2017, the Pilot was being extensivly debugged for communications issues, resulting in significant off-time.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1		2012															
2		Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	VVO/CVR O&M	Total ISR Capital Investment	VVO/CVR Cap	VVO/CVR % to Total Capital	Average Rate Base	Allowed ROE	Company Earnings After-tax	VVO/CVR Proportionate Share of Earnings
3	Infrastructure Safety, Reliability (e.g., VVO/CVR)																
4	FY 13									$0	($7,819,012)	$0	0.00%	($2,520,717)	9.50%	($117,675)	$0
5	Total ISR Earnings															($117,675)	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1									2013								
2		Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	VVO/CVR O&M	Total ISR Capital Investment	VVO/CVR Cap	VVO/CVR % to Total Capital	Average Rate Base	Allowed ROE	Company Earnings After-tax	VVO/CVR Proportionate Share of Earnings
3	Infrastructure Safety, Reliability (e.g., VVO/CVR)																
4	FY 14									$0	$12,842,359	$56,889	0.44%	$670,654	9.50%	$31,308	$139
5	FY 13												0.00%	($4,847,343)	9.50%	($226,289)	$0
6	Total ISR Earnings															($194,980)	
7																	
8																	
9																	
10																	
11																	
12																	
13																	
14																	
15																	
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28																	
29																	
30																	
31																	
32																	
33										0.44%							

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1		2014															
2		Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	VVO/CVR O&M	Total ISR Capital Investment	VVO/CVR Cap	VVO/CVR % to Total Capital	Average Rate Base	Allowed ROE	Company Earnings After-tax	VVO/CVR Proportionate Share of Earnings
3	Infrastructure Safety, Reliability (e.g., VVO/CVR)																
4	FY 15									$0	$76,340,403	$2,014,587	2.64%	$11,321,526	9.50%	$528,523	$13,947
5	FY 14												0.44%	$2,776,084	9.50%	$129,596	$574
6	FY 13												0.00%	($4,462,400)	9.50%	($208,318)	$0
7	Total ISR Earnings															$449,801	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1		2015															
2		Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	VVO/CVR O&M	Total ISR Capital Investment	VVO/CVR Cap	VVO/CVR % to Total Capital	Average Rate Base	Allowed ROE	Company Earnings After-tax	VVO/CVR Proportionate Share of Earnings
3	Infrastructure Safety, Reliability (e.g., VVO/CVR)																
4	FY 16									$0	$72,003,445	$2,212,462	3.07%	$13,079,273	9.50%	$610,580	$18,761
5	FY 15												2.64%	$21,601,446	9.50%	$1,008,420	$26,612
6	FY 14												0.44%	$2,296,849	9.50%	$107,224	$475
7	FY 13												0.00%	($4,083,689)	9.50%	($190,639)	$0
8	Total ISR Earnings															$1,535,585	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1		2016															
2		Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	VVO/CVR O&M	Total ISR Capital Investment	VVO/CVR Cap	VVO/CVR % to Total Capital	Average Rate Base	Allowed ROE	Company Earnings After-tax	VVO/CVR Proportionate Share of Earnings
3	Infrastructure Safety, Reliability (e.g., VVO/CVR)																
4	FY 17									$0	$75,489,338	$1,573,303	2.08%	$9,613,558	9.50%	$448,790	$9,353
5	FY 16												3.07%	$25,350,698	9.50%	$1,183,447	$36,364
6	FY 15												2.64%	$19,546,098	9.50%	$912,470	$24,080
7	FY 14												0.44%	$1,825,365	9.50%	$85,214	$377
8	FY 13												0.00%	($3,710,743)	9.50%	($173,229)	$0
9	Total ISR Earnings															$2,456,692	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1		2017															
2		Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	VVO/CVR O&M	Total ISR Capital Investment	VVO/CVR Cap	VVO/CVR % to Total Capital	Average Rate Base	Allowed ROE	Company Earnings After-tax	VVO/CVR Proportionate Share of Earnings
3	Infrastructure Safety, Reliability (e.g., VVO/CVR)																
4	FY 18									$60,000	$74,843,000	$1,393,536	1.86%	$14,921,086	9.50%	$696,561	$12,970
5	FY 17												2.08%	$18,280,458	9.50%	$853,387	$17,786
6	FY 16												3.07%	$23,801,658	9.50%	$1,111,133	$34,142
7	FY 15												2.64%	$17,516,401	9.50%	$817,718	$21,579
8	FY 14												0.44%	$1,323,312	9.50%	$61,776	$274
9	FY 13												0.00%	($3,311,205)	9.50%	($154,577)	$0
10	Total ISR Earnings															$3,385,998	

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2													
3													
4				VVO/CVR Pilot			VVO/CVR Expansion						
5				C053111	C046352	C052708	C075571	C075573	C077200	C076365	C077201	C076367	**TOTAL**
6			FY13										
7			FY14	$33,706	$18,926	$4,258							**$56,889**
8			FY15	$362,894	$1,490,001	$161,692							**$2,014,587**
9			FY16	$615,566	$1,540,206	$56,690							**$2,212,462**
10			FY17	$244,830	$1,319,335	$9,138	$0	$0	$0	$0	$0	$0	**$1,573,303**
11			FY18	$54,019	$298,732	$19	$214.20	$40,055	$182,509	$57,501	$498,398	$262,089	**$1,393,536**

PUC 1-3

Request:

For each year in the response to 1-2, please provide the following:

a. The minimum, maximum, and average Program Cost for each Outcome Category for that year;

b. The minimum, maximum, and average Company Earnings for each Outcome Category for that year.

Response:

Please see Attachment PUC 1-3, which provides the information requested for relevant outcomes for each year. The Company's response to part a. is addressed in the table beginning at Column A, Row 23. The Company's response to part b. is addressed in the table beginning at Column H, Row 23. Please note that, when an incentive is calculated over multiple outcomes as suggested in part b. of the question, the value of that incentive for an individual outcome will be overstated.

(This response is identical to the Company's response to PUC 9-27 in Docket No. 4770.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2													
3													
4													
5							2012						
6		Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)	
7	Energy Efficiency	N/A	119,666,157	N/A	19,947	N/A	56,243	201,351	119,666,157	$ -	$ 49,869,528	$ 2,469,411	
8	System Reliability Procurement	N/A	132,000	N/A	N/A	42	N/A	107	224600	$ -	$ 133,400	$ -	
9	VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ -	$ -	$ -	
10	Renewable Energy Growth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Long-term Contracts	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 581,777	$ -	
12	DG Contracts	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ -	$ -	
13	Net Metering	6	N/A	N/A	N/A	N/A	N/A	61	N/A	N/A	$ 329,386	N/A	
14	Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 12,803,595	N/A	
15													
16		Notes:											
17		CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"											
18		Program costs for Long-term Contracts represents administrative costs associated with PPA negotiation											
19		For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2012											
20		Nameplate capacity for Long-term Contracts and DG Contracts is cumulative											
21		The Company does not have estimates of generation from net metering and REGrowth											
22													
23		**Program cost per unit of outcome**							**Incentive cost per unit of outcome**				
24		Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2			Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
25	Minimum	$ 53,576	$ 0.42	$ 2,500	$ 3,176	$ 887		Minimum	N/A	$ 0.02	N/A	N/A	N/A
26	Average (weighted)	$ 53,576	$ 0.42	$ 2,500	$ 3,176	$ 887		Average (weight	N/A	$ 0.02	N/A	N/A	N/A
27	Maximum	$ 53,576	$ 1.01	$ 2,500	$ 3,176	$ 887		Maximum	N/A	$ 0.02	N/A	N/A	N/A

	A	N	O	P	Q	R	S	T	U	V	W	X	Y
1													
2													
3													
4													
5			Program cost per unit						Incentive cost per unit				
6		Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2		Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2	
7	Energy Efficiency		$ 0	$ 2,500		$ 887			$ 0.02	N/A	N/A	N/A	
8	System Reliability Procurement		$ 1		$ 3,176				$ -		$ -		
9	VVO/CVR												
10	Renewable Energy Growth												
11	Long-term Contracts												
12	DG Contracts												
13	Net Metering	$ 53,576											
14	Renewable Energy Standard												
15													
16													
17													
18													
19													
20													
21													
22													
23													
24													
25	Minimum												
26	Average (weighted)												
27	Maximum												

	A	B	C	D	E	F	G	H	I	J	K	L
1	2013											
2		Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
3	Energy Efficiency	N/A	157,121,309	N/A	26,427	N/A	73847.0154	493,271	157,121,309		$ 63,145,737	$ 2,997,681
4	System Reliability Procurement	N/A	790,000	N/A	N/A	266	N/A	321	653000		$ 672,400	$ -
5	Infrastructure Safety, Reliability (e.g., VVO/CVR)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 139
6	FY 14									$56,889	$ -	$ 139
7	FY 13									-	-	$ -
8												
9	Renewable Energy Growth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Long-term Contracts	36	81,666,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 2,204,145	$ 146,297
11	DG Contracts	11	4,490,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 416,028	$ 20,238
12	Net Metering	1	N/A	N/A	N/A	N/A	N/A	60	N/A	N/A	$ 51,554	N/A
13	Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 18,964,816	N/A

Notes:
CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"
For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2013
Nameplate capacity for Long-term Contracts and DG Contracts is cumulative
The Company does not have estimates of generation from net metering and REGrowth

Program cost per unit of outcome

	Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
Minimum	$ 37,228	$ 0.03	$ 2,389	$ 2,528	$ 855
Average (weighted)	$ 55,176	$ 0.27	$ 2,389	$ 2,528	$ 855
Maximum	$ 61,128	$ 0.85	$ 2,389	$ 2,528	$ 855

Incentive cost per unit of outcome

	Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
Minimum	$ 1,811.03	$ 0.00	N/A	N/A	N/A
Average (weighted	$ 3,525.82	$ 0.01	N/A	N/A	N/A
Maximum	$ 4,057.27	$ 0.02	N/A	N/A	N/A

	A	N	O	P	Q	R	S	T	U	V	W	X
1			Program cost per unit						Incentive cost per unit			
2		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2		Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
3	Energy Efficiency		$ 0.40	$ 2,389.47		$ 855.09			$ 0.02	N/A	N/A	N/A
4	System Reliability Procurement		$ 0.85		$ 2,527.82							
5	Infrastructure Safety, Reliability (e.g., VVO/CVR)											
6	FY 14											
7	FY 13											
8												
9	Renewable Energy Growth											
10	Long-term Contracts	$ 61,127.77	$ 0.03					$ 4,057.27	$ 0.00			
11	DG Contracts	$ 37,228.44	$ 0.09					$ 1,811.03	$ 0.00			
12	Net Metering	$ 43,359.13										
13	Renewable Energy Standard											
14												
15												
16												
17												
18												
19												
20												
21												
22												
23	Minimum											
24	Average (weighted)											
25	Maximum											

	A	B	C	D	E	F	G	H	I	J	K	L	M
1		2014											
2		Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)	
3	Energy Efficiency	N/A	268,468,226	N/A	38,693	N/A	126,180	551,882	268,468,226	N/A	$ 85,348,093	$ 4,223,321	
4	System Reliability Procurement	N/A	455,000	N/A	N/A	120	N/A	197	464,000	N/A	$ 569,300	$ -	
5	Infrastructure Safety, Reliability (e.g., VVO/CVR)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 14,522	
6	FY 15									$ 2,014,587	$ -	$ 13,947	
7	FY 14									-	-	$ 574	
8	FY 13									-	-	$ -	
9													
10	Renewable Energy Growth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 77,121	$ -	
11	Long-term Contracts	36	234,392,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 4,642,891	$ 757,319	
12	DG Contracts	16	18,108,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 2,649,080	$ 119,283	
13	Net Metering	1	N/A	N/A	N/A	N/A	N/A	88	N/A	N/A	$ 125,526	N/A	
14	Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 17,899,440	N/A	
15													
16		Notes:											
17		CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"											
18		For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2014											
19		Nameplate capacity for Long-term Contracts and DG Contracts is cumulative											
20		The Company does not have estimates of generation from net metering and REGrowth											
21													
22		**Program cost per unit of outcome**							**Incentive cost per unit of outcome**				
23		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2			Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
24	Minimum	$ 128,762	$ 0.02	$ 2,206	$ 4,744	$ 676		Minimum	$ 7,334.14	$ 0.00	N/A	N/A	N/A
25	Average (weighted)	$ 140,016	$ 0.12	$ 2,206	$ 4,744	$ 676		Average (weighte	$ 16,753.98	$ 0.01	N/A	N/A	N/A
26	Maximum	$ 191,936	$ 1.25	$ 2,206	$ 4,744	$ 676		Maximum	$ 21,002.81	$ 0.02	N/A	N/A	N/A

	A	N	O	P	Q	R	S	T	U	V	W	X
1			Program cost per unit					Incentive cost per unit				
2		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
3	Energy Efficiency		$ 0.32	$ 2,205.79		$ 676.40			$ 0.02	N/A	N/A	N/A
4	System Reliability Procurement		$ 1.25		$ 4,744.17							
5	Infrastructure Safety, Reliability (e.g., VVO/CVR)											
6	FY 15											
7	FY 14											
8	FY 13											
9												
10	Renewable Energy Growth											
11	Long-term Contracts	$ 128,761.73	$ 0.02					$ 21,002.81	$ 0.00			
12	DG Contracts	$ 162,880.00	$ 0.15					$ 7,334.14	$ 0.01			
13	Net Metering	$ 191,935.78										
14	Renewable Energy Standard											
15												
16												
17												
18												
19												
20												
21												
22												
23												
24	Minimum											
25	Average (weighted)											
26	Maximum											

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2													
3													
4													
5							2015						
6		Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)	
7	Energy Efficiency	N/A	222,822,045	N/A	33335.385	N/A	104726.4	622,822.43	222,822,045	N/A	$ 87,430,831	$ 4,533,360	
8	System Reliability Procurement	N/A	685,000	N/A	N/A	144	N/A	267.00	251,700.00	N/A	$ 1,029,400	$ -	
9	Infrastructure Safety, Reliability (e.g., VVO/CVR)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 45,848	
10	FY 16									$ 2,212,462	$ -	$ 18,761	
11	FY 15									-	-	$ 26,612	
12	FY 14									-	-	$ 475	
13	FY 13									-	-	$ -	
14													
15	Renewable Energy Growth	3	N/A	N/A	N/A	N/A	N/A	438	N/A	N/A	$ 675,133	$ 103	
16	Long-term Contracts	36	238,276,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 7,150,901	$ 792,715	
17	DG Contracts	19	22,784,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 3,516,629	$ 141,560	
18	Net Metering	3	N/A	N/A	N/A	N/A	N/A	330	N/A	N/A	$ 551,915	N/A	
19	Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 13,958,024	N/A	
20													

21 Notes:
22 CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"
23 For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2015
24 Nameplate capacity for Long-term Contracts and DG Contracts is cumulative
25 The Company does not have estimates of generation from net metering and REGrowth
26

	A	B	C	D	E	F	G	H	I	J	K	L	M
27		Program cost per unit of outcome							Incentive cost per unit of outcome				
28		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2			Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
29	Minimum	$ 184,571	$ 0.03	$ 2,623	$ 7,149	$ 835		Minimum	$ 33.18	$ 0.00	$ 40.80	N/A	N/A
30	Average (weighted)	$ 195,355	$ 0.20	$ 2,623	$ 7,149	$ 835		Average (weigh	$ 16,050.45	$ 0.01	$ 40.80	N/A	N/A
31	Maximum	$ 217,504	$ 1.50	$ 2,623	$ 7,149	$ 835		Maximum	$ 21,984.43	$ 0.01	$ 40.80	N/A	N/A

	A	N	O	P	Q	R	S	T	U	V	W	X
1												
2												
3												
4												
5			Program cost per unit					Incentive cost per unit				
6		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
7	Energy Efficiency		$ 0.39	$ 2,622.76		$ 834.85			$ 0.014	$ 40.80	N/A	N/A
8	System Reliability Procurement		$ 1.50		$ 7,148.61							
9	Infrastructure Safety, Reliability (e.g., VVO/CVR)											
10	FY 16											
11	FY 15											
12	FY 14											
13	FY 13											
14												
15	Renewable Energy Growth	$ 217,504.19						$ 33.18				
16	Long-term Contracts	$ 198,316.63	$ 0.03					$ 21,984.43	$ 0.00			
17	DG Contracts	$ 184,570.88	$ 0.15					$ 7,429.78	$ 0.01			
18	Net Metering	$ 206,555.01										
19	Renewable Energy Standard											
20												
21												
22												
23												
24												
25												
26												
27												
28												
29	Minimum											
30	Average (weighted)											
31	Maximum											

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2													
3													
4													
5							2016						
6		Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)	
7	Energy Efficiency	N/A	214,328,549	N/A	30,530	N/A	100,734	758,284	214,328,549	N/A	$ 78,402,087	$ 4,128,034	
8	System Reliability Procurement	N/A	550,000	N/A	N/A	96	N/A	155	(158,500)	N/A	$ 989,700	$ -	
9	Infrastructure Safety, Reliability (e.g., VVO/CVR)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 70,175	
10	FY 17									$1,573,303	$ -	$ 9,353	
11	FY 16											$ 36,364	
12	FY 15											$ 24,080	
13	FY 14											$ 377	
14	FY 13											$ -	
15													
16	Renewable Energy Growth	12	N/A	N/A	N/A	N/A	N/A	906	N/A	N/A	$ 1,797,768	$ 16,843	
17	Long-term Contracts	66	235,107,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 14,654,577	$ 812,217	
18	DG Contracts	23	26,695,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 4,228,911	$ 168,717	
19	Net Metering	13	N/A	N/A	N/A	N/A	N/A	677	N/A	N/A	$ 1,713,779	N/A	
20	Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 8,968,717	N/A	
21													
22		Notes:											
23		CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"											
24		For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2016											
25		Nameplate capacity for Long-term Contracts and DG Contracts is cumulative											
26		The Company does not have estimates of generation from net metering and REGrowth											
27		The annual impacts of VVO/CVR are not available. During 2016, the pilot was in M&V and undergoing commissioning efforts, resulting in many "off" days.											
28													
29		Program cost per unit of outcome							Incentive cost per unit of outcome				
30		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2			Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
31	Minimum	$ 128,123	$ 0.06	$ 2,568	$ 10,309	$ 778		Minimum	$ 1,437	$ 0.00	$ 40.56	N/A	N/A
32	Average (weighted)	$ 196,536	$ 0.21	$ 2,568	$ 10,309	$ 778		Average (weighted	$ 9,921	$ 0.01	$ 40.56	N/A	N/A
33	Maximum	$ 221,844	$ 1.80	$ 2,568	$ 10,309	$ 778		Maximum	$ 12,296	$ 0.01	$ 40.56	N/A	N/A

	A	N	O	P	Q	R	S	T	U	V	W	X
1												
2												
3												
4												
5			Program cost per unit						Incentive cost per unit			
6		Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2		Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
7	Energy Efficiency		$ 0.37	$ 2,568.00		$ 778.30			$ 0.01	$ 40.56	N/A	N/A
8	System Reliability Procurement		$ 1.80		$ 10,309.38							
9	Infrastructure Safety, Reliability (e.g., VVO/CVR)											
10	FY 17											
11	FY 16											
12	FY 15											
13	FY 14											
14	FY 13											
15												
16	Renewable Energy Growth	$ 153,393.14						$ 1,437.12				
17	Long-term Contracts	$ 221,844.09	$ 0.06					$ 12,295.51	$ 0.00			
18	DG Contracts	$ 185,519.25	$ 0.16					$ 7,401.49	$ 0.01			
19	Net Metering	$ 128,123.43										
20	Renewable Energy Standard											
21												
22												
23												
24												
25												
26												
27												
28												
29												
30												
31	Minimum											
32	Average (weighted)											
33	Maximum											

	A	B	C	D	E	F	G	H	I	J	K	L
5						2017						
6		Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
7	Energy Efficiency	N/A	232023450.1	N/A	29363.339	N/A	109051.022	687141.1338	232023450.1		94841567.13	$ 4,829,847
8	System Reliability Procurement	N/A	718000	N/A	N/A	352	N/A	120	63000		1349400	$ -
9	VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 86,750
10	FY 18									$ 1,393,536	$60,000	$ 12,970
11	FY 17									-	-	$ 17,786
12	FY 16									-	-	$ 34,142
13	FY 15									-	-	$ 21,579
14	FY 14									-	-	$ 274
15	FY 13									-	-	$ -
16												
17	Renewable Energy Growth	13	N/A	N/A	N/A	N/A	N/A	922	N/A		$7,040,636	$ 120,473
18	Long-term Contracts	69	332,488,731	N/A	N/A	N/A	N/A	N/A	N/A		$37,154,188	$ 1,480,355
19	DG Contracts	23	27,979,500	N/A	N/A	N/A	N/A	N/A	N/A		$4,890,691	$ 171,131
20	Net Metering	13	N/A					512			$3,149,512	N/A
21	Renewable Energy Standard	N/A	N/A	N/A							$3,753,535	N/A

Notes:

CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"

For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2017

Nameplate capacity for Long-term Contracts and DG Contracts is cumulative

The Company does not have estimates of generation from net metering and REGrowth

ReGrowth program costs and earnings are preliminary and have not yet been filed

Renewable Energy Standard obligation year is not yet complete.

2017 kWh values for Long-term and DG Contracts are estimates

The annual impacts of VVO/CVR are not available. During 2017, the Pilot was being extensivly debugged for communications issues, resulting in significant off-time.

		Program cost per unit of outcome				
34		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
35	Minimum	$ 214,551	$ 0.11	$ 3,230	$ 3,834	$ 870
36	Average (weighted)	$ 440,902	$ 0.23	$ 3,230	$ 3,834	$ 870
37	Maximum	$ 537,494	$ 1.88	$ 3,230	$ 3,834	$ 870

	Incentive cost per unit of outcome			
	Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW
Minimum	$ 7,507	$ 0.00	$ 49.35	N/A
Average (weight	$ 16,851	$ 0.01	$ 49.35	N/A
Maximum	$ 21,374	$ 0.01	$ 49.35	N/A

	A	N	O	P	Q	R	S	T	U	V	W	X	Y
1													
2													
3													
4													
5			Program cost per unit						Incentive cost per unit				
6		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2	
7	Energy Efficiency		$ 0.41	$ 3,229.93		$ 869.70			$ 0.01	$ 49.35	N/A	N/A	
8	System Reliability Procurement		$ 1.88		$ 3,833.52								
9	VVO/CVR												
10	FY 18												
11	FY 17												
12	FY 16												
13	FY 15												
14	FY 14												
15	FY 13												
16													
17	Renewable Energy Growth	$ 537,494.16						$ 9,197.13					
18	Long-term Contracts	$ 536,460.59	$ 0.11					$ 21,374.49	$ 0.00				
19	DG Contracts	$ 214,551.05	$ 0.17					$ 7,507.38	$ 0.01				
20	Net Metering	$ 236,432.10											
21	Renewable Energy Standard												
22													
23													
24													
25													
26													
27													
28													
29													
30													
31													
32													
33													
34													
35	Minimum												
36	Average (weighted)												
37	Maximum												

PUC 1-4

Request:

Please complete the table above (in 1-2), but in this response provide information for all programs and sub-programs proposed by National Grid in Docket 4780 that are associated with a performance incentive in Chapter 9, Section 3. For each program or subprogram, highlight (color or bold font) the metric National Grid has proposed and the metric for determining performance and related incentives. Please use the proposed target achievement and incentive for completing the table in this response.

Response:

The information requested is provided for all proposed programs and subprograms associated with a performance incentive in Attachment PUC 1-4. Note that the Company has modified Column B to include storage and has added Column J to account for outcomes/metrics not captured in the table from PUC 1-2.

(This response is identical to the Company's response to PUC 9-28 in Docket No. 4770.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

	1	2	3	4	5	6	7	8	9	10	11	12
5												
6		Nameplate Capacity (MW Generation or Storage)	kWh Saved, Generated, or Shited off-peak	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2 (short tons)	Participants	Net savings (kWh)	Incremental EV Adoption (above forecast)	Program Cost (FY or CY 2019)	Company Earnings (Concurrent with Year 2019)
7	EV Off-Peak Rebate	N/A	300,000	N/A	90	N/A	22	***100***	N/A	N/A	$178,745.00	$117,243
8	DR--Connected Solutions Participation	N/A	N/A	N/A	TBD	N/A	N/A	***TBD***	N/A	N/A	TBD	TBD
9	DR-- C&I Participation	N/A	N/A	N/A	TBD	N/A	N/A	***TBD***	N/A	N/A	TBD	TBD
10	Electric Heat Initiative	N/A	N/A	N/A	44	N/A	***188***	N/A	N/A	N/A	$408,640	$38,925
11	Electric Vehicles	N/A	N/A	N/A	N/A	N/A	557	N/A	N/A	***259***	$1,451,283	$93,794
12	Utility-Owned Storage	***3***	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$899,375	$46,897
13												
14	Notes:											
15	Metrics for incentive are indicated in bold and italics											
16	EV Off Peak Rebate -- kWh value is estimated kWh shifted from peak to off-peak in Company submitted in response to Division 5-1											
17	DR -- Connected Solutions and C& I Participation targets and incentives to be determined through Energy Efficiency 1-Year Plan											
18	The Company's proposed Electric Heat Initiative targets were converted from metric to short tons for this table											
19	Electric Vehicles Program costs reflects only the portion of the Electric Vehicle Initiative related to vehicle conversion											
20	Company's proposed storage program impacts and costs are included; however, the program itself is not sufficient to achieve the target for Utility-owned Storage											
21	Company earnings reflect estimated performance incentive mechanism payment a the target level											
22												
23	The Company's assumed value of a basis point for all 3 years is the estimated 2019 value of $46,897 submitted by the Company it its response to NECEC 1-11											

	1	2	3	4	5	6	7	8	9	10	11	12
5												
6		Nameplate Capacity (MW Generation or Storage)	kWh Saved, Generated, or Shited off-peak	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2 (short tons)	Participants	Net savings (kWh)	Incremental EV Adoption (above forecast)	Program Cost (FY or CY 2020)	Company Earnings (Concurrent with Year 2020)
7	EV Off-Peak Rebate	N/A	750,000	N/A	220	N/A	62	***250***	N/A	N/A	$244,420.00	$117,243
8	DR--Connected Solutions Participation	N/A	N/A	N/A	TBD	N/A	N/A	***TBD***	N/A	N/A	TBD	TBD
9	DR-- C&I Participation	N/A	N/A	N/A	TBD	N/A	N/A	***TBD***	N/A	N/A	TBD	TBD
10	Electric Heat Initiative	N/A	N/A	N/A	96	N/A	***279***	N/A	N/A	N/A	$1,032,390	$38,925
11	Electric Vehicles	N/A	N/A	N/A	N/A	N/A	757	N/A	N/A	***352***	$2,433,822	$93,794
12	Utility-Owned Storage	***3***	217,391	N/A	360	N/A	N/A	N/A	N/A	N/A	$1,365,563	$46,897
13												
14	Notes:											
15	Metrics for incentive are indicated in bold and italics											
16	EV Off Peak Rebateand Utility-onwed Storage -- kWh value is estimated kWh shifted from peak to off-peak in Company submitted in response to Division 5-1											
17	DR -- Connected Solutions and C& I Participation targets and incentives to be determined through Energy Efficiency 1-Year Plan											
18	The Company's proposed Electric Heat Initiative targets were converted from metric to short tons for this table											
19	Electric Vehicles Program costs reflects only the portion of the Electric Vehicle Initiative related to vehicle conversion											
20	Company's proposed storage program impacts and costs are included; however, the program itself is not sufficient to achieve the target for Utility-owned Storage											
21	Company earnings reflect estimated performance incentive mechanism payment a the targe heat											
22												
23	The Company's assumed value of a basis point for all 3 years is the estimated 2019 value of $46,897 submitted by the Company it its response to NECEC 1-11											

	1	2	3	4	5	6	7	8	9	10	11	12
5												
6		Nameplate Capacity (MW Generation or Storage)	kWh Saved, Generated, or Shited off-peak	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2 (short tons)	Participants	Net savings (kWh)	Incremental EV Adoption (above forecast)	Program Cost (FY or CY 2021)	Company Earnings (Concurrent with Year 2021)
7	EV Off-Peak Rebate	N/A	1,500,000	N/A	450	N/A	97	***500***	N/A	N/A	$332,567.00	$117,243
8	DR--Connected Solutions Participation	N/A	N/A	N/A	TBD	N/A	N/A	***TBD***	N/A	N/A	TBD	TBD
9	DR-- C&I Participation	N/A	N/A	N/A	TBD	N/A	N/A	***TBD***	N/A	N/A	TBD	TBD
10	Electric Heat Initiative	N/A	N/A	N/A	154	N/A	***247***	N/A	N/A	N/A	$466,140	$38,925
11	Electric Vehicles	N/A	N/A	N/A	N/A	N/A	1026	N/A	N/A	***477***	$5,295,299	$93,794
12	Utility-Owned Storage	***3***	543,478	N/A	900	N/A	N/A	N/A	N/A	N/A	$41,250	$46,897
13												
14	Notes:											
15	Metrics for incentive are indicated in bold and italics											
16	EV Off Peak Rebateand Utility-onwed Storage -- kWh value is estimated kWh shifted from peak to off-peak in Company submitted in response to Division 5-1											
17	DR -- Connected Solutions and C& I Participation targets and incentives to be determined through Energy Efficiency 1-Year Plan											
18	The Company's proposed Electric Heat Initiative targets were converted from metric to short tons for this table											
19	Electric Vehicles Program costs reflects only the portion of the Electric Vehicle Initiative related to vehicle conversion											
20	Company's proposed storage program impacts and costs are included; however, the program itself is not sufficient to achieve the target for Utility-owned Storage											
21	Company earnings reflect estimated performance incentive mechanism payment a the target level											
22												
23	The Company's assumed value of a basis point for all 3 years is the estimated 2019 value of $46,897 submitted by the Company it its response to NECEC 1-11											

PUC 1-5

Request:

For all programs and sub-programs proposed by National Grid in Docket 4780 that are associated with a performance incentive in Chapter 9, Section3, and that propose a range of achievement levels and associated incentives:

a. Provide the $/metric value for each proposed achievement level;

b. For any responses in part a that do not have a uniform $/metric value for all achievement levels, please provide a justification for the variation.

c. For any proposed $/metric value in part b that is above of the ranges identified in PUC 1-3.b for 2016 and 2017, please provide a justification for the value being above the range.

Response:

a. Please see Attachment PUC 1-5 for the requested information. Note that in preparing this response, the Company has corrected the minimum target for the EV Off-Peak Charging Rebate performance incentive mechanism for 2020.

b. For the Electric Heat Initiative, differences in the per-ton incentive value for the minimum and target levels reflect rounding in the number of basis points assigned. The maximum value was expanded to ensure that the incentive was large enough to motivate achievement of the stretch targets, given the relatively small number of basis points assigned to this incentive relative to other performance incentive mechanisms.

   For the Electric Vehicle Initiative, the per-vehicle value at the maximum level is slightly smaller than the minimum and target levels. This differential reflects modest rebalancing for the performance incentive mechanism portfolio at the maximum level, such as that described for the Electric Heat Initiative above, to ensure that each incentive had a sufficiently meaningful maximum earning opportunity.

   For Company-owned storage, the slight difference between the per-MW incentive value at the minimum and target levels reflects rounding in the number of basis points assigned.

c. The Company does not currently earn incentives for any of the outcomes shown in Attachment PUC 1-5.

(This response is identical to the Company's response to PUC 9-29 in Docket No. 4770.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

Calculation of per unit incentive payments

Off-Peak Charging Rebate Pilot

						$/participant		
	2019	**2020**	**2021**	**Basis Points**	**Incentive Value**	**2019**	**2020**	**2021**
Min	80	200	400	2	$ 93,794	$ 1,172	$ 782	$ 469
Target	100	250	500	2.5	$ 117,243	$ 1,172	$ 782	$ 469
Maximum	120	300	600	3	$ 140,691	$ 1,172	$ 782	$ 469

Minimum Off-Peak Charging Rebate target for 2020 (in red) has been corrected

Electric Heat Initiatve

						$/metric ton		
	2019	2020	2021		Incentive Value	2019	2020	2021
Min	137	202	179	0.670	$ 31,421	$ 229	$ 155	$ 175
Target	171	253	224	0.830	$ 38,925	$ 227	$ 154	$ 174
Maximum	206	303	269	2.000	$ 93,794	$ 456	$ 309	$ 349

Electric Vehicle Initiative

						$/vehicle		
	2019	2020	2021		Incentive Value	2019	2020	2021
Min	130	176	239	1.00	$ 46,897	$ 362	$ 267	$ 197
Target	259	352	477	2.00	$ 93,794	$ 362	$ 267	$ 197
Maximum	518	703	954	3.50	$ 164,140	$ 317	$ 233	$ 172

Company-owned storage

						$/MW		
	2019	2020	2021		Incentive Value	2019	2020	2021
Min	1	1	1	0.33	$ 15,476	$ 15,476	$ 15,476	$ 15,476
Target	3	3	3	1.00	$ 46,897	$ 15,632	$ 15,632	$ 15,632
Maximum	6	6	6	2.00	$ 93,794	$ 15,632	$ 15,632	$ 15,632

Assumed value
of a BPS $ 46,897

PUC 1-6

Request:

What is the Company's current expectation of the cost of RGGI allowances and Renewable Energy Certificates (RECs) over the next three years?

Response:

The current RGGI program runs through 2020. The RGGI states have proposed program changes that would apply to years 2021-2030. Modeling of the proposed program changes released by RGGI Inc. on September 18, 2017[1] projects an allowance price of $5.51/ton in 2017, $6.56/ton in 2020 (under existing program rules), and $7.81/ton in 2023 (under new program rules).[2] Linear interpolation of these results leads to the following allowance prices for 2019-2021, as shown below.

Projected RGGI Allowance Prices for 2019-2021 based on RGGI, Inc. Modeling (Nominal dollars)

Year	$ per/ton
2019	$6.21
2020	$6.56
2021	$6.98

The Avoided Energy Supply Costs in New England (AESC): 2015 Report[3] contained projections for Renewable Energy Credit (REC) prices. Projections for 2019-2021 are shown in the table below.

Projected REC prices based on AESC 2015 (Nominal dollars)

Year	$ per/MWh
2019	$46.24
2020	$44.79
2021	$54.93

(This response is identical to the Company's response to PUC 9-30 in Docket No. 4770.)

[1] RGGI, Inc. Draft IPM Base Model Rule Policy Case Results. September 18, 2017.
[2] The model does not produce results for each year. All prices are in nominal dollars.
[3] Hornby, R., et al. Avoided Energy Supply Costs in New England: 2015 Report. Prepared for the AESC 2015 Study Group. Revised April 3, 2015. See Exhibit F-1. An inflation rate of 2% is assumed to convert to nominal dollars.

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

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PUC 1-7

Request:

How much CO2 does company expect is abated by purchase of a single RGGI allowance and REC?

Response:

By definition, purchase (and retirement) of a single RGGI allowance should imply 1 ton of CO_2 abatement. In practice, however, the potential for the RGGI cap to be non-binding, as well as the potential for emissions leakage outside of the RGGI states, means that actual abatement is uncertain.

With respect to RECs, the CO_2 grid emissions factor of 1029 lbs/MWh assumed in the Company's benefit-cost analysis filed in support of proposed Power Sector Transformation Plan programs implies that a single REC generated by a zero-emission resource would represent 1029 pounds of avoided CO_2 emissions. Because emissions are capped under RGGI, however, the purchase and retirement of a REC would not actually lead to verifiable CO_2 abatement. This is because RECs effectively free up room under the CO_2 emissions cap and, in doing so, lower the demand for (and thus price of) CO_2 allowances.

(This response is identical to the Company's response to PUC 9-31 in Docket No. 4770.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

PUC 1-8

Request:

Is the Company's expected cost/tonCO2 for RGGI allowances or RECs less than the Company's estimate of the value of a ton of CO2?

Response:

The expected cost per ton of RGGI allowances included in the Company's response to PUC 1-6 is less than the Company's estimate of the value of a ton of CO_2. In its benefit cost analysis, the Company assumed a value of $100 per ton net of embedded costs (*i.e.*, CO_2 compliance costs already reflected in retail energy prices). This is consistent with the value assumed in implementing the Rhode Island Test used for energy efficiency cost-effectiveness analysis. Based on the Company's responses to PUC 1-6 and PUC 1-7, the implied cost per ton of CO_2 for RECs would be approximately $89.70 in 2019. This is based on the Company's assumed grid CO_2 emissions factor, in which approximately 1.94 RECs would represent 1 ton of CO_2 emissions. As noted in the Company's response to PUC 1-7, RECs, even if purchased and retired, cannot be assumed to represent CO_2 abatement because of the emissions cap under RGGI, and the level of abatement implied by purchase and retirement of 1 RGGI allowance is also somewhat uncertain.

(This response is identical to the Company's response to PUC 9-32 in Docket No. 4770.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

PUC 1-9

Request:

Is the Company's expected cost/tonCO2 for RGGI allowances or RECs less than any of the Company's expected cost/tonCO2 in the Company's Electric Heat Initiative?

Response:

Expected costs per ton of CO_2 reduced through the Electric Heat Initiative are shown in Attachment PUC 1-9. The Company shows both lifetime average and marginal costs (*i.e.*, the cost of reductions from an incremental installation). The marginal costs, however, are the most appropriate for this comparison. Although the marginal cost per ton of CO_2 is higher than the cost per ton of CO_2 implied by RGGI allowances and RECs only when the Ground Source Heat Pump Program is included, , neither RECs nor RGGI allowances represent guaranteed additional CO_2 abatement, as discussed in the Company's response to PUC 1-8. Further details are provided in the Company's responses to PUC 1-7 and PUC 1-10.

(This response is identical to the Company's response to PUC 9-33 in Docket No. 4770.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

CO2 TARGETS (CORRECTED in DIV 25-18)

Program Design Element	Target Levels	Targets (annual metric tons CO2) 2018	2019	2020
1. GSHP Program	**Mid (annual)**	**0**	**59**	**0**
	Mid (lifetime)	**0**	**1466**	**0**
2. Equipment Incentives	**Mid (annual)**	**171**	**194**	**224**
	Mid (lifetime)	**3479**	**3917**	**4577**

Total Targets (combined metric tons CO2 avoided per yer)		2018	2019	2020
	Mid (annual)	**171**	**253**	**224**
	Mid (lifetime	**3479**	**5383**	**4577**

PROGRAM COSTS

Program Design Element	Program Cost	2018	2019	2020
1. GSHP Program	O&M		$ 95,000	
	Capital		$ 500,000	
	Total	**$ -**	**$ 595,000**	**$ -**
2. Equipment Incentives	Incentive Pool	$207,500	$236,250	$265,000
	Labor & Administration	$44,640	$44,640	$44,640
	Total	**$ 252,140**	**$ 280,890**	**$ 309,640**
3. Community Based Outreach	O&M	$ 95,500	$ 95,500	$ 95,500
	Capital	**$ -**	**$ -**	**$ -**
	Total	**$ 95,500**	**$ 95,500**	**$ 95,500**
4. Oil-dealer training	O&M	$ 61,000	$ 61,000	$ 61,000
	Capital	**$ -**	**$ -**	**$ -**
	Total	**$ 61,000**	**$ 61,000**	**$ 61,000**
Total		**$ 408,640**	**$ 1,032,390**	**$ 466,140**

Lifetime Abatement Cost Estimates	Notes	2018	2019	2020
Average CO2 abatement (lifetime) **Total EHI Program**	Total program costs divided by lifetime CO2 avoided	**$ 117**	**$ 192**	**$ 102**
Marginal CO2 abatement (lifetime)	Incentive costs divided by lifetime CO2 avoided			
GSHP		n/a	$ 406	n/a
Equipment Incentives		$ 60	$ 60	$ 58
Total EHI Program		**$ 60**	**$ 154**	**$ 58**

PUC 1-10

Request:

Was the voluntary purchase of RECs and RGGI when the price of each is below a certain price, such as the company's benchmark for CO2, considered for meeting the Company's GHG reduction targets?

Response:

No. First, as discussed in the Company's responses to PUC 1-8 and PUC 1-9, the purchase and retirement of RECs alone does not imply any additional CO_2 abatement. In addition, at current cap levels and with the potential for emissions leakage outside of the RGGI region, the purchase and retirement of RGGI allowances does not provide certainty of additional CO_2 abatement.

Second, the Company's CO_2 reduction targets and incentive are intended to reward the Company for its effectiveness in driving emissions reductions outside of the electric sector. Electrification of heat will be essential for Rhode Island to meet its greenhouse gas reduction goals, and therefore the Company proposes to achieve these goals through the Electric Heat Initiative. For example, the 2050 Pathway in The Rhode Island Executive Climate Change Coordinating Council's "Rhode Island Greenhouse Gas Emissions Reduction Plan" implies an annual conversion rate of approximately 13,000 customers per year to heat pumps every year between now and 2050.

The proposed incentive was designed to reward the Company for effectively targeting highly-emitting customers, maximizing participation on a fixed incentive budget, and encouraging proper system design and utilization.

(This response is identical to the Company's response to PUC 9-34 in Docket No. 4770.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

PUC 1-11

Request:

Please provide the expected or target rebate, per month, that would be paid to participant in the EV Off-Peak Charging Rebate program. Please indicate which months are summer which months are winter rebate months. Please provide the number of hours participants are expected to charge their vehicles per month during on- and off-peak hours. Please reference or include supporting material, and indicate which are Rhode Island-specific data.

Response:

As described in the Company's response to Division 10-29, a copy of which is provided as Attachment PUC 1-11-1 for ease of reference, the Company estimated that participants might earn up to $18 per month in summer months (June – September) and up to $12 per month in winter months (October – May). This estimate assumes that participants perform 100 percent of their charging at home during off-peak hours in all months to maximize their benefit.

Home charging session lengths vary, depending upon the voltage level (120v Level 1, or 240v Level 2), amperage of the charger, the vehicle's acceptance rate from a Level 2 charger if available (3.3KW or greater), and the amount of battery required to charge.

For average daily commuters with a Level 2 charger, the Company expects regular overnight charging to satisfy most, if not all, of these drivers' regular charging needs. A Level 2 charger can supply 10 to 20 miles of range per hour, according to the US Department of Energy.[1] Given this, a single nine-hour off-peak charging session (for example, starting at 9:00 p.m. and ending at 6:00 a.m.) could deliver 90 to 180 miles of battery range. One of the purposes of the proposed pilot is to validate this assumption and gather more specific data on Rhode Island drivers' charging levels and charging patterns.

(This response is identical to the Company's response to PUC 9-35 in Docket No. 4770.)

[1] See Attachment PUC 1-11-2 for this reference.

Prepared by or under the supervision of: Carlos Nouel

Division 10-29

Request:

NOTE: The references to responses to division data requests refer to docket 4770.

Refer to PST-1, Chapter 5, page 3 regarding the Company's estimate of the likely monthly earnings for customers under the proposed off-peak charging rebate:

a. Provide all calculations underlying the estimate of these monthly earnings values, in machine-readable format with formulas intact.
b. Provide the Company's hourly EV charging assumptions underlying these earnings values.

Response:

a. Please see Attachment DIV 10-29. The Company assumed that an average electric vehicle (EV) uses 30 kWh to travel 100 miles, for an efficiency of 0.30 kWh per mile. Assuming an average 12,000 electric miles driven per year, an EV will use approximately 3,600 kWh per year, or 300 kWh per month. If 100 percent of a drivers' usage could be conducted during the off-peak, a driver could earn 300 kWh * $0.06/kWh for $18 per month in summer, and 300 kWh * $0.04/kWh for $12 per month in all other months.

   The Company reserves the right to change the value per kWh as necessary during this pilot to achieve the pilot goals.

b. The Company's estimate of these earnings values assumes 100 percent of kWh are charged during the off-peak period eligible for the rebate (9:00 p.m. until the following day 1:00 p.m.).

(This response is identical to the Company's response to Division 32-29 in Docket No. 4770.)

Prepared by or under the supervision of: Carlos Nouel

Potential EV driver earnings per month under Off-Peak Charging Rebate Program

Average electric vehicle efficiency (kWh per mi)		0.3
Average electric miles driven annually		12,000
Average electricity used annually (kWh)		3600
Average electricity used monthly (kWh)		300
Summer month rebate per kWh	$	0.06
Non-summer month rebate per kWh	$	0.04
Potential earnings per summer month	**$**	**18**
Potential earnings per non-summer month	**$**	**12**

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Vehicle Charging

Home » Vehicle Charging

The standard J1772 electric power receptacle (right) can receive power from Level 1 or Level 2 charging equipment. The CHAdeMO DC fast charge receptacle (left) uses a different type of connector.

To get the most out of your plug-in electric vehicle (also known as an electric car or EV), you must charge it on a regular basis. Charging frequently maximizes the range of all-electric vehicles and the electric-only miles of plug-in hybrid electric vehicles. Drivers can charge at home, at work, or in public places. While most drivers do more than 80% of their charging at home and it is often the least expensive option, workplace and public charging can complement residential charging.

TYPES OF CHARGERS

Charging your EV requires plugging into a charger connected to the electric grid, also called electric vehicle supply equipment (EVSE). There are three major categories of chargers, based on the maximum amount of power the charger provides to the battery from the grid:

- **Level 1: Provides charging through a 120 V AC plug and does not require installation of additional charging equipment. Can deliver 2 to 5 miles of range per hour of charging. Most often used in homes, but sometimes used at workplaces.**
- **Level 2: Provides charging through a 240 V (for residential) or 208 V (for commercial) plug and requires installation of additional charging equipment. Can deliver 10 to 20 miles of range per hour of charging. Used in homes, workplaces, and for public charging.**
- **DC Fast Charge: Provides charging through 480 V AC input and requires highly specialized, high-powered equipment as well as sp**

(Plug-in hybrid electric vehicles typically do not ha
deliver 60 to 80 miles of range in 20 minutes of charging. Used most often in public charging stations, especially along heavy traffic corridors.

Charging times range from less than 30 minutes to 20 hours or more based on the type of EVSE, as well as the type of battery, how depleted it is, and its capacity. All-electric vehicles typically have more battery capacity than plug-in hybrid electric vehicles, so charging a fully depleted all-electric vehicle takes longer.

In addition to the three types above, wireless charging uses an electro-magnetic field to transfer electricity to an EV without a cord. The Department of Energy is supporting research to develop and improve wireless charging technology. Wireless chargers are currently available for use with certain vehicle models.

TYPES OF PLUGS

Most modern chargers and vehicles have a standard connector and receptacle, called the SAE J1772. Any vehicle with this plug receptacle can use any Level 1 or Level 2 EVSE. All major vehicle and charging system manufacturers support this standard, so your vehicle should be compatible with nearly all non-fast charging workplace and public chargers.

Fast charging currently does not have a consistent standard connector. SAE International, an engineering standards-setting organization, has passed a standard for fast charging that adds high-voltage DC power contact pins to the SAE J1772 connector currently used for Level 1 and Level 2. This connector enables use of the same receptacle for all levels of charging, and is available on certain models like the Chevrolet Spark EV. However, other EVs (the Nissan Leaf and Mitsubishi i-MiEV in particular) use a different type of fast-charge connector called CHAdeMO. Fortunately, an increasing number of fast chargers have outlets for both SAE and CHAdeMO fast charging. Lastly, Tesla's Supercharger system can only be used by Tesla vehicles and is not compatible with vehicles from any other manufacturer. Tesla vehicles can use CHAdeMO connectors through a vehicle adapter.

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PUC 1-12

Request:

In National Grid's response to Sierra Club 1-16 in Docket No. 4780, National Grid states, "As part of the EV Off-Peak Charging Rebate, the Company will evaluate the technical capability of Level 2 electric vehicle supply equipment to function as residential revenue-grade meters.

a. In what way will this evaluation be similar to the streetlight metering pilot conducted as part of Docket No. 4513? In what ways will it be similar?

b. Why does National Grid believe the results of the proposed study will be different from the results of the study conducted in Docket No. 4513?

Response:

a. In Docket No. 4513, the Company conducted a pilot metering program for municipal-owned street lights that tested the meter accuracy of the customer-owned devices. The general conclusion reached through this testing was that the network lighting controls did not meet industry standards for accuracy. At this time, given limited resources and the results of the Docket No. 4513 study, the Company plans to evaluate the technical capability of Level 2 electric vehicle supply equipment through monitoring research by others in the industry on the topic, including the Plug-in Electric Vehicle Submetering Pilot underway in California, rather than perform its own testing of residential EV chargers.

b. The Company does not know how the results of industry research on residential EV chargers will compare to the study conducted in Docket No. 4513.

(This response is identical to the Company's response to PUC 9-36 in Docket No. 4770.)

Prepared by or under the supervision of: Carlos Nouel

PUC 1-13

Request:

Regarding the proposal to electrify portions of National Grid's fleet:

a. Where will these vehicles be housed, recharged, and registered?

b. Will the vehicles be used in other jurisdictions? If so, will some of the costs of these vehicles be paid for by ratepayers in other jurisdictions?

Response:

a. The vehicles will be housed at various existing Company locations throughout the State of Rhode Island and will be recharged at that same location. The vehicles will be registered in Rhode Island as well.

b. No, the vehicles will not be used in other jurisdictions.

(This response is identical to the Company's response to PUC 9-37 in Docket No. 4770.)

Prepared by or under the supervision of: Carlos Nouel

PUC 1-14

Request:

In National Grid's response to Sierra Club 1-24 in Docket No. 4780, National Grid states, "Although funding for the beneficial heat electrification will originate from both the EE and PST programs, most part of the implementation and delivery… will be undertaken by the same internal staff."

a. How will employees understand when they are working on EE versus PST initiatives?

b. How will these employees' time be tracked and accounted for appropriately in the different programs' administrative costs.

c. For electric heating activities that are identical in the EE and PST programs, would National Grid's metric achievement measurement and incentive structure identical for these activities? If not, why not?

Response:

a. National Grid has established accounting processes that define what employees charge for various initiatives. Steps in that process include establishing funding projects for portfolios or funding streams, work orders for project levels, and operations for different types of work. These three components are parts of an accounting string. In developing new accounting strings and modifying existing ones, a financial assurance team works with employees to differentiate funding streams and work types in accordance with regulatory orders. That process results in clearly defined and named funding projects and work orders, which reside in cost centers within the organization. The financial assurance team then manages the database, communication, training, and review necessary for appropriate accounting. An employee will understand they are working on energy efficiency versus Power Sector Transformation because they 1) were part of an established process that clearly defined one versus the other; 2) new accounting strings clearly differentiate the work streams; and 3) communication and training of new accounting has been provided. National Grid has experience with this process, such as various funding streams for Rhode Island energy efficiency and more recently with New York REV.

b. In addition to the response above, National Grid has established accounting processes specific to charging time and reporting administrative costs. The accounting strings described above, which will differentiate between energy efficiency and Power Sector Transformation, are used in the SAP time entry system. Components of accounting strings also define where the costs are reported and their source, such as administrative costs that will be reported as either energy efficiency or Power Sector Transformation,

Prepared by or under the supervision of: Mackay Miller labor or non-labor. Charges are reviewed for appropriateness at several intervals throughout the year by various teams.

c. The Company believes that, in the long run, heat electrification efforts should place CO_2 reductions at the core of utility metrics and incentives, as currently described in the performance incentive mechanisms framework. In the short run, the metrics and incentive structures will not be identical between the two programs, as the energy efficiency program retains its focus on energy savings reductions. Over the course of the three-year Power Sector Transformation Plan, the Company will work with the PUC and stakeholders to consider options for harmonization of metrics and incentive structures over the longer term.

(This response is identical to the Company's response to PUC 9-38 in Docket No. 4770.)

Prepared by or under the supervision of: Mackay Miller

PUC 1-15

Request:

For any PST program or subprogram described as a "pilot" or "demonstration" by the National Grid

a. Please confirm that the primary objective of the activity is to learn.

b. For each activity that also would count toward a proposed incentive and is supported by capital spending, please explain why an incentive beyond the return on investment is justified.

c. For each activity that also would count toward a proposed incentive and is not supported by capital spending, please confirm that no existing program incentive or proposed program incentive could apply to the activity in the case that the Company's pilot or demonstration leads to a full-fledged program deployment

Response:

a. Three Power Sector Transformation Plan programs are described as a "pilot" or "demonstration" project: the Electric Transportation Initiative, the Energy Storage System Initiative, and the Solar demonstration Program.

The primary objective of the Electric Transportation Initiative is market development for electric vehicles and charging. Because the market for vehicles and charging is in its infancy in Rhode Island, the Company's Electric Transportation Initiative is structured as a three-year pilot to test multiple market development strategies. Under the Electric Transportation Initiative, three components are further characterized as pilots or demonstrations: the Off-Peak Charging Rebate Pilot, the Charging Station Demonstration Program, and the Discount Pilot for Direct Current Fast Charging Station Accounts. As the end of these three-year programs approaches, the Company will return to the Public Utilities Commission with proposals to continue some or all of the activities as required to meet customers' needs.

For the Energy Storage System Initiative, the Company noted in PST Book 1, Bates Page 137, that, "[t]o effectively integrate energy storage, utilities must become involved with this technology early on, developing process improvements and methods to properly and efficiently take advantage of the benefits that storage can provide. It is for this reason that the Company proposes an Energy Storage System Initiative in its clean energy portfolio." The Company noted three major objectives of this proposal on Bates Page 138 of PST Book 1: maximize quantifiable benefits; advance internal research and

Prepared by or under the supervision of: Kayte O'Neill

development; and promote energy awareness through educational outreach to community and youth organizations.

For the Solar demonstration program, the Company's stated objective described in PST Book 1, Bates Page 147, is to allow the Company to learn from the siting, permitting, construction, interconnection, and operation of solar PV systems, to benefit customers and solar developers as renewable projects progress forward, and to spur new market growth.

b. **Electric Transportation Initiative**

The Company has proposed two performance incentives related to the Electric Transportation Initiative:

- EV-Off Peak Charging Rebate Participation, measured by number of participants in the program; and
- Electric vehicles, measured by the number of incremental EVs adopted above forecasted levels.

Two of the proposed components of the initiative include capital:

- Charging Station Demonstration Program; and
- Company Fleet Expansion.

The Charging Station Demonstration Program may contribute to achievement of the EV targets because increasing charging station availability should help to enable EV adoption. Achievement of these targets, however, will also rely heavily on the Company's outreach and education efforts. An incentive beyond the return on charging station capital is warranted because it will reward the effectiveness of the Company's overall efforts to drive EV adoption, which is critical to state's greenhouse gas policy goals.

Company Fleet Expansion would not count toward a proposed incentive.

Energy Storage System Initiative: This project will contribute to but not be sufficient to meet the targets for the Company's proposed Utility-Owned Storage Performance Incentive Mechanism. An incentive for energy storage is warranted to support Company efforts to help spur cost effective deployment in recognition of the role that cost-effective storage can play in supporting Rhode Island's clean energy and climate goals.

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Solar Program: This project is not specifically linked to any proposed incentive. Any reductions in peak demand due to this program could potentially contribute to the FCM and Monthly Transmission Peak Demand Reduction targets. However, peak reductions would not count toward the FCM Peak Demand Reduction target if the Company bids this capacity into the ISO-NE Forward Capacity Market.

c. This question only applies to certain components of the Electric Transportation Initiative (e.g., Off-Peak Charging Rebate Pilot, and education and outreach that would support incremental EV adoption). There are no existing program incentives that could apply to these proposed Electric Transportation Initiative activities in the event that it becomes a full-fledged program.

(This response is identical to the Company's response to PUC 9-39 in Docket No. 4770.)

Prepared by or under the supervision of: Kayte O'Neill

PUC 1-16

Request:

Regarding National Grid's proposed increase to the Residential customer charge:

a. What, increase to National Grid proposed to the Residential distribution charge would be necessary to achieve the proposed revenue requirement if the customer charge remained at $5/customer-bill?

b. What would be the average annual value of such an increase to existing residential net metering customers? Please provide the number of existing residential net metering customers and their annual kWh generation used to respond to this data request.

Response:

a. Please see Attachment PUC 1-16. Under a $5/customer-bill charge, the volumetric distribution charge would be $0.04787 per kWh to achieve the proposed revenue requirement. For the purposes of this response, the Company assumed that the same rate would be proposed for A-16 and A-60 customers.

b. The Company does not have load or generation information from net metered customers. The net meter used for these customers only measures the net usage less any generation over the billing period. Therefore, the Company is unable to calculate this value.

(This response is identical to the Company's response to PUC 9-40 in Docket No. 4770.)

Prepared by or under the supervision of: Kayte O'Neill

The Narragansett Electric Company
Illustrative Rate Design for Residential Rates A-16 / A-60
Based on a $5.00 per Month Customer Charge

Line		Billing Units	Illustrative Rates	Revenue
		(a)	(b)	(c)
1	Revenue Allocation			**$167,491,395**
2				
3	Customer Charge:			
4	Monthly Bills- A-16	4,847,495	$5.00	$24,237,475
5	Monthly Bills- A-60	437,171	$5.00	$2,185,855
6	**Customer Charge Revenue**	5,284,666		**$26,423,330**
7				
8	Energy-based Charge:			
9	kWh Sales- A-16	2,723,228,532	$0.04787	$130,360,950
10	kWh Sales- A-60	223,496,800	$0.04787	$10,698,792
11	**Distribution Charge Revenue**	2,946,725,332		**$141,059,742**
12				
13	Rate A-16 Rev			$154,598,425
14	Rate A-60 Rev			$12,884,647
15				
16	**Total Revenue**			**$167,483,072**
17				
18	Difference			($8,323)
19				
20	Customer costs per month	Sch. HSG-1C-1 (REV-1), Line 23		$9.38
21	Demand costs per kW-month	Sch. HSG-1C-1 (REV-1), Line 10		$11.00
22	Use kW X		0.50	$5.50
23	Total			$14.88
24	Use		A-16	$5.00
25			A-60	$5.00
26				
27	Item		Source	
28	Line 1		Schedule HSG-3 (REV-1), Line 47	
29	Lines 4-5, Column (a)		Schedule HSG-4L (REV-1), Lines 10-11	
30	Lines 4-5, Column (b)		Per information request PUC 9-40	
31	Lines 9-10, Column (a)		Schedule HSG-4L (REV-1), Lines 10-11	
32	Lines 9-10, Column (b)		Calculated to produce revenue requirement	

PUC 1-17

Request:

In National Grid's response to Division 8-12 in Docket No. 4770 (Division 2-12 in Docket No. 4780), National Grid describes the undepreciated costs associated with existing meters that are replaced by AMI meters as "sunk costs and, therefore, should not be factored into the benefit-cost analysis." For simplicity, assume book life is equal to useful life, and meters are replaced when they are fully depreciated.

Regarding costs, in both the case that AMI are installed, and the case they are not installed, customers cannot avoid paying the undepreciated cost for the existing meters, and in that sense the undepreciated cost for the meters appear to be sunk costs, and thus should not be included as a cost category of the benefit-cost analysis.

Turning to benefits, if AMI are installed, customers will lose the value of the remaining metering life of the existing meters. However, if AMI are not installed, customers will get to use the remaining metering life of the existing meters—thus customers can avoid losing the value of the remaining metering life. Please explain why the different outcomes related to this (negative) benefit category (i.e., the remaining value to customers in existing meters) is not considered in National Grid's cost-benefit analysis.

Response:

There is a fundamental conceptual issue embedded in this question. This issue centers on whether the undepreciated plant balances that will exist at the time that a transition is made from an *existing* metering system to a *new* metering system should be accounted for in the cost-benefit analysis supporting the implementation of the new metering system. The question defines the meter-related undepreciated plant balances as a "negative benefit", meaning that the relinquishment of the remaining metering life of existing metering equipment suggests a loss of value to customers. The Company does not agree with this proposition because the value of AMR is accounted for in the Company's analysis.

First, it is important to note that, whether viewed as a "cost" or "negative benefit," the impact to customers of retiring AMR meters prior to being fully depreciated is accounted for within the context of the Company's cost-benefit analysis in the same way. That is, the Company's analysis factors in the cost of the AMI system replacing those AMR meters, plus the incremental benefits of AMI in providing the metering functionality originally provided by AMR. Counting the cost of AMI, as it replaces AMR, captures the "negative" benefit of not utilizing AMR meters for their entire useful life.

Prepared by or under the supervision of: John Leana

A simplified illustration of this approach is provided below. The AMF benefit-cost analysis (BCA) computes the present value of the incremental net benefits of the AMI implementation scenario as compared to the AMR replacement scenario over a 20-year study period beginning in fiscal year 2020. The AMR replacement scenario assumes the electric AMR meters are replaced when they reach the end of their 20-year useful life. Because the AMI alternative provides all of the benefits that the AMR replacement scenario provides over the 20-year term of the analysis, there is no loss of AMR driven benefits between the two scenarios.

Simplified BCA Illustration
Rhode Island Only Implementation with Scenario 4 Benefits (NPV, $million)

AMI Alternative			AMR Replacement Alternative	
Costs:		$259.75	Costs:	$66.49
Benefits:				
	Avoided AMR	$66.49		
	Avoided O&M	$52.64	Incremental Benefits to AMR Replacement Alternative	
	Customer	$162.02		
	Societal	$47.50		
	Total Benefits	$328.65		
Benefits less Costs		$68.90	Incremental Value as Compared to AMR Replacement Scenario	

In addition, it cannot be overlooked that costs and benefits attach to the use of *both* metering systems that are completely independent of each other. For example, at the time that AMR was implemented, the equipment was purchased and installed at a cost. Once installed, the equipment had the effect of automating the meter-reading function, replacing field organizations that utilities historically maintained to perform premises-by-premises, manual meter-reading services, which required the hiring, training, and management of a large field staff among other cost components. With the introduction of AMR, *all* utility customers realized significant savings associated with the efficiencies of automation, which eliminated the need for a meter reader to manually read the meters on every customer premises with frequency.

Consequently, there are costs and benefits associated with the AMR equipment that are entirely independent from the AMI metering system. The BCA analysis shows that there would be no "loss in value" to customers inherently created by the transition to AMI. Thus, any undepreciated plant balance remaining on the Company's books at the time of transition to AMI is accounted for within the BCA and, at the same time, represents the remainder of the prior metering system, which had its own costs and benefits.

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With the implementation of new technology, it is necessary to have the expectation that the technology, regardless of how "cutting edge" it may be at the time it is implemented, will be supplanted in the future by newer technology that will have its own costs and benefits in relation to going-forward deployment. A transition to AMI cannot occur without an understanding that, to achieve the goals identified for the implementation of AMI, it is necessary to make a jump from AMR to AMI at a point in time that will not necessarily correlate with the end of the useful life of the entire population of AMR meters. Because it is not physically possible to make a clean cutover to an AMI system, with an AMI meter installed exactly at the point that each AMR meter reaches the end of its useful life, undepreciated balances for the AMR meters will exist.

Undepreciated balances associated with AMR meters represent a "cost" to customers because the Company has paid for those meters and should not lose its recovery simply because a decision is made to change the platform used by the Company to provide service to customers. However, the recovery of these costs from customers is not improper or inequitable because the entire customer base has benefitted over a long period of time from the significant operating cost reductions gained through the implementation of AMR – and will benefit over a long period of time into the future with the functionality added by AMI. Therefore, the need to address these costs should not hinder the transition to new technology that will ultimately transform the way that customers take service from the Company.

(This response is identical to the Company's response to PUC 9-41 in Docket No. 4770.)

Prepared by or under the supervision of: John Leana