
Division 10-1

Request:

Refer to Appendix 10.10, page 277, regarding the Annual Report on PST Plan Activities which the Company proposes to file by August 1 of each year. The text states that circumstances "may require reasonable deviations from the original PST Plan for the PST Plan Year approved by the Commission. In such cases, for each PST Initiative, the Company shall include in the report an explanation of (1) Actual Capital Investment in excess of Forecasted Capital Investment by ten (10) percent, and (2) Actual O&M Expense in excess of Forecasted O&M Expense by ten (10) percent. For cost recovery purposes, the Company has the burden to show that any such deviations were due to circumstances out of its reasonable control or, if within its control, were reasonable and prudent."

a. Please describe the Company's proposal regarding the process for review and approval of any cost deviations, including whether such a review would occur within a separate proceeding, whether parties would have an opportunity to ask discovery, and the proposed duration of the review process.

b. Please describe how the Company would provide assurance that all costs were assigned to appropriate cost categories and not allocated to non-PST categories.

c. If any costs associated with achieving the PIM targets for system efficiency, distributed energy resources, and network support services will be recovered through the PST tracker, does the Company believe that cost overages necessary to achieve the targets should be considered prudent?

Response:

a. Since the Company's proposal for PST Plan Activities is based on forecasted Capital Investments and forecasted Operation and Maintenance Expenses (O&M), the most appropriate process for review and approval of PST Plan activities would be one that is consistent with the Company's existing annual Infrastructure, Safety and Reliability (ISR) reconciliation process. Under the current annual ISR reconciliation process, the Company files with the PUC a reconciliation report that identifies capital projects that exceed $1.0 million in total project costs and identifies capital variances that exceed +/- 10% of the annual fiscal year capital budget. For the identified capital projects, the Company must note whether variances were due to the project being accelerated or delayed, or whether the variances were due to an increase or decrease in total project cost. In addition, in the annual PST reconciliation report, the Company would also report actual O&M expenses that exceeded forecasted expenses by +/- 10% of the annual fiscal year O&M budget. As with the ISR process, the burden will be on the Company in the annual PST reconciliation filing to support the prudency and the appropriateness of any actual excess capital or O&M expense that exceeded the initial forecasts. Finally, like with the ISR process, the need for any hearing or discovery for a formal review of the annual PST reconciliation filing would be determined by the PUC.

b. As noted in part (a), under the annual PST reconciliation filing, the burden will be on the Company to support the prudency and the appropriateness of any actual excess capital investment costs or O&M expense that exceeded the initial forecasts, including the appropriate assignment of costs.

c. If the PUC approves the proposed PST tracker, the Company will be entitled to recover the costs associated with approved PST Plan activities. See response to part (b), above regarding the prudency of any cost overages.

(This response is identical to the Company's response to Division 3-1 in Docket No. 4780.)

Prepared by or under the supervision of: Melissa Little

Division 10-2

Request:

Refer to Appendix 2.1, page 16, regarding the assumed number of electric vehicles that will be adopted due to the construction of each port, by vehicle type.

a. Please discuss whether the development of these assumptions accounted for state-specific factors such as the price of electricity relative to gas, state incentive programs for electric vehicles, or other factors in order to tailor the estimated ratios to Rhode Island. If so, please provide such calculations. If not, please explain why not.

b. Please provide all data and studies used to develop the assumptions in (a). Please provide the requested data in machine-readable format with all formulas intact.

c. Do these adoption rates depend on the location of the charging port within National Grid's territory, such as in dense urban areas or along highways rather than in more rural areas?

d. If the response to (c) is yes, please explain whether and how the decision regarding where to install a charging port will take into account the assumed incremental adoption rate of that location.

Response:

a. The Electric Transportation Initiative is a three-year pilot designed to test multiple market development strategies and evaluate the impact that each strategy has on the purchase or lease of electric vehicles by consumers and fleet operators. The Company's assumptions of "EV Enablement Ratios" on Schedule PST-1, Appendix 2.1 - Program BCA, Page 16 (Bates Page 208 of PST Book 1) are estimates of the potential adoption rate of electric vehicles by consumers and fleet operators resulting from the overall Electric Transportation Initiative, including the construction of charging ports. The development of these assumptions did not account for state-specific factors because the Company believes the impact of these factors on the Company's potential program outcomes cannot be estimated with certainty at this time. Indeed, the purpose of the proposed pilot is to test the impact of multiple strategies on electric vehicle adoption in the State.

b. The table below explains the Company's assumptions and describes the supporting data and analysis that the Company has provided as Attachment DIV 10-2-1 and Attachment DIV 10-2-2. The Company used the analyses in these attachments to estimate potential vehicles enabled by the Electric Transportation Initiative.

Assumption	Vehicles Enabled per Port	Comments / rationale
Consumer	5.25	This number was calculated by analyzing and adapting the ratio of registered electric vehicles to publicly-reported charging ports in selected Northeast states. Please refer to Attachment DIV 10-2-1. This analysis first showed an average ratio of 8.3 EVs-to-Level 2 ports in the selected states, and an average ratio of 44.5 EVs-to-DC Fast Charging ports in these states (shown on Pages 2 and 3 of Attachment DIV 10-2-1). The Company then discounted these ratios by 50 percent to be conservative. The resulting L2 enablement per port is four vehicles, and the DC Fast Charging enablement per port is 22.3. These enablement ratios per port were then multiplied by the proportions of L2 and DCFC in the Company’s proposal (93 percent L2 and seven percent DC Fast Charging), which yielded an average of approximately 5.25 vehicles per port in the Company’s Rhode Island proposal. This is shown on Page 1 of Attachment DIV 10-2-1.
Light duty fleet	2	The Company estimated that two fleet cars could feasibly and regularly operate per charge point installed at the fleet operator’s premise.
Ridesharing	5.25	This number was assumed to be the same as consumer vehicle enablement for consistency, although this number could be higher given that Uber/Lyft drivers benefit greatly from vehicle efficiency and DC Fast Charging for ride-sharing may enable a greater number of vehicles than the consumer station average based on L2 and DCFC.
Heavy duty buses	4	Data from a CalStart report, provided as Attachment DIV 10-2-2, Page 8, indicates four to eight electric buses operated per charge point installed.
Heavy duty fleet vehicles	1	The Company estimated that one heavy duty fleet vehicle would likely be assigned per charge point installed.

c. The Company has not assumed a specific geographic distribution of the planned stations.

With regard to the Company's proposal to establish charging stations for consumer vehicles, however, the Company expects charging stations that are visible and accessible to drivers on a daily basis would most likely encourage the purchase or lease of electric vehicles by consumers currently considering them, and increase awareness of electric vehicles by those consumers who may be wholly unfamiliar with the option. For this reason, the Company's proposal prioritizes Level 2 charging stations in workplaces, apartment buildings, and public transit stations (see Table 5-2 on Page 4 of Schedule PST-1, Chapter 5 - Electric Transportation (Bates Page 104 of PST Book 1)). These are places where Level 2 stations will be visible to large numbers of daily users, and where the length of time electric vehicles are parked will match the amount of time needed to charge. In addition, the Company's proposal to demonstrate ownership and operation of DC Fast Charging stations in four locations would prioritize highly visible locations near major highway exits or in urban locations with large numbers of multi-family buildings or no dedicated residential parking, so that Fast Charging would enable electric vehicle adoption by customers who cannot charge at home.

With regard to Fleet Vehicle segments, the Company would select sites where fleet operators have plans to electrify a portion of their fleet. The Company would consider the scale of planned electrification at each site as part of site selection to maximize the usefulness of the Company's investment in infrastructure and achieve the expected benefits of vehicle adoption.

d. As part of site selection in the Charging Demonstration Program, the Company will consider the likely utilization of a charging site, and the impact of establishing the site on prospective electric vehicle driver or fleet operators' vehicle purchase or lease decisions. The Company will include these as qualitative criteria, alongside other factors such as anticipated site costs, in prioritizing among interested customers (prospective site hosts).

(This response is identical to the Company's response to Division 3-2 in Docket No. 4780.)

Prepared by or under the supervision of: Carlos Nouel

Consumer Vehicle Enablement per Port

	EV-Port Ratio	Discount	Enablement per Port
EV to L2 Ratio	8	50%	4.0
EV to DCFC Ratio	44.5	50%	22.3

Enablement per National Grid RI Charging Demonstration Program Consumer Vehicle Port

NG Proposed Ports	#	%
L2	268	93%
DCFC	20	7%
Weighted Enablement per Port	5.27	

	L2 Chargers	EV	PHEV	Total	Ratio (EV:L2)
CA	11,646	138,971	122,535	261,506	22.45
FL	1,487	12,717	10,659	23,376	15.72
TX	1,956	10,691	8,590	19,281	9.86
NY	1,378	7,917	12,037	19,954	14.48
WA	1,468	14,917	7,289	22,206	15.13
GA	1,392	18,403	4,915	23,318	16.75
MA	1,159	3,748	5,021	8,769	7.57
NC	791	3,321	3,754	7,075	8.94
OR	911	7,329	4,581	11,910	13.07
MI	689	2,017	11,816	13,833	20.08
IL	782	5,749	6,080	11,829	15.13
CO	978	4,934	3,939	8,873	9.07
MD	923	2,988	4,938	7,926	8.59
VA	609	2,997	4,517	7,514	12.34
TN	796	2,753	1,840	4,593	5.77
AZ	835	6,815	4,581	11,396	13.65
PA	526	3,182	5,918	9,100	17.30
MO	1,369	485	405	890	0.65
OH	451	2,703	4,930	7,633	16.92
CT	552	1,792	2,841	4,633	8.39
MN	430	1,758	2,557	4,315	10.03
WI	246	2,157	2,704	4,861	19.76
HI	484	4,086	1,369	5,455	11.27
NJ	361	4,740	6,352	11,092	30.73
SC	302	954	1,191	2,145	7.10
NV	467	2,017	1,576	3,593	7.69
KS	652	604	1,012	1,616	2.48
IN	269	1,281	2,510	3,791	14.09
VT	284	387	1,098	1,485	5.23
UT	231	2,307	1,726	4,033	17.46
AL	106	657	917	1,574	14.85
ME	152	305	911	1,216	8.00
IA	145	440	1,170	1,610	11.10
DC	174	520	527	1,047	6.02
NH	113	441	986	1,427	12.63
RI	175	222	586	808	4.62
KY	99	489	932	1,421	14.35
LA	97	599	526	1,125	11.60
ID	80	456	608	1,064	13.30
WV	131	106	313	419	3.20
NE	103	320	604	924	8.97
AR	58	197	445	642	11.07
OK	51	865	710	1,575	30.88
NM	63	579	676	1,255	19.92
MS	38	212	233	445	11.71
DE	50	273	645	918	18.36
WY		76	95	171	
MT	39	245	241	486	6.28
SD	22	134	180	314	6.09
ND	11	125	121	246	11.36
AK	9	196	213	409	21.78

Results	
Average	**12.6**
Average (ex-CA)	**12.4**
Select Jursidictions	**8.28**

Sources:
L2 Chargers: Alternative Fuels Data Center: https://www.afdc.energy.gov/data_download
Alternative Fuel Stations, Electric, All Access types, Open
EV and PHEV: Alliance of Automobile Manufacturers: https://autoalliance.org/energy-environment/advanced-technology-vehicle-sales-dashboard/

	DC Chargers	EV	PHEV	Total	Ratio (EV:DC)
CA	1,550	138,971	122,535	261,506	168.71
FL	236	12,717	10,659	23,376	99.05
TX	265	10,691	8,590	19,281	72.76
NY	175	7,917	12,037	19,954	114.02
WA	161	14,917	7,289	22,206	137.93
GA	228	18,403	4,915	23,318	102.27
MA	135	3,748	5,021	8,769	64.96
NC	169	3,321	3,754	7,075	41.86
OR	218	7,329	4,581	11,910	54.63
MI	84	2,017	11,816	13,833	164.68
IL	141	5,749	6,080	11,829	83.89
CO	134	4,934	3,939	8,873	66.22
MD	160	2,988	4,938	7,926	49.54
VA	148	2,997	4,517	7,514	50.77
TN	125	2,753	1,840	4,593	36.74
AZ	143	6,815	4,581	11,396	79.69
PA	140	3,182	5,918	9,100	65.00
MO	106	485	405	890	8.40
OH	134	2,703	4,930	7,633	56.96
CT	92	1,792	2,841	4,633	50.36
MN	94	1,758	2,557	4,315	45.90
WI	66	2,157	2,704	4,861	73.65
HI	70	4,086	1,369	5,455	77.93
NJ	125	4,740	6,352	11,092	88.74
SC	66	954	1,191	2,145	32.50
NV	117	2,017	1,576	3,593	30.71
KS	44	604	1,012	1,616	36.73
IN	64	1,281	2,510	3,791	59.23
VT	55	387	1,098	1,485	27.00
UT	90	2,307	1,726	4,033	44.81
AL	50	657	917	1,574	31.48
ME	32	305	911	1,216	38.00
IA	32	440	1,170	1,610	50.31
DC	5	520	527	1,047	209.40
NH	48	441	986	1,427	29.73
RI	20	222	586	808	40.40
KY	41	489	932	1,421	34.66
LA	53	599	526	1,125	21.23
ID	43	456	608	1,064	24.74
WV	21	106	313	419	19.95
NE	34	320	604	924	27.18
AR	2	197	445	642	321.00
OK	43	865	710	1,575	36.63
NM	51	579	676	1,255	24.61
MS	17	212	233	445	26.18
DE	37	273	645	918	24.81
WY	#N/A	76	95	171	
MT	44	245	241	486	5.57
SD	14	134	180	314	9.57
ND	-	125	121	246	#DIV/0!
AK	-	196	213	409	#DIV/0!

Results	
Average	**66.2**
Average (ex-CA)	**63.9**
Select Jursidictions	**44.52**

Sources:
L2 Chargers: Alternative Fuels Data Center: https://www.afdc.energy.gov/data_download
Alternative Fuel Stations, Electric, All Access types, Open
EV and PHEV: Alliance of Automobile Manufacturers: https://autoalliance.org/energy-environment/advanced-technology-vehicle-sales-dashboard/

Electric Truck & Bus Grid Integration

Opportunities, Challenges & Recommendations

September 2015

CALSTART, Inc.

Acknowledgments

CALSTART would like to express its appreciation to the Energy Foundation for providing funding for this project. In addition, CALSTART would like to thank the following industry stakeholders who shared their knowledge, experience, and learnings, provided valuable input and feedback, corrected our errors, and participated in an extensive review process. The views and opinions expressed in this report do not necessarily state or reflect those of the following individuals and companies.

- Edward Kjaer, Director, Transportation Electrification and Dean Taylor, Senior Scientist at Southern California Edison,
- Evelyne McCleland, Marketing Director and Matt Horton, Vice President of Sales at Proterra Inc.,
- Frank De Rosa, Chief Commercial Officer at SunEdison,
- Jana Corey, Director, Electrification & Electric Vehicles at Pacific Gas & Electric,
- Jason Greenblatt, Electric Vehicle Program Specialist at San Diego Gas & Electric,
- Jerry Estrada, General Manager at Santa Barbara Metro Transit District,
- Joshua Goldman, Vice President of Business Development at TransPower,
- Micheal Austin, Vice President & Andrew Swanton, Director of Business Development at BYD America,
- Mike Britt, Director of Maintenance and Engineering at UPS,
- Nancy Ryan, Director, Policy and Strategy at Energy and Environmental Economics,
- Paula Faust, Deputy Director of Transportation at Gardena Municipal Bus Lines,
- Peter Klauer, Smart Grid Solutions Manager at California ISO,
- Roland Cordero, Director of Maintenance and Vehicle Technology at Foothill Transit,
- Russell Musgrove, Managing Director of Global Vehicles & Thomas Griffin, Chief Engineer, Global Vehicles at FedEx Express,
- Steve Hanson, Director of Fleet Engineering at PepsiCo,
- Toni Williamson, Director of Business Development and Diversity Services at Total Transportation Services, Inc.

Table of Contents

Executive Summary (1)

With funding from the Energy Foundation, CALSTART researched and analyzed the opportunities and challenges faced by the medium and heavy-duty electric truck or E-Truck & Bus market. A comprehensive research of the latest literature was done to provide an up-to-date review of current and future vehicle-grid integration issues facing the industry. In addition, interviews of truck and bus fleets, early adopters of E-Trucks & Buses, were conducted. Three E-Truck & Bus manufacturers were also consulted for their past experiences with the installation of charging infrastructure. Individuals from the following companies provided input for this report. The companies are listed for information purposes only and does not necessarily imply their agreement on all points of this study.

Lastly, an extensive review process was completed with a wide variety of relevant industry stakeholders.

The E-Truck & Bus market is in its early stages where technologies and solutions are still being researched, developed and tested. However, several nationwide fleets and transit agencies across the US have shown serious interest and commitment to electrify part of their fleet of buses, refuse trucks, delivery vans, drayage trucks, shuttle buses, yard hostlers and utility trucks. As a result, the E-Truck & Bus market is expected to see significant growth in the near term, especially in transit bus applications.

Photo courtesy: Efficient Drivetrains

E-Trucks & Buses present unique challenges and opportunities compared to light-duty electric vehicles (EVs). One E-Truck or E-Bus provides substantial environmental benefits but draws more power and consumes more energy than one light-duty EV. Utility load planning will be easier for E-Trucks & Buses as they will be concentrated in fewer areas. But local distribution grid infrastructure may be significantly impacted by new E-Truck & Bus charging loads which can be much higher than for light-duty EVs.

Current utility rate structures can discourage fleets from adopting E-Trucks & Buses. Charging has to support vehicle operation and unlike light-duty EVs cannot easily be shifted. In addition, demand charges can be prohibitively costly for early E-Truck & Bus deployments. Lastly, E-Truck & Bus charging infrastructure is a limiting factor for further vehicle adoption. To electrify the truck & bus market, innovative utility rates and public utility commission policy changes are necessary to reduce the costs for fleets to install E-Truck & Bus charging infrastructure.

Executive Summary (2)

E-Truck & Bus charging, if unmanaged, can have negative impacts on the grid, but implementing smart charging systems will reduce these impacts. Range extenders, energy storage and on-site generation are of high interest to fleets to mitigate charging costs and could also enable E-Trucks & Buses to become true grid resources. Although electricity currently accounts for a small share of the California Low Carbon Fuel Standard credits, securing these credits could further reduce vehicle operating costs. Vehicle-To-Grid could benefit E-Trucks & Buses but is still years away from commercial application.

Photo courtesy: Smith Electric Vehicles

This report developed several recommendations to promote further electrification of trucks & buses:

- **Expand & enhance industry stakeholder forums to better tackle industry issues**
- **Commission a comprehensive E-Truck & Bus load study**
- **Create dedicated E-Truck & Bus program manager positions to support fleets**
- **Secure existing low carbon fuel standard credits to reduce E-Truck & Bus operating costs**
- **Continue to support the electrification of trucks & buses through grants, incentives and tax credits**
- **Fund demonstration projects focusing on advancing technologies that will enable further electrification**
- **Adapt utility rate structure to accelerate the cost effective electrification of trucks & buses**
- **Change current public utility commission policy to mitigate the costs of E-Truck & Bus charging infrastructure**

Lastly, this report identified next steps for the E-Truck & Bus industry that we believe would help implement the recommendations listed above and accelerate the commercialization of medium and heavy-duty electric vehicles.

Photo courtesy: BYD

Photo courtesy: CALSTART

Photo courtesy: TransPower

Photo courtesy: San Joaquin RTD

Although in its early stages, the E-Truck & Bus* industry is dynamic and attracting the attention of fleets nationwide

"[E-Trucks & Buses] are commercially available or in early commercialization in some heavy-duty applications. Additional promising […] platforms are in the concept and demonstration phase in many heavy-duty applications across multiple sectors." [1] Several nationwide fleets with a strong presence in California and a number of California transit agencies have purchased E-Trucks & Buses. Below is a sample of manufacturers currently offering E-Truck & Bus models (right) and a sample of E-Truck & Bus fleets in California (left).

*E-Trucks & Buses are defined in this report as medium & heavy-duty plug-in electric vehicles (GVWR > 6,001 lbs.).

E-Trucks & Buses are already moving people and goods in California and in the United States

Photo courtesy (upper row, from left to right): LA Metro, Motiv Power Systems, CALSTART, California Energy Commission, (middle row, from left to right): TransPower, Motiv Power Systems, Foothill Transit, Complete Coach Works, (lower row, from left to right): New Flyer Industries, TransPower, Motiv Power Systems, Odyne.

E-Trucks & Buses come with different levels of vehicle electrification and different charging infrastructure needs

Like light-duty EVs, E-Trucks & Buses come with different levels of vehicle electrification (Table 1). One vehicle electrification model cannot fit all the many diverse vehicle applications of the truck & bus market. For instance, some of these applications are:

- Transit bus,
- Refuse truck,
- Delivery van,
- Shuttle bus,
- Yard hostler,
- Utility and work truck.

Plug-in Hybrid Electric Vehicles (PHEV) provide zero-emission miles, operational flexibility and require charging infrastructure that is simpler and easier to install. Short range Battery Electric Vehicles (BEV) can be charged quickly to operate indefinitely without long interruptions for charging, while long range BEVs have a higher vehicle assignment flexibility as vehicles are not limited to on-route charging infrastructure. Each level of vehicle electrification has its place in the current E-Truck & Bus market and industry stakeholders should work together to facilitate the electrification of trucks and buses without picking a specific technology and stifling market innovation.

All E-Trucks & Buses will require the installation of charging infrastructure and will impact the grid. Selecting one technology over another involves trade-offs between specific vehicle operation requirements, power demand on the grid and operational savings.

Table 1: Different levels of truck and bus electrification

Truck & Bus Electrification Technology	Example	Average Peak Demand	Battery Size
Short Range PHEV	Volvo PHEV Class 8 Drayage Truck	10 kW	10 kWh
Work Truck PHEV	Odyne Advanced Diesel PHEV Truck	3.3 kW	14/28 kWh
Long Range PHEV	Efficient Drivetrain PHEV/CNG Class 4 Truck	up to 6.6 kW	40 kWh
Short Range BEV	Proterra Fast Charge Catalyst	280 to 380 kW*	53 kWh 131 kWh
Mid Range BEV	Transpower Electric Drayage Drive	70 kW	215 kWh
Long Range BEV	BYD 40-ft Electric Transit Bus	Option 1 - 80 kW Option 2 - 200 kW	324 kWh

* *For bus deployments of 4 to 8 buses per fast charger.*

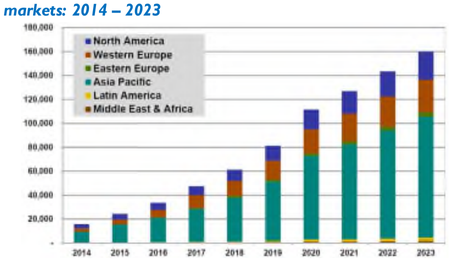
With modest sales, the E-Truck & Bus market is small but significant growth is expected in the near term

E-Trucks & Buses represent a small number of the medium & heavy-duty vehicle market in California and in the US. In California, the Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP) has supported the purchase of about 400 E-Trucks & Buses during its four years of existence [2] and there are now over 500 battery electric medium and heavy-duty vehicles in California, not including buses [3]. In the US overall, there are about 1,000 E-Trucks currently in operation [4].

The California Air Resources Board "believes there are opportunities in regional applications to deploy larger numbers of zero and near-zero emission vehicles near-term" [1]. Two studies have recently been released that support this:

- Navigant Research expects global sales of electric drive and electric-assisted commercial vehicles to grow from less than 16,000 in 2014 to nearly 160,000 in 2023 (Figure 1). While the Asia Pacific region will likely see the majority of the volume, sales in both North America and Western Europe are also expected to be significant. Globally, diesel Hybrid Electric Vehicles (HEV) is expected to remain the most popular format for the whole of the forecast period, followed by BEVs [5].
- In its latest Transportation Electrification Assessment, CalETC commissioned a market sizing and forecasting analysis on a wide variety of transportation technologies. Using three different cases ("In Line with Current Adoption", "In Between" and "Aggressive Adoption"), it forecasts a significant growth in the medium-duty (MDV) and heavy-duty vehicle (HDV) market in California over the next 15 years (Table 2) [6].

Figure 1: Annual MHDV electric drive sales by region world markets: 2014 – 2023



Source: Navigant Research [5]

Table 2: Electric technology total population projections in CA

		Current Adoption	In Between	Aggressive Adoption
I-710 (Truck Miles)	2013	0	0	0
	2020	0	30,700	76,031
	2030	0	194,000	241,000
SR-60 (Truck Miles)	2013	0	0	0
	2020	0	0	0
	2030	0	0	315,000
MDV (Population)	2013	500	500	500
	2020	4,200	6,300	16,400
	2030	96,500	183,700	834,000
HDV (Population)	2013	0	0	0
	2020	80	380	795
	2030	8,800	23,500	65,800

Source: ICF International [6]

Transit agencies across the country are deploying a growing number of battery electric buses

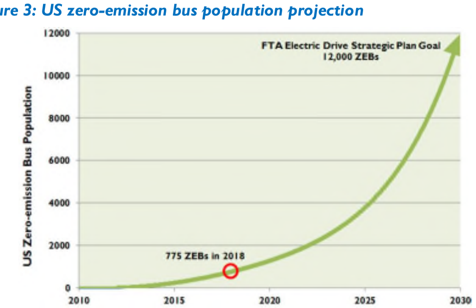
The publicly-funded transit bus sector offers an ideal platform for the validation and early adoption of advanced vehicle technologies [7]. That is why the E-Bus market is currently in a more advanced position than the E-Truck market. Electric drive and electric-assisted buses have already taken off in the US, making up 17% of the fleet in 2014 (up from 1% in 2005). So far most are gasoline or diesel hybrid buses [8]. Battery electric buses are still in the early commercialization phase but transit agencies are deploying a growing number of battery electric buses all across the US with a large number operating in California (Figure 2) [1] .

The large majority of battery electric buses have been manufactured by Proterra and BYD with about 110 and 102 buses sold in the US respectively [9] [10]. Other manufacturers of battery electric buses and shuttle buses include New Flyer, Complete Coach Works and Motiv Power Systems.

The number of zero-emission buses (battery electric and fuel cell hydrogen buses) is expected to double in 2016 and account for 20% of the transit bus market by 2030 [8]. In order to meet the FTA's Electric Drive Strategic Plan ambitious goal of 12,000 zero-emission buses in 2030 (Figure 3), rapid growth in zero-emission bus sales is necessary. Recent announcements show that the industry is on the right growth path: BYD projects to sell as many as 200 electric buses in the US in 2015 [11] and Proterra is building a second plant in California after a stream of new orders [12].

Figure 2: Transit agencies with electric buses operating or on order

Figure 3: US zero-emission bus population projection



One E-Truck or E-Bus provides substantial environmental benefits compared to one light-duty EV

Medium and heavy-duty vehicles account for 9% of greenhouse gases (GHG) in California, and approximately 20% of fuel used [13]. In addition, they are the largest contributors of NO_x in both the San Joaquin Valley and South Coast air basins, which hold more than 50% of the population of California [14] [15]. E-Trucks & Buses provide a substantial opportunity to reduce emissions and fuel used. While electric vehicles still produce NO_x through electricity consumption, power plant emissions are generally produced outside city centers where smog is the most harmful. Thus E-Trucks & Buses can provide dramatic results in criteria emission reductions. For example, Figure 4 shows that an electric bus will save about 47 kg of NO_x per year compared to a diesel bus and 19 kg per year compared to a CNG bus.

A truck or a bus consumes a large amount of fuel compared to a light-duty vehicle. Thus, one E-Truck or E-Bus can provide more environmental benefits than a light-duty EV. Table 3 shows that an E-Bus will emit 78 metric tons less of GHG per year than a conventional diesel bus, an electric Class 8 drayage truck will emit 18 metric tons less than a diesel drayage truck and an electric medium-duty delivery van will emit 10 metric tons less than a diesel delivery truck. In comparison, one light-duty EV only emits 3 metric tons of GHG less per year and a PHEV with 40 miles all-electric emits 1.5 metric tons less than a conventional car.

Figure 4: NO_x emissions from different transit technologies

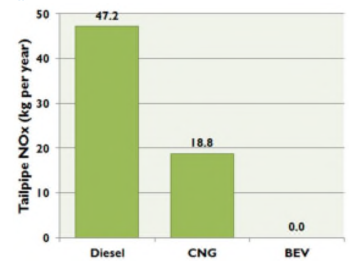


Table 3: Environmental savings comparison

	Technology	GGE/yr	kWh/yr	CO2/yr petroleum	CO2/yr electricity	Total CO2/yr	CO2/yr Savings
LDV	Conventional	400	0	3.5	0.0	3.5	-
	PHEV40	140	3,276	1.2	0.8	2.0	1.5
	BEV	0	2,800	0.0	0.7	0.7	2.8
MDV Delivery Van	Conventional	1,413	0	12.8	0.0	12.8	-
	BEV	0	12,500	0.0	3.1	3.1	9.7
HDV Class 8 Port Drayage	Conventional	3,060	0	27.7	0.0	27.7	-
	BEV	0	40,625	0.0	9.9	9.9	17.7
HDV 40-ft Transit Bus	Conventional	11,300	0	102.1	0.0	102.1	-
	BEV	0	100,000	0.0	24.4	24.4	77.7

Assumptions:
The gasoline light-duty vehicle drives 14,000 mi/yr at a fuel economy of 35 MPG, the PHEV40 14,000 mi/yr with 60% of the miles in all-electric at an efficiency of 0.39 kWh/mi and 40% in hybrid mode at 40 MPG. The light-duty EV drives 10,000 mi/yr at an efficiency of 0.28 kWh/yr. The medium-duty delivery van drives 12,500 miles/yr at a fuel economy of 10 MPG for a diesel vehicle and an efficiency of 1.0 kWh/mi for the EV. The heavy-duty Class 8 port drayage truck drives 16,250 mi/yr at a fuel economy of 6 MPG for a diesel vehicle and an efficiency of 2.5 kWh/mi for the EV. The 40-ft transit bus drives 40,000 mi/yr at a fuel economy of 4 MPG for a diesel vehicle and an efficiency of 2.5 kWh/mi for the EV. One gallon of gasoline produces 8.78 kg of CO_2, one gallon of diesel 10.21 kg and 1,000 kWh produces 244.4 kg of CO_2 (CalISO annual CO_2 total output emission rate from eGRID2012 version 1.0). Diesel NO_x emission rate for a 40-ft transit bus = 1.18 g/mile and CNG NO_x emission rate = 0.47 g/mile (from MJB&A, Comparison of Modern CNG, Diesel and Diesel Hybrid-Electric Transit Buses: Efficiency & Environmental Performance, 2013).

Utility load planning will be easier for E-Trucks & Buses as they will be concentrated in fewer areas

Figure 5 shows the distribution of Clean Vehicle Rebate Project rebates in Southern California. Many zip codes show large numbers of light-duty electric vehicles. With millions of single-family homes in California, utility load planning for personal electric vehicles is complex and uncertain. On the other hand, utility load planning for E-Trucks & Buses will be simpler, at least in the early phases of the market. A limited number of truck and bus fleets will deploy electric vehicles at a limited number of bus depots, delivery centers and truck yards. Figure 6 shows the distribution of UPS customer centers in Southern California and demonstrates that only sixteen UPS customer centers have or could deploy E-Trucks. Similarly, there are only 101 transit agencies in California and just over 35 in Southern California that have or could deploy electric buses.

At these potential deployment sites, the local distribution grid infrastructure may be significantly impacted by new E-Truck & Bus charging loads which can be much higher than for light-duty electric vehicles. E-Truck & Bus notification, where truck and bus fleets provide "information to identify new […] charging locations to electric utilities for the purpose of ensuring grid stability, reliability of safety [16]", can be achieved by encouraging the participation of a limited number of interested truck and bus fleets that are motivated and willing to participate in order to help successful deployments of E-Trucks & Buses in California and beyond.

Figure 5: Map of CVRP rebates in Southern California [17]

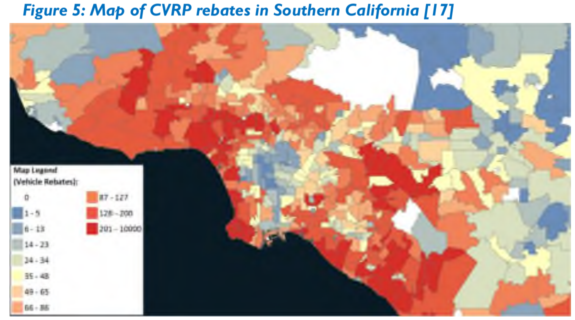
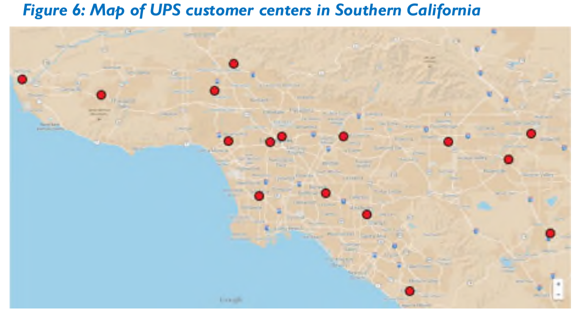


Figure 6: Map of UPS customer centers in Southern California



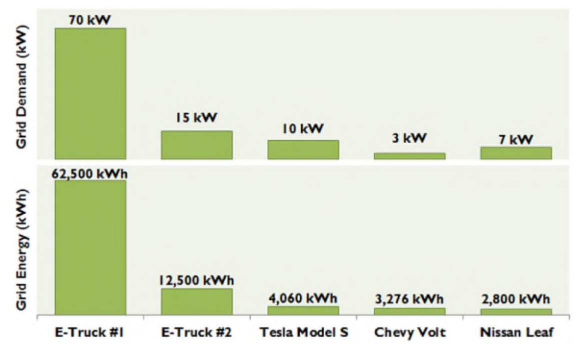
One E-Truck or E-Bus draws more power and consumes more energy compared to one light-duty EV

With much larger batteries and higher charging rates, one E-Truck or E-Bus draws the same amount of power and consumes the same amount of energy as several light-duty electric vehicles. For instance, Figure 7 shows how E-Truck #2 pulls the same amount of power from the grid while charging as 5 Chevrolet Volts and E-Truck #1 consumes the same amount of energy a year as 21 Tesla Model S.

The electrification of one truck or bus can potentially provide more benefits to utility customers and shareholders than the electrification of one light-duty vehicle. "For utility customers, [E-Trucks & Buses] can lower rates by improving asset utilization and decreasing costs. For shareholders, they can increase returns and present a new source of growth and investment" [18]. To achieve these benefits E-Trucks & Buses, like light-duty EVs, need to contribute more revenue to utilities than the cost of serving them [18]. At this stage of the E-Truck & Bus market, more information is needed to understand what the costs to generate and deliver electricity to E-Trucks & Buses will be. An in-depth analysis is needed to better understand the implications of charging E-Trucks & Buses, such as:

- The impacts on utility distribution grids,
- The need for additional infrastructure to support them,
- Utility distribution system upgrade costs, fleet facility upgrade costs and charging infrastructure costs.

Figure 7: Comparison of grid power and energy demand for different EV models



Assumptions:
E-Truck #1 drives 100 miles/day, 250 days/year, has an efficiency of 2.5 AC kWh/mile and draws 70 kW from the grid when charging. E-Truck #2 drives 50 miles/day, 250 days/year, has an efficiency of 1.0 AC kWh/mile and draws 15 kW from the grid when charging.
The Tesla Model S drives 14,000 miles/year and has an efficiency of 0.29 AC kWh/mile. The Nissan Leaf drives 10,000 miles/year and has an efficiency of 0.28 AC kWh/mile. The Chevrolet Volt drives 14,000 miles/year and has an efficiency of 0.39 AC kWh/mile. The Chevy Volt drives 60% of the miles on electric mode.

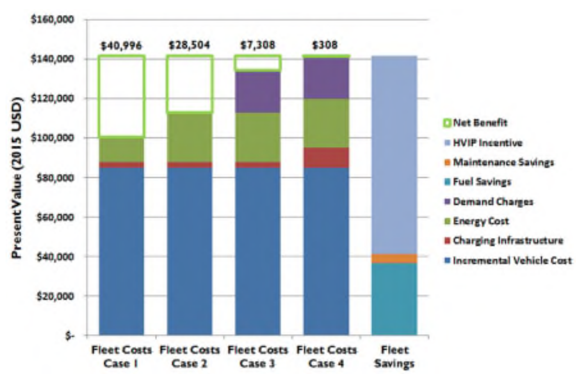
Current utility rate structures can discourage fleets from adopting E-Trucks & Buses

While the interest of truck and bus fleets in electric vehicles is diverse, the main reason why fleets are interested in E-Trucks & Buses generally revolves around operation & maintenance savings. But electric vehicles also have costs that conventionally fueled vehicles do not have. For instance, vehicle charging requires specific infrastructure and the price of electricity goes beyond a simple price per energy dispensed. Some of these costs have come as surprises to truck and bus fleets.

Following a methodology presented in [18], a simple cost benefit analysis was performed on a medium-duty electric delivery van under different cases looking at the impact of charging infrastructure, electricity and demand charges costs (Figure 8). As expected, Case 1 shows the most net benefit for the fleet. As charging infrastructure, electricity costs, and demand charges increase, the net benefit for the fleet decreases to almost zero.

As we will explore in the following pages, charging infrastructure costs can be quite large, Time-Of-Use rates can make the price of electricity increase sharply during peak hours and demand charges do apply to most large commercial and industrial utility customers. For E-Trucks & Buses to be successfully adopted by fleets, changes to current public utility commission policies that take into account the need to transform the market and reduce the costs to charge and operate E-Trucks & Buses are needed. Striking the right balance between incentivizing further vehicle adoption, staying technology neutral, and respecting utility rate design principles are key goals for the industry.

Figure 8: Medium duty delivery van costs & savings analysis



Assumptions:
The medium-duty delivery van drives 12,500 miles/yr at a fuel economy of 10 MPG for a diesel vehicle and an efficiency of 1.0 kWh/mi for the EV. A conventional medium-duty delivery van costs $65,000 and an electric one, $150,000 and both have a lifetime of 12 years. The electric medium-duty delivery van charges at a rate of 15 kW. Maintenance savings for the EV are estimated to be $0.05/mile. Diesel fuel prices were derived from the EIA 2015 Annual Energy Outlook for the Pacific Region. Electricity prices were assumed to increase by 1% every year. The discount rate is set at 7%.
Case 1: charging infrastructure cost at $3,000, electricity cost in 2015 at $0.12/kWh and no demand charges.
Case 2: charging infrastructure cost at $3,000, electricity cost in 2015 at $0.24/kWh and no demand charges.
Case 3: charging infrastructure cost at $3,000, electricity cost in 2015 at $0.24/kWh and $14/kW.
Case 4: charging infrastructure cost at $10,000, electricity cost in 2015 at $0.24/kWh and $14/kW.

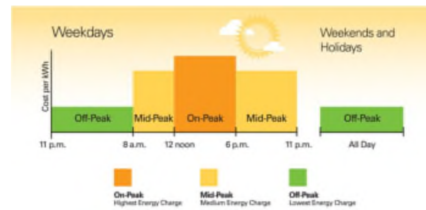
E-Truck & Bus charging has to support vehicle operation and unlike light-duty EVs cannot easily be shifted

Truck and bus fleets work with the specific requirement to provide timely and regular service to their customers. As a result, E-Trucks & Buses will generally operate on set schedules mirroring business hours or commute hours. Time-Of-Use (TOU) pricing, where energy is more expensive when the electric demand on the grid is higher (Figure 9), has been effective at shifting light-duty EV charging off peak. But truck and bus fleets do not have the same flexibility to shift charging based on utility price signals. While TOU pricing can work for some delivery vehicles operating during business hours and charging at night, they can make it difficult when charging on route, during lunch breaks, between two shifts or after an early shift. Figure 10 compares the fuel costs of a diesel, CNG and electric bus. Three different electricity prices are considered: $0.10, $0.05 (off-peak) and $0.20 (on-peak) per kWh. The price of the electricity used to recharge an E-Truck or E-Bus is an important component of its fuel costs. Charging off-peak when prices are low can lead to significant savings. On the other hand, charging on-peak when prices are high can dramatically increase fuel costs per mile [19].

In the future, TOU pricing could be replaced by real-time pricing to accommodate higher levels of intermittent energy resources into the grid. Real-time pricing could be an opportunity for E-Trucks & Buses to benefit from low or even negative energy prices but it could also add a layer of complexity for some fleets and make it more difficult for them to adopt E-Trucks or Buses. Technical solutions, such as smart charging, energy storage or distributed generation could help mitigate the impact of TOU or real-time pricing but will add costs and may prevent further electrification of trucks and buses.

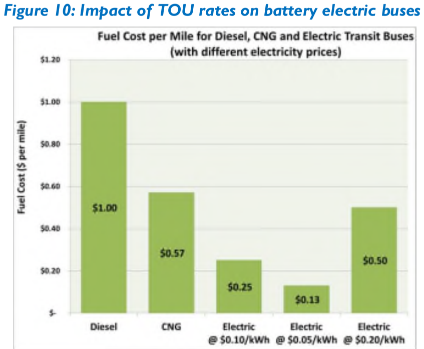
Assumptions for Figure 10: Each bus drives 40,000 miles/year. The diesel bus has a fuel economy of 4 MPG and diesel is priced at $4.00/gallon. The CNG bus has a fuel economy of 3.5 MPDGE and CNG is priced at $2.00/DGE. The electric bus has an efficiency of 2.5 AC kWh/mile.

Figure 9: Illustration of SCE Summer Time-Of-Use pricing



Source: Southern California Edison

Figure 10: Impact of TOU rates on battery electric buses



Source: CALSTART [19]

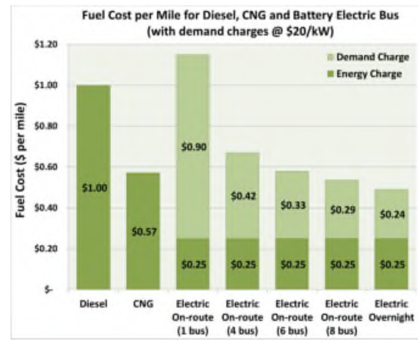
Demand charges can be prohibitively costly for early E-Truck & Bus deployments

In addition to charging for energy used (in kWh), electric utilities charge for power demand (in kW) on commercial and industrial customers to repay the fixed costs associated with the grid infrastructure needed during peak hours. Demand charges are considered as the appropriate way to allow recovery of utility capital costs and to give a price signal that pushes for market innovation promoting economically viable alternatives. However, they may discourage transportation electrification if loads cannot be shifted to off-peak periods [19]. Figure 11 gives an example of how demand charges impact fuel cost. E-Buses have a clear advantage when no demand charges are included. With high demand charges, fuel cost increase by $0.24/mile for one electric bus charging overnight and by $0.90/mile for one electric bus charging on-route. As the number of electric buses using a single on-route fast charger is optimized, demand charges can be spread over more buses and electric buses charging on-route regain their operating cost advantage.

Demand charges have a greater impact on small pilot deployments. In 2012, the California Public Utilities Commission granted a three-year reprieve on electricity rates for transit agencies with E-Buses, which allowed Foothill Transit to test three Proterra buses in real world operations that may not have been economically feasible with demand charges. Successful testing enabled by this waiver convinced Foothill Transit to purchase more buses for a current total of 17.

However, longer term solutions (explored in the following pages) are needed as the three-year reprieve only delays the application of demand charges and shift costs to non-participating customers. Vehicle deployments should be optimized to maximize the load factor, the amount of kWh used per each kW of demand. This can be achieved for E-Buses charging on-route by deploying the optimum number of buses using a single fast charger in order to maximize fast charger usage and spread demand charges over more E-Buses.

Figure 11: Impact of peak demand charges on E-Buses



Source: CALSTART [19]

Assumptions:

Each bus drives 40,000 miles per year. The diesel bus has a fuel economy of 4 MPG and diesel is priced at $4.00 per gallon. The CNG bus has a fuel economy of 3.5 MPDGE and CNG is priced at $2.00 per DGE. The electric transit buses have an efficiency of 2.5 AC kWh/mile and electricity is priced at $0.10/kWh. One electric bus charging on-route draws 150 kW from the grid, 4 draw 280 kW, 6 draw 330 kW and 8 draw 380 kW. The electric bus charging overnight draws 40 kW from the grid.

The need to electrify the truck & bus market requires innovative utility rates

The current utility rate structure promotes the efficient utilization of grid resources and allows for recovery of utility capital costs but may discourage the electrification of medium and heavy-duty vehicles. Innovative EV rates should be adopted to enable the further expansion of the E-Truck & Bus market. Specifically, electric utility rates should:

- *Acknowledge the unique needs of the E-Truck & Bus market.*

Truck & bus fleets do not have the same flexibility to shift charging as light-duty EVs so E-Trucks & Buses need to be looked as a distinct market.

- *Recognize the environmental and grid benefits of E-Trucks & Buses.*

LADWP and SCE have adopted specific rates for cold ironing to provide cleaner hoteling options to merchant ships and long-haul trucks. Georgia Power provides a very competitive rate for E-Bus operation (Table 4).

- *Separately submeter E-Truck & Bus charging where it makes sense.*

In their recent applications to the CPUC, PG&E and SCE require separate metering of EV energy consumption.

- *Be compatible with truck & bus fleet operation.*

SCE adopted several utility rates that accommodate EV charging at commercial facilities and stay true to principles of rate design. SCE's TOU-EV-3 & 4 rates waive demand charges for EV charging if the EV demand does not exceed the demand of the associated facility (Table 4).

- *Remain technology & business model neutral.*

Electrifying different truck & bus applications will require utility rates that do not favor one electrification technology over another. For instance, fleets will need both on-route opportunity and overnight charging. Considering a pricing option that charges more per kWh and less per kW could put both technologies on equal footing and allow for the electrification of more trucks & buses (Table 5).

Table 4: Examples of utility rates designed for E-Trucks & Buses

Utility	SCE			Georgia Power
Rate Schedule	*TOU-EV-3*	*TOU-EV-4*	*TOU-8 Option A*	*ET-15*
Maximum Demand	<20kW	>20kW <500kW	>500kW	N/A
EV Submetering	Required	Required	N/A	Yes
Energy Charge	Max. \$0.36/kWh Min. \$0.06/kWh	Max. \$0.29/kWh Min. \$0.06/kWh	Max. \$0.39/kWh Min. \$0.06/kWh	Max. \$0.08/kWh Min. \$0.00/kWh
Demand Charge	A - \$0.00/kW B - \$7.23/kW	\$13.20/kW	\$15.57/kW	\$0.00/kW
Notes	No EV demand charges for Option B if EV account demand does not exceed General Service account demand of associated facility.	No EV demand charges if EV account demand does not exceed General Service account demand of associated facility.	For cold ironing pollution mitigation programs (vessels hoteling at the Port of Long Beach and the Port of Hueneme, and long-haul trucks hotelling at truck stops).	For the operation of electric transportation at 3Ø, 60 Hz and 19.8kV or higher.

Source: [20], [21]

Table 5: Utility charges for 2 different energy/power options

	Option 1 Lower kW / Higher kWh	Option 2 Higher kW / Lower kWh
Daily driving distance	120 miles / day	
Electric efficiency	2.5 AC kWh/mi	
Charging power	280 kW	60 kW
Energy charge	\$0.15/kWh	\$0.05/kWh
Demand charge	\$2.00/kW	\$20.00/kW
Total monthly charge	**\$1505**	**\$1515**

Source: CALSTART [19]

E-Truck & Bus charging infrastructure is a limiting factor for further vehicle adoption

Several truck and bus fleets that we have interviewed indicated that E-Trucks & Buses could be deployed on a much larger scale than today. Although the availability of commercial product offerings is currently the most important issue preventing further adoption, the cost to provide electricity for charging has been underestimated by many fleets. Below are observations from some of the fleets interviewed for this report:

- Vehicles generally need to be charged where they are parked (near a conveyor belt or on a yard) which may not be close to the existing utility service drop. Figure 12 shows a bus yard where the bus parking location may be located several hundred feet from an adequate power source. Figure 13 shows a sorting facility where package delivery vans have to be parked near a conveyor belt for loading and unloading.
- Bringing power to the vehicle parking location may require excavation, conduits, cabling and repaving.
- Every bus depot, delivery center or truck yard is different. In addition, the age of the electric infrastructure, the electric capacity available for expansion and the charging infrastructure costs are hard to estimate.
- The duration to complete an infrastructure upgrade can vary from several days to up to one year and depends on many parameters. While fleets wait for upgrades, vehicles cannot be operated.
- Utility rates are difficult to understand and it is difficult to analyze charging data and find ways to minimize costs without utility assistance.
- Not all electric utilities are actively engaged and provide helpful guidance to truck and bus fleets deploying electric vehicles.
- Charging systems are not all standardized, raising concerns about operability of future vehicle models using existing infrastructure.

Figure 12: Aerial shot of the Gardena Municipal Bus Lines yard

Figure 13: Parked FedEx vans being loaded at a sorting facility

Photo courtesy: NorthJersey.com

Public utility commission policy changes are needed to reduce the costs for fleets to install charging infrastructure

Some fleets have considered all-electric facilities only to realize that the infrastructure costs to fully electrify a 100 to 200 - vehicle facility would be prohibitive. Table 6 lists cost estimates for charging infrastructure from actual fleets and OEMs. Infrastructure costs are high and vary widely. In addition, the faster a vehicle needs to be charged, the more expensive the charging infrastructure will be. These costs do not include upgrades in the distribution system that may be needed if the rated capacity of the installed electric equipment is exceeded. One fleet who deployed 20 E-Trucks at a facility in Southern California had to upgrade a transformer on the customer side of the meter to accommodate the added load to the facility. In this particular case, the $470,000 transformer price tag had a significant impact on the total project cost.

Faced with these high infrastructure costs, several fleets have taken a cautious approach by limiting the number of vehicles deployed at a single location. Instead of having a set number of vehicles to deploy at a single location, fleets prefer to only deploy the maximum number of vehicles without exceeding the rated capacity of the installed electric equipment which would trigger major utility upgrades.

Public utility commission policies should be changed to reduce the cost of installing charging infrastructure. Specifically, electric utilities should be allowed to rate base some or all of the costs to bring the necessary power up to and including the "make-ready" stub. In addition, electric utilities should be allowed to play a role, along with other market players in developing and supporting charging stations to allow truck & bus fleets, E-Truck & Bus manufacturers and federal and/or state agencies to focus their resources on purchasing and deploying vehicles.

Table 6: E-Truck & Bus charging infrastructure cost estimates

Fleet cost estimates per one charger installation	*EVSE*	EVSE Installation	
		Low	High
16.5kW (220V / 75A)	*$1,000 - $3,000*	$17,000	$32,000
70kW (208VAC 3Ø / 200A)	*$5,000 - $10,000*	$20,000	$75,000
450kW (480VAC 3Ø / 640A)	*$350,000*	$150,000	$200,000

Source: [22], [23], [24] and confidential communications with truck and bus fleet managers and E-Truck & Bus manufacturers, May and June 2015.

E-Truck & Bus charging, if unmanaged, can have significant impacts on the grid

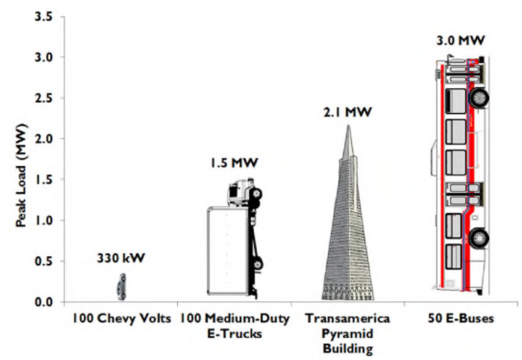
Like light-duty EVs, the grid impacts caused by charging E-Trucks & Buses represent a key issue. In page 12, we saw that E-Trucks & Buses will be concentrated in urban areas, at a limited number of bus depots, delivery centers and truck yards. If E-Truck & Bus charging is not managed properly at these locations, the local distribution grid infrastructure could be significantly impacted and would require expansive upgrades. Figure 14 makes it clear that an all-electric truck or bus facility is not feasible without ways to mitigate the grid impacts of charging. For instance, 100 medium-duty E-Trucks charging at the same time would demand 1.5 MW of power on the grid and 50 E-Buses would demand 3.0 MW. This is in the same order of magnitude as the peak power demand of the Transamerica Pyramid building, the tallest skyscraper in San Francisco, CA [25].

To remedy this issue, several fleets are actively exploring technical solutions such as:

- Smart charging,
- Range extenders,
- Energy storage, and
- On-site electricity generation.

Demand response, a solution to reduce the peak demand of buildings like the Transamerica Pyramid, is not believed to be a viable solution in its current form, as customers have to make loads available for curtailment when the utility requests. This may not be feasible for fleets who need to provide timely and regular service and may not have vehicles available for curtailment.

Figure 14: Peak loads for various electric vehicle fleets (without mitigating grid impacts)



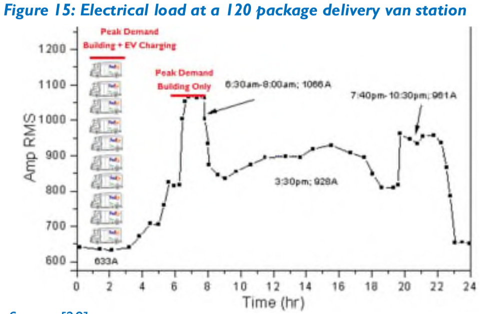
Assumptions: the Chevy Volt charging rate is 3.3 kW, the medium-duty E-Truck charging rate is 15 kW and the E-Bus charging rate is 60 kW. The peak load for the Transamerica Pyramid building is from [26].

Implementing smart charging systems will reduce the grid impacts of charging E-Trucks & Buses

Smart charging systems can enable better grid integration by balancing EV charging and building load to charge the greatest number of vehicles at the lowest cost possible and increase certainty of service for the fleets. Figure 15 shows how charging 10 E-Trucks off-peak without a smart charging strategy could increase the peak load of a 120 - truck package delivery station. A solution was developed by GE Global Research and Columbia University to be deployed by FedEx Express in New York City. The system "regulate[s] the charging rate of multiple EVSEs to facilitate cost-optimal charging subject to past and predicted building load, vehicle energy requirements, and current conditions" [27]. Figure 16 shows how for a fleet of 100 E-Trucks, the system can decrease peak facility demand by over 500 kW and save approximately $11,500 per month in demand charges compared to a fleet without the smart charging system. For a fleet of 200 E-Trucks, peak facility demand could be reduced by over 1,000 kW and demand charges savings could expand to about $23,000 per month [27]. Control systems for smart charging are in the development phase and one interviewed fleet expects costs between $5,000 and $7,000 per facility.

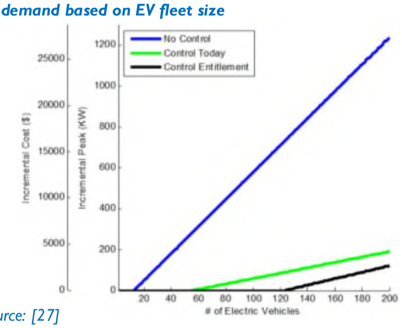
In addition to reducing demand charges, smart charging E-Trucks & Buses can also minimize the impact of TOU and reduce charging infrastructure costs. But to achieve the latter benefit, smart charging strategies need to be taken into account when calculating the load added by E-Truck & Bus charging. One fleet detailed a particular case where utility code mandated that a facility electric infrastructure be upgraded to accommodate all the E-Trucks charging at the same time at the maximum charging rate even if charging could easily be managed to reduce the peak facility load.

Figure 15: Electrical load at a 120 package delivery van station



Source: [28]

Figure 16: Incremental peak demand and associated cost incurred for demand based on EV fleet size



Source: [27]

Range extenders, energy storage and on-site generation are of high interest to fleets to mitigate charging costs

Range extenders, energy storage and on-site generation have been identified as potential technical options that could mitigate the grid impacts of charging and are actively researched by several of the fleets that we interviewed [19].

Integrated on E-Trucks & Buses, range extenders could decrease the amount of electricity needed between two charging events and the overall required charging power (Figure 17). They could also decrease markedly charging infrastructure issues. For some fleets, H_2 refueling infrastructure is seen as an easier and ultimately cheaper option. Fuel cell range extenders may represent a smoother transition from current vehicle operating models and could circumvent the inconvenient need to have to charge at the location where the truck or bus is parked.

Energy storage systems (batteries, ultracapacitors, or flywheels) can be used as buffers between the grid and EV chargers to smooth out peak loads. Table 7 describes the ABB TOSA bus charging system in demonstration in Switzerland. The use of ultracapacitors decreases the maximum power demand on the grid from 400 kW to 40 kW while maintaining the benefits of on-route fast charging. In addition, lower charging power allows for easier siting of the charging infrastructure as it may not require complex and expensive upgrades to the electric infrastructure [19]. Some fleets, early adopters of hybrid, plug-in hybrid, and electric trucks & buses will start retiring vehicles in the next 3 to 5 years. These fleets are eager to reuse the batteries from these vehicles for second-life applications to facilitate the deployment of more E-Trucks & Buses. Lastly, coupling on-site electricity generation (solar PV, fuel cell or microturbine) with energy storage is another interesting option for fleets to mitigate charging infrastructure costs, reduce demand and TOU charges, and provide certainty of service during grid outages.

Figure 17: Comparison of all-electric and range extended transit bus operation

Source and assumptions: [19].

Table 7: Description of ABB TOSA bus charging system

	Grid to Charger	Charger to Bus
Maximum charging power	40 kW	400 kW
Charging duration	2.5 minutes	15 seconds
Energy transferred	1.7 kWh	1.7 kWh

Source: [19].

E-Trucks & Buses could provide additional benefits to the grid and profit from low carbon fuel standards

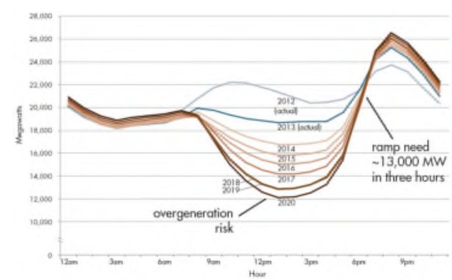
With very ambitious targets for renewable energy integration, the California grid will be stressed in new ways [29]. Spring and fall days in particular, could soon see overgeneration risks when solar generation peaks and steep ramp needs when it declines (Figure 18). Flexible resources will be needed to reliably manage these new challenges [30]. In addition to transporting goods and people, E-Trucks & Buses could provide additional grid benefits:

- E-Trucks & Buses charging on route, during lunch breaks, between two shifts or after an early shift could represent a large source of diurnal energy storage available to reduce overgeneration risks.
- Smart charging could slow down or even suspend charging during periods of high ramp needs while still guaranteeing vehicle availability.
- Energy storage systems could enable more E-Trucks & Buses to charge during periods of overgeneration, discharge during periods of high ramp needs and take advantage of real-time pricing.

For fleets to make E-Trucks & Buses serve as true grid resources, key players will be needed to aggregate loads, automate charging and adopt consistent standards and communication protocols [29].

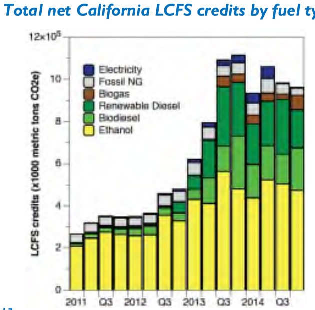
Electricity currently accounts for a small share of the California Low Carbon Fuel Standard (LCFS) credits (Figure 19). However, the California LCFS represents a viable opportunity for truck & bus fleets to decrease the costs to operate E-Trucks & Buses. With current LCFS carbon intensities, a fleet of 10 E-Buses could generate almost 1,000 LCFS credits per year, for a value of $44,000/year at current credit prices. It may be difficult for truck & bus fleets to become the credit generator and other market players may be better suited to secure these LCFS credits. These credits could then be given back to the fleets either as a rebate or as an on-bill credit.

Figure 18: The California ISO "duck curve" (March 31)



Source: [30]

Figure 19: Total net California LCFS credits by fuel type



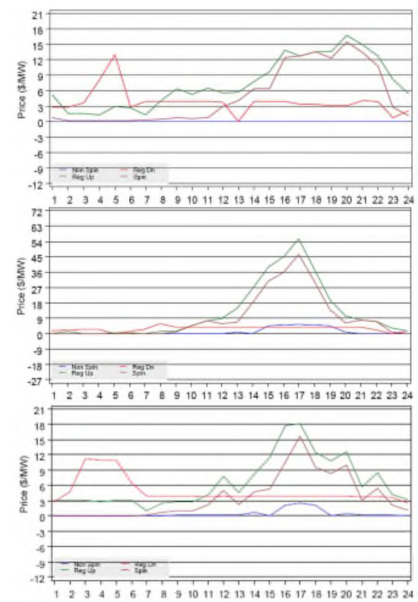
Source: [31]

Vehicle-To-Grid could benefit E-Trucks & Buses but is still years away from commercial application

Two pilot projects (one at the U.S. Army base of Fort Carson, CO and one with Frito-Lay in Texas) have demonstrated the technical feasibility of using E-Trucks & Buses as power sources for grid balancing services such as frequency regulation [32] [33]. But several of the fleets that we interviewed, while interested in V2G, did not see it as a solution that they could benefit from in the short term. Some of their observations are listed below:

- While a fleet of E-Trucks & Buses, with vehicles equipped with larger batteries and charging power compared to light-duty EVs, can more easily satisfy the minimum power requirements for participation in the ancillary market, fleets did not think they could provide enough grid services to be of interest to market regulators or aggregators.
- E-Truck & Bus charging is set on rigid operating schedules while ancillary service prices vary throughout the day depending on grid and weather conditions. For example, Figure 20 shows the ancillary service average prices for a late June weekday for three consecutive years.
- While a recent project validated the technical feasibility of V2G for commercial vehicles, it also concluded that "economics in current market structure [are] not viable for participation" [33].
- Fleets will not adopt a technology (such as V2G) that will prevent vehicle operation by decreasing range or delaying availability.
- Fleets are not opposed to third party ownership of charging infrastructure but cannot let a third party influence their operation.
- No key players in the ancillary / utility / facility market currently exist and fleets are seeing V2G more as a long term (5 to 10 years) technology, preferring simpler approaches such as Vehicle-to-Building.

Figure 20: CAISO ancillary service average price on 06/27/2014 (upper), 06/28/2013 (middle) and 06/28/2012 (lower)



Source: [34]

Recommendations (1)

There is currently a lot of interest in the E-Truck & Bus market. While E-Trucks have been deployed for several years, significant activity is now focused on all-electric buses. In its early market stages, technologies and solutions are still being researched, developed and tested. The current picture of the market is bound to change as technology matures but the decisions taken now by regulators, utilities, fleets and vehicle manufacturers will shape the future of E-Trucks & Buses and influence their success. As demonstrated in this report, E-Trucks & Buses present unique challenges and opportunities compared to light-duty electric vehicles. In addition, E-Truck & Bus loads are different from other facility loads and light-duty EVs. The success of electric vehicles in the commercial medium and heavy-duty vehicle market will require different approaches. Below are several recommendations derived from this report:

- **Expand & enhance industry stakeholder forums to better tackle industry issues**

The E-Truck & Bus community, while still small, is composed of motivated stakeholders committed to the progress of the industry. Expanding and enhancing the activities of industry stakeholder forums such as CALSTART's E-Truck Task Force would promote industry stakeholder engagement, increase information sharing between utilities, fleets, and manufacturers, and better tackle some of the industry issues identified in this report.

- **Commission a comprehensive E-Truck & Bus load study**

There is currently a lack of information on E-Truck & Bus charging infrastructure costs and charging patterns. A comprehensive E-Truck & Bus load study would monitor the actual distribution system upgrade costs and develop charging load profiles for different medium and heavy-duty vehicle vocations. Such a study could also look at answering questions fleets have: What is the available capacity (kW) and utilization (%) of the transformer that will support the E-Truck & Bus deployment? Is a single (larger) new substation or substation upgrade or several (smaller) feeder upgrades more cost effective? How would a "E-Truck or Bus ready facility" look like and how much would it cost to create a purpose-built facility that can easily accommodate vehicle deployments in the future?

- **Create dedicated E-Truck & Bus program manager positions to support fleets**

Electric utilities should create specific E-Truck & Bus program manager positions to guide fleets make better decisions when procuring E-Trucks & Buses and accelerate the electrification of medium & heavy-duty vehicles in a way that is cost effective for truck & bus fleets, "reduces rates for other customers, provides value to shareholders and minimizes criteria pollutant and GHG emissions" [18].

- **Secure existing low carbon fuel standard credits to reduce E-Truck & Bus operating costs**

A process should be developed to secure low carbon fuel standard credits from E-Trucks & Buses and make it simple for truck & bus fleets to be given back these credits either as a rebate or as an on-bill credit.

Recommendations (2)

- **Continue to support the electrification of trucks & buses through grants, incentives and tax credits**

E-Trucks & Buses are already in use today in several fleets across the nation, and we are seeing increases in sales and in interest, especially among transit agencies. Technology is improving and costs are coming down. However, grants, incentives and tax credits are still needed to reduce the costs to purchase and charge E-Trucks & Buses at this early stage of the market. In particular, more cost effective larger vehicle deployments should be targeted.

- **Fund demonstration projects focusing on advancing technologies that will enable further electrification**

Federal and state funding agencies should fund high quality, competitive projects that will accelerate the commercialization of technologies that maximize load factors (the amount of kWh used per each kW of demand) and can make E-Trucks & Buses true grid resources. Such projects should include smart charging technology, range extenders, on-site generation and energy storage systems, specifically those looking at second-life applications of E-Truck & Bus batteries.

- **Adapt utility rate structure to accelerate the cost effective electrification of trucks & buses**

The current utility rate structure promotes the efficient utilization of grid resources and allows for recovery of utility capital costs but may discourage the electrification of medium and heavy-duty vehicles. Innovative EV rates should be adopted to enable the further expansion of the E-Truck & Bus market. Specifically, electric utility rates should:

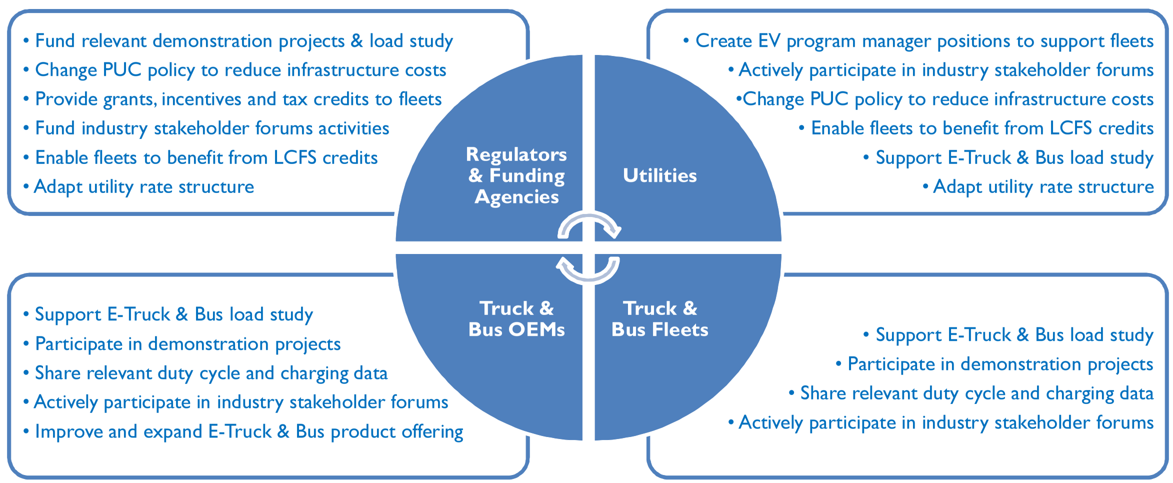
  - ❖ Acknowledge the unique needs of the E-Truck & Bus market.
  - ❖ Recognize the environmental and grid benefits of E-Trucks & Buses.
  - ❖ Separately submeter E-Truck & Bus charging where it makes sense.
  - ❖ Be compatible with truck & bus fleet operation.
  - ❖ Remain technology and business model neutral.

- **Change current public utility commission policy to mitigate the costs of E-Truck & Bus charging infrastructure**

Electric utilities should be allowed to rate base some or all of the costs to bring the necessary power up to and including the "make-ready" stub. In addition, electric utilities should be allowed to play a role, along with other market players, in developing and supporting charging stations to allow truck & bus fleets, E-Truck & Bus manufacturers and federal and/or state agencies to focus their resources on purchasing and deploying vehicles.

Next Steps

Lastly, this report identifies next steps for the E-Truck & Bus industry that we believe would help implement the recommendations listed in the two previous pages and accelerate the commercialization of medium and heavy-duty electric vehicles.



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Division 10-3

Request:

Refer to Appendix 2.1, page 24, regarding wholesale market price impacts. Please explain why the wholesale market price impact is only included in the RIM test, and whether this is consistent with current practice for energy efficiency cost-effectiveness.

Response:

Wholesale Market Price Impacts are not included in the Societal Cost Test (SCT) because they represent a transfer payment rather than a net benefit or cost to society. For example, wholesale price suppression is a transfer from large generators to other market participants who experience equal and offsetting impacts. Wholesale Market Price Impacts are included in the Rate Impact Measure (RIM) because a change in wholesale market prices will be reflected in the total retail rate paid by customers.

The cost-effectiveness of energy efficiency programs in Rhode Island is currently evaluated based on the Rhode Island Test, rather than an SCT or RIM.[1] Wholesale Market Price Impacts are included in the Rhode Island Test.[2]

(This response is identical to the Company's response to Division 3-3 in Docket No. 4780.)

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[1] *See* Attachment DIV 5-2-1 to the Company's response to Division 5-2 in Docket No. 4755 (The Narragansett Electric Company d/b/a National Grid, Annual Energy Efficiency Plan for 2018). The Rhode Island Test is described in Attachment 4 of the 2018 Annual Energy Efficiency Plan. Attachment 4– 2018 Rhode Island Test Description.

[2] *Id*. at 11-12.

Division 10-4

Request:

Refer to Appendix 2.1, pages 28-29, regarding the cost categories for the transportation electrification initiative.

a. Please provide all assumptions, data, and calculations for the costs of the transportation electrification initiative. Please provide the requested data in machine-readable format with all formulas intact.

b. Please provide a detailed description of the total program administration costs and the assumptions used to develop this cost category. Please provide the requested data in machine-readable format with all formulas intact.

c. Has the Company performed an analysis of whether there are any locations on its system where distribution system infrastructure upgrades would be required prior to installing EV charging stations? If yes, please provide this analysis.

d. Please describe whether and how the cost of distribution system infrastructure upgrades at various locations will impact which sites are chosen for DC fast charging investments, if at all.

e. Please describe whether and how the cost of distribution system infrastructure upgrades at various locations will impact which sites are chosen for non-DC fast charging investments, if at all.

f. Please identify who would bear the costs of any distribution system infrastructure upgrades required to install EV charging stations.

g. Has the Company estimated the cost of any distribution system infrastructure upgrades that might be necessary in order to install the planned charging stations? If so, please provide such estimates. Please provide the requested data in machine-readable format with all formulas intact.

Response:

a. The Company's cost estimates for Years 1 through 3 of the Electric Transportation Initiative are provided in Excel format as Attachment DIV 10-4-1 (originally filed as Workpaper 5.1 in the Appendices and Workpapers of: Power Sector Transformation Panel, Book 3 of 3 REDACTED).

Cost Summary

The first tab of Attachment DIV 10-4-1 (Cost Summary) shows the Total Costs by Program Type for the six components of the Initiative:

- Off-Peak Charging Rebate Pilot
- Charging Station Demonstration Program
- Discount Pilot for DC Fast Charging Accounts
- Transportation Education and Outreach
- Company Fleet Expansion
- Initiative Evaluation

This tab also shows the breakdown by operation and maintenance (O&M) expense and capital expense at both a summary level and for each of the components of the Initiative. This tab also shows the potential Offsetting Participation Payment that the Company could expect from site hosts choosing the Utility-Operated Site option in the Charging Demonstration Program.

Off-Peak Charging Rebate Pilot

The second tab of Attachment DIV 10-4-1 (Off-Peak Rebate) contains an estimate of the O&M costs required to implement this program in Rhode Island. This includes:

- *NG Program Manager FTE:* Lines 12 – 18 of this tab show the calculation of the incremental Full Time Equivalent (FTE) the Company estimates will be necessary to implement this program at the Senior Program Manager salary level. The cost estimate uses a 2016 labor rate escalated at two percent annually for two years to 2018, and then fully burdened at 72.75 percent. The program is envisioned to require 0.5 FTE for the first two years, reducing to 0.25 FTE in the third year.

- *Data Acquisition Cost:* Lines 21-24 reflect the estimated annual cost per participant of obtaining charging data at an estimated $200 per participant per year, multiplied by the number of participants per year. The Company's technology solution is not yet determined and could include WiFi-connected home chargers/ Electric Vehicle Supply Equipment (EVSE), WiFi-connected circuit monitoring devices, measurement devices that capture data from the vehicle's onboard diagnostics port, obtaining charging data from automakers collected via existing electric vehicle (EV) on-board telematics, and/or disaggregating EV charging load from an advanced meter. This cost is informed by the Company's initial discussions with potential technology providers, with some cost improvements assumed.

- *Pilot Support:* This portion of the cost estimate consists of a total of $120,000 over three years shown in Line 32 for customer support, call center, surveys, and data analysis. This includes the costs of rebate processing. (The reference in the file to marketing is an error; this cost is included under *Program Marketing* on Line 5.) These services could be provided by third-party vendor(s) or conducted at incremental cost by the Company.

- *Evaluation* – This portion of the cost estimate consists of $30,000 in Year 3 for a comprehensive third-party evaluation study.

- *Program Marketing* – This cost is estimated at $150 per participant and is multiplied by the number of annual participants to determine the total marketing budget. Marketing costs for this type of program include design costs, marketing program management, and marketing campaign execution costs (such as online advertising and social media costs, and production of bill inserts or other physical collateral).

- *Rebate Cost:* This consists of the expected rebate value paid to participants over the course of the program and was estimated at $75 per participant per year.

Charging Station Demonstration Program

The third tab of Attachment DIV 10-4-1 (ChargingStations) contains an estimate of the capital and O&M costs required to implement this program.

<u>Page 1</u>

Page 1 of ChargingStations tab provides the Program Inputs and Direct Site Cost inputs that are used to calculate the detailed costs of this demonstration program.

Program Inputs

These assumptions include the Targeted Charging Segments, Type of Station (Level 2, DC Fast Charging, or Other), Number of Sites, Ports per Site, Ports per Segment, Proportion of Sites assumed to be constructed with the Make-Ready option (where National Grid constructs the "make-ready" infrastructure and the site host owns and operates the charging station), Proportion of Sites assumed to be constructed under the Utility-Operated option, and the assumed rebate level toward the cost of Electric Vehicle

Supply Equipment (EVSE; aka charging station equipment) provided to customers under the Make-Ready EVSE.

Estimated EDC Equipment Cost per Site

The Company calculated the Estimated Electric Distribution Company (EDC) Equipment Cost per site, consisting of the distribution system costs on the utility side of the meter. Given the diversity of customer sites expected, the Company used four different potential design cases for installing a new distribution service (ranging in cost from $15,562 to $37,989), and then estimated the proportion of sites in each distribution design case to create a weighted average cost. The supporting estimates for each of these design costs are provided as Attachments 10-4-2 through 10-4-5. .

Estimated Premise Work Cost per Site

The Company calculated the estimated cost of work required on the customer's side of the meter to install new electrical infrastructure between the meter and the EVSE. The Company obtained two estimates from external vendors for the customer premise work required for Level 2 station installations, and three estimates for the work required for DC Fast Charging sites. This work includes Plans and Permits, Labor (electrician), Materials (panel, breakers, conduit, fittings, concrete), Miscellaneous (site prep, signage), and Other (bore or trenching, excavation). Detailed breakdowns of these estimates are provided in Attachment 10-4-6.

Estimated EVSE Cost per Port

The final costs included on page 1 of the ChargingStations tab are Estimated EVSE Cost per Port. EVSE is the equipment, often also referred to as charging station hardware, that delivers electricity directly into the vehicle. The Company's estimate for each type of EVSE is based on networked equipment capable of communicating with a central EVSE management platform. Cost estimates for Level 2 and DCFC are based on EVSE purchasing experience by the Company's Massachusetts affiliate. The Company estimated the cost of EVSE for Other Heavy Duty applications, including public transit buses, municipal school buses, and other heavy-duty vehicle types such as port or airport equipment, at the same price as DC Fast Charging equipment.

These EVSE Costs per Port are used to calculate the cost of EVSE the Company will purchase for Utility-Operated sites, and to calculate the value of the EVSE rebate the Company will offer site hosts under the Make-Ready model.

Page 2

Page 2 of ChargingStations tab calculates the Direct Site Costs using inputs from Page 1 of the tab, and then calculates the Program Management Office (PMO) costs.

Direct Site Costs

In this section of the file, the Company estimates the Cost per Port and Cost per Site for each of the Make-Ready and Utility-Operated site types, using the inputs described above. Costs per Make-Ready Site include the EDC Costs, Premise Work Costs, and Make-Ready EVSE Rebate Costs. Costs per Utility-Operated Site are identical to Make-Ready sites for the first two categories (EDC Costs and Premise Work Costs), but differ for the third cost type (EVSE Costs) because the full cost of the EVSE is assumed by the Company in this case.

The Company estimates that 10 percent of sites will be installed in year 1, 25 percent in Year 2, and 65 percent in Year 3.

Program Management Office (PMO) Cost Inputs

The Company estimates the costs of operating a PMO for the Program will include Labor, Site Agreement Contracting Costs, Customer Site Estimation Costs, Project Management Customer Relationship Management (CRM) Tool Modifications, and a Station Data Reporting Interface.

This section of the file includes Labor cost estimates for one Charging Demonstration Program Manager, two Senior Project Managers, and one Account Manager, multiplied by the estimated fully loaded annual salary for these roles applicable to a National Grid USA Service Company, Inc. employee. The annual salaries are adjusted by a two percent escalation factor to reflect annual increases in labor costs.

The estimated Site Agreement Contracting Cost per site of $2,000 is the Company's estimated labor cost to execute a lease agreement. It was based on estimated costs associated with the Company's execution of lease agreements with site hosts for the Company's existing publicly-accessible charging stations. The Company anticipates using internal counsel for executing the Charging Demonstration Program lease agreements.

The estimated Customer Site Cost Estimation cost per site consists of labor costs for a vendor to conduct a site assessment and provide a site plan detailing the location of the charging stations at the site facility, number of charging stations, and service requirements (*e.g.* new service or existing). This estimate is based on the Company's use of a third-party vendor to provide site assessment for the Company's three DC fast charging stations operated by its Massachusetts affiliate.

The Project Management / CRM Tool Modification cost of $50,000 is an estimate of the costs the Company would incur to develop a project tracking tool and modify the existing CRM tool to support the Program. The Company proposes modifying the Company's existing CRM tool (SalesForce) to track the Customer-Sales Organization promotion of the Program to prospective site hosts.

The Data Analysis & Reporting Tools cost of $50,000 is to implement software to enable Site Hosts (or EVSE vendors) to upload networked charging station utilization data into a data repository managed by the Company. The Company anticipates needing a secure, encrypted upload interface because the charging stations are owned by the Site hosts; therefore, the Company may not have direct access to their data. The uploaded data stored in the Company's data repository can then be analyzed for a variety of purposes including ongoing reporting on station utilization and understanding the electric system impacts of EV charging.

Page 3

Summary of Charging Demonstration Program Capital Costs

The Company applies a Capital Overhead Burden of 13 percent and assumes the following depreciable lives for each part of the infrastructure:

- EDC Costs (Make-Ready & Utility-Operated): 40 years
- Premise Work Costs (Make-Ready & Utility-Operated): 20 years
- EVSE Costs (Utility-Operated Only): 10 years

Furthermore, the Company estimates that it may capitalize 50 percent of the Program Manager's labor cost and 75 percent of the Senior Project Managers' labor cost based on the percentage of work attributable to site development after the point that an installation is considered likely at that site.

The Company uses these assumptions, and the previously-mentioned annual estimate of the proportion of sites completed, to estimate the annual Direct Capital Costs (for direct site work) and Capitalized Labor & Tool Costs. The Project Management / CRM Tool Modification and Data Analysis & Reporting Tools are considered capital investments in the Company's estimates.

Pages 4-5

Summary of Charging Demonstration Program O&M Costs

The Company estimates the O&M costs for the program, including:

- PMO Labor and Other O&M
- EVSE Rebate Cost for Make-Ready Sites
- Station O&M for Utility-Operated Sites
- Charging Demonstration Program

The Company’s PMO Labor Cost treated as O&M is the portion not capitalized as described above. Site Agreement Contracting Costs and Customer Site Cost Estimation costs are also treated as O&M, and calculated by multiplying the per-site estimate by the number of sites.

The Company’s EVSE Rebate Costs for Make-Ready projects is also treated as O&M to be expensed in the year incurred.

Station O&M for Utility Operated Sites is estimated at $500 per port per year for Repairs and Maintenance, and $200 per port per year for Network Service Fees. These are generally based on the Company’s experience operating EVSE to date, with some assumed cost improvements.

Charging Demonstration Marketing is necessary to achieve the Company’s goals for site host recruitment. This work is estimated to include website, social media, digital, content development, and internal marketing program management costs.

Discount Pilot for DC Fast Charging Accounts

On the fourth tab of Attachment DIV 10-4-1 (DCFC Discount) the Company calculates the implementation cost and potential annual value of the DC Fast Charging discount the Company has proposed to offer to site hosts. Implementation cost is estimated at $50,000 annually and includes marketing, customer support, billing system modifications, metering, and data reporting.

The potential annual value of the discount per KW is based on the monthly value of the discount per kW multiplied by 12. This annual value per KW is then multiplied by a potential number of stations at participating sites (growing from 20 stations in year 1 to 40 in year 3) with an assumed billed kW per station (growing from 45KW in year 1 to 90 in year 3) to arrive at a total potential annual discount value for the group.

Participation in the discount will determine the actual costs incurred by the Company for the discount. As the Company stated in Chapter 5, page 9, the Discount Pilot will be made available on a first-come, first-serve basis, and the Company intends to limit the annual value of the discount to a maximum of $300,000 per year.

Prepared by or under the supervision of: Carlos Nouel

Transportation Education and Outreach

On the fifth tab of Attachment DIV 10-4-1 (Educ Outreach) the Company estimated the following costs for a targeted education and outreach campaign for electric transportation in Rhode Island, including:

- Direct Mailings: Direct mailing costs are to develop, print, and produce bill inserts, direct mail pieces including leveraging existing mailings to consumers (*e.g.* OPower reports)
- Ride-n-Drive Events: EV ride and drive events provide consumers the firsthand experience of test driving an EV.
- Website: Website costs are the estimated costs for development, testing, and ongoing maintenance of a webpage and mobile application.
- Social Media: Social media costs are for the development, testing, and ongoing promotion of electric transportation options, highlighting EV benefits and raising awareness of events, partnerships, and sponsorship efforts to drive EV adoption.
- Billboard/Radio: Advertising costs are the combined estimated costs for the placement of visual and recorded messages through appropriately placed billboards and radio advertisements.
- Digital Marketing: Digital marketing costs are for the placement of digital banners on appropriate webpages and select Search Engine Optimization.
- Content Development: The agency contract is expected to include limited contracted creative for the channels described above.
- Internal Marketing Program Management costs are estimated at approximately $50,000 per year, providing for a partial FTE to manage the activities described above.

Company Fleet Expansion

On the sixth tab of Attachment DIV 10-4-1 (NG Fleet), the Company estimates the cost of adding 12 new Class 7-8 electrified trucks to the Company’s Rhode Island fleet.

The Company’s Fleet Department estimates that the incremental cost to modify (“upfit”) a Class 7-8 truck is approximately $80,000, spread over a 10-year lease term. In addition, the Company estimates an annual support cost of approximately the same amount, for repairs, maintenance, and spare parts. These costs are treated as O&M.

To power these vehicles, the Company will install Level 2 EVSE at the Company's facilities, at a ratio of 1 port per vehicle. The cost per port is estimated at $16,667 or a total of $200,000 for 12 ports. This cost is treated as Capital.

Evaluation

On the seventh tab of Attachment DIV 10-4-1 (Eval), the Company reflects the cost of annual third-party evaluation reports, estimated at a cost of $30,000 per year.

b. As used in Appendix 2.1 (BCA summary), the Program Administration cost category encompasses all costs that the Company would incur (described in part a above).

c. No. The Company has not prospectively identified potential EV charging site locations, and the analysis of required distribution system upgrades will require case-by-case assessment.

d. If the Company determines that infrastructure upgrades are necessary at a DC fast-charging site then the Company will make a determination whether to proceed with the installation based on the impact these costs will have on the program budget.

e. The Company does not anticipate that distribution system infrastructure upgrades will be necessary at sites for non-DC fast charging investments due to the relatively small incremental load of non-DC fast charging equipment. However, if infrastructure upgrades are necessary at a site, the Company will make a determination whether to proceed with the installation based on the impact these costs will have on the program budget.

f. The costs of distribution system infrastructure upgrades required to install EV charging stations at the sites designed and approved under the Charging Demonstration Program will be charged to the Program and recovered from all customers.

g. Yes, the Company has estimated the cost of distribution system infrastructure upgrades that might be necessary in order to bring service to a Level 2 or DCFC site. These estimates are described in part (a), above, for the Charging Station Demonstration Program, under the section titled "*Estimated EDC Equipment Cost per Site".*

(This response is identical to the Company's response to Division 3-4 in Docket No. 4780.)

Project Information					
Project Name:	8/30/16 - Electric Vehicle Service - New Pad Mount Transformer and Meter - CNC				
Funding Project #:		Work Order #:		Estimate Type:	Investment
PPM ID #:		Bus. Segment:	Distribution	Estimator:	John Duffy
State:	MA	Company:	5310 - Massachusetts Electric Company	Project Lead:	Mark Siegel
Alternative:		Revision #:		Last Updated:	8/29/2016
Description:					

CAPEX	**OPEX**	**COR**	**Total**
37,989	-	-	37,989

Install:
Furnish and install new 100kva transformer, 25lf of concrete encased ductbank for primary feed from existing transformer; Install new meter on new transformer.

Remove:

Maintain:

Prepared by: ______________________ Date: ______________________
John Duffy

Reviewed by: ______________________ Date: ______________________

Reviewed by: ______________________ Date: ______________________

Approved by: ______________________ Date: ______________________

Date: *1/25/2018* **This estimate is valid until:**

Project Summary

Project Name:	8/30/16 - Electric Vehicle Service - New Pad Mount Transformer and Meter - CNC				
Funding Project #:		Work Order #:		Estimate Type:	Investment
PPM ID #:		Bus. Segment:	Distribution	Estimator:	John Duffy
State:	MA	Company:	5310 - Massachusetts Elect	Project Lead:	Mark Siegel
Alternative:		Revision #:		Last Updated:	8/29/2016
Description:					

		CAPEX	OPEX	COR	Totals
Craft Labor		6,398	-	-	6,398
Materials		6,925	-	-	6,925
Engineering Cost		1,580	-	-	1,580
Contractors/Consultants		3,500	-	-	3,500
Project Management Cost		2,637	-	-	2,637
Equipment Rental		-	-	-	-
Craft Supervision		764	-	-	764
Other		-	-	-	-
Subtotal Direct Cost		**21,804**	**-**	**-**	**21,804**
Sales Tax (A70) %	-	-	-	-	-
Stores Handling (M50) %	20.00	1,385	-	-	1,385
Labor Adders %	81.80	9,308	-	-	9,308
Transportation (T10) %	16.00	1,146	-	-	1,146
Contingency %	-	-	-	-	-
Contractor Tax %	-	-	-	-	-
CAD (A50) %	26.61	3,427	-	-	3,427
	-				-
Equipment Tax %	-	-	-	-	-
AFUDC (A10, A11) %	2.48	919	-	-	919
Totals		**37,989**	**-**	-	**37,989**

Project Information					
Project Name:	8/30/16 - Electric Vehicle Service - Existing Pad Mount Transformer to Meter - CNC				
Funding Project #:		Work Order #:		Estimate Type:	Investment
PPM ID #:		Bus. Segment:	Distribution	Estimator:	John Duffy
State:	MA	Company:	5310 - Massachusetts Electric Company	Project Lead:	Mark Siegel
Alternative:		Revision #:		Last Updated:	8/29/2016
Description:					

CAPEX	OPEX	COR	Total
16,394	-	-	16,394

Install:
Install new three phase meter mounted on existing transformer from the existing secondary feed.

Remove:

Maintain:

Prepared by: ______________________ Date: ______________________

John Duffy

Reviewed by: ______________________ Date: ______________________

Reviewed by: ______________________ Date: ______________________

Approved by: ______________________ Date: ______________________

Date: *1/25/2018* **This estimate is valid until:**

Project Summary

Project Name:	8/30/16 - Electric Vehicle Service - Existing Pad Mount Transformer to Meter - CNC				
Funding Project #:		Work Order #:		Estimate Type:	Investment
PPM ID #:		Bus. Segment:	Distribution	Estimator:	John Duffy
State:	MA	Company:	5310 - Massachusetts Elect	Project Lead:	Mark Siegel
Alternative:		Revision #:		Last Updated:	8/29/2016
Description:					

		CAPEX	OPEX	COR	Totals
Craft Labor		608	-	-	608
Materials		193	-	-	193
Engineering Cost		1,580	-	-	1,580
Contractors/Consultants		3,500	-	-	3,500
Project Management Cost		2,637	-	-	2,637
Equipment Rental		-	-	-	-
Craft Supervision		764	-	-	764
Other		-	-	-	-
Subtotal Direct Cost		**9,281**	**-**	**-**	**9,281**
Sales Tax (A70) %	-	-	-	-	-
Stores Handling (M50) %	20.00	39	-	-	39
Labor Adders %	81.80	4,571	-	-	4,571
Transportation (T10) %	16.00	219	-	-	219
Contingency %	-	-	-	-	-
Contractor Tax %	-	-	-	-	-
CAD (A50) %	26.61	1,886	-	-	1,886
	-				-
Equipment Tax %	-	-	-	-	-
AFUDC (A10, A11) %	2.48	397	-	-	397
Totals		**16,394**	**-**	-	**16,394**

Project Information					
Project Name:	8/30/16 - Electric Vehicle Service - OH Drop With New Transformer to Meter on Pole CNC				
Funding Project #:		Work Order #:		Estimate Type:	Investment
PPM ID #:		Bus. Segment:	Distribution	Estimator:	John Duffy
State:	MA	Company:	5310 - Massachusetts Electric Company	Project Lead:	Mark Siegel
Alternative:		Revision #:		Last Updated:	8/29/2016
Description:					

CAPEX	**OPEX**	**COR**	**Total**
19,814	-	-	19,814

Install:
Furnish and install new pole mounted transformer; Tap primary to new transformer and install secondary cable down pole to meter mounted on pole.

Remove:

Maintain:

Prepared by: ______________________ Date: ______________________
John Duffy

Reviewed by: ______________________ Date: ______________________

Reviewed by: ______________________ Date: ______________________

Approved by: ______________________ Date: ______________________

Date: *1/25/2018* **This estimate is valid until:**

Project Summary

Project Name:	8/30/16 - Electric Vehicle Service - OH Drop With New Transformer to Meter on Pole CNC				
Funding Project #:		Work Order #:		Estimate Type:	Investment
PPM ID #:		Bus. Segment:	Distribution	Estimator:	John Duffy
State:	MA	Company:	5310 - Massachusetts Elect	Project Lead:	Mark Siegel
Alternative:		Revision #:		Last Updated:	8/29/2016
Description:					

		CAPEX	OPEX	COR	Totals
Craft Labor		1,109	-	-	1,109
Materials		3,739	-	-	3,739
Engineering Cost		1,580	-	-	1,580
Contractors/Consultants		2,500	-	-	2,500
Project Management Cost		2,264	-	-	2,264
Equipment Rental		-	-	-	-
Craft Supervision		764	-	-	764
Other		-	-	-	-
Subtotal Direct Cost		**11,956**	**-**	**-**	**11,956**
Sales Tax (A70) %	-	-	-	-	-
Stores Handling (M50) %	20.00	748	-	-	748
Labor Adders %	81.80	4,677	-	-	4,677
Transportation (T10) %	16.00	300	-	-	300
Contingency %	-	-	-	-	-
Contractor Tax %	-	-	-	-	-
CAD (A50) %	26.61	1,654	-	-	1,654
	-				-
Equipment Tax %	-	-	-	-	-
AFUDC (A10, A11) %	2.48	480	-	-	480
Totals		**19,814**	**-**	-	**19,814**

Project Information					
Project Name:	8/30/16 - Electric Vehicle Service - OH Secondary Drop to Meter on Pole - CNC				
Funding Project #:		Work Order #:		Estimate Type:	Investment
PPM ID #:		Bus. Segment:	Distribution	Estimator:	John Duffy
State:	MA	Company:	5310 - Massachusetts Electric Company	Project Lead:	Mark Siegel
Alternative:		Revision #:		Last Updated:	8/29/2016
Description:					

CAPEX	**OPEX**	**COR**	**Total**
15,562	-	-	15,562

Install:
Install secondaries down pole from existing transformer to new meter mounted on pole.

Remove:

Maintain:

Prepared by: ______________________ Date: ______________________

John Duffy

Reviewed by: ______________________ Date: ______________________

Reviewed by: ______________________ Date: ______________________

Approved by: ______________________ Date: ______________________

Date: *1/25/2018* **This estimate is valid until:**

Project Summary

Project Name:	8/30/16 - Electric Vehicle Service - OH Secondary Drop to Meter on Pole - CNC				
Funding Project #:		Work Order #:		Estimate Type:	Investment
PPM ID #:		Bus. Segment:	Distribution	Estimator:	John Duffy
State:	MA	Company:	5310 - Massachusetts Elect	Project Lead:	Mark Siegel
Alternative:		Revision #:		Last Updated:	8/29/2016
Description:					

		CAPEX	OPEX	COR	Totals
Craft Labor		737	-	-	737
Materials		977	-	-	977
Engineering Cost		1,580	-	-	1,580
Contractors/Consultants		2,500	-	-	2,500
Project Management Cost		2,264	-	-	2,264
Equipment Rental		-	-	-	-
Craft Supervision		764	-	-	764
Other		-	-	-	-
Subtotal Direct Cost		**8,822**	**-**	**-**	**8,822**
Sales Tax (A70) %	-	-	-	-	-
Stores Handling (M50) %	20.00	195	-	-	195
Labor Adders %	81.80	4,372	-	-	4,372
Transportation (T10) %	16.00	240	-	-	240
Contingency %	-	-	-	-	-
Contractor Tax %	-	-	-	-	-
CAD (A50) %	26.61	1,555	-	-	1,555
	-				-
Equipment Tax %	-	-	-	-	-
AFUDC (A10, A11) %	2.48	377	-	-	377
Totals		**15,562**	**-**	-	**15,562**

Level 2: 5 Dual-Port Stations

Customer-Side Costs	Estimate 1	Estimate 2	Estimate 2 Allocation based on Estimate 1
Plans & Permits	$ 350	$ 535	1%
Labor (electrician)	$ 11,200	$ 17,118	35%
Materials (panel, breakers, condiut, fittings, concrete)	$ 8,500	$ 12,991	26%
Misc (site prep, signage)	$ 4,600	$ 7,031	14%
Other (bore or trenching, excavation)	$ 7,500	$ 11,463	23%
Total	**$ 32,150**	**$ 49,138**	100%

Summary: Customer-Side Costs	Average	Average Cost/ Site
Plans & Permits	$ 442	$ 442
Labor (electrician)	$ 14,159	$ 14,159
Materials (panel, breakers, condiut, fittings, concrete)	$ 10,746	$ 10,746
Misc (site prep, signage)	$ 5,815	$ 5,815
Other (bore or trenching, excavation)	$ 9,481	$ 9,481
Total	**$ 40,644**	**$ 40,644**

DCFC: 4 Single-Port Stations

Customer-Side Costs	Estimate 1	Estimate 2	Estimate 3	Estimate 3 Allocation based on Estimate 1
Plans & Permits	$ 600	$ 800	$ 641	1%
Labor (electrician)	$ 24,700	$ 25,000	$ 26,391	41%
Materials (panel, breakers, condiut, fittings, concrete)	$ 18,400	$ 35,000	$ 19,660	31%
Misc (site prep, signage)	$ 4,600	$ 2,500	$ 4,915	8%
Other (bore or trenching, excavation)	$ 11,800	$ 12,000	$ 12,608	20%
Total	**$ 60,100**	**$ 75,300**	**$ 64,215**	100%

Summary: Customer-Side Costs	Average	Average Cost/ Site
Plans & Permits	$ 680	$ 680
Labor (electrician)	$ 25,364	$ 25,364
Materials (panel, breakers, condiut, fittings, concrete)	$ 24,353	$ 24,353
Misc (site prep, signage)	$ 4,005	$ 4,005
Other (bore or trenching, excavation)	$ 12,136	$ 12,136
Total	**$ 66,538**	**$ 66,538**

Division 10-5

Request:

Refer to Appendix 2.1, pages 64- 80, regarding energy storage.

a. Does this section refer only to utility-owned storage, as described in PST Book 1, Chapter 7?

b. If the answer to (a) is yes, please reconcile the statement on Schedule PST - 1, Chapter 7, page 1 that "the Company proposes to install and own approximately two MWh of energy storage" with the 1.25 MWh of storage identified on page 65 of Appendix 2.1.

c. Please explain why the Company expects to charge and discharge the battery on a daily basis, rather than only for a small subset of system peak hours.

d. Has the Company analyzed whether the daily on-peak to off-peak price ratios are sufficient to make it economic to charge and discharge the battery on a daily basis, rather than only for a small subset of system peak hours? If so, please provide this analysis in machine-readable format with all formulas intact.

e. Will the customer at whose site the battery is located pay for the energy from the grid used to charge the battery?

f. If the answer to (e) is yes, please provide the expected rate schedule that would apply for distribution service.

g. If the answer to (e) is yes, please provide the supply service rates that are expected to apply.

h. If the host customer is assessed a demand charge, please explain how the demand charge would be taken into account when determining when to charge and discharge the battery.

i. Please provide the assumed battery degradation over the battery lifetime due to cycling, environmental factors, or other factors, and any supporting data used to develop this assumption.

j. Please provide the number and capacity of behind-the-meter storage systems owned by the Company's C&I customers. Please provide the requested data in machine-readable format with all formulas intact.

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k. Does the Company procure any demand response services from the systems identified in (j) for the purposes of system peak reductions or local transmission or distribution capacity benefits? If yes, please describe the program(s). If no, please explain why not.

l. Has the Company analyzed the procurement of capacity and energy services from customer-owned storage relative to utility-owned storage? If yes, please provide all relevant data and analyses in machine-readable format. If not, please explain why not.

m. Please explain what benefits utility-owned and operated storage provides relative to procurement of capacity and energy services from customer-owned storage.

n. Please describe what the “lease charge” is that is referenced on page 79 of Appendix 2.1.

<u>Response</u>:

a. Yes. Appendix 2.1, Pages 64-80 (Bates Pages 256-272 of PST Book 1), refer only to the utility-owned storage program, as described in Schedule PST-1, Chapter 7, Pages 1-9 (Bates Pages 137-145 of PST Book 1).

b. The specific Energy Storage project size and cost information for the project is included in Appendix 2.1, Pages 64-80. Schedule PST 1, Chapter 7, Page 1, references an approximate number that was larger to anticipate the possibility that the Company may be able to deploy more than 1.25 MWh of energy storage if market prices trend downwards. Also, energy storage pricing is complicated by the ability to change both power and energy of a system depending on use cases. The Company plans to maximize the value of the learning opportunities of the system with the proposed estimates.

c. The Company anticipates charging and discharging daily to help understand different use cases. Since the proposed installations are intended to provide lessons, it is important to capture daily use to allow a better understanding of how customer might leverage an energy storage system.

d. The Company did investigate the daily on-peak to off-peak price and determined that, based on the data provided, operation on this use case alone would not provide an economic justification. Please see the Company’s response to Division 5-1 .

e. The Company anticipates that, in the event that an energy storage unit is sited behind a customer meter, the customer would be responsible for any energy used to charge the battery or benefit from discharging. However, the Company is willing to consider the idea of reimbursing the customer for use of the battery for energy used for grid-related support

f. At this time, the Company has not developed rates for utility-owned storage.

g. Please see the Company's response to part f. above. The Company anticipates that the customer would continue to utilize a standard rate.

h. Depending on the customer load shape, the specific installation would seek to balance the proposed use cases to maximize the benefits for learning and minimize the customer demand charges.

i. At this time, the Company has not determined the best type of energy storage technology. Degradation of the energy storage unit would be a factor in determining the best use cases and would be a consideration in the evaluating equipment. The benefit-cost analysis assumes a 15-year life of the energy storage unit.

j. Please see the Company's response to Division 5-43, which is attached as Attachment DIV 10-5. Currently, the Company is unaware of any interconnected energy storage systems in the state.

k. Please see the Company's response to part j. above.

l. Please see the Company's response to part j. above.

m. As explained in the Company's response to part j. above, there are currently no available services for procurement in Rhode Island. This program would allow the Company to learn about the value of capacity and energy services before customers could provide such services. In addition, this would provide lessons, which would influence strategies and help develop the market and increase awareness of energy storage.

n. Lease charges were included as a potential cost in the situation where the energy storage units are interconnecting directly to the electric system and installed on land that the Company does not own. In this situation, the landowner would not be receiving any electrical benefits, and it is anticipated that the Company would need to provide a lease payment to the customer for hosting the system.

(This response is identical to the Company's response to Division 3-5 in Docket No. 4780.)

Prepared by or under the supervision of: Carlos Nouel

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Responses to Division's Fifth Set of Data Requests
Issued January 3, 2018

Division 5-43

Request:

Regarding behind-the-meter storage:

a. Please provide the total MWs of behind-the-meter storage currently installed in National Grid's Rhode Island service territory, by customer class.

b. Please provide the annual incremental MW of installed behind-the-meter storage for the past five years.

c. Please describe how the Company is informed of, and tracks, behind-the-meter storage.

d. Please discuss whether the Company will be rewarded for any additional behind-the-meter storage installed, or only incremental to a baseline forecast of naturally-occurring storage installations.

Response:

a. The Company has not provided any authorizations to connect customer-owned behind-the-meter electric storage.

b. The Company has not provided any authorizations to connect customer-owned behind-the-meter electric storage.

c. The Company tracks storage applications through the interconnection application process, per tariff guidelines. Additionally, the Company is in the process of developing a supplemental information request for prospective battery storage customers and plans on collecting the information during the application review process.

d. The Company proposes to earn a behind-the-meter storage incentive only for customer-owned storage applications that are incremental to a baseline forecast of storage applications that the Company expects to be submitted without influence by the Company.

(This response is identical to the Company's response to Division 1-43 in Docket No. 4780.)

Prepared by or under the supervision of: Carlos Nouel

Division 10-6

Request:

Regarding the Complex Capital Projects Capital Cost Incentive:

a. Please provide a definition for "complex capital projects".

b. How will the Company determine whether a capital project qualifies as "complex" and thereby included in the metric for this incentive?

c. Please describe how the Company currently estimates ISR project costs; including who is responsible for the cost estimates and what data sources are used to develop the estimates.

d. Please discuss whether the Complex Capital Projects Capital Cost Incentive would create an implicit incentive for the Company to over-estimate project costs in order to ensure that the delivered cost would be less than the estimate?

e. Has the Company reviewed its historical accuracy in estimating complex capital costs? If so, please describe the Company's historical accuracy, and provide supporting data if available. Please provide the requested data in machine-readable format with all formulas intact.

Response:

a. As discussed in the Company's response to Division 5-29 part a., National Grid defines "complex capital projects" as projects that require a Project Manager.

b. Please see the Company's response to Division 5-29 part a.

c. Complex projects in the Infrastructure, Safety, and Reliability Plan are estimated by the Company's Electric Project Estimating Group. The Electric Project Engineering Group utilizes unitized libraries (which are routinely reviewed and updated) to develop detailed cost estimates based on the scope of a project using Success Enterprise estimating software. Project teams use a risk register to set appropriate project contingencies. The project teams reviews final estimates, and the estimates go through a quality control process prior to being released to the project manager for sanction. Cost data, completed project data, US Geological Survey, and other commercially available data are used in addition to the Success Enterprise libraries, when necessary.

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

d. The Company's Electric Project Estimating Group performs estimates according to national standards set forth by AACE International and the American Society of Professional Estimators. In addition, the Electric Project Estimating Group uses risk registers to assess risk on a project to apply appropriate contingency based on project scope. Over-estimating for the purpose of the cost incentive would have a negative impact on the Company's ability to meet annual budget and portfolio delivery goals.

e. The tables below provide comparisons of sanctioned and actual project costs over the last four years. Review of the portfolio shows consistent estimating practice with the goal of reaching "0" but falling just below or above the target. The Electric Project Estimating Group monitors the portfolio to ensure estimates are not too aggressive or conservative in assumptions. Attachment DIV 10-6 provides the supporting data and calculations in machine-readable format.

CAPEX Pivot

Row Labels	Count of Project	Sum of Sanction CAPEX	Sum of Actual CAPEX	Sum of (Sanction CAPEX - Actual CAPEX)/Sanction CAPEX
2014	2	$5,191.00	$4,887.24	5.85%
2015	4	$4,874.00	$5,323.08	-9.21%
2016	8	$11,188.00	$10,811.27	3.37%
2017	4	$15,616.00	$15,523.15	0.59%
Grand Total	**18**	**$36,869.00**	**$36,544.74**	**0.88%**

Total (CAPEX+OPEX+COR) Pivot

Row Labels	Count of Project	Sum of Total Sanction	Sum of Total Actuals	Sum of (Total Sanction - Total Actuals)/Total Sanction
2014	2	$5,262.09	$5,085.93	3.35%
2015	4	$5,423.00	$5,632.97	-3.87%
2016	8	$11,396.00	$11,223.01	1.52%
2017	4	$15,662.08	$15,832.76	-1.09%
Grand Total	**18**	**$37,743.18**	**$37,774.67**	**-0.08%**

(This response is identical to the Company's response to Division 3-6 in Docket No. 4780.)

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

Project	Project Description	Closure Year (includes case where all work orders are closed, but Funding Project is opened)	Baseline - CAPEX Sanction Amount Data Source	Sanction CAPEX (baseline data)	Actual CAPEX
C036230	Langworthy Substation (D-Sub)	FY15	USSC-12-444vdtd Jan 1 2014	$1,574	$1,682
C033535	Johnston Sub 12.47 kV Expansion	FY16	USSC0110W259 v3 dtd June 20th 2015	$4,284	$4,590
C034002	Johnston Sub 12kV Expansion Getawa.	FY15	USSC0110W259 v3 dtd June 20th 2015	$326	$318
CD00659	Eldred Sub Asset Replacement(D-Lin	FY16	USSC-1 1-045v4 dtd 3/4/2014	$148	$244
C036232	Langworthy Substation (D-Line)	FY16	USSC-12-444vdtd Jan 1 2014	$116	$172
C046832		FY17	USSC-12-085 v3 dtd Dec 9th 2014 - did not include resanction paper	$389	$425
CD01243	Pontiac substation Flood Restoratio	FY17	USSC-12-433 v3 dtd 9/9/14 - did not look at resanction paper	$473	$593
C024180	Coventry MITS (Dist Line)	FY17	USSC0408P37 dtd June 13th 2012	$775	$678
C046398	Memorial Blvd Easton's Beach inst d	FY17	USSC-14-123 v2 dtd Nov 10th 2015 - did not include resanction paper	$1,390	$1,440
C046831	CLARKE 65J12 Feeder Upgrade (D-Sub)	FY17	USSC-12-085 v3 dtd Dec 9th 2014 - did not include resanction paper	$2,130	$2,172
CD01242	Pontiac substation Flood Restoratio	FY17	USSC-12-433 v3 dtd 9/9/14 - did not look at resanction paper	$2,811	$3,080
C054788	ValleySub 102 NERC CIP v3.25	FY17	Electronic DoA dtd May 2 2014. DOA was used from orignal electronic sanction, not re-sanction	$250	$317
C024179	Coventry MITS (Dist Sub)	FY17	USSC0408P37 dtd June 13th 2012	$2,970	$2,106
CD01104	Kent County 2nd Transformer (D-Line	FY18	USSC-12-355 v4 dtd Feb 23rd, 2016	$212	$167
C049981	Nsnvlle 127W41 New Customer Load	FY18	Originally, the project was less than $1M so there is only electronic DOA in PowerPlan. Project was resanctions. Amounts reflect original sanction	$700	$1,696
C023852	Inst Ductline Governor St. Prov.	FY18	USSC-13-239 dtd 8/20/2013	$1,571	$1,528
CD00972	New Highland Drive Substation - DSu	FY18	USSC 12-287 v4 dtd July 23rd, 2014	$13,133	$12,132

CAPEX Pivot

Row Labels	Count of Project	Sum of Sanction CAPEX	Sum of Actual CAPEX	Sum of (Sanction CAPEX - Actual CAPEX)/Sanction CAPEX
2014	2	$5,191.00	$4,887.24	5.85%
2015	4	$4,874.00	$5,323.08	-9.21%
2016	8	$11,188.00	$10,811.27	3.37%
2017	4	$15,616.00	$15,523.15	0.59%
Grand Total	**18**	**$36,869.00**	**$36,544.74**	**0.88%**

Total (CAPEX+OPEX+COR) Pivot

Row Labels	Count of Project	Sum of Total Sanction	Sum of Total Actuals	Sum of (Total Sanction - Total Actuals)/Total Sanction
2014	2	$5,262.09	$5,085.93	3.35%
2015	4	$5,423.00	$5,632.97	-3.87%
2016	8	$11,396.00	$11,223.01	1.52%
2017	4	$15,662.08	$15,832.76	-1.09%
Grand Total	**18**	**$37,743.18**	**$37,774.67**	**-0.08%**

Project	Project Description	FP Status	FP Completion Date	Closure Year (includes case where all work orders are closed, but Funding Project is opened)	WO Status	Total Cost	Source	Sanction CAPEX	Sanction OPEX	Sanction CoR	Total Sanction	Actual CAPEX	Actual OPEX	Actual CoR	Total Actuals
C052708	Volt Var-Substation	open			completed	$239.22	USSC-14-009 dtd July 12th 2016	$228.00	$0.00	$0.00	$228.00	$231.80	$7.73	$0.00	$239.53
C049981	Nsnvlle 127W41 New Customer Load	open	11/03/17	2017	3 Closed	$1,985.90	Originally, the project was less than $1M so there i	$700.00	$18.00	$10.00	$728.00	$1,696.07	$196.52	$93.32	$1,985.90
C053111	Volt Var - IT/IS	open			completed	$1,494.19	USSC-14-009 dtd July 12th 2016	$1,222.00	$177.00	$70.00	$1,469.00	$1,309.88	$177.14	$6.79	$1,493.82
CD00649	Gate 2 Substation (D-Sub)	open			1 closed 1 Op	$1,900.27	USSC-14-262 v2 dtd Feb 10th 2016; bundled with /	$1,804.00	$51.00	$35.00	$1,890.00	$2,189.46	$56.97	$322.73	$2,569.15
C046386	BITS Wakefield Sub Upgrades (D-Sub)	in service			in service	$2,837.06	US5C13-007v3 dtd May 23rd, 2016	$2,009.00	$22.00	$11.00	$2,042.00	$2,735.41	$0.08	$102.24	$2,837.74
CD01101	Kent County 2nd Transformer (D-Sub)	open			1 completed :	$2,445.87	USSC-12-355 v4 dtd Feb 23rd, 2016	$2,850.00	$19.00	$31.00	$2,900.00	$2,429.12	$17.09	$14.63	$2,460.85
C046352	Volt Var Dline RI Pilot Project	open			7 closed, 1 ca	$5,264.10	USSC-14-009 dtd July 12th 2016	$4,387.00	$475.00	$98.00	$4,960.00	$4,625.79	$590.72	$134.55	$5,351.06
CD00972	New Highland Drive Substation - DSu	open	11/03/17	2017	closed	$12,144.04	USSC 12-287 v4 dtd July 23rd, 2014	$13,133.00	$0.00	$0.00	$13,133.00	$12,132.08	$11.96	$0.00	$12,144.04
C023852	Inst Ductline Governor St. Prov.	open	11/03/17	2017	Closed	$1,532.78	USSC-13-239 dtd 8/20/2013	$1,571.00	$0.08	$0.00	$1,571.08	$1,527.54	$0.00	$5.25	$1,532.78
C024176	Chase Hill Sub (D-Sub)	open			in-service/car	$10,445.68	USSCO4O8P36v6 dtd June 10 2015	$9,916.00	$0.07	$0.04	$9,916.11	$10,472.32	$31.41	$0.48	$10,504.21
C068946	Flood Mitigation West Howard	open			Closed - appe	$0.00						$ 0.00	$ -	$ -	

Division 10-7

Request:

Regarding the Construction Costs per Mile Productivity Incentive:

a. The Company states that this incentive is still in development. Is the Company requesting approval of this incentive in the instant proceeding?

b. Please describe the rationale for this incentive and provide data to support your response. For example, have per-mile overhead distribution line construction costs been increasing at a faster rate than other costs? Please provide supporting data in machine-readable format with all formulas intact.

c. Please describe the types of strategies that the Company might employ to reduce per-mile distribution line construction costs.

Response:

a. The Company is not requesting approval of the Construction Costs per Mile Productivity Incentive at this time. However, the Company plans to include a fully-developed proposal for this incentive with targets in the Fiscal Year 2020 Electric Infrastructure, Safety, and Reliability Plan. To clarify, the Company is seeking approval of the Complex Capital Projects Capital Cost Incentive in this proceeding.

b. This incentive is intended to foster the delivery of meaningful capital savings to customers on a portfolio of approximately $45 million "routine" capital expenditures each year. The use of, and management to, the cost-per-mile metric is in the best interest of the Company's customers because of its potential to deliver cost reductions. The Company has developed this metric not as a result of cost trends, but rather, because that the metric represents the best full process view of the Company's costs for electric distribution line construction, providing the Company with a high-level view of its process cost efficiency. The Company is still reviewing the specifics of this proposed metric so does not have data to review at this time.

c. All strategies that would reduce costs related to the end-to-end construction process would potentially reduce the Company's construction costs per mile. Some potential examples could include:

- Increasing line crew productivity (through a variety of means) would result in more work being performed per hour/dollar;

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- Increasing support staff productivity would result in lower charges to the work orders for the same tasks performed;
- Decreasing use of premium time;
- Employing strategies to lower costs of contractors performing work of any kind;
- Employing strategies to lower material purchase prices;
- Changing design/construction standards to produce a lower cost approach to construction;
- Optimizing fleet and supply chain processes to lower support costs; and
- Evaluating the Company's design function to ensure that the Company is providing the highest value during the design phase.

(This response is identical to the Company's response to Division 3-7 in Docket No. 4780.)

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

Division 10-8

Request:

Refer to Appendix 2.1, page 4, regarding benefits and costs accounted for.

a. Please explain why there are no avoided distribution capacity, O&M, or losses associated with any of the projects, particularly company owned storage.

b. Please define "Lost Utility Revenues (Cost shift from non-participants to [truncated]".

c. Please explain how lost utility revenues are calculated for electric transportation and provide the calculations with supporting data and assumptions. Please provide the requested data in machine-readable format with all formulas intact.

d. Please explain how lost utility revenues are calculated for electric heat and provide the calculations with supporting data and assumptions. Please provide the requested data in machine-readable format with all formulas intact.

e. Please explain how lost utility revenues are calculated for company owned solar and provide the calculations with supporting data and assumptions. Please provide the requested data in machine-readable format with all formulas intact.

f. Please explain how lost utility revenues are calculated for company owned storage and provide the calculations with supporting data and assumptions. Please provide the requested data in machine-readable format with all formulas intact.

g. Please explain why the category of lost revenues is included in the utility cost test.

Response:

a. Regarding Avoided Distribution Capacity benefits, the four proposed projects included on Page 4 of Appendix 2.1 of the Company's Power Sector Transformation Plan[1] were not reviewed for load reduction impacts that avoid or defer the need for incremental distribution infrastructure caused by demand growth. Two of the projects, the proposed Energy Storage System Investment and the Company-Owned Solar Facilities have yet to be sited. However, as the Company noted in its proposal, the Company will look to site in locations that may have deferral benefits. If this is successful, the Company will determine any deferral benefits.

[1] The Narragansett Electric Company d/b/a National Grid, Investigation as to the Propriety of the Proposed Tariff Changes, Rhode Island Public Utilities Commission, RIPUC Docket No. 4770, November 27, 2017, Schedule PST-1, Appendix 2.1, at 4.

Regarding Avoided Operations and Maintenance Costs (O&M), the four proposed projects included on Page 4 of Appendix 2.1 of the Company's Power Sector Transformation Plan were not assumed to reduce the Company's O&M costs. As described in Chapter 7 of the Power Sector Transformation Plan, the Company does plan to advance internal research and development and gain a better understanding of the potential for avoided O&M benefits from the proposed Energy Storage System Investments.[2]

Regarding Avoided Distribution Losses, the four proposed projects included on Page 4 of Appendix 2.1 of the Company's Power Sector Transformation Plan do not impact the topology of the distribution system such that the system loss percentage (quantity of losses between relevant voltage levels divided by total electricity send-out) is reduced.[3]

b. The "Lost" Utility Revenue[4] cost shown in the table on Page 4 of Appendix 2.1 of the Company's Power Sector Transformation Plan is analogous to the Program Participant/Prosumer Benefits/Costs category included in Appendix B: Benefit-Cost Framework of the Public Utilities Commission's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid.[5] The "Lost" Utility Revenue Cost captures any cost shift to customers participating in a proposed program/project from customers who do not participate, and is included only in the Ratepayer Impact Measure (RIM). The "Lost" Utility Revenue cost represents a net transfer of funds rather than a net cost to society and is, therefore, not included in the Societal Cost Test (SCT).

[2] *Id*. Chapter 7, at 138.

[3] Please note that the Avoided Distribution Losses benefit shown in the table on Page 4 of Appendix 2.1 of the Power Sector Transformation Plan would capture only loss reduction impacts resulting from changes to the topology of the distribution system that reduce the system loss percentage and is distinct from any benefits resulting from the additional quantity of energy or capacity saved from load reductions when losses are accounted for; the latter impacts are embedded in the calculation of Forward Commitment: Capacity Value, Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP), Avoided Renewable Energy Credit (REC) Cost, Wholesale Market Price Impacts, Greenhouse Gas (GHG) Externality Costs, and Criteria Air Pollutant and Other Environmental Costs benefits. *See*, Attachment DIV 5-1-3 to the Company's response to Division Data Request 5-1, tab 5.EV-Benefits rows 20, 29, 37, 45, 204, 213, 221, 229, 413, 423,431,439, 515, and 524; tab 11.EH – Benefits, rows 12, 25, 34, 43, and 52; tab 17. SOL – Benefits, rows 12, 23, 24, and 25; and tab 22. ES – Benefits, rows 12, 25, 41, 63, 74, 90, and 100.

[4] Because of the use of a Revenue Decoupling Mechanism (RDM) in Rhode Island a decrease in base distribution revenue billed resulting from a decrease in electricity sales or demand (*i.e.*, the under-recovery of revenue as determined through a reconciliation of billed distribution revenue to the annual revenue target approved by the PUC in a general rate case) is ultimately recovered from all electric customers through the RDM. *See* Rhode Island Public Utilities Commission Order No. 20745 in Docket No. 4206 (May 25, 2012),

[5] *See* Attachment DIV 5-2-2 to the Company's response to Division 5-2.

c. In the benefit-cost analysis of the Electric Transportation Initiative, the “Lost” Utility Revenue cost is treated as a Net Utility Revenue Increase benefit in the RIM because the increased electric sales from electric vehicle charging offsets the total cost of the project paid by all customers. The calculation of Net Utility Revenue Increase for the Electric Transportation Initiative is shown on tab 6, rows 406 and 508 of Attachment DIV 5-1-3 to the Company’s response to Division 5-1.

d. In the benefit-cost analysis of the Electric Heat Initiative, the “Lost” Utility Revenue cost is treated as a Change in Utility Revenue benefit. Similar to the Electric Transportation Initiative, the increased sales revenue from electric heating usage offsets the total cost of the project paid by all customers. The calculation of the Change in Utility Revenue benefit is shown on tab 11, row 143 of Attachment DIV 5-1-3.

e. The “Lost” Utility Revenue cost is not applied in the benefit-cost analysis of the Company-Owned Solar Facilities and Income Eligible Rewards Program. The omission of this notation in the “Company-Owned Solar” column of the table shown on page 4 of Appendix 2.1 of the Company’s Power Sector Transformation Plan is in error.

f. The “Lost” Utility Revenue cost is not applied in the benefit-cost analysis of the Energy Storage System Investments. The omission of this notation in the Company-Owned Storage column of the table shown on page 4 of Appendix 2.1 of the Company’s Power Sector Transformation Plan was in error.

g. Please note that the Company did not calculate or present Utility Cost Test (UCT) results for any of the proposed PST projects; the references to the UCT in Appendix 2.1 of the Company’s Power Sector Transformation Plan represent an element of the process followed by the Company and its consultants to develop the benefit-cost analysis methodology ultimately employed. The notation in the UCT column of the table shown on Page 4 of Appendix 2.1 represents the potential applicability of project-specific variations of the “Lost” Utility Revenue cost to a UCT, for example positive changes in revenue that may reduce the total net cost of a project incurred by a utility and its customers.

(This response is identical to the Company’s response to Division 3-8 in Docket No. 4780).

Prepared by or under the supervision of: Carlos Nouel

Division 10-9

Request:

Regarding the Monthly Peak Demand Reduction incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:
    i. The expected benefits of achieving the annual targets
    ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

e. Please provide the rationale for only allocating 1.75 basis points to the achievement of the associated target, whereas the Annual Peak Demand Reduction incentive target is allocated 12 basis points.

Response:

a. In general, the Company expects that peak reductions will be supported by a number of programs and resources, including energy efficiency, energy storage, distributed generation, grid modernization efforts (*e.g.*, volt-var optimization (VVO) deployment), and demand response. The Company's proposed Electric Heat Initiative and Energy Storage System, both included in the PST Plan (See Schedule PST-1, Chapters 6 and 7, respectively), are expected to make very small contributions toward the peak reduction targets. The Company's proposed VVO expansion, included in Narragansett Electric's Fiscal Year 2019 Infrastructure, Safety, and Reliability Plan, will also contribute to the peak reduction targets. Although all of these programs will contribute to peak demand reductions, achievement of the targets will require incremental effort by the Company beyond these programs. The Company expects that it will have to develop an appropriate program to manage monthly peak loads in support of achieving the proposed targets.

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b. Cost associated with energy efficiency and demand response will be recovered from customers through the Energy Efficiency Program Charge, as provided for under the Energy Efficiency Program Provision. Costs associated with other ongoing Company efforts will be recovered through base distribution rates. Costs associated with the Electric Heat Initiative and Energy Storage System would be recovered through the PST Factors. Costs associated with the Company's planned expansion of VVO would be recovered through the ISR Factors.

c. As described in Schedule PST-1, Chapter 9, the Company has not conducted a complete cost-benefit analysis of achieving these targets. The initiatives described above are intended to serve multiple objectives – therefore, it would not be appropriate to include the full costs of these programs in a cost-benefit analysis of these targets. Further, the Company expects to develop new programs in support of these targets, but these programs (and their costs) have yet to be defined. The Company estimated potential customer savings that could result from the achievement of this target. Please see Schedule PST-1, Chapter 9, Page 19 for discussion of this calculation and Schedule PST-1, Chapter 9, Table 9-19 (Bates Page 180 of PST Book 1).

d. Please see Attachment DIV 10-9-1 and Attachment DIV 10-9-2 for the calculations described in part c. above.

e. As Schedule PST-1, Chapter 9, Table 9-19 demonstrates, basis points were allocated for this incentive such that customers retain between two-thirds and three-fourths of estimated transmission savings. The Company has similarly designed the Annual Peak Demand Reduction metric to ensure that the vast majority of savings would be returned to customers. As Tables 9-18 and 9-19 (copied below) suggest, the potential benefits from avoided capacity costs due to reduction in annual peak demand are expected to be considerably larger than the transmission cost savings due to reduction in monthly peak demand, and justify the larger basis point allocation to the Annual Peak Demand Reduction metric. (Note that to avoid double counting, the Company did not attribute any capacity savings from the month where the annual peak occurs to the Monthly Peak Demand Reduction metric).

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Table 9-18: Comparison of Benefits and Incentive Value for Forward Capacity Market Peak Demand Reduction

	NPV of Benefit in 2022 Due to 2019-2021 Targets	NPV of 2021 Value of Incentive	NPV of Value of Incentive (2019-2021)
Minimum	$ 2,594,124	$ 285,752	$ 886,970
Target	$ 4,816,010	$ 571,505	$ 1,773,940
Maximum	$ 6,901,576	$ 857,257	$ 2,660,910

Table 9-19: Potential Savings and Company Earnings from Monthly Transmission Peak Reductions

	NPV of Customer Savings (2019-2021)	NPV of Incentive (2019-2021)	Share of Savings to Customer
Minimum	$575,166	$ 147,828	0.74
Target	$779,652	$ 258,700	0.67
Maximum	$1,016,979	$ 369,571	0.64

(This response is identical to the Company's response to Division 3-9 in Docket No. 4780.)

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Benefits and Savings Comparisons for PIMs

Key Inputs and Assumptions	**Source/Notes**	**Values**			
Discount Rate:	Company WACC	0.075			
Value of a Basis Point:	Revenue Requirements Calculations				
			2019	2020	2021
			$ 59,493	$ 60,526	$ 63,602
RNS Transmission Rate	RNS rate 6/1/17-5/31 2018, assumed for 2019-2021	110.35	kW-yr		
		9.20	kW-month		

Transmission Savings and Value of Incentive Comparision

Monthly Peak Tarkets (Annual sum of MW reduced, year over year)

2019	2020	2021	Basis Points
28	23	26	1.00
36	34	36	1.75
47	44	46	2.50

Annual Value of Incremental Transmission Cost Savings

	2018	2019	2020	2021	2022	NPV
Min	0	$ 254,076	$ 214,880	$ 243,504		$575,166
Target	0	$ 328,329	$ 308,927	$ 329,679		$779,652
Max	0	$ 431,216	$ 403,864	$ 425,667		$1,016,979

Annual Value of Incentive at Target Levels

	2018	2019	2020	2021	2022	NPV
Min	0	$ 59,493	$ 60,526	$ 63,602		$ 147,828
Target	0	$ 104,113	$ 105,921	$ 111,304		$ 258,700
Max	0	$ 148,734	$ 151,316	$ 159,006		$ 369,571

Division 10-10

Request:

Regarding the Annual Peak Demand Reduction incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

    i. The expected benefits of achieving the annual targets

    ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

Response:

a. In general, the Company expects that peak reductions will be supported by a number of programs and resources, including energy efficiency, energy storage, distributed generation, grid modernization efforts (*e.g.*, volt-var optimization (VVO) deployment), and demand response. The Company's proposed Electric Heat Initiative and Energy Storage System, both included in the PST Plan (See Schedule PST-1, Chapters 6 and 7, respectively), are expected to make very small contributions toward the annual peak reduction targets. The Company's proposed VVO expansion, included in Narragansett Electric's Fiscal Year 2019 Infrastructure, Safety, and Reliability (ISR) Plan, will also contribute to the peak reduction targets. Although all of the programs will contribute to annual peak demand reductions, achievement of the targets will require incremental effort by the Company beyond these programs. The Company has not yet defined these incremental programs or activities.

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b. Cost associated with energy efficiency and demand response will be recovered from customers through the Energy Efficiency Program Charge, as provided for under the Energy Efficiency Program Provision. Costs associated with other ongoing Company efforts will be recovered through base distribution rates. Costs associated with the Electric Heat Initiative and Energy Storage System would be recovered through the PST Factors. Costs associated with the Company's planned expansion of VVO would be recovered through the ISR Factors.

c. As described in Schedule PST-1, Chapter 9, the Company has not conducted a complete cost-benefit analysis of achieving these targets. The initiatives described above are intended to serve multiple objectives – thus, it would not be appropriate to include the full costs of these programs in a cost-benefit analysis of these targets. Further, the Company expects to develop new programs in support of these targets, but these programs (and their costs) have yet to be defined. However, the Company described its approach to valuing the potential annual benefits to customers on Schedule PST -1, Chapter 9 (Bates Pages 179-180 of PST Book 1), copied below:

> While the Company has set annual Forward Capacity Market Peak Demand Reduction targets for the years 2019-2021, it is important to note that these reductions will not result in material capacity costs savings in the FCA until 2022. In the years 2020 and 2021, customers could expect to benefit from some savings through a reduced capacity share. The Company expects that MW reductions made in support of the 2019-2021 targets will be maintained for the duration of project lives.[1] To illustrate the magnitude of potential annual savings, the Company estimated the net present value (NPV) of the annual value, in the year 2022, of the benefits from avoided capacity needs due to the achievement of the 2019-2021 targets. Comparing this value against the NPV of the annual value of the incentive in 2021, and against the NPV of the incentive over the period 2019-2021, demonstrates that the incentive represents a small fraction of the overall benefits being created, particularly given that these benefits will carry well beyond 2022.
>
> **Table 9-18: Comparison of Benefits and Incentive Value for Forward Capacity Market Peak Demand Reduction**

[1] An exception to this might be called demand response events; however, the Company expects to be able to grow demand response enrolled and participating capacity as programs ramp up, such that it can be expected that the same reductions are achieved (and expanded) from year to year.

	NPV of Benefit in 2022 Due to 2019-2021 Targets	NPV of 2021 Value of Incentive	NPV of Value of Incentive (2019-2021)
Minimum	$ 2,594,124	$ 285,752	$ 886,970
Target	$ 4,816,010	$ 571,505	$ 1,773,940
Maximum	$ 6,901,576	$ 857,257	$ 2,660,910

The Company also provided an estimate of potential customer savings in 2020 and 2021 due to generation capacity share reductions from the achievement of these targets in its response to Division 5-51, which is attached as Attachment 10-10-1.

d. The analysis summarized in Table 9-19 is provided in Attachment DIV 10-10-2 and Attachment DIV 10-10-3.

(This response is identical to the Company's response to Division 3-10 in Docket No. 4780.)

Estimate of potential savings from capacity share reductions in 2020 and 2021 due to Forward Capacity Market peak reduction target

1. Approximation of projected capacity share of total ISO-NE peak based on peak forecast

a. Peak Forecast

	2019	2020
Company	1,691	1,679
ISO-NE	26,409	26,298
b. Capacity share	0.0640	0.0638

Note: assumes 100% peak coincidence in both years; ISO-NE forecast from 2017 ISO-NE CELT Report, reference case accounting for BTM PV and passive DR; Company forecast adjusted for PV and energy efficiency

2. Estimate of change in capacity share calculated in CY 2019 and 2020 due to achievement of peak reduction targets

a. Peak Reduction Targets for 2019 and 2020 Expressed as Incremental Reduction to Company Forecast

	2019	2020
Min	7	13
Target	13	27
Max	22	42

b. Company Peak Adjusted for Targets (1.a-2.a)

	2019	2020
Min	1,684	1,666
Target	1,677	1,651
Max	1,668	1,637

c. ISO-NE Peak Adjusted for Company Targets (1.a-2.a)

	2019	2020
Min	26,403	26,285
Target	26,396	26,271
Max	26,387	26,256

d. Capacity Share after Target Achievement (2.b/2.c)

	2019	2020
Min	0.0638	0.0634
Target	0.0635	0.0629
Max	0.0632	0.0623

e. Change in Capacity Share after Target Achievement (1.b-2.d)

	2019	2020
Min	0.0002	0.0005
Target	0.0005	0.0010
Max	0.0008	0.0015

3. Calculation of CY 2020 and 2021 Savings

Relevant CY 2021 Capacity Load Obligation and NRCP by Month

			CCP 2019-2020						**CCP 2020-2021**			
	2020-01	2020-02	2020-03	2020-04	2020-05	2020-06	2020-07	2020-08	2020-09	2020-10	2020-11	2020-12
a. Capacity Load Obligation (MW)	N/A	N/A	N/A	N/A	N/A	34,284	34,284	34,284	34,284	34,544	34,544	34,544
b. NRCP ($/kW-month)	N/A	N/A	N/A	N/A	N/A	6.341	6.341	6.341	6.341	6.325	6.325	6.324

Source: ISO-NE Forward Capacity Market Net Regional Clearing Price and Effective Charge-Rate Forecast

c. 2020 Avoided MW of CLO due to reduced 2019 capacity share (3.a*2.e)

	2020-01	2020-02	2020-03	2020-04	2020-05	2020-06	2020-07	2020-08	2020-09	2020-10	2020-11	2020-12
Min						8.33	8.33	8.33	8.33	8.40	8.40	8.40
Target						16.24	16.24	16.24	16.24	16.36	16.36	16.36
Max						27.13	27.13	27.13	27.13	27.34	27.34	27.34

d. 2020 Savings (3.c*3.b*1000)

	2020-06	2020-07	2020-08	2020-09	2020-10	2020-11	2020-12	**Total**
Min	$ 52,838	$ 52,838	$ 52,838	$ 52,838	$ 53,105	$ 53,105	$ 53,096	**$ 370,660**
Target	$ 102,988	$ 102,988	$ 102,988	$ 102,988	$ 103,507	$ 103,507	$ 103,491	**$ 722,456**
Max	$ 172,044	$ 172,044	$ 172,044	$ 172,044	$ 172,911	$ 172,911	$ 172,884	**$ 1,206,880**

Relevant CY 2021 Capacity Load Obligation and NRCP by Month

			CCP 2020-2021						**CCP 2021-2022**			
	2021-01	2021-02	2021-03	2021-04	2021-05	2021-06	2021-07	2021-08	2021-09	2021-10	2021-11	2021-12
e. Capacity Load Obligation (MW)	34,544	34,544	34,544	34,544	34,544	*34,544*	*34,544*	*34,544*	*34,544*	*34,544*	*34,544*	*34,544*
f. NRCP ($/kW-month)	6.324	6.324	6.324	6.325	6.325	*6.325*	*6.325*	*6.325*	*6.325*	*6.325*	*6.325*	*6.325*

Source: ISO-NE Forward Capacity Market Net Regional Clearing Price and Effective Charge-Rate Forecast (forecast for CCP 2021-2022 not available, so values assumed to remain at 5/2021 levels)

g. 2021 Avoided MW of CLO due to reduced 2020 capacity share (3.e*2.e)

	2021-01	2021-02	2021-03	2021-04	2021-05	2021-06	2021-07	2021-08	2021-09	2021-10	2021-11	2021-12
Min	15.97	15.97	15.97	15.97	15.97	15.97	15.97	15.97	15.97	15.97	15.97	15.97
Target	33.73	33.73	33.73	33.73	33.73	33.73	33.73	33.73	33.73	33.73	33.73	33.73
Max	51.59	51.59	51.59	51.59	51.59	51.59	51.59	51.59	51.59	51.59	51.59	51.59

f. 2021 Savings (3.g*3.f*1000)

													Total
Min	$ 101,003	$ 101,003	$ 101,003	$ 101,019	$ 101,019	$ 101,019	$ 101,019	$ 101,019	$ 101,019	$ 101,019	$ 101,019	$ 101,019	**$ 707,130**
Target	$ 213,332	$ 213,332	$ 213,332	$ 213,366	$ 213,366	$ 213,366	$ 213,366	$ 213,366	$ 213,366	$ 213,366	$ 213,366	$ 213,366	**$ 1,493,560**
Max	$ 326,227	$ 326,227	$ 326,227	$ 326,279	$ 326,279	$ 326,279	$ 326,279	$ 326,279	$ 326,279	$ 326,279	$ 326,279	$ 326,279	**$ 2,283,953**

Benefits and Savings Comparisons for PIMs

Key Inputs and Assumptions	**Source/Notes**	**Values**							
Discount Rate:	Company WACC	0.075							
Value of a Basis Point:	Revenue Requirements Calculations								
			2019	2020	2021				
			$ 59,493	$ 60,526	$ 63,602				
RNS Transmission Rate	RNS rate 6/1/17-5/31 2018, assumed for 2019-2021	110.35	kW-yr						
		9.20	kW-month						
Avoided Unit Cost of Electric Capacity	AESC 2015 Update - Appendix B	Below	$/MW-yr						
		2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
		$ -	$ -	$ -	$ -	$ 151,748	$ 145,443	$ 154,497	$ 173,685

FCM Savings and Value of Incentive Comparision

FCM Peak Tarkets (MW reduced, year over year)

Targets	2019	2020	2021	Basis Points
	22	18	19	6
	29	26	26	12
	38	31	31	18

FCM Peak Targets expressed as MW reductions relative to Company forecast including EE and solar impacts
Note: these values were used for calculating FCM benefits

Targets	2019	2020	2021
	7	13	25
	13	27	46
	22	42	65

Annual Capacity Benefits	**2018**	**2019**	**2020**	**2021**	**2022**	**NPV**
Min	0	0	0	0	$ 3,724,200	$ 2,594,124
Target	0	0	0	0	$ 6,914,005	$ 4,816,010
Max	0	0	0	0	$ 9,908,105	$ 6,901,576

Annual Value of Incentive at Target Levels

	2018	**2019**	**2020**	**2021**	**2022**	**NPV**
Min	0	$ 356,961	$ 363,159	$ 381,613		$ 886,970
Target	0	$ 713,921	$ 726,317	$ 763,227		$ 1,773,940
Max	0	$ 1,070,882	$ 1,089,476	$ 1,144,840		$ 2,660,910

Present Value of 2021 Incentive

	2018	**2019**	**2020**	**2021**	**2022**	**NPV**
	0	0	0	$ 381,613		$ 285,752
	0	0	0	$ 763,227		$ 571,505
	0	0	0	$ 1,144,840		$ 857,257

Division 10-11

Request:

Regarding the Off-Peak Charging Rebate Pilot Participation incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

    i. The expected benefits of achieving the annual targets
    ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

e. Please explain why the allocated basis points for this incentive are reasonable.

Response:

a. Achievement of these targets will be driven by the Company's proposed Off-Peak Charging Rebate Pilot, which is described in Schedule PST-1, Chapter 5, Section 2.1.

b. The costs of the Off-Peak Charging Rebate are included in the PST Plan and will be recovered through the PST Factors.

c. Yes, the Company conducted a cost-benefit analysis of the Off-peak Charging Rebate Pilot, based on based on the target participation levels included in Schedule PST-1, Chapter 9,Table 9-4.

d. The Company has provided this analysis in machine-readable format in the response to Division 5-1. Please see the electronic version of Attachment DIV 5-1-3, and refer to tabs 3 through 7 in that attachment. A summary of this analysis is included in the table below.

	Electric Vehicles -- Off Peak Rebate	
Benefit	Forward Commitment: Capacity Value	$ -
	Energy Supply & Transmission Operating Value of Energy Provided or Saved	$ 43,185
	Greenhouse Gas (GHG) Externality Costs	$ 6,897
Cost	**Total**	**$ 645,482**

e. Although the limited size of the proposed Off-peak Charging Rebate pilot prevents it from demonstrating positive quantified net benefits as a stand-alone program in the Company's benefit-cost analysis, the Company believes that the proposed size of the incentive is justified due to the value placed on the transition to time-varying rates in Docket 4600, and the value that this program will provide in understanding customer response to time-differentiated price signals. The program is also important to the State's ZEV and GHG near-term goals because it provides a timely means to reward off-peak charging by many electric vehicle drivers during the period before time-varying rates are implemented. The pilot will improve the economics of electric vehicle ownership and help ensure that additions of new load from participating electric vehicle owners are concentrated during off-peak hours. Notably, because the program as proposed is limited to a three-year period, the benefit-cost analysisA does not recognize potential avoided generation capacity costs that would occur due to avoided peak demand over the course of a longer term program.

(This response is identical to the Company's response to Division 3-11 in Docket No. 4780.)

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

Division 10-12

Request:

Regarding the Distributed Generation ("DG") – Friendly Substations incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

    i. The expected benefits of achieving the annual targets

    ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

e. Please explain why the allocated basis points for this incentive are reasonable.

Response:

a. The Company's 3V0 Program, proposed in Narragansett Electric's Fiscal Year 2019 (FY19) Infrastructure, Safety, and Reliability (ISR) Plan, will support the installation of 3V0 protective devices in Rhode Island substations on a priority basis, thereby supporting achievement of these targets.

b. The costs of the 3V0 Program would be recovered through the ISR Factors, as proposed in Narragansett Electric's FY19 ISR Plan.

c. The Company has not conducted a cost-benefit analysis associated with achievement of the proposed targets. As discussed in Schedule PST-1, Chapter 9 (Bates Page 181 of PST Book 1), the Company has not quantified the net benefits to customers from these efforts, because the assumptions that would have to be made about the timing of distributed generation installations absent these investments, the number and size of installations accelerated, and the specific distributed generation technology being installed are subject to a high degree of subjectivity and uncertainty.

d. Please see the Company's response to part c. above.

e. The Company has allocated up to 10 basis points for this metric at the maximum target levels because of this metric's direct support of the State's renewable energy goals, and in recognition of the role that these investments will play in support of accelerating the benefits from distributed generation. The Company is committed to supporting a carbon-free future and realizes this is a fundamental design shift needed to advance interconnection of large quantities of distributed generation, thereby expediting the achievement of the benefits from these resources, including reductions in CO_2 and criteria pollutant emissions, avoided energy and capacity costs, and avoided renewable energy credit costs. The Company has allocated more basis points to this metric than other distributed energy resource metrics in recognition of its importance to the State's renewable energy goals.

(This response is identical to the Company's response to Division 3-12 in Docket No. 4780.)

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

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Division 10-13

Request:

Regarding the Demand Response – Residential Participation incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please provide the historical number of enrolled residential customers, by month, in the ConnectedSolutions program. Please provide the requested data in machine-readable format with all formulas intact.

b. Please provide the magnitude of any incentives offered to customers through the ConnectedSolutions program, including any changes in incentive levels over time. Please provide the requested data in machine-readable format with all formulas intact.

c. Please provide the historical costs of operating the ConnectedSolutions program by cost category. Please provide the costs by month, or in the most granular format available. Please provide the requested data in machine-readable format with all formulas intact.

d. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets that will be developed in the 2019 energy efficiency plan

e. Please explain how the costs associated with (d) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

f. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

g. If the answer to (f) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

    i. The expected benefits of achieving the annual targets

    ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

h. Please explain why the allocated basis points for this incentive are reasonable when the targets have not yet been developed.

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Response:

a. Please see the table below and Attachment DIV 10-13, which show the number of customers and thermostats in the Connected Solutions Program in Rhode Island since the beginning of the program in 2016.

Year	Month	# of Thermostats	# of Customers
2016	May	30	30
	June	97	84
	July	176	140
	August	225	175
	September	301	229
	October	326	250
	November	394	300
	December	450	340
2017	January	490	365
	February	563	421
	March	605	454
	April	620	465
	May	623	468
	June	717	546
	July	1070	811
	August	1161	876
	September	1185	896
	October	1208	919
	November	1212	929
	December	1220	934

b. Please see the table below and Attachment DIV 10-13.

Customer Incentive Type	Nest Thermostats	Honeywell and ecobee Thermostats
Subscription Incentive	0	$25
Incentive After 1st Summer	$40	$25*
Incentive After Every Following Summer	$40	$25*

*For Honeywell and ecobee thermostat, the after-summer incentive is only paid if customers participate in at least 75 percent of demand response events.

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c. Please see the table below and Attachment DIV 10-13.

Year	Month	Program, Planning Administration, Marketing, and Evaluation	Sales, Technical Assistance, and Training	Participant Incentive	Total
2016	January	$617	$0	$0	$617
	February	$617	$0	$0	$617
	March	$7,685	$0	$0	$7,685
	April	$1,798	$0	$0	$1,798
	May	$2,672	$0	$0	$2,672
	June	$3,872	$0	$0	$3,872
	July	$617	$0	$0	$617
	August	$3,956	$52,200	$150	$56,306
	September	$5,960	$300	$0	$6,260
	October	$11,227	$32,135	$0	$43,362
	November	$3,494	$225	$50	$3,769
	December	$56,053	$34,305	$9,026	$99,384
2017	January	$428	$10,178	$0	$10,606
	February	$3,600	$2,051	$0	$5,651
	March	$23,310	$0	$36,240	$59,550
	April	$19,945	$9,961	$1,500	$31,405
	May	$4,425	$5,179	$0	$9,604
	June	$73,206	$793	$0	$73,999
	July	$31,026	$60,775	$0	$91,801
	August	$15,317	$0	$0	$15,317
	September	$3,905	$0	$0	$3,905
	October	$37,667	$0	$0	$37,667
	November	$29,541	$6,647	$5,725	$41,913
	December	$62,548	$600	$0	$63,148
Total		**$403,481**	**$215,348**	**$52,691**	**$671,520**

d. Achievement of the Demand Response – Connected Solutions Participation targets, which will be developed under the Company's Annual Energy Efficiency (EE) Plan for 2019, will be supported by the Company's implementation of the Connected Solutions program, which the Company intends to include in the Annual EE Plan for 2019.

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e. Assuming that the Connected Solutions program is included in the Company's Annual EE Plan for 2019, the Company would recover the costs of the program through the Energy Efficiency Program Charge under the Energy Efficiency Program Provision. However, because demand response program such as Connected Solutions are also consistent with the goals of the Power Sector Transformation Initiative, namely to control the long-term costs of the electric system and to give customers more energy choices and information, the Company may, at a later date, opt to include this program under the Power Sector Transformation (PST) Plan and recover associated costs in accordance with the PST Provision.

f. As noted in the Company's response to part a. above, the targets for this metric have not yet been developed. The Company has not conducted a cost-benefit analysis related to this metric at this time. Note that the pilot costs may not reflect future costs because the Company is actively pursuing methods to reduce operating costs in 2018.

g. See the Company's response to part f. above.

h. As noted in Schedule PST-1, Chapter 9, Page 11 (Bates Page 172 of PST Book 1), the basis points allocated to this incentive were intended to illustrate the potential size of the incentive.

(This response is identical to the Company's response to Division 3-13 in Docket No. 4780.)

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

Enrolled residential thermostats and customers by month

Year	Month	# of Thermostats	# of Customers
2016	May	30	30
	June	97	84
	July	176	140
	August	225	175
	September	301	229
	October	326	250
	November	394	300
	December	450	340
2017	January	490	365
	February	563	421
	March	605	454
	April	620	465
	May	623	468
	June	717	546
	July	1070	811
	August	1161	876
	September	1185	896
	October	1208	919
	November	1212	929
	December	1220	934

Incentive payments

Customer Incentive Type	Nest Thermostats	Honeywell and ecobee Thermostats
Subscription Incentive	0	$25
Incentive After 1st Summer	$40	$25
Incentive After Every Following Summer	$40	$25

Monthly costs by category

Year	Month	Program, Planning Administration, Marketing, and Evaluation	Sales, Technical Assistance, and Training	Participant Incentive	Total
2016	January	$617	$0	$0	$617
	February	$617	$0	$0	$617
	March	$7,685	$0	$0	$7,685
	April	$1,798	$0	$0	$1,798
	May	$2,672	$0	$0	$2,672
	June	$3,872	$0	$0	$3,872
	July	$617	$0	$0	$617
	August	$3,956	$52,200	$150	$56,306
	September	$5,960	$300	$0	$6,260
	October	$11,227	$32,135	$0	$43,362
	November	$3,494	$225	$50	$3,769
	December	$56,053	$34,305	$9,026	$99,384
2017	January	$428	$10,178	$0	$10,606
	February	$3,600	$2,051	$0	$5,651
	March	$23,310	$0	$36,240	$59,550
	April	$19,945	$9,961	$1,500	$31,405
	May	$4,425	$5,179	$0	$9,604
	June	$73,206	$793	$0	$73,999
	July	$31,026	$60,775	$0	$91,801
	August	$15,317	$0	$0	$15,317
	September	$3,905	$0	$0	$3,905
	October	$37,667	$0	$0	$37,667
	November	$29,541	$6,647	$5,725	$41,913
	December	$62,548	$600	$0	$63,148
Total		**$403,481**	**$215,348**	**$52,691**	**$671,520**

Division 10-14

Request:

Regarding the Demand Response – C&I Participation incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the Company’s current C&I demand response programs, and when each program began.

b. Please provide the historical number of enrolled C&I customers, by month, in the Company’s current C&I demand response programs. Please provide the requested data in machine-readable format with all formulas intact.

c. Please provide the magnitude of any incentives offered to customers through the Company’s C&I demand response programs, including any changes in incentive levels over time. Please provide the requested data in machine-readable format with all formulas intact.

d. Please provide the historical costs of operating the Company’s C&I demand response programs by cost category. Please provide the costs by month, or in the most granular format available. Please provide the requested data in machine-readable format with all formulas intact.

e. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets that will be developed in the 2019 energy efficiency plan.

f. Please explain how the costs associated with (e) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

g. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

h. If the answer to (g) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

    i. The expected benefits of achieving the annual targets

    ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

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

i. Please explain why the allocated basis points for this incentive are reasonable when the targets have not yet been developed.

Response:

a. The Company has one demand response program for C&I customers. The program began during the Summer of 2017. The responses provided below are based on that single year of results for the program.

The Company's demand response program for C&I customers aims to help customers reduce their energy use when the grid is at peak demand.

The Company and its vendors help customers identify strategies and technologies that will help customers reduce their energy use at peak times. Through a competitive RFP process, the Company selected three approved curtailment service providers (CSPs) to guide customers through this process. Through another competitive RFP process, the Company procured a demand response management system (DRMS) to identify when the grid will be at peak demand, notify vendors and customers of peak events, and measure each customer's reduction in energy use during demand response events.

The program is set up to run in June, July, August, and September of each program year. The Company may call demand response events on any weekday (except holidays) between the hours of 2-5 PM. On average, three to five demand response events will be called every year. The Company will not call more than seven events in a single year.

Customers and vendors are paid incentives based on their performance. The vendors and customers split the incentive amounts based on negotiations between the customers and the vendor. However, historically, customers have always received the majority of the incentives paid.

b. Please see the table below and Attachment DIV 10-14.

Month	Customers Who Signed Up During That Month
April 2017	7
May 2017	18
June 2017	7
Total	**32**

c. Please see the table below and Attachment DIV 10-14.

Incentives	2017	2018
Capacity Incentive	$20/kW-Year	$35/kW-Year
Energy Incentive	$0.75/kWh During Demand Response Events	$0

d. Please see the table below and Attachment DIV 10-14.

Year	Month	Program Planning and Administration, Marketing, and Evaluation	Sales, Technical Assistance, and Training	Participant Incentive	Total
2017	Jan	$0	$0	$0	$0
	Feb	$0	$0	$0	$0
	Mar	$0	$0	$0	$0
	April	$0	$0	$0	$0
	May	$0	$0	$0	$0
	June	$53.48	$0	$0	$53
	July	$3,422.72	$0	$0	$3,423
	August	$3,422.72	$0	$0	$3,423
	Sep	$2,567.04	$3,548	$0	$6,115
	Oct	$3,810.68	$7,096	$0	$10,907
	Nov	$3,422.72	$3,548	$0	$6,971
	Dec	$460.86	$5,793	$248,457	$254,711
	Total	$17,160	$19,985	$248,457	$285,602

e. Achievement of the Demand Response – C&I Participation targets which will be developed under the Company's Annual Energy Efficiency (EE) Plan for 2019 and will be supported by the Company's implementation of its C&I demand response program, which the Company intends to include in the Annual EE Plan for 2019.

f. Assuming that the Company's C&I demand response program is included in the Company's Annual EE Plan for 2019, the Company would recover the costs of the program through the Energy Efficiency Program Charge under the Energy Efficiency Program Provision. However, because demand response programs are also consistent with the goals of the Power Sector Transformation Initiative, namely to control the long-term costs of the electric system and to give customers more energy choices and information, the Company may, at a later date, opt to include this program under the PST Plan and recover associated costs in accordance with the PST Provision.

g. As noted in the Company's response to part a., the targets for this metric have not yet been developed. The Company has not conducted a cost-benefit analysis related to this metric at this time. However, the Company expects a cost-benefit analysis of its current C&I Demonstration program to be available in at the end of the first quarter of 2018.

h. See the Company's response to subpart (g) above.

i. As noted in the Schedule PST-1, Chapter 9, Page 11 (Bates Page 172 of PST Book 1), the basis points allocated to this incentive were intended to be illustrative of the potential size of the incentive.

(This response is identical to the Company's response to Division 3-14 in Docket No. 4780.)

Enrolled C&I Customers by Month

Month	Customers Who Signed Up During That Month
Apr-2017	7
May-2017	18
Jun-2017	7
Total	**32**

Incentives for Participating Customers

Incentives	2017	2018
Capacity Incentive	$20/kW-Year	$35/kW-Year
Energy Incentive	$0.75/kWh During Demand Response Events	$0

Costs by Category

Year	Month	Program Planning and Administration, Marketing, and Evaluation	Sales, Technical Assistance, and Training	Participant Incentive	Total
2017	Jan	$0	$0	$0	$0
	Feb	$0	$0	$0	$0
	Mar	$0	$0	$0	$0
	April	$0	$0	$0	$0
	May	$0	$0	$0	$0
	June	$53.48	$0	$0	$53
	July	$3,422.72	$0	$0	$3,423
	August	$3,422.72	$0	$0	$3,423
	Sep	$2,567.04	$3,548	$0	$6,115
	Oct	$3,810.68	$7,096	$0	$10,907
	Nov	$3,422.72	$3,548	$0	$6,971
	Dec	$460.86	$5,793	$248,457	$254,711
	Total	$17,160	$19,985	$248,457	$285,602

Division 10-15

Request:

Regarding the Electric Heat Program incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

    i. The expected benefits of achieving the annual targets

    ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

e. Please explain why the allocated basis points for this incentive are reasonable.

Response:

a. The Company will undertake four categories of activities and investments to achieve the targets. These four categories, which are outlined in Schedule PST -1, Chapter 6, Pages 1-15 (Bates Pages 121-135 of PST Book 1), include: (i) partial utility ownership of ground-source heat pumps for large commercial and industrial building owners; (ii) ground- and air-source heat pump equipment incentives for residential customers, including income-eligible customers; (iii) community-based outreach; and (iv) oil/propane dealer training programs. Together, these actions are intended to accelerate efficient heat electrification in Rhode Island, delivering cost savings to participating customers and realizing CO_2 emission reductions. Achieving these targets will require the Company to: achieve effective targeting highly-emitting customers; maximize participation on a fixed incentive budget; partner with local communities to achieve customer conversions; support the development of a robust installer base; and encourage proper system design and utilization.

b. The costs of the Electric Heat Initiative will be included in the Power Sector Transformation (PST) Plan and recovered through the PST Factors.

c. The Company has conducted a cost-benefit analysis of the Electric Heat Initiative. This analysis assumed the achievement of the midpoint targets.

d. Please see the electronic version of Attachment DIV 5-1-3, tabs 8 through 12, for the cost-benefit analysis of the Electric Heat Initiative.

e. As the Company notes in Schedule PST-1, Chapter 9, Section 4.2 (Bates Page 181 of PST Book 1), although the quantified net benefits of the Electric Heat Initiative suggest that customers would retain only about 25 percent of the net benefits under the proposed incentive, the proposed maximum incentive equal to two basis points annually is warranted given that the Electric Heat Initiative provides important economic development benefits that have not been quantified in the benefit-cost analysis. In particular, the program will support the growth in the state of a labor-intensive sector with a direct positive impact on the building trades.

(This response is identical to the Company's response to Division 3-15 in Docket No. 4780.)

Division 10-16

Request:

Regarding the Electric Vehicles incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

    i. The expected benefits of achieving the annual targets

    ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

e. Please explain why the allocated basis points for this incentive are reasonable.

Response:

a. The Company intends to achieve these targets through its activities under the Electric Transportation Initiative, described in Schedule PST-1, Chapter 5, Pages 1-19 (Bates Pages 101-120 of PST Book 1). As described in that chapter, the Company is proposing a three-year, multi-part Electric Transportation Initiative to meaningfully accelerate electrification of transportation in Rhode Island through multiple market development strategies. The initiative is comprised of six components:

    1. Off-Peak Charging Rebate Pilot
    2. Charging Station Demonstration Program
    3. Discount Pilot for Direct Current Fast Charging Station Accounts
    4. Transportation Education and Outreach

5. Company Fleet Expansion
6. Initiative Evaluation

b. The costs of the Electric Transportation Initiative are included in the Power Sector Transformation (PST) Plan and will be recovered through the PST Factors.

c. The Company has conducted a cost-benefit analysis of the Electric Transportation Initiative. The calculated benefits in this analysis are linked to the number of incremental electric vehicles in the model, which is derived using assumptions on electric vehicle enablement per charging station. Although not linked to the incentive targets in Appendix 10.10 specifically, the incremental electric vehicles in the model fall within the Minimum and Target range in 2019, and the Target and Maximum range in 2020 and 2021. Thus, the benefit-cost analysis provides a reasonable representation of the net benefits that would accrue at target levels.

d. The Company has provided the analysis described in part c. in machine-readable format in the response to Division 5-1. Please see the electronic version of Attachment DIV 5-1-3, and refer to tabs 3 through 7 in that attachment.

e. Please see the Company's discussion in Schedule PST-1, Chapter 9, Page 20, and Table 9-20 on Page 21 (Bates Pages 181-182 of PST Book 1). As the Company indicates in that schedule, the Company's earnings at the Maximum level would be such that 60 percent of the net benefits as estimated in the analysis described in part c. would remain with customers. Expected net benefits at the Maximum target levels would actually be higher than estimated in that analysis, given that the number of incremental electric vehicles would be greater than was assumed. Therefore, customers' share of net benefits after the incentive is paid would actually be higher than 60 percent.

(This response is identical to the Company's response to Division 3-16 in Docket No. 4780.)

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

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Division 10-17

Request:

Regarding the Behind the Meter Storage incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

   i. The expected benefits of achieving the annual targets

   ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

e. Please explain why the allocated basis points for this incentive are reasonable.

Response:

a. As discussed in Schedule PST – 1, Chapter 9, the Company does not have a program in place to encourage behind-the-meter storage, and the Company is not proposing one at this time. However, the Company is committed to working with interested customers to evaluate opportunities for storage. Achievement of these targets would be supported by these efforts.

b. The Company has not proposed any new costs associated with the activities in support of achieving these targets.

c. The Company has not conducted a cost-benefit analysis for the achievement of these targets.

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d. See response to part c. above.

e. The Company's proposed incentive of up to two basis points is intended to provide a modest but meaningful incentive to promote effective customer engagement on behind the meter storage and exploration of customer opportunities to achieve savings and provide system benefits through storage.

(This response is identical to the Company's response to Division 3-17 in Docket No. 4780.)

Division 10-18

Request:

Regarding the Company-Owned Storage incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

   i. The expected benefits of achieving the annual targets

   ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

e. Please explain why the allocated basis points for this incentive are reasonable, given that the Company will presumably earn a return on the storage investment.

Response:

a. The Company's proposed Energy Storage System described in Schedule PST- 1, Chapter 7 would contribute to achieving this target. In addition, the Company expects to continually evaluate the business case for storage and has set targets and associated basis points to encourage this ongoing evaluation.

b. The costs of the Company's proposed Energy Storage System project are included in the PST Plan and will be recovered through the PST Factors. The Company has not proposed to recover any other costs associated with these targets from customers.

c. The Company has not conducted a cost-benefit analysis for the achievement of these targets.

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d. See response to part (c), above.

e. The Company's proposed incentive of up to two basis points is intended to provide the Company with a modest but meaningful incentive for the ongoing evaluation of the business case for Company-owned storage, in recognition of the potential system benefits and broader policy goals that energy storage could support.

(This response is identical to the Company's response to Division 3-18 in Docket No. 4780.)

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

Division 10-19

Request:

Regarding the AMF Customer Engagement and Deployment incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

    i. The expected benefits of achieving the annual targets

    ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

e. Please explain why an incentive is warranted for delivering a customer engagement plan.

f. Please explain why an incentive is warranted for conducting and reporting on customer awareness.

g. Please explain why an incentive is warranted for commencing mass scale meter deployment.

h. Please explain the target "30% deployment and customer portal access." Does this target mean that 30% of customers have accessed the portal? Or that 30% of customers could theoretically access the portal?

i. Please explain why the incentive for 30% deployment and customer portal access is reasonable.

Response:

a. The Company expects to undertake multiple activities to achieve its proposed targets. These activities include, but are not limited to, the following:

1. A procurement exercise to obtain the necessary goods, services, and resources required to deploy advanced metering functionality (AMF) on schedule and as cost-effectively as possible.

2. A comprehensive effort to develop a detailed customer engagement plan for AMF deployment with input and feedback integrated from both internal and external stakeholders throughout the process. This effort would also include a detailed plan for developing, launching, and incorporating customer awareness surveys, messaging studies, and other valuable customer insights that are obtained by the Company via past experiences with pilots and/or through industry research.

3. Appropriate alignment of internal resources to achieve the ambitious deployment timeline proposed in this case.

4. Exercise to obtain highest value for Rhode Island customers by optimizing AMF deployment with similar efforts that may be occurring in the Company's other jurisdictions, particularly New York.

b. The costs of the activities under part a. are included in the Power Sector Transformation (PST) Plan and would be recovered through the PST Factors.

c. The Company has not conducted a cost-benefit analysis on the specific targets proposed for this performance incentive mechanism. However, the Company has performed a cost-benefit analysis of AMF deployment. The targets for this performance incentive mechanism are intended to support the Company's ability to deliver the benefits identified in that analysis as expeditiously as possible, and to maximize near-term benefits from deployment.

d. The Company has provided a machine-readable version of the cost-benefit analysis for AMF deployment in its response to Division 5-1. Please see the electronic versions of Attachment DIV 5-1-1 and Attachment DIV 5-1-2.

e. Customer education is important to prepare customers for AMF meter deployment. The proposal is intended to incent the Company to deliver an engagement plan that fosters customer awareness of AMF technology, features, and benefits, and provide support to customers. A successful engagement plan will help expedite the achievement of benefits to customers from AMF, providing them with the knowledge and skills to take advantage of this new technology. To that end, the Company believes the incentive is appropriate and will help fulfill the objectives of power sector transformation.

f. Understanding customer awareness and how it changes as a result of early customer outreach efforts will inform the Company's further efforts as AMF deployment commences. Public sharing of the information learned by the Company through these efforts will inform other Rhode Island stakeholders, who will in turn be able to provide additional feedback to the Company as it moves forward with customer outreach and deployment. The modest incentive proposed by the Company will reinforce the alignment of the Company's customer awareness efforts and the State's broader energy policy goals that will be supported by AMF.

g. The proposal is intended to provide an incentive for commencing deployment on the timeline proposed. This incentive is intended to reinforce the Company's commitment to the expeditious and cost-effective delivery to customers of the benefits from AMF deployment.

h. This target is meant to provide an incentive for the Company to successfully complete 30 percent of its proposed AMF deployment, while providing access to the customer portal for any customer who has been successfully transitioned from an AMR to an AMI meter. Once the Company has fully deployed AMF to all Rhode Island customers (*i.e.* 100 percent deployment), all customers will have access to the proposed customer portal.

i. As is the case with the incentive for commencement of deployment discussed in part g., this incentive is intended to reinforce the Company's commitment to its proposed schedule in support of the expeditious and cost-effective delivery to customers of the benefits from AMF deployment.

(This response is identical to the Company's response to Division 3-19 in Docket No. 4780.)

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

Division 10-20

Request:

Regarding the Volt/Var Optimization ("VVO") Pilot Delivery incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:
   i. The expected benefits of achieving the annual targets
   ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

e. Please explain why it is appropriate to provide an incentive for the project being in service.

f. Please explain whether the target for 2021 is incremental to the 2020 target.

g. Please explain why the basis point allocation for these targets is reasonable.

Response:

a. Achievement of these targets will be supported by the VVO Pilot proposed in the Fiscal Year 2019 ISR. The immediate focus of this project is the integration of interval voltage data from AMF meters into the optimization algorithms of the volt-var optimization/conservation voltage reduction (VVO/CVR) to improve system efficiency. For this pilot, the Company will undertake a small-scale deployment of 8,384 meters. Through this effort, the Company will evaluate AMF's contribution to power sector transformation objectives.

b. The costs of this pilot will be recovered through the ISR Factors.

c. The Company has conducted a cost-benefit analysis of this pilot, but not for each of the specific targets identified for the proposed performance incentive mechanism.

d. Attachment DIV 10-20 contains the Company's cost-benefit analysis of the combination of AMF and VVO for the Washington substation. The Company's cost benefit analysis of combined AMF/VVO shows a benefit cost ratio of 1.75 using the societal cost test. Although the addition of AMI lowers the benefit cost ratio relative to VVO alone, it is important to note that the incremental impact of AMF in this BCA is not a good indicator of the costs and benefits of a full-scale AMF deployment. VVO enhancement represents only a small piece of the broader business case for AMF, described in Chapter 4 of Schedule PST 1. Under full-scale deployment, the marginal cost to achieve the incremental 1% peak and energy reduction through VVO enhancement would be close to zero following this pilot. A major value of the pilot is in the role that it will play demonstrating the realization of system efficiencies through the combination of AMF and VVO/CVR. The pilot will offer important lessons for both the Company and stakeholders that will inform broader AMF deployment, VVO expansion, and other grid modernization investments.

e. Successful project delivery reflects the Company's commitment to ensuring this project provides the greatest benefits to the system, and to maximizing this opportunity to derive lessons learned in support of AMF deployment, and state policy goals. For this reason, the Company believes that the modest proposed incentive of two basis points for this milestone is warranted.

f. The 2021 target is not incremental to the 2020 target. Rather, it reflects sustained performance over that timeframe.

g. The opportunity to earn two basis points per year will provide a modest but meaningful incentive to the Company for a successful project that lends itself to an improved understanding of the system optimization benefits from AMF. In so doing, it will help to lay the foundation for broader successful deployment of AMF, which is central to the state's Power Sector Transformation and Docket 4600 goals.

(This response is identical to the Company's response to Division 3-20 in Docket No. 4780.)

BCA ratios and comprehensive benefits and costs

25 Year BCA

BCA Summary

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VVO ONLY (Washington)

Societal Cost Test

	BCA Ratio		
Benefits	Forward Commitment: Capacity Value	`	
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time-	$	5,992,752
		$	-
	Greenhouse Gas (GHG) Externality Costs	$	3,727,193
		$	**9,719,945**
	Utility Costs	$	2,001,242
		$	**2,001,242**

BCA Ratio **4.86**

RIM Cost Test

	BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	3,468,808
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time-	$	5,992,752
	Wholesale Market Price Impacts	$	23,978
		$	**9,485,537**
	Utility Costs	$	2,001,242
		$	**2,001,242**

BCA Ratio **4.74**

Comprehensive Benefits & Costs

	Applicable Cost Test			BCA Ratio		
	SCT	UCT	RIM			
Benefits	x	x	x	Forward Commitment: Capacity Value	$	3,468,808
	x	x	x	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time	$	5,992,752
		x	x	Wholesale Market Price Impacts	$	23,978
	x			Greenhouse Gas (GHG) Externality Costs	$	3,727,193
					$	**13,212,730**
	x	x	x	Utility Costs	$	2,001,242
					$	**2,001,242**

FY19 Proposed ISR Costs	$	1,231,508

VVO + AMI (Washington)

Societal Cost Test

	BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	4,603,260
	Energy Supply & Transmission Operating Value of Energy	$	7,990,336
	Greenhouse Gas (GHG) Externality Costs	$	4,969,591
		$	**17,563,187**
	Utility Costs	$	10,029,624
		$	**10,029,624**

BCA Ratio **1.75**

RIM Cost Test

	BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	4,603,260
	Energy Supply & Transmission Operating Value of Energy	$	7,990,336
	Wholesale Market Price Impacts	$	31,970
		$	**12,625,567**
	Utility Costs	$	10,029,624
		$	**10,029,624**

BCA Ratio **1.26**

Comprehensive Benefits & Costs

	Applicable Cost Test			BCA Ratio		
	SCT	UCT	RIM			
Benefits	x	x	x	Forward Commitment: Capacity Value	$	4,603,260
	x	x	x	Energy Supply & Transmission Operating Value of Energy	$	7,990,336
		x	x	Wholesale Market Price Impacts	$	31,970
	x			Greenhouse Gas (GHG) Externality Costs	$	4,969,591
					$	**17,595,157**
	x	x	x	Utility Costs	$	10,029,624
					$	**10,029,624**

FY19 Proposed ISR Costs	$	7,256,024

AMI Incremental (Washington)

Societal Cost Test

	BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	1,134,453
	Energy Supply & Transmission Operating Value of Energy Pr	$	1,997,584
	Greenhouse Gas (GHG) Externality Costs	$	1,242,398
		$	**4,374,435**
	Utility Costs	$	8,028,382
		$	**8,028,382**

BCA Ratio **0.54**

RIM Cost Test

	BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	1,134,453
	Energy Supply & Transmission Operating Value of Energy Pr	$	1,997,584
	Wholesale Market Price Impacts	$	7,993
		$	**3,140,029**
	Utility Costs	$	8,028,382
		$	**8,028,382**

BCA Ratio **0.39**

Comprehensive Benefits & Costs

	Applicable Cost Test			BCA Ratio		
	SCT	UCT	RIM			
Benefits	x	x	x	Forward Commitment: Capacity Value	$	1,134,453
	x	x	x	Energy Supply & Transmission Operating Value of Energy P	$	1,997,584
		x	x	Wholesale Market Price Impacts	$	7,993
	x			Greenhouse Gas (GHG) Externality Costs	$	1,242,398
					$	**4,382,427**
	x	x	x	Utility Costs	$	8,028,382
					$	**8,028,382**

FY19 Proposed ISR Costs	$	6,024,516

VVO/CVR AMI control panel, inputs, and sub-models

VVO/CVR AMI - Inputs

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Control Panel - VVO/AMI Scenario

Scenario Selection

System Type	Type	# of Systems	2018	2019	2020	2021	2022	Check
VVO Only	VVO	1	1					Match
VVO and AMI	VVO+AMI	0	0					Match
AMI Incremental	AMI	0	0					Match
	Total	1	1	0	0	0	0	

System Specifications

Category	Expected MW reduction	Lifecycle Capital Cost	System Count	OPEX	Annual Operating Expense	Useful Life	Annual Energy (GWhrs)	MWhrs
VVO Only	1.59	1,231,508	1	206,767	52,600	25	7.02	7020
VVO and AMI	2.11	7,256,024	0	1,091,767	179,552	25	9.36	9360
AMI Incremental	0.52	6,024,516	0	885,000	126,952	25	2.34	2340
Total			1.00	2,183,534.21		N/A		

System Installation Schedule

CAPEX	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
VVO Only	-	1.00	-	-	-	-									
VVO and AMI	-	-	-	-	-	-									
AMI Incremental	-	-	-	-	-	-									
Total	-	1.00	-	-	-	-	-	-	-	-	-	-	-	-	-

OPEX	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
VVO Only	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Incremental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Lag from Install to Receive Operating Benefit 1.00

Annual Operating Expense	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
VVO Only	-	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Incremental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Cost Schedule

Expense	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Capital Expenditure	1,231,508.18	-	-	-	-	-	-	-	-	-	-	-	-	-
OPEX	206,767.10	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenditures	-	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00
Opex Sub-total	206,767.10	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00

Annual Avoided Capacity Savings

Benefit does not start until system is operating post lag time

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Electric Capacity	-	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59

Annual Energy Displaced

Source for each system: MWhrs

Annual Energy Displaced	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
VVO Only		7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00
VVO and AMI		-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Incremental		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00

Annual Avoided Energy Savings

	$ 38.77	$ 44.28	$ 50.14	$ 55.99	$ 58.77	$ 64.41	$ 68.96	$ 73.55	$ 75.38	$ 77.99	$ 82.01	$ 86.09	$ 90.35	$ 94.44	$ 98.82
Annual Energy Savings	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
VVO Only	-	310,851.68	351,962.35	393,037.03	412,578.47	452,139.11	484,117.38	516,351.08	529,201.83	547,475.31	575,705.60	604,319.65	634,251.15	662,945.48	693,687.75
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Incremental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	310,851.68	351,962.35	393,037.03	412,578.47	452,139.11	484,117.38	516,351.08	529,201.83	547,475.31	575,705.60	604,319.65	634,251.15	662,945.48	693,687.75

CVR - Avoided Energy Cost

CVR - Avoided Energy Cost (pre-inflation)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Winter On-Peak	0.04	0.04655	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Winter Off-Peak	0.04	0.04066	0.04	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.07	0.07
Summer On-Peak	0.03	0.03388	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.08
Summer Off-Peak	0.02	0.02687	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06

MRP	1.09
Inflation	2%
Convert to MW	1,000.00

CVR - Avoided Energy Cost (post inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Winter On-Peak	47.75	52.79	58.88	65.57	68.50	74.52	79.33	83.60	85.16	88.19	91.72	95.66	99.75	102.31	106.13	110.09	114.21
Winter Off-Peak	41.00	46.11	50.15	56.47	58.90	64.07	68.21	72.53	73.75	76.36	79.49	83.40	88.16	91.28	95.26	99.41	103.74
Summer On-Peak	31.91	38.42	48.61	53.03	56.26	62.11	66.45	73.33	76.75	79.01	85.82	91.14	95.57	105.43	112.34	119.70	127.55
Summer Off-Peak	24.22	30.47	35.61	40.29	43.12	48.78	53.91	57.55	59.63	61.77	65.93	69.46	72.91	76.45	80.34	84.44	88.74

VO/CVR AMI control panel, inputs, and sub

/VO/CVR AMI - Inputs

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Control Panel - VVO/AMI Scenario

Scenario Selection

System Type
VVO Only
VVO and AMI
AMI Incremental

System Specifications

Category
VVO Only
VVO and AMI
AMI Incremental
Total

System Installation Schedule

CAPEX	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
VVO Only																
VVO and AMI																
AMI Incremental																
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

OPEX	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
VVO Only	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	-	-	-	-
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Incremental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	-	-	-	-

Lag from Install to Receive Operating Bene

Annual Operating Expense	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
VVO Only	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	-	-	-	-
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Incremental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	-	-	-	-

Cost Schedule

Expense	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Capital Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPEX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenditures	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	-	-	-	-
Opex Sub-total	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	52,600.00	-	-	-	-

Annual Avoided Capacity Savings

Benefit does not start until system is oper

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Electric Capacity	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	-	-	-	-

Annual Energy Displaced

Source for each system:

Annual Energy Displaced	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
VVO Only	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00				
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-				
AMI Incremental	-	-	-	-	-	-	-	-	-	-	-				
Total	**7,020.00**	**7,020.00**	**7,020.00**	**7,020.00**	**7,020.00**	**7,020.00**	**7,020.00**	**7,020.00**	**7,020.00**	**7,020.00**	**7,020.00**	-	-	-	-

Annual Avoided Energy Savings

	$ 103.41	$ 108.22	$ 113.27	$ 118.57	$ 124.12	$ 129.95	$ 136.07	$ 142.48	$ 149.21	$ 156.28	$ 163.70	$ 171.48	$ 179.66	$ 188.24	$ 197.25
Annual Energy Savings	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
VVO Only	725,921.08	759,721.35	795,168.51	832,346.76	871,344.84	912,256.23	955,179.49	1,000,218.46	1,047,482.63	1,097,087.41	1,149,154.50				
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-				
AMI Incremental	-	-	-	-	-	-	-	-	-	-	-				
Total	**725,921.08**	**759,721.35**	**795,168.51**	**832,346.76**	**871,344.84**	**912,256.23**	**955,179.49**	**1,000,218.46**	**1,047,482.63**	**1,097,087.41**	**1,149,154.50**	-	-	-	-

CVR - Avoided Energy Cost

CVR - Avoided Energy Cost (pre-inflation)	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Winter On-Peak	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.0932
Winter Off-Peak	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.0915
Summer On-Peak	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.12	0.12	0.13	0.14	0.14	0.1475
Summer Off-Peak	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.0858

MRP
Inflation
Convert to MW

CVR - Avoided Energy Cost (post inflation)

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Winter On-Peak	118.47	122.90	127.49	132.26	137.20	142.32	147.64	153.16	158.88	164.81	170.97	177.36	183.99
Winter Off-Peak	108.26	112.97	117.90	123.03	128.39	133.98	139.82	145.91	152.27	158.90	165.83	173.05	180.59
Summer On-Peak	135.91	144.82	154.31	164.43	175.21	186.70	198.93	211.98	225.87	240.68	256.46	273.27	291.18
Summer Off-Peak	93.26	98.01	103.01	108.26	113.77	119.57	125.66	132.06	138.79	145.86	153.30	161.11	169.32

Detailed build-up of VVO/CVR AMI benefits

VVO/CVR AMI - Benefits

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	RI Benefit Description / Calculations	Unit	SCT	UTC	RIM	Source	Yr 1 FY18	Yr 2 FY19	Yr 3 FY20	Yr 4 FY21	Yr 5 FY22	Yr 6 FY23	Yr 7 FY24	Yr 8 FY25	Yr 9 FY26	Yr 10 FY27
	Forward Commitment: Capacity Value															
	Nameplate Capacity	MW					-	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59
/	1 - Losses	%				AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Adjusted Peak Load	MW					-	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
x	Avoided Unit Cost of Electric Capacity	$/MW				AESC 2015 Update - Appendix B	-	-	-	-	151,748.25	145,443.49	154,497.40	173,684.98	193,938.75	214,296.15
=	**Benefit from Forward Commitment: Capacity Value**	**$**	**x**	**x**	**x**		**$ -**	**$ -**	**$ -**	**$ -**	**$ 262,261**	**$ 251,364**	**$ 267,012**	**$ 300,173**	**$ 335,177**	**$ 370,360**
	Energy Reduction from System															
	VVO Only	$				Calculated	$ -	$ 310,852	$ 351,962	$ 393,037	$ 412,578	$ 452,139	$ 484,117	$ 516,351	$ 529,202	$ 547,475
	VVO and AMI	$				Calculated	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	AMI Incremental	$				Calculated	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
=	**Total Energy Savings**	**$**	**x**	**x**	**x**		**$ -**	**$ 310,852**	**$ 351,962**	**$ 393,037**	**$ 412,578**	**$ 452,139**	**$ 484,117**	**$ 516,351**	**$ 529,202**	**$ 547,475**
	Wholesale Market Price Impact	DRIPE														
	Total Energy Reduction from VVO System	MW					-	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00
x	DRIPE (Energy + Cross-fuel Capacity)	$ / MWh				2015 AESC. Appendix B	1.39	0.91	0.91	0.19	0.19	0.19	0.20	0.20	0.20	0.21
=	**Wholesale Market Price Impact**	**$**		**x**	**x**		**$ -**	**$ 6,422**	**$ 6,416**	**$ 1,321**	**$ 1,343**	**$ 1,365**	**$ 1,387**	**$ 1,410**	**$ 1,432**	**$ 1,455**
	Greenhouse Gas (GHG) Externality Costs															
	Total Energy Savings	MWh					-	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00
x	Non-Embedded CO2 Cost	$ / MWh				2015 AESC. Exhibit 4-7	48.03	48.54	49.05	48.71	48.33	47.92	47.47	46.99	46.47	45.91
=	**Benefit from Reduced Greenhouse Gas Externality Costs**	**$**	**x**				**$ -**	**$ 340,749**	**$ 344,344**	**$ 341,926**	**$ 339,274**	**$ 336,379**	**$ 333,274**	**$ 329,868**	**$ 326,192**	**$ 322,281**

Detailed build-up of VVO/CVR AMI benefits

VVO/CVR AMI - Benefits

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	RI Benefit Description / Calculations	Yr 11 FY28	Yr 12 FY29	Yr 13 FY30	Yr 14 FY31	Yr 15 FY32	Yr 16 FY33	Yr 17 FY34	Yr 18 FY35
	Forward Commitment: Capacity Value								
	Nameplate Capacity	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59
/	1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%
=	Adjusted Peak Load	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
x	Avoided Unit Cost of Electric Capacity	235,794.87	259,373.47	290,550.94	308,169.87	314,333.27	320,619.93	327,032.33	333,572.98
=	**Benefit from Forward Commitment: Capacity Value**	**$ 407,515**	**$ 448,265**	**$ 502,148**	**$ 532,598**	**$ 543,250**	**$ 554,115**	**$ 565,197**	**$ 576,501**
	Energy Reduction from System								
	VVO Only	$ 575,706	$ 604,320	$ 634,251	$ 662,945	$ 693,688	$ 725,921	$ 759,721	$ 795,169
	VVO and AMI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	AMI Incremental	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
=	**Total Energy Savings**	**$ 575,706**	**$ 604,320**	**$ 634,251**	**$ 662,945**	**$ 693,688**	**$ 725,921**	**$ 759,721**	**$ 795,169**
	Wholesale Market Price Impact								
	Total Energy Reduction from VVO System	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00
x	DRIPE (Energy + Cross-fuel Capacity)	0.21	0.21	0.22	0.22	0.23	0.23	0.24	0.24
=	**Wholesale Market Price Impact**	**$ 1,479**	**$ 1,503**	**$ 1,527**	**$ 1,557**	**$ 1,589**	**$ 1,620**	**$ 1,653**	**$ 1,686**
	Greenhouse Gas (GHG) Externality Costs								
	Total Energy Savings	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00
x	Non-Embedded CO2 Cost	45.30	44.66	43.97	54.23	55.31	56.41	57.53	58.68
=	**Benefit from Reduced Greenhouse Gas Externality Costs**	**$ 318,039**	**$ 313,498**	**$ 308,648**	**$ 380,726**	**$ 388,293**	**$ 396,009**	**$ 403,879**	**$ 411,906**

	RI Benefit Description / Calculations	Yr 19 FY36	Yr 20 FY37	Yr 21 FY 38	Yr 22 FY 39	Yr 23 FY 40	Yr 24 FY 41	Yr 25 FY 42	Yr 26 FY 43	Yr 27 FY 44
	Forward Commitment: Capacity Value									
	Nameplate Capacity	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	-
/	1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Adjusted Peak Load	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	-
x	Avoided Unit Cost of Electric Capacity	340,244.44	347,049.33	353,990.31	361,070.12	368,291.52	375,657.35	383,170.50	390,833.91	398,650.59
=	**Benefit from Forward Commitment: Capacity Value**	**$ 588,031**	**$ 599,792**	**$ 611,788**	**$ 624,023**	**$ 636,504**	**$ 649,234**	**$ 662,219**	**$ 675,463**	**$ -**
	Energy Reduction from System									
	VVO Only	$ 832,347	$ 871,345	$ 912,256	$ 955,179	$ 1,000,218	$ 1,047,483	$ 1,097,087	$ 1,149,154	$ -
	VVO and AMI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	AMI Incremental	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
=	**Total Energy Savings**	**$ 832,347**	**$ 871,345**	**$ 912,256**	**$ 955,179**	**$ 1,000,218**	**$ 1,047,483**	**$ 1,097,087**	**$ 1,149,154**	**$ -**
	Wholesale Market Price Impact									
	Total Energy Reduction from VVO System	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	-
x	DRIPE (Energy + Cross-fuel Capacity)	0.24	0.25	0.25	0.26	0.27	0.27	0.28	0.28	0.29
=	**Wholesale Market Price Impact**	**$ 1,719**	**$ 1,754**	**$ 1,789**	**$ 1,825**	**$ 1,861**	**$ 1,898**	**$ 1,936**	**$ 1,975**	**$ -**
	Greenhouse Gas (GHG) Externality Costs									
	Total Energy Savings	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	7,020.00	-
x	Non-Embedded CO2 Cost	59.84	61.03	62.24	63.48	64.74	66.03	67.34	68.68	70.05
=	**Benefit from Reduced Greenhouse Gas Externality Costs**	**$ 420,092**	**$ 428,441**	**$ 436,955**	**$ 445,639**	**$ 454,495**	**$ 463,528**	**$ 472,740**	**$ 482,135**	**$ -**

Detailed build-up of VVO/CVR AMI benefits

VVO/CVR AMI - Benefits

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	RI Benefit Description / Calculations	Yr 28 FY 45	Yr 29 FY 46	Yr 30 FY 47	Nominal Value	NPV
	Forward Commitment: Capacity Value					
	Nameplate Capacity	-	-	-		
/	1 - Losses	92%	92%	92%		
=	Adjusted Peak Load	-	-	-		
x	Avoided Unit Cost of Electric Capacity	406,623.60	414,756.07	423,051.19		
=	**Benefit from Forward Commitment: Capacity Value**	**$ -**	**$ -**	**$ -**	**$ 10,962,988**	**$ 3,468,808**
	Energy Reduction from System					
	VVO Only	$ -	$ -	$ -		
	VVO and AMI	$ -	$ -	$ -		
	AMI Incremental	$ -	$ -	$ -		
=	**Total Energy Savings**	**$ -**	**$ -**	**$ -**	**$ 17,314,505**	**$ 5,992,752**
	Wholesale Market Price Impact					
	Total Energy Reduction from VVO System	-	-	-		
x	DRIPE (Energy + Cross-fuel Capacity)	0.29	0.30	0.30		
=	**Wholesale Market Price Impact**	**$ -**	**$ -**	**$ -**	**$ 49,924**	**$ 23,978**
	Greenhouse Gas (GHG) Externality Costs					
	Total Energy Savings	-	-	-		
x	Non-Embedded CO2 Cost	71.44	72.86	74.30		
=	**Benefit from Reduced Greenhouse Gas Externality Costs**	**$ -**	**$ -**	**$ -**	**$ 9,539,310**	**$ 3,727,193**

Total

Detailed build-up of VVO/CVR AMI costs

VVO/CVR AMI- Costs

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	RI Cost Description / Calculations	Unit	SCT	UTC	RIM	Source	Yr 1 FY18	Yr 2 FY19	Yr 3 FY20	Yr 4 FY21	Yr 5 FY22	Yr 6 FY23	Yr 7 FY24	Yr 8 FY25	Yr 9 FY26	Yr 10 FY27
	Capital Expenditures	$					$ 1,231,508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
+	Opex Sub-total	$					$ 206,767	$ 53,652	$ 54,725	$ 55,820	$ 56,936	$ 58,075	$ 59,236	$ 60,421	$ 61,629	$ 62,862
=	**Total Program Administrator Costs**	**$**	**x**	**x**	**x**		**$ 1,438,275**	**$ 53,652**	**$ 54,725**	**$ 55,820**	**$ 56,936**	**$ 58,075**	**$ 59,236**	**$ 60,421**	**$ 61,629**	**$ 62,862**

	RI Cost Description / Calculations	Yr 11 FY28	Yr 12 FY29	Yr 13 FY30	Yr 14 FY31	Yr 15 FY32	Yr 16 FY33	Yr 17 FY34	Yr 18 FY35	Yr 19 FY36
	Capital Expenditures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
+	Opex Sub-total	$ 64,119	$ 65,401	$ 66,710	$ 68,044	$ 69,405	$ 70,793	$ 72,209	$ 73,653	$ 75,126
=	**Total Program Administrator Costs**	**$ 64,119**	**$ 65,401**	**$ 66,710**	**$ 68,044**	**$ 69,405**	**$ 70,793**	**$ 72,209**	**$ 73,653**	**$ 75,126**

Detailed build-up of VVO/CVR AMI costs

VVO/CVR AMI- Costs

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	RI Cost Description / Calculations	Yr 20 FY37	Yr 21 FY 38	Yr 22 FY 39	Yr 23 FY 40	Yr 24 FY 41	Yr 25 FY 42	Yr 26 FY 43	Yr 27 FY 44	Yr 28 FY 45	Yr 29 FY 46	Yr 30 FY 47	Nominal Value	NPV
	Capital Expenditures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,231,508	$ 1,145,589
+	Opex Sub-total	$ 76,628	$ 78,161	$ 79,724	$ 81,319	$ 82,945	$ 84,604	$ 86,296	$ -	$ -	$ -	$ -	$ 1,925,257	$ 855,653
=	**Total Program Administrator Costs**	**$ 76,628**	**$ 78,161**	**$ 79,724**	**$ 81,319**	**$ 82,945**	**$ 84,604**	**$ 86,296**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,156,765**	**$ 2,001,242**

VVO/CVR AMI control panel, inputs, and sub-models

VVO/CVR AMI - Inputs

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Control Panel - VVO/AMI Scenario

Scenario Selection

System Type	Type	# of Systems	2018	2019	2020	2021	2022	Check
VVO Only	VVO	0	0					Match
VVO and AMI	VVO+AMI	1	1					Match
AMI Incremental	AMI	0	0					Match
	Total	1	1	0	0	0	0	

System Specifications

Category	Expected MW reduction	Lifecycle Capital Cost	System Count	OPEX	Annual Operating Expense	Useful Life	Annual Energy (GWhrs)	MWhrs
VVO Only	1.59	1,231,508	0	206,767	52,600	25	7.02	7020
VVO and AMI	2.11	7,256,024	1	1,091,767	179,552	25	9.36	9360
AMI Incremental	0.52	6,024,516	0	885,000	126,952	25	2.34	2340
Total			1.00	2,183,534.21		N/A		

System Installation Schedule

CAPEX	2017	2018	2019	2020	2021	2022	2023	2024	2025
VVO Only	-	-	-	-	-	-			
VVO and AMI	-	1.00	-	-	-	-			
AMI Incremental	-	-	-	-	-	-			
Total	-	1.00	-	-	-	-	-	-	-

OPEX	2017	2018	2019	2020	2021	2022	2023	2024	2025
VVO Only	-	-	-	-	-	-	-	-	-
VVO and AMI	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
AMI Incremental	-	-	-	-	-	-	-	-	-
Total	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Lag from Install to Receive Operating Benefit 1.00

Annual Operating Expense	2017	2018	2019	2020	2021	2022	2023	2024	2025
VVO Only	-	-	-	-	-	-	-	-	-
VVO and AMI	-	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00
AMI Incremental	-	-	-	-	-	-	-	-	-
Total	-	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Cost Schedule

Expense	2018	2019	2020	2021	2022	2023	2024	2025
Capital Expenditure	7,256,024.18	-	-	-	-	-	-	-
OPEX	1,091,767.10	-	-	-	-	-	-	-
Operating Expenditures	-	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00
Opex Sub-total	1,091,767.10	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00

Annual Avoided Capacity Savings

Benefit does not start until system is operating post lag time

	2018	2019	2020	2021	2022	2023	2024	2025	2026
Electric Capacity	-	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11

Annual Energy Displaced

Source for each system: MWhrs

Annual Energy Displaced	2018	2019	2020	2021	2022	2023	2024	2025	2026
VVO Only		-	-	-	-	-	-	-	-
VVO and AMI		9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00
AMI Incremental		-	-	-	-	-	-	-	-
Total	-	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00

Annual Avoided Energy Savings

	2018	2019	2020	2021	2022	2023	2024	2025	2026
	$ 38.77	$ 44.28	$ 50.14	$ 55.99	$ 58.77	$ 64.41	$ 68.96	$ 73.55	$ 75.38
Annual Energy Savings									
VVO Only	-	-	-	-	-	-	-	-	-
VVO and AMI	-	414,468.90	469,283.14	524,049.37	550,104.63	602,852.14	645,489.84	688,468.11	705,602.44
AMI Incremental	-	-	-	-	-	-	-	-	-
Total	-	414,468.90	469,283.14	524,049.37	550,104.63	602,852.14	645,489.84	688,468.11	705,602.44

CVR - Avoided Energy Cost

CVR - Avoided Energy Cost (pre-inflation)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter On-Peak	0.04	0.04655	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07
Winter Off-Peak	0.04	0.04066	0.04	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06
Summer On-Peak	0.03	0.03388	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.06	0.06
Summer Off-Peak	0.02	0.02687	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	0.05

MRP	1.09
Inflation	2%
Convert to MW	1,000.00

CVR - Avoided Energy Cost (post inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter On-Peak	47.75	52.79	58.88	65.57	68.50	74.52	79.33	83.60	85.16	88.19	91.72
Winter Off-Peak	41.00	46.11	50.15	56.47	58.90	64.07	68.21	72.53	73.75	76.36	79.49
Summer On-Peak	31.91	38.42	48.61	53.03	56.26	62.11	66.45	73.33	76.75	79.01	85.82
Summer Off-Peak	24.22	30.47	35.61	40.29	43.12	48.78	53.91	57.55	59.63	61.77	65.93

VVO/CVR AMI control panel, inputs, and sub-

VVO/CVR AMI - Inputs

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Control Panel - VVO/AMI Scenario

Scenario Selection

System Type
VVO Only
VVO and AMI
AMI Incremental

System Specifications

Category
VVO Only
VVO and AMI
AMI Incremental
Total

System Installation Schedule

CAPEX	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
VVO Only																	
VVO and AMI																	
AMI Incremental																	
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

OPEX	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
VVO Only	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VVO and AMI	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
AMI Incremental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Lag from Install to Receive Operating Bene

Annual Operating Expense	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
VVO Only	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VVO and AMI	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
AMI Incremental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Cost Schedule

Expense	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Capital Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPEX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenditures	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00
Opex Sub-total	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00	179,552.00

Annual Avoided Capacity Savings

Benefit does not start until system is oper

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Electric Capacity	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11

Annual Energy Displaced

Source for each system:

Annual Energy Displaced	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
VVO Only	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VVO and AMI	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00
AMI Incremental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**	**9,360.00**

Annual Avoided Energy Savings

	$ 77.99	$ 82.01	$ 86.09	$ 90.35	$ 94.44	$ 98.82	$ 103.41	$ 108.22	$ 113.27	$ 118.57	$ 124.12	$ 129.95	$ 136.07	$ 142.48	$ 149.21	$ 156.28	$ 163.70
Annual Energy Savings	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
VVO Only	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VVO and AMI	729,967.09	767,607.47	805,759.53	845,668.20	883,927.31	924,917.00	967,894.77	1,012,961.80	1,060,224.68	1,109,795.68	1,161,793.12	1,216,341.65	1,273,572.65	1,333,624.61	1,396,643.50	1,462,783.21	1,532,206.00
AMI Incremental	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**729,967.09**	**767,607.47**	**805,759.53**	**845,668.20**	**883,927.31**	**924,917.00**	**967,894.77**	**1,012,961.80**	**1,060,224.68**	**1,109,795.68**	**1,161,793.12**	**1,216,341.65**	**1,273,572.65**	**1,333,624.61**	**1,396,643.50**	**1,462,783.21**	**1,532,206.00**

CVR - Avoided Energy Cost

CVR - Avoided Energy Cost (pre-inflation)	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Winter On-Peak	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09
Winter Off-Peak	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.09
Summer On-Peak	0.07	0.07	0.07	0.08	0.08	0.08	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.12	0.12	0.13	0.14
Summer Off-Peak	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08

MRP
Inflation
Convert to MW

CVR - Avoided Energy Cost (post inflation)	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Winter On-Peak	95.66	99.75	102.31	106.13	110.09	114.21	118.47	122.90	127.49	132.26	137.20	142.32	147.64	153.16	158.88	164.81	170.97
Winter Off-Peak	83.40	88.16	91.28	95.26	99.41	103.74	108.26	112.97	117.90	123.03	128.39	133.98	139.82	145.91	152.27	158.90	165.83
Summer On-Peak	91.14	95.57	105.43	112.34	119.70	127.55	135.91	144.82	154.31	164.43	175.21	186.70	198.93	211.98	225.87	240.68	256.46
Summer Off-Peak	69.46	72.91	76.45	80.34	84.44	88.74	93.26	98.01	103.01	108.26	113.77	119.57	125.66	132.06	138.79	145.86	153.30

VVO/CVR AMI - Inputs

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Control Panel - VVO/AMI Scenario

Scenario Selection

System Type
VVO Only
VVO and AMI
AMI Incremental

System Specifications

Category
VVO Only
VVO and AMI
AMI Incremental
Total

System Installation Schedule

CAPEX	2043	2044	2045	2046	2047
VVO Only					
VVO and AMI					
AMI Incremental					
Total	-	-	-	-	-

OPEX	2043	2044	2045	2046	2047
VVO Only	-	-	-	-	-
VVO and AMI	1.00	-	-	-	-
AMI Incremental	-	-	-	-	-
Total	1.00	-	-	-	-

Lag from Install to Receive Operating Bene

Annual Operating Expense	2043	2044	2045	2046	2047
VVO Only	-	-	-	-	-
VVO and AMI	1.00	-	-	-	-
AMI Incremental	-	-	-	-	-
Total	1.00	-	-	-	-

Cost Schedule

Expense	2043	2044	2045	2046	2047
Capital Expenditure	-	-	-	-	-
OPEX	-	-	-	-	-
Operating Expenditures	179,552.00	-	-	-	-
Opex Sub-total	179,552.00	-	-	-	-

Annual Avoided Capacity Savings

Benefit does not start until system is opera

	2044	2045	2046	2047
Electric Capacity	-	-	-	-

Annual Energy Displaced

Source for each system:

Annual Energy Displaced	2044	2045	2046	2047
VVO Only				
VVO and AMI				
AMI Incremental				
Total	-	-	-	-

Annual Avoided Energy Savings

	$ 171.48	$ 179.66	$ 188.24	$ 197.25
Annual Energy Savings	**2044**	**2045**	**2046**	**2047**
VVO Only				
VVO and AMI				
AMI Incremental				
Total	-	-	-	-

CVR - Avoided Energy Cost

CVR - Avoided Energy Cost (pre-inflation)	2046	2047
Winter On-Peak	0.09	0.0932
Winter Off-Peak	0.09	0.0915
Summer On-Peak	0.14	0.1475
Summer Off-Peak	0.08	0.0858
MRP		
Inflation		
Convert to MW		

CVR - Avoided Energy Cost (post inflation)

	2046	2047
Winter On-Peak	177.36	183.99
Winter Off-Peak	173.05	180.59
Summer On-Peak	273.27	291.18
Summer Off-Peak	161.11	169.32

Detailed build-up of VVO/CVR AMI benefits

VVO/CVR AMI - Benefits

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	RI Benefit Description / Calculations	Unit	SCT	UTC	RIM	Source	Yr 1 FY18	Yr 2 FY19	Yr 3 FY20	Yr 4 FY21	Yr 5 FY22	Yr 6 FY23	Yr 7 FY24	Yr 8 FY25	Yr 9 FY26	Yr 10 FY27	Yr 11 FY28	Yr 12 FY29	Yr 13 FY30	Yr 14 FY31	Yr 15 FY32	Yr 16 FY33
	Forward Commitment: Capacity Value																					
	Nameplate Capacity	MW					-	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11
/	1 - Losses	%				AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Adjusted Peak Load	MW					-	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
x	Avoided Unit Cost of Electric Capacity	$/MW				AESC 2015 Update - Appendix B	-	-	-	-	151,748.25	145,443.49	154,497.40	173,684.98	193,938.75	214,296.15	235,794.87	259,373.47	290,550.94	308,169.87	314,333.27	320,619.93
=	**Benefit from Forward Commitment: Capacity Value**	**$**	**x**	**x**	**x**		**$ -**	**$ -**	**$ -**	**$ -**	**$ 348,031**	**$ 333,571**	**$ 354,336**	**$ 398,343**	**$ 444,794**	**$ 491,484**	**$ 540,790**	**$ 594,867**	**$ 666,372**	**$ 706,781**	**$ 720,917**	**$ 735,335**
	Energy Reduction from System																					
+	VVO Only	$				Calculated	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
+	VVO and AMI	$				Calculated	$ -	$ 414,469	$ 469,283	$ 524,049	$ 550,105	$ 602,852	$ 645,490	$ 688,468	$ 705,602	$ 729,967	$ 767,607	$ 805,760	$ 845,668	$ 883,927	$ 924,917	$ 967,895
+	AMI Incremental	$				Calculated	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
=	**Total Energy Savings**	**$**	**x**	**x**	**x**		**$ -**	**$ 414,469**	**$ 469,283**	**$ 524,049**	**$ 550,105**	**$ 602,852**	**$ 645,490**	**$ 688,468**	**$ 705,602**	**$ 729,967**	**$ 767,607**	**$ 805,760**	**$ 845,668**	**$ 883,927**	**$ 924,917**	**$ 967,895**
	Wholesale Market Price Impact	DRIPE																				
	Total Energy Reduction from VVO System	MW					-	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00
x	DRIPE (Energy + Cross-fuel Capacity)	$ / MWh				2015 AESC. Appendix B	1.39	0.91	0.91	0.19	0.19	0.19	0.20	0.20	0.20	0.21	0.21	0.21	0.22	0.22	0.23	0.23
=	**Wholesale Market Price Impact**	**$**		**x**	**x**		**$ -**	**$ 8,563**	**$ 8,555**	**$ 1,761**	**$ 1,791**	**$ 1,821**	**$ 1,850**	**$ 1,880**	**$ 1,910**	**$ 1,940**	**$ 1,972**	**$ 2,004**	**$ 2,036**	**$ 2,077**	**$ 2,118**	**$ 2,160**
	Greenhouse Gas (GHG) Externality Costs																					
	Total Energy Savings	MWh					-	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00
x	Non-Embedded CO2 Cost	$ / MWh				2015 AESC. Exhibit 4-7	48.03	48.54	49.05	48.71	48.33	47.92	47.47	46.99	46.47	45.91	45.30	44.66	43.97	54.23	55.31	56.41
=	**Benefit from Reduced Greenhouse Gas Externality Costs**	**$**	**x**				**$ -**	**$ 454,332**	**$ 459,126**	**$ 455,902**	**$ 452,366**	**$ 448,505**	**$ 444,365**	**$ 439,824**	**$ 434,923**	**$ 429,709**	**$ 424,052**	**$ 417,997**	**$ 411,531**	**$ 507,635**	**$ 517,723**	**$ 528,012**

Detailed build-up of VVO/CVR AMI benefits

VVO/CVR AMI - Benefits

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	RI Benefit Description / Calculations	Yr 17 FY34	Yr 18 FY35	Yr 19 FY36	Yr 20 FY37	Yr 21 FY 38	Yr 22 FY 39	Yr 23 FY 40	Yr 24 FY 41	Yr 25 FY 42	Yr 26 FY 43	Yr 27 FY 44	Yr 28 FY 45	Yr 29 FY 46	Yr 30 FY 47	Nominal Value	NPV
	Forward Commitment: Capacity Value																
	Nameplate Capacity	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	-	-	-	-		
/	1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%		
=	Adjusted Peak Load	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	-	-	-	-		
x	Avoided Unit Cost of Electric Capacity	327,032.33	333,572.98	340,244.44	347,049.33	353,990.31	361,070.12	368,291.52	375,657.35	383,170.50	390,833.91	398,650.59	406,623.60	414,756.07	423,051.19		
=	**Benefit from Forward Commitment: Capacity Value**	**$ 750,042**	**$ 765,042**	**$ 780,343**	**$ 795,950**	**$ 811,869**	**$ 828,106**	**$ 844,669**	**$ 861,562**	**$ 878,793**	**$ 896,369**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 14,548,368**	**$ 4,603,260**
	Energy Reduction from System																
+	VVO Only	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
+	VVO and AMI	$ 1,012,962	$ 1,060,225	$ 1,109,796	$ 1,161,793	$ 1,216,342	$ 1,273,573	$ 1,333,625	$ 1,396,644	$ 1,462,783	$ 1,532,206	$ -	$ -	$ -	$ -		
+	AMI Incremental	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
=	**Total Energy Savings**	**$ 1,012,962**	**$ 1,060,225**	**$ 1,109,796**	**$ 1,161,793**	**$ 1,216,342**	**$ 1,273,573**	**$ 1,333,625**	**$ 1,396,644**	**$ 1,462,783**	**$ 1,532,206**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 23,086,007**	**$ 7,990,336**
	Wholesale Market Price Impact																
	Total Energy Reduction from VVO System	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	-	-	-	-		
x	DRIPE (Energy + Cross-fuel Capacity)	0.24	0.24	0.24	0.25	0.25	0.26	0.27	0.27	0.28	0.28	0.29	0.29	0.30	0.30		
=	**Wholesale Market Price Impact**	**$ 2,204**	**$ 2,248**	**$ 2,293**	**$ 2,339**	**$ 2,385**	**$ 2,433**	**$ 2,482**	**$ 2,531**	**$ 2,582**	**$ 2,634**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 66,565**	**$ 31,970**
	Greenhouse Gas (GHG) Externality Costs																
	Total Energy Savings	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	9,360.00	-	-	-	-		
x	Non-Embedded CO2 Cost	57.53	58.68	59.84	61.03	62.24	63.48	64.74	66.03	67.34	68.68	70.05	71.44	72.86	74.30		
=	**Benefit from Reduced Greenhouse Gas Externality Costs**	**$ 538,506**	**$ 549,208**	**$ 560,123**	**$ 571,254**	**$ 582,607**	**$ 594,185**	**$ 605,994**	**$ 618,037**	**$ 630,320**	**$ 642,846**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 12,719,080**	**$ 4,969,591**

Total

Detailed build-up of VVO/CVR AMI costs

VVO/CVR AMI- Costs

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	RI Cost Description / Calculations	Unit	SCT	UTC	RIM	Source	Yr 1 FY18	Yr 2 FY19	Yr 3 FY20	Yr 4 FY21	Yr 5 FY22	Yr 6 FY23	Yr 7 FY24	Yr 8 FY25
	Capital Expenditures	$					$ 7,256,024	$ -	$ -	$ -	$ -	$ -	$ -	$ -
+	Opex Sub-total	$					$ 1,091,767	$ 183,143	$ 186,806	$ 190,542	$ 194,353	$ 198,240	$ 202,205	$ 206,249
=	**Total Program Administrator Costs**	**$**	**x**	**x**	**x**		**$ 8,347,791**	**$ 183,143**	**$ 186,806**	**$ 190,542**	**$ 194,353**	**$ 198,240**	**$ 202,205**	**$ 206,249**

	RI Cost Description / Calculations	Yr 9 FY26	Yr 10 FY27	Yr 11 FY28	Yr 12 FY29	Yr 13 FY30	Yr 14 FY31	Yr 15 FY32	Yr 16 FY33
	Capital Expenditures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
+	Opex Sub-total	$ 210,374	$ 214,581	$ 218,873	$ 223,250	$ 227,715	$ 232,270	$ 236,915	$ 241,653
=	**Total Program Administrator Costs**	**$ 210,374**	**$ 214,581**	**$ 218,873**	**$ 223,250**	**$ 227,715**	**$ 232,270**	**$ 236,915**	**$ 241,653**

Detailed build-up of VVO/CVR AMI costs

VVO/CVR AMI- Costs

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	RI Cost Description / Calculations	Yr 17 FY34	Yr 18 FY35	Yr 19 FY36	Yr 20 FY37	Yr 21 FY 38	Yr 22 FY 39	Yr 23 FY 40	Yr 24 FY 41	Yr 25 FY 42	Yr 26 FY 43	Yr 27 FY 44	Yr 28 FY 45	Yr 29 FY 46	Yr 30 FY 47	Nominal Value	NPV
	Capital Expenditures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,256,024	$ 6,749,790
+	Opex Sub-total	$ 246,486	$ 251,416	$ 256,444	$ 261,573	$ 266,805	$ 272,141	$ 277,584	$ 283,135	$ 288,798	$ 294,574	$ -	$ -	$ -	$ -	$ 6,957,894	$ 3,279,834
=	**Total Program Administrator Costs**	**$ 246,486**	**$ 251,416**	**$ 256,444**	**$ 261,573**	**$ 266,805**	**$ 272,141**	**$ 277,584**	**$ 283,135**	**$ 288,798**	**$ 294,574**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 14,213,918**	**$ 10,029,624**

##
VVO/CVR AMI control panel, inputs, and sub-models

VVO/CVR AMI - Inputs

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Control Panel - VVO/AMI Scenario

Scenario Selection

System Type	Type	# of Systems	2018	2019	2020	2021	2022	Check
VVO Only	VVO	0	0					Match
VVO and AMI	VVO+AMI	0	0					Match
AMI Incremental	AMI	1	1					Match
	Total	**1**	**1**	**0**	**0**	**0**	**0**	

System Specifications

Category	Expected MW reduction	Lifecycle Capital Cost	System Count	OPEX	Annual Operating Expense	Useful Life	Annual Energy (GWhrs)	MWhrs
VVO Only	1.59	1,231,508	0	206,767	52,600	25	7.02	7020
VVO and AMI	2.11	7,256,024	0	1,091,767	179,552	25	9.36	9360
AMI Incremental	0.52	6,024,516	1	885,000	126,952	25	2.34	2340
Total			**1.00**	**2,183,534.21**		**N/A**		

System Installation Schedule

CAPEX	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
VVO Only	-	-	-	-	-	-								
VVO and AMI	-	-	-	-	-	-								
AMI Incremental	-	1.00	-	-	-	-								
Total	-	1.00	-	-	-	-	-	-	-	-	-	-	-	-

OPEX	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
VVO Only	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Incremental	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Total	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Lag from Install to Receive Operating Benefit **1.00**

Annual Operating Expense	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
VVO Only	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Incremental	-	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Total	-	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Cost Schedule

Expense	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital Expenditure	6,024,516.00	-	-	-	-	-	-	-	-	-	-	-	-
OPEX	885,000.00	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenditures	-	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00
Opex Sub-total	885,000.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00

Annual Avoided Capacity Savings

Benefit does not start until system is operating post lag time

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Electric Capacity	-	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52

Annual Energy Displaced

Source for each system: MWhrs

Annual Energy Displaced	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
VVO Only		-	-	-	-	-	-	-	-	-	-	-	-	-
VVO and AMI		-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Incremental		2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00
Total	**-**	**2,340.00**	**2,340.00**	**2,340.00**	**2,340.00**	**2,340.00**	**2,340.00**	**2,340.00**	**2,340.00**	**2,340.00**	**2,340.00**	**2,340.00**	**2,340.00**	**2,340.00**

Annual Avoided Energy Savings

	$ 38.77	$ 44.28	$ 50.14	$ 55.99	$ 58.77	$ 64.41	$ 68.96	$ 73.55	$ 75.38	$ 77.99	$ 82.01	$ 86.09	$ 90.35	$ 94.44
Annual Energy Savings	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
VVO Only	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Incremental	-	103,617.23	117,320.78	131,012.34	137,526.16	150,713.04	161,372.46	172,117.03	176,400.61	182,491.77	191,901.87	201,439.88	211,417.05	220,981.83
Total	**-**	**103,617.23**	**117,320.78**	**131,012.34**	**137,526.16**	**150,713.04**	**161,372.46**	**172,117.03**	**176,400.61**	**182,491.77**	**191,901.87**	**201,439.88**	**211,417.05**	**220,981.83**

CVR - Avoided Energy Cost

CVR - Avoided Energy Cost (pre-inflation)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter On-Peak	0.04	0.04655	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Winter Off-Peak	0.04	0.04066	0.04	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.07
Summer On-Peak	0.03	0.03388	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.08	0.08
Summer Off-Peak	0.02	0.02687	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06

MRP	1.09
Inflation	2%
Convert to MW	1,000.00

CVR - Avoided Energy Cost (post inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter On-Peak	47.75	52.79	58.88	65.57	68.50	74.52	79.33	83.60	85.16	88.19	91.72	95.66	99.75	102.31	106.13	110.09
Winter Off-Peak	41.00	46.11	50.15	56.47	58.90	64.07	68.21	72.53	73.75	76.36	79.49	83.40	88.16	91.28	95.26	99.41
Summer On-Peak	31.91	38.42	48.61	53.03	56.26	62.11	66.45	73.33	76.75	79.01	85.82	91.14	95.57	105.43	112.34	119.70
Summer Off-Peak	24.22	30.47	35.61	40.29	43.12	48.78	53.91	57.55	59.63	61.77	65.93	69.46	72.91	76.45	80.34	84.44

##
VVO/CVR AMI control panel, inputs, and sub-m

VVO/CVR AMI - Inputs

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Control Panel - VVO/AMI Scenario

Scenario Selection

System Type
VVO Only
VVO and AMI
AMI Incremental

System Specifications

Category
VVO Only
VVO and AMI
AMI Incremental
Total

System Installation Schedule

CAPEX	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
VVO Only																	
VVO and AMI																	
AMI Incremental																	
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

OPEX	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
VVO Only	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Incremental	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	-	-	-	-
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	-	-	-	-

Lag from Install to Receive Operating Bene

Annual Operating Expense	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
VVO Only	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Incremental	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	-	-	-	-
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	-	-	-	-

Cost Schedule

Expense	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Capital Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPEX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenditures	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	-	-	-	-
Opex Sub-total	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	126,952.00	-	-	-	-

Annual Avoided Capacity Savings

Benefit does not start until system is opera

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Electric Capacity	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	-	-	-	-

Annual Energy Displaced

Source for each system:

Annual Energy Displaced	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
VVO Only	-	-	-	-	-	-	-	-	-	-	-	-				
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-	-				
AMI Incremental	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00				
Total	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	-	-	-	-

Annual Avoided Energy Savings

	$ 98.82	$ 103.41	$ 108.22	$ 113.27	$ 118.57	$ 124.12	$ 129.95	$ 136.07	$ 142.48	$ 149.21	$ 156.28	$ 163.70	$ 171.48	$ 179.66	$ 188.24	$ 197.25
Annual Energy Savings	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
VVO Only	-	-	-	-	-	-	-	-	-	-	-	-				
VVO and AMI	-	-	-	-	-	-	-	-	-	-	-	-				
AMI Incremental	231,229.25	241,973.69	253,240.45	265,056.17	277,448.92	290,448.28	304,085.41	318,393.16	333,406.15	349,160.88	365,695.80	383,051.50				
Total	231,229.25	241,973.69	253,240.45	265,056.17	277,448.92	290,448.28	304,085.41	318,393.16	333,406.15	349,160.88	365,695.80	383,051.50	-	-	-	-

CVR - Avoided Energy Cost

CVR - Avoided Energy Cost (pre-inflation)	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Winter On-Peak	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.0932
Winter Off-Peak	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.0915
Summer On-Peak	0.08	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.12	0.12	0.13	0.14	0.14	0.1475
Summer Off-Peak	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.0858

MRP
Inflation
Convert to MW

CVR - Avoided Energy Cost (post inflation)

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Winter On-Peak	114.21	118.47	122.90	127.49	132.26	137.20	142.32	147.64	153.16	158.88	164.81	170.97	177.36	183.99
Winter Off-Peak	103.74	108.26	112.97	117.90	123.03	128.39	133.98	139.82	145.91	152.27	158.90	165.83	173.05	180.59
Summer On-Peak	127.55	135.91	144.82	154.31	164.43	175.21	186.70	198.93	211.98	225.87	240.68	256.46	273.27	291.18
Summer Off-Peak	88.74	93.26	98.01	103.01	108.26	113.77	119.57	125.66	132.06	138.79	145.86	153.30	161.11	169.32

Detailed build-up of VVO/CVR AMI benefits

VVO/CVR AMI - Benefits

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	RI Benefit Description / Calculations	Unit	SCT	UTC	RIM	Source	Yr 1 FY18	Yr 2 FY19	Yr 3 FY20	Yr 4 FY21	Yr 5 FY22	Yr 6 FY23	Yr 7 FY24	Yr 8 FY25	Yr 9 FY26	Yr 10 FY27	Yr 11 FY28	Yr 12 FY29	Yr 13 FY30	Yr 14 FY31	Yr 15 FY32	Yr 16 FY33
	Forward Commitment: Capacity Value																					
	Nameplate Capacity	MW					-	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
/	1 - Losses	%				AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Adjusted Peak Load	MW					-	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
x	Avoided Unit Cost of Electric Capacity	$/MW				AESC 2015 Update - Appendix B	-	-	-	-	151,748.25	145,443.49	154,497.40	173,684.98	193,938.75	214,296.15	235,794.87	259,373.47	290,550.94	308,169.87	314,333.27	320,619.93
=	**Benefit from Forward Commitment: Capacity Value**	**$**	**x**	**x**	**x**		**$ -**	**$ -**	**$ -**	**$ -**	**$ 85,771**	**$ 82,207**	**$ 87,325**	**$ 98,170**	**$ 109,618**	**$ 121,124**	**$ 133,275**	**$ 146,602**	**$ 164,224**	**$ 174,183**	**$ 177,667**	**$ 181,220**
	Energy Reduction from System																					
+	VVO Only	$				Calculated	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
+	VVO and AMI	$				Calculated	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
+	AMI Incremental	$				Calculated	$ -	$ 103,617	$ 117,321	$ 131,012	$ 137,526	$ 150,713	$ 161,372	$ 172,117	$ 176,401	$ 182,492	$ 191,902	$ 201,440	$ 211,417	$ 220,982	$ 231,229	$ 241,974
=	**Total Energy Savings**	**$**	**x**	**x**	**x**		**$ -**	**$ 103,617**	**$ 117,321**	**$ 131,012**	**$ 137,526**	**$ 150,713**	**$ 161,372**	**$ 172,117**	**$ 176,401**	**$ 182,492**	**$ 191,902**	**$ 201,440**	**$ 211,417**	**$ 220,982**	**$ 231,229**	**$ 241,974**
	Wholesale Market Price Impact	DRIPE																				
	Total Energy Reduction from VVO System	MW					-	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00
x	DRIPE (Energy + Cross-fuel Capacity)	$ / MWh				2015 AESC. Appendix B	1.39	0.91	0.91	0.19	0.19	0.19	0.20	0.20	0.20	0.21	0.21	0.21	0.22	0.22	0.23	0.23
=	**Wholesale Market Price Impact**	**$**		**x**	**x**		**$ -**	**$ 2,141**	**$ 2,139**	**$ 440**	**$ 448**	**$ 455**	**$ 462**	**$ 470**	**$ 477**	**$ 485**	**$ 493**	**$ 501**	**$ 509**	**$ 519**	**$ 530**	**$ 540**
	Greenhouse Gas (GHG) Externality Costs																					
	Total Energy Savings	MWh					-	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00
x	Non-Embedded CO2 Cost	$ / MWh				2015 AESC. Exhibit 4-7	48.03	48.54	49.05	48.71	48.33	47.92	47.47	46.99	46.47	45.91	45.30	44.66	43.97	54.23	55.31	56.41
=	**Benefit from Reduced Greenhouse Gas Externality Costs**	**$**	**x**				**$ -**	**$ 113,583**	**$ 114,781**	**$ 113,975**	**$ 113,091**	**$ 112,126**	**$ 111,091**	**$ 109,956**	**$ 108,731**	**$ 107,427**	**$ 106,013**	**$ 104,499**	**$ 102,883**	**$ 126,909**	**$ 129,431**	**$ 132,003**

Detailed build-up of VVO/CVR AMI benefits

VVO/CVR AMI - Benefits

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	RI Benefit Description / Calculations	Yr 17 FY34	Yr 18 FY35	Yr 19 FY36	Yr 20 FY37	Yr 21 FY 38	Yr 22 FY 39	Yr 23 FY 40	Yr 24 FY 41	Yr 25 FY 42	Yr 26 FY 43	Yr 27 FY 44	Yr 28 FY 45	Yr 29 FY 46	Yr 30 FY 47	Nominal Value	NPV
	Forward Commitment: Capacity Value																
	Nameplate Capacity	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	-	-	-	-		
/	1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%		
=	Adjusted Peak Load	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	-	-	-	-		
x	Avoided Unit Cost of Electric Capacity	327,032.33	333,572.98	340,244.44	347,049.33	353,990.31	361,070.12	368,291.52	375,657.35	383,170.50	390,833.91	398,650.59	406,623.60	414,756.07	423,051.19		
=	**Benefit from Forward Commitment: Capacity Value**	**$ 184,844**	**$ 188,541**	**$ 192,312**	**$ 196,158**	**$ 200,081**	**$ 204,083**	**$ 208,165**	**$ 212,328**	**$ 216,575**	**$ 220,906**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,585,380**	**$ 1,134,453**
	Energy Reduction from System																
+	VVO Only	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
+	VVO and AMI	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
+	AMI Incremental	$ 253,240	$ 265,056	$ 277,449	$ 290,448	$ 304,085	$ 318,393	$ 333,406	$ 349,161	$ 365,696	$ 383,051	$ -	$ -	$ -	$ -		
=	**Total Energy Savings**	**$ 253,240**	**$ 265,056**	**$ 277,449**	**$ 290,448**	**$ 304,085**	**$ 318,393**	**$ 333,406**	**$ 349,161**	**$ 365,696**	**$ 383,051**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5,771,502**	**$ 1,997,584**
	Wholesale Market Price Impact																
	Total Energy Reduction from VVO System	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	-	-	-	-		
x	DRIPE (Energy + Cross-fuel Capacity)	0.24	0.24	0.24	0.25	0.25	0.26	0.27	0.27	0.28	0.28	0.29	0.29	0.30	0.30		
=	**Wholesale Market Price Impact**	**$ 551**	**$ 562**	**$ 573**	**$ 585**	**$ 596**	**$ 608**	**$ 620**	**$ 633**	**$ 645**	**$ 658**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 16,641**	**$ 7,993**
	Greenhouse Gas (GHG) Externality Costs																
	Total Energy Savings	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	2,340.00	-	-	-	-		
x	Non-Embedded CO2 Cost	57.53	58.68	59.84	61.03	62.24	63.48	64.74	66.03	67.34	68.68	70.05	71.44	72.86	74.30		
=	**Benefit from Reduced Greenhouse Gas Externality Costs**	**$ 134,626**	**$ 137,302**	**$ 140,031**	**$ 142,814**	**$ 145,652**	**$ 148,546**	**$ 151,498**	**$ 154,509**	**$ 157,580**	**$ 160,712**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 3,179,770**	**$ 1,242,398**

Total

Detailed build-up of VVO/CVR AMI costs

VVO/CVR AMI- Costs

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	RI Cost Description / Calculations	Unit	SCT	UTC	RIM	Source	Yr 1 FY18	Yr 2 FY19	Yr 3 FY20	Yr 4 FY21	Yr 5 FY22	Yr 6 FY23	Yr 7 FY24	Yr 8 FY25
	Capital Expenditures	$					$ 6,024,516	$ -	$ -	$ -	$ -	$ -	$ -	$ -
+	Opex Sub-total (Lease + Operating Expenses)	$					$ 885,000	$ 129,491	$ 132,081	$ 134,722	$ 137,417	$ 140,165	$ 142,969	$ 145,828
=	**Total Program Administrator Costs**	**$**	**x**	**x**	**x**		**$ 6,909,516**	**$ 129,491**	**$ 132,081**	**$ 134,722**	**$ 137,417**	**$ 140,165**	**$ 142,969**	**$ 145,828**

	RI Cost Description / Calculations	Yr 9 FY26	Yr 10 FY27	Yr 11 FY28	Yr 12 FY29	Yr 13 FY30	Yr 14 FY31	Yr 15 FY32	Yr 16 FY33
	Capital Expenditures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
+	Opex Sub-total (Lease + Operating Expenses)	$ 148,745	$ 151,719	$ 154,754	$ 157,849	$ 161,006	$ 164,226	$ 167,510	$ 170,861
=	**Total Program Administrator Costs**	**$ 148,745**	**$ 151,719**	**$ 154,754**	**$ 157,849**	**$ 161,006**	**$ 164,226**	**$ 167,510**	**$ 170,861**

Detailed build-up of VVO/CVR AMI costs

VVO/CVR AMI- Costs

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	RI Cost Description / Calculations	Yr 17 FY34	Yr 18 FY35	Yr 19 FY36	Yr 20 FY37	Yr 21 FY 38	Yr 22 FY 39	Yr 23 FY 40	Yr 24 FY 41	Yr 25 FY 42	Yr 26 FY 43	Yr 27 FY 44	Yr 28 FY 45	Yr 29 FY 46	Yr 30 FY 47	Nominal Value	NPV
	Capital Expenditures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,024,516	$ 5,604,201
+	Opex Sub-total (Lease + Operating Expenses)	$ 174,278	$ 177,763	$ 181,319	$ 184,945	$ 188,644	$ 192,417	$ 196,265	$ 200,191	$ 204,194	$ 208,278	$ -	$ -	$ -	$ -	$ 5,032,637	$ 2,424,181
=	**Total Program Administrator Costs**	**$ 174,278**	**$ 177,763**	**$ 181,319**	**$ 184,945**	**$ 188,644**	**$ 192,417**	**$ 196,265**	**$ 200,191**	**$ 204,194**	**$ 208,278**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 11,057,153**	**$ 8,028,382**

General assumptions applied to investment categories

Inputs - General

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General Assumptions

Assumption	Value	Unit	Source
Line Losses	8.0%	%	AESC 2015, p. 286. ISO Distribution Losses.
Wholesale Risk Premium (WRP)	9.0%	%	AESC 2015. Appendix B
Distribution Losses	8.0%	%	AESC 2015. Appendix B
Real Discount Rate	1.4%	%	AESC 2015. Appendix B
Percent of Capacity Bid into FCM (%Bid)	75.0%	%	AESC 2015. Appendix B
After-tax WACC	7.5%	%	See email from Josh Nowak
Inflation Rate	2.0%	%	

Emissions Assumptions

Assumption	Value	Unit	Source	Comments
CO2 Grid Emissions Factors	1029	lbs / MWh	http://www.neep.org/sites/default/files/Emission_F1	short ton = 1 US ton = 2,000 lbs
SO2 Grid Emissions Factor	0.17	lbs / MWh	http://www.neep.org/sites/default/files/Emission_F1	short ton = 1 US ton = 2,000 lbs
NOX Grid Emissions Factor	0.35	lbs / MWh	http://www.neep.org/sites/default/files/Emission_F1	short ton = 1 US ton = 2,000 lbs
NE-ISO Off-Peak LMU Marginal CO2 Emission rate	832	lbs / MWh	2015 ISO New England Electric Generator Air Emissions Report, Table 5.3, https://www.iso-ne.com/static-assets/docume	
NE-ISO On-Peak LMU Marginal CO2 Emission rate	891	lbs / MWh	2015 ISO New England Electric Generator Air Emissions Report, Table 5.3, https://www.iso-ne.com/static-assets/docume	

Unit Conversions

Assumption	Value	Unit	Source
Pounds to Tons conversion	0.0005	#	Standard value
kg to pounds conversion	2.2046		
kWh to MWh conversion	1000		

Time Assumptions

Assumption	Unit	Source	Comments	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
CO2 Abatement Cost	$ / short ton	2015 AESC. Exhibit 4-7	AESC duration terminated at 2030. Kept same value through 2042	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Embedded Cost in Electric Energy Market Prices	$ / short ton	2015 AESC. Exhibit 4-7	AESC duration terminated at 2030. Projected linear trend through 2042	8.47	9.32	10.16	12.54	14.92	17.30	19.67	22.05	24.43	26.80	29.18	31.56	33.94	20.11	20.12
Non-embedded CO2 Costs (pre-inflation)	$ / short ton	2015 AESC. Exhibit 4-7		91.53	90.68	89.84	87.46	85.08	82.70	80.33	77.95	75.57	73.20	70.82	68.44	66.06	79.89	79.88
Non-embedded CO2 Costs (post-inflation)	$ / short ton	2015 AESC. Exhibit 4-7		93.36	94.34	95.34	94.67	93.94	93.13	92.27	91.33	90.31	89.23	88.06	86.80	85.46	105.41	107.51
Non-embedded CO2 Costs (pre-inflation)	$ / MWh	Calculated		47.09	46.65	46.22	45.00	43.77	42.55	41.33	40.11	38.88	37.66	36.44	35.21	33.99	41.10	41.10
Non-embedded CO2 Costs (post-inflation)	$ / MWh	Calculated		48.03	48.54	49.05	48.71	48.33	47.92	47.47	46.99	46.47	45.91	45.30	44.66	43.97	54.23	55.31

Assumption	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
CO2 Abatement Cost	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Embedded Cost in Electric Energy Market Prices	20.13	20.14	20.15	20.16	20.17	20.18	20.19	20.20	20.21	20.22	20.23	20.24	20.25	20.26	20.27
Non-embedded CO2 Costs (pre-inflation)	79.87	79.86	79.85	79.84	79.83	79.82	79.81	79.80	79.79	79.78	79.77	79.76	79.75	79.74	79.73
Non-embedded CO2 Costs (post-inflation)	109.64	111.82	114.04	116.31	118.62	120.98	123.38	125.84	128.34	130.89	133.49	136.14	138.85	141.61	144.42
Non-embedded CO2 Costs (pre-inflation)	41.09	41.09	41.08	41.08	41.07	41.07	41.06	41.06	41.05	41.05	41.04	41.04	41.03	41.03	41.02
Non-embedded CO2 Costs (post-inflation)	56.41	57.53	58.68	59.84	61.03	62.24	63.48	64.74	66.03	67.34	68.68	70.05	71.44	72.86	74.30

SO2 & NOx Emissions Factors - non-electric fuels

Fuel	Physical Units						Conversion Factors		Short Tons/MMBTU			Source
	Reported Unit	SO2 Constant	S value	SO2		NOx	MMBTU	Short Tons	SO2	NOx	lbs/MMBTU	
Natural Gas	lb/million cuft	0.6		2000	0.6	94	1032	2000	2.90698E-07	4.55426E-05	0.000581395	EPA
Propane	lb/thousand gallons	0.1		0.54	0.054	13	91.333	2000	2.95622E-07	7.11681E-05	0.000591243	https://www3.
Fuel Oil	lb/thousand gallons	142		0.003	42.6	18	138.5	2000	0.000153791	6.49819E-05	0.307581227	https://www3.

SO2 and NOX - AESC 2015 Update

Source: AESC 2015 Exhibit 4.1. Emission Allowance Prices per Short Ton. AESC notes pulled from SNL Financial.

	NOX		SO2	
Year	2015$	2017$	2015$	2017$
2015	10	10	1.11	1.11
2016	10	10.2	1.11	1.1322
2017	10	10.404	1.11	1.154844
2018	10	10.61208	1.11	1.17794088
2019	10	10.8243216	1.11	1.201499698
2020	10	11.04080803	1.11	1.225529692
2021	10	11.26162419	1.11	1.250040285
2022	10	11.48685668	1.11	1.275041091
2023	10	11.71659381	1.11	1.300541913
2024	10	11.95092569	1.11	1.326552751
2025	10	12.1899442	1.11	1.353083806
2026	10	12.43374308	1.11	1.380145482
2027	10	12.68241795	1.11	1.407748392
2028	10	12.9360663	1.11	1.43590336
2029	10	13.19478763	1.11	1.464621427
2030	10	13.45868338	1.11	1.493913856
2031	10	13.72785705	1.11	1.523792133
2032	10	14.00241419	1.11	1.554267975
2033	10	14.28246248	1.11	1.585353335
2034	10	14.56811173	1.11	1.617060402
2035	10	14.85947396	1.11	1.64940161
2036	10	15.15666344	1.11	1.682389642
2037	10	15.45979671	1.11	1.716037435
2038	10	15.76899264	1.11	1.750358183
2039	10	16.08437249	1.11	1.785365347
2040	10	16.40605994	1.11	1.821072654
2041	10	16.73418114	1.11	1.857494107
2042	10	17.06886477	1.11	1.894643989
2043	10	17.41024206	1.11	1.932536869
2044	10	17.7584469	1.11	1.971187606
2045	10	18.11361584	1.11	2.010611358
2046	10	18.47588816	1.11	2.050823586
2047	10	18.84540592	1.11	2.091840057

NOX & SO2 Costs (pre-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
NOX Cost	10.61208	10.8243216	11.04080803	11.26162419	11.48685668	11.71659381	11.95092569	12.1899442	12.43374308	12.68241795	12.9360663	13.19478763	13.45868338	13.72785705	14.00241419
SO2 Cost	1.17794088	1.201499698	1.225529692	1.250040285	1.275041091	1.300541913	1.326552751	1.353083806	1.380145482	1.407748392	1.43590336	1.464621427	1.493913856	1.523792133	1.554267975

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
NOX Cost	14.28246248	14.56811173	14.85947396	15.15666344	15.45979671	15.76899264	16.08437249	16.40605994	16.73418114	17.06886477	17.41024206	17.7584469	18.11361584	18.47588816	18.8454059
SO2 Cost	1.585353335	1.617060402	1.64940161	1.682389642	1.716037435	1.750358183	1.785365347	1.821072654	1.857494107	1.894643989	1.932536869	1.971187606	2.010611358	2.050823586	2.09184006

NOX & SO2 Costs (post-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
NOX Cost	10.8243216	11.26162419	11.71659381	12.1899442	12.68241795	13.19478763	13.72785705	14.28246248	14.85947396	15.45979671	16.08437249	16.73418114	17.41024206	18.11361584	18.84540592
SO2 Cost	1.201499698	1.250040285	1.300541913	1.353083806	1.407748392	1.464621427	1.523792133	1.585353335	1.64940161	1.716037435	1.785365347	1.857494107	1.932536869	2.010611358	2.091840057

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
NOX Cost	19.60676032	20.39887344	21.22298792	22.08039664	22.97244466	23.90053142	24.86611289	25.87070385	26.91588029	28.00328185	29.13461444	30.31165286	31.53624364	32.81030788	34.1358443
SO2 Cost	2.176350396	2.264274952	2.35575166	2.450924027	2.549941357	2.652958988	2.760138531	2.871648128	2.987662712	3.108364286	3.233942203	3.364593468	3.500523044	3.641944175	3.78907872

Avoided Unit Cost of Electric Capacity

Source: AESC 2015 Update, Appendix B

Period	Unit	Value	Source
2018	$/kW-yr	0	AESC 2015 Update-Appendix B
2019	$/kW-yr	0	AESC 2015 Update-Appendix B
2020	$/kW-yr	0	AESC 2015 Update-Appendix B
2021	$/kW-yr	0	AESC 2015 Update-Appendix B
2022	$/kW-yr	137.4430625	AESC 2015 Update-Appendix B
2023	$/kW-yr	129.149657	AESC 2015 Update-Appendix B
2024	$/kW-yr	134.4992808	AESC 2015 Update-Appendix B
2025	$/kW-yr	148.2384617	AESC 2015 Update-Appendix B
2026	$/kW-yr	162.2792734	AESC 2015 Update-Appendix B
2027	$/kW-yr	175.7974832	AESC 2015 Update-Appendix B
2028	$/kW-yr	189.6410963	AESC 2015 Update-Appendix B
2029	$/kW-yr	204.5142091	AESC 2015 Update-Appendix B
2030	$/kW-yr	224.6053249	AESC 2015 Update-Appendix B
2031	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2032	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2033	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2034	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2035	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2036	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2037	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2038	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2039	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2040	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2041	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2042	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2043	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2044	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2045	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2046	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2047	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Avoided Capacity Cost (pre-	-	-	-	-	137.44	129.15	134.50	148.24	162.28	175.80	189.64	204.51	224.61	233.55	233.55
Inflation	2%														
Conversion to MW	1000														
Avoided Capacity Cost (post-	-	-	-	-	151,748.25	145,443.49	154,497.40	173,684.98	193,938.75	214,296.15	235,794.87	259,373.47	290,550.94	308,169.87	314,333.27

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Avoided Capacity Cost (pre-	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55
Avoided Capacity Cost (post-	320,619.93	327,032.33	333,572.98	340,244.44	347,049.33	353,990.31	361,070.12	368,291.52	375,657.35	383,170.50	390,833.91	398,650.59	406,623.60	414,756.07	423,051.19

Avoided Unit Cost of Energy

Source: AESC 2015 Update, Appendix B

Period	Units	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric Heat Weighted Avg.
2018	$/kWh	0.042948462	0.036876354	0.028704835	0.02178498	0.032578658
2019	$/kWh	0.046553286	0.04066292	0.033877957	0.026867315	0.03699037
2020	$/kWh	0.050901503	0.043353232	0.042024216	0.030786197	0.041766287
2021	$/kWh	0.055575249	0.047862525	0.044949693	0.034145396	0.045633216
2022	$/kWh	0.056916434	0.048943738	0.046748022	0.03582828	0.047109119
2023	$/kWh	0.060706346	0.052195695	0.050601754	0.039739327	0.050810781
2024	$/kWh	0.063356121	0.054474697	0.053075039	0.043059944	0.05349145
2025	$/kWh	0.065459372	0.056791445	0.057419018	0.045059684	0.05618238
2026	$/kWh	0.065377361	0.056618223	0.058916675	0.045774345	0.056671651
2027	$/kWh	0.066370041	0.057470526	0.059460932	0.04649156	0.057448265
2028	$/kWh	0.067678713	0.058651355	0.063320806	0.048644215	0.059573772
2029	$/kWh	0.069197745	0.060328826	0.065926997	0.050250116	0.061425921
2030	$/kWh	0.070740047	0.06252036	0.067778112	0.051705298	0.063185955
2031	$/kWh	0.071133805	0.063467611	0.073302463	0.05315417	0.065264512
2032	$/kWh	0.072344541	0.064933877	0.076576345	0.05476718	0.067155486
2033	$/kWh	0.073575886	0.066434018	0.079996448	0.056429138	0.069108872
2034	$/kWh	0.074828188	0.067968815	0.083569301	0.05814153	0.071126959
2035	$/kWh	0.076101805	0.069539071	0.087301728	0.059905886	0.073212123
2036	$/kWh	0.0773971	0.071145603	0.091200854	0.061723783	0.075366835
2037	$/kWh	0.078714442	0.072789251	0.095274126	0.063596846	0.077593666
2038	$/kWh	0.080054206	0.074470871	0.099529321	0.065526748	0.079895286
2039	$/kWh	0.081416773	0.076191341	0.103974564	0.067515215	0.082274473
2040	$/kWh	0.082802531	0.077951558	0.108618344	0.069564024	0.084734114
2041	$/kWh	0.084211876	0.079752441	0.113469527	0.071675006	0.087277212
2042	$/kWh	0.085645209	0.081594929	0.118537377	0.073850047	0.08990689
2043	$/kWh	0.087102938	0.083479983	0.12383157	0.076091092	0.092626396
2044	$/kWh	0.088585479	0.085408586	0.129362216	0.078400143	0.095439106
2045	$/kWh	0.090093253	0.087381746	0.135139876	0.080779265	0.098348535
2046	$/kWh	0.09162669	0.08940049	0.141175581	0.083230583	0.101358336
2047	$/kWh	0.093186227	0.091465873	0.147480857	0.085756288	0.104472311

Avoided Energy Costs Electric Heat and Electric Vehicles Weighted Average

Seasonal Avoided Energy Costs (pre-inflation)

Period	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Winter On-Peak	0.042948462	0.046553286	0.050901503	0.055575249	0.056916434	0.060706346	0.063356121	0.065459372	0.065377361	0.066370041	0.067678713	0.069197745	0.070740047	0.071133805	0.072344541
Winter Off-Peak	0.036876354	0.04066292	0.043353232	0.047862525	0.048943738	0.052195695	0.054474697	0.056791445	0.056618223	0.057470526	0.058651355	0.060328826	0.06252036	0.063467611	0.064933877
Summer On-Peak	0.028704835	0.033877957	0.042024216	0.044949693	0.046748022	0.050601754	0.053075039	0.057419018	0.058916675	0.059460932	0.063320806	0.065926997	0.067778112	0.073302463	0.076576345
Summer Off-Peak	0.02178498	0.026867315	0.030786197	0.034145396	0.03582828	0.039739327	0.043059944	0.045059684	0.045774345	0.04649156	0.048644215	0.050250116	0.051705298	0.05315417	0.05476718

Period	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Winter On-Peak	0.073575886	0.074828188	0.076101805	0.0773971	0.078714442	0.080054206	0.081416773	0.082802531	0.084211876	0.085645209	0.087102938	0.088585479	0.090093253	0.09162669	0.093186227
Winter Off-Peak	0.066434018	0.067968815	0.069539071	0.071145603	0.072789251	0.074470871	0.076191341	0.077951558	0.079752441	0.081594929	0.083479983	0.085408586	0.087381746	0.08940049	0.091465873
Summer On-Peak	0.079996448	0.083569301	0.087301728	0.091200854	0.095274126	0.099529321	0.103974564	0.108618344	0.113469527	0.118537377	0.12383157	0.129362216	0.135139876	0.141175581	0.147480857
Summer Off-Peak	0.056429138	0.05814153	0.059905886	0.061723783	0.063596846	0.065526748	0.067515215	0.069564024	0.071675006	0.073850047	0.076091092	0.078400143	0.080779265	0.083230583	0.085756288

Seasonal and Peak Segmentation

Winter months / year	8
Summer months / year	4
Hours / year	8760
On-peak hours / day	16
Off-peak hours / day	8

Season	On-Peak	Off-Peak	Total
Winter	3,893.33	1,946.67	5,840.00
Summer	1,946.67	973.33	2,920.00

Electric Heat & EV Seasonal Load Segmentation

Season	Ratio
Summer Off-Peak	11.11%
Summer On-Peak	22.22%
Winter Off-Peak	22.22%
Winter On-Peak	44.44%
	100.00%

Weighted Average Annual Price (pre-inflation & WRP)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hourly Wght. Avg. YOY	0.0361	0.0402	0.0450	0.0491	0.0505	0.0542	0.0568	0.0595	0.0598	0.0606	0.0626	0.0644	0.0661	0.0679	0.0697

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Hourly Wght. Avg. YOY	0.0715	0.0734	0.0753	0.0773	0.0794	0.0815	0.0837	0.0860	0.0883	0.0907	0.0932	0.0958	0.0985	0.1012	0.1040

Add MRP & Inflation

MRP	1.09
Inflation	0.02

Weighted Average Annual Price (pre-inflation & WRP)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hourly Wght. Avg. YOY	0.0401	0.0456	0.0521	0.0580	0.0608	0.0666	0.0712	0.0760	0.0779	0.0806	0.0848	0.0890	0.0933	0.0977	0.1022

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Hourly Wght. Avg. YOY	0.1070	0.1120	0.1173	0.1228	0.1286	0.1347	0.1411	0.1478	0.1549	0.1623	0.1701	0.1783	0.1869	0.1959	0.2054

Avoided REC Cost

Source: AESC 2015 Update, Appendix B

Period	Units	Value
2018	$/kWh	0.005508139
2019	$/kWh	0.005958249
2020	$/kWh	0.005659665
2021	$/kWh	0.00680032
2022	$/kWh	0.006509963
2023	$/kWh	0.006051674
2024	$/kWh	0.005772086
2025	$/kWh	0.005405181
2026	$/kWh	0.004985127
2027	$/kWh	0.004586611
2028	$/kWh	0.004206788
2029	$/kWh	0.004558828
2030	$/kWh	0.004253013
2031	$/kWh	0.004253013
2032	$/kWh	0.004253013
2033	$/kWh	0.004253013
2034	$/kWh	0.004253013
2035	$/kWh	0.004253013
2036	$/kWh	0.004253013
2037	$/kWh	0.004253013
2038	$/kWh	0.004253013
2039	$/kWh	0.004253013
2040	$/kWh	0.004253013
2041	$/kWh	0.004253013
2042	$/kWh	0.004253013
2043	$/kWh	0.004253013
2044	$/kWh	0.004253013
2045	$/kWh	0.004253013
2046	$/kWh	0.004253013
2047	$/kWh	0.004253013

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Avoided Capacity Cost (pre-infla	0.0055	0.0060	0.0057	0.0068	0.0065	0.0061	0.0058	0.0054	0.0050	0.0046	0.0042	0.0046	0.0043	0.0043	0.0043
Avoided Capacity Cost (post-infl	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Avoided Capacity Cost (pre-infla	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043
Avoided Capacity Cost (post-infl	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

MRP	1.09
Inflation	2%
Convert to MW	-

DRIPE

Source AESC 2015 Update, Appendix B

Energy

Period	Unit	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric Heat -Wgt. Avg.	Seasonal Weighted Average
2018	$/kWh	1.25566E-06	5.06517E-07	0	0	4.40545E-07	7.39688E-07
2019	$/kWh	0	0	0	0	0	0
2020	$/kWh	0	0	0	0	0	0

Capacity

Period	Unit	Winter	Summer	Electric Heat - Weighted Average	Solar - Seasonal Weighted Average
2018	$/kWh	0.001583956	0.00103838	0.001311168	0.00136285
2019	$/kWh	0.001012791	0.00068337	0.00084808	0.000879286
2020	$/kWh	0.000991781	0.000669757	0.000830769	0.000861274
2021	$/kWh	0.000179686	0.000165304	0.000172495	0.000173857
2022	$/kWh	0.000179201	0.000164577	0.000171889	0.000173274
2023	$/kWh	0.000178737	0.000163881	0.000171309	0.000172717
2024	$/kWh	0.000178182	0.000163048	0.000170615	0.000172049
2025	$/kWh	0.00017763	0.000162221	0.000169925	0.000171385
2026	$/kWh	0.000177082	0.000161399	0.000169241	0.000170726
2027	$/kWh	0.000176538	0.000160583	0.00016856	0.000170072
2028	$/kWh	0.000175998	0.000159772	0.000167885	0.000169422
2029	$/kWh	0.000175461	0.000158967	0.000167214	0.000168776
2030	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2031	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2032	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2033	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2034	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2035	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2036	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2037	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2038	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2039	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2040	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2041	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2042	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2043	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2044	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2045	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2046	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135
2047	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135

Electric Heat and Electric Vehicles - DRIPE (pre-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy	4.40545E-07	0	0												
Capacity	0.001311168	0.00084808	0.000830769	0.000172495	0.000171889	0.000171309	0.000170615	0.000169925	0.000169241	0.00016856	0.000167885	0.000167214	0.000166548	0.000166548	0.000166548
Total DRIPE	0.001311609	0.00084808	0.000830769	0.000172495	0.000171889	0.000171309	0.000170615	0.000169925	0.000169241	0.00016856	0.000167885	0.000167214	0.000166548	0.000166548	0.000166548

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Energy															
Capacity	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548
Total DRIPE	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548	0.000166548

Inflation	2%
Conversion to MW	1,000.00

Electric Heat DRIPE (post inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total DRIPE	1.337840737	0.882342644	0.881618693	0.186713876	0.189779136	0.19292199	0.195982934	0.199094693	0.202258148	0.205474195	0.208743747	0.212067732	0.215447097	0.219756039	0.22415116

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total DRIPE	0.228634183	0.233206867	0.237871004	0.242628424	0.247480993	0.252430613	0.257479225	0.262628809	0.267881385	0.273239013	0.278703793	0.284277869	0.289963427	0.295762695	0.301677949

Solar DRIPE

Solar DRIPE (pre-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy	7.39688E-07	0	0												
Capacity	0.00136285	0.000879286	0.000861274	0.000173857	0.000173274	0.000172717	0.000172049	0.000171385	0.000170726	0.000170072	0.000169422	0.000168776	0.000168135	0.000168135	0.000168135
Total DRIPE	0.00136359	0.000879286	0.000861274	0.000173857	0.000173274	0.000172717	0.000172049	0.000171385	0.000170726	0.000170072	0.000169422	0.000168776	0.000168135	0.000168135	0.000168135

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Energy															
Capacity	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135
Total DRIPE	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135	0.000168135

Inflation	2%
Conversion to MW	1,000.00

Solar DRIPE (post-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total DRIPE	1.39086186	0.914809363	0.913991069	0.188188586	0.19130869	0.194506868	0.197629728	0.200805036	0.20403371	0.207316685	0.210654913	0.214049364	0.217501024	0.221851045	0.226288066

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total DRIPE	0.230813827	0.235430104	0.240138706	0.24494148	0.249840309	0.254837116	0.259933858	0.265132535	0.270435186	0.275843889	0.281360767	0.286987983	0.292727742	0.298582297	0.304553943

Solar - Seasonal Demand by System Type

Season	Sum of 250 kW System - Annual Output (MW)	Sum of 500 kW System - Annual Output (MW)	Sum of 1,500 kW System - Annual Output (MW)
Summer Off-Peak	1%	1%	1%
Summer On-Peak	39%	39%	39%
Winter Off-Peak	1%	1%	1%
Winter On-Peak	59%	59%	59%
Total	1	1	1

New England Residential Energy Prices

Energy Prices Residential (Case Reference case Region New England)
https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2017&region=1-1&cases=ref2017~ref_no_cpp&start=2015&end=2050&f=A&li
09:51:48 GMT-0400 (Eastern Daylight Time)
Source: U.S. Energy Information Administration

New England Residential Energy Prices

Year	Propane 2016 $/MMBtu	Distillate Fuel Oil 2016 $/MMBtu	Natural Gas 2016 $/MMBtu	Electricity 2016 $/MMBtu
2015	20.059196	19.634937	12.999855	57.913372
2016	18.986731	15.391558	12.499926	52.962849
2017	19.159531	18.481035	12.559583	53.759666
2018	20.3908	20.35202	12.730404	46.24337
2019	20.428343	21.432173	12.863449	47.102016
2020	20.36684	21.913502	13.038426	45.619492
2021	20.38199	22.292168	13.248834	45.495861
2022	20.818222	22.562029	13.447027	47.376621
2023	21.09973	22.895624	13.598397	49.17429
2024	21.193447	23.217937	13.719156	50.349106
2025	21.149662	23.695726	13.810126	51.765896
2026	21.188416	24.066542	13.868716	52.806141
2027	21.388361	24.263973	13.997381	53.399616
2028	21.446894	24.305296	14.186235	53.822887
2029	21.470636	24.524441	14.388145	54.817307
2030	21.637087	24.984591	14.524349	55.649223
2031	22.067629	25.394388	14.584588	55.851391
2032	22.390608	25.889307	14.683081	55.949352
2033	22.452869	25.806747	14.751159	56.23835
2034	22.691654	26.115984	14.936297	56.59457
2035	22.800667	26.332081	15.181598	57.886639
2036	23.140226	26.861704	15.332048	58.283558
2037	23.296213	26.936857	15.496017	58.576546
2038	23.60668	27.103247	15.618446	58.816032
2039	24.046312	27.475222	15.740956	57.837711
2040	24.210247	27.673616	15.790576	59.10891
2041	24.474936	27.717131	15.916462	59.452782
2042	24.614227	27.769522	16.047209	59.981743
2043	24.814363	27.830799	16.209641	60.750565
2044	24.986708	27.928757	16.403036	61.422989
2045	25.068331	28.020597	16.601873	61.820881
2046	25.256636	28.191952	16.78653	62.281025
2047	25.456972	28.537254	16.932384	63.031494
2048	25.692049	28.555511	17.094194	63.291729
2049	25.812935	28.743196	17.232834	63.588299
2050	26.039854	29.019983	17.207699	65.033279

Spot vs. Long-term Fuel Purchases

Category	Percent of Total	Discount from Base Residential
Long-term	10%	10%
Spot Purchase	90%	0%
Total	100%	N/A

Source http://www.treesfullofmoney.com/2017-heating-oil-price-predictions/

Assumptions Based on EIA forecast, assume prices are increasing and customers experience historical 5 - 15% savings from pre-buy cont

Spot vs. Long-term - Natural Gas

Category	Percent of Total	Discount from Base Residential
Long-term	5%	5%
Spot Purchase	95%	0%
Total	100%	N/A

Spot vs. Long-term - Natural Gas

Category	Percent of Total	Discount from Base Residential
Long-term	0%	5%
Spot Purchase	100%	0%
Total	100%	N/A

Adjusted Residential Natural Gas Prices Based on Pre-Buy Forecast

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base Natural Gas ($ / MMBTU)	13.00	12.50	12.56	12.73	12.86	13.04	13.25	13.45	13.60	13.72	13.81	13.87	14.00	14.19	14.39	14.52	14.58	14.68
Natural Gas - Apply Price Protection Discount	12.96735536	12.46867619	12.52818404	12.69857799	12.83129038	13.00582994	13.21571192	13.41340943	13.56440101	13.68485811	13.77560069	13.83404421	13.96238755	14.15076941	14.35217464	14.48803813	14.54812653	14.6463733

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Base Natural Gas ($ / MMBTU)	14.75	14.94	15.18	15.33	15.50	15.62	15.74	15.79	15.92	16.05	16.21	16.40	16.60	16.79	16.93	17.09	17.23	17.21
Natural Gas - Apply Price Protection Discount	14.7142811	14.89895626	15.14364401	15.29371788	15.45727696	15.57939989	15.70160361	15.75109956	15.87667085	16.00709098	16.1691169	16.36202841	16.56036832	16.74456368	16.89005304	17.05145852	17.1897519	17.1647

Assume pre-buy discount is 5%, with 5% of customers using

Propane 2016 $/MMBtu

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base Propane 2016 $/MMBtu	20.06	18.99	19.16	20.39	20.43	20.37	20.38	20.82	21.10	21.19	21.15	21.19	21.39	21.45	21.47	21.64	22.07	22.39
Propane - Apply Price Discount	20.06	18.99	19.16	20.39	20.43	20.37	20.38	20.82	21.10	21.19	21.15	21.19	21.39	21.45	21.47	21.64	22.07	22.39

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Base Propane 2016 $/MMBtu	22.45	22.69	22.80	23.14	23.30	23.61	24.05	24.21	24.47	24.61	24.81	24.99	25.07	25.26	25.46	25.69	25.81	26.04
Propane - Apply Price Discount	22.45	22.69	22.80	23.14	23.30	23.61	24.05	24.21	24.47	24.61	24.81	24.99	25.07	25.26	25.46	25.69	25.81	26.04

Assume pre-buy discount is zero

Division 10-21

Request:

Regarding the Interconnection Support – Time to ISA incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

   i. The expected benefits of achieving the annual targets; and

   ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

e. Please explain why the allocated basis points for this incentive are reasonable.

Response:

a. The Company has not proposed any specific new actions, investments, or activities in this proceeding in support of achieving the targets. However, the Company expects to achieve the targets for all three proposed Interconnection Support performance incentive mechanisms (Interconnection Support - Time to ISA, Interconnection Support – Average Days to System Modification, and Interconnection Support – Estimate versus Actual Costs incentives) through the following: (i) increased efficiencies in the overall process, (ii) better and more accurate reporting needs, (iii) the introduction of an on-line portal for application and tracking of all interconnection proposals, (iv) additional technical training for engineers who conduct needed studies, and (v) increased levels of key performance indicators, which together will enhance performance for studies, construction of necessary system modifications, and more accurate accounting of costs.

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b. The Company has proposed funding in the general rate case for these efforts, which would be recovered through base distribution rates.

c. The Company has not conducted a cost-benefit analysis associated with achieving the targets for any of the three Interconnection Support metrics. As the Company noted in Schedule PST-1, Chapter 9, Section 4.3 (Bates Page181of PST Book 1), the benefits from achieving the interconnection targets are difficult to quantify. Quantification would require making assumptions regarding the timing of distributed generation installations with and without the target achievements, the number and size of installations affected, and the specific technologies being installed. However, timely and efficient interconnection of distributed generation is foundational to providing the benefits from distributed generation, including:

- Reductions in CO_2 and criteria pollutant emissions;
- Avoided energy and capacity costs; and
- Avoided renewable energy credit costs.

d. See the Company's response to subpart (c) above.

e. The Company's proposed allocation of up to six basis points for each Interconnection Support incentive at the maximum target level is reasonable because this incentive level is commensurate with the emphasis that the Division of Public Utilities and Carriers, the Rhode Island Public Utilities Commission, the Governor's office, the Office of Energy Resources, the General Assembly, and other Rhode Island stakeholders have placed on the expansion of renewable energy sources in-state. The Company has assigned a relatively high value to interconnection in comparison with many of the other Performance Incentive Mechanisms in recognition of the foundational importance of efficient interconnection processes to achievement of the state's energy and economic development goals. This earnings opportunity will help to incent the Company to improve interconnection practices, resulting in expedited interconnection timelines that accelerate the benefits from distributed generation.

(This response is identical to the Company's response to Division 3-21 in Docket No. 4780.)

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<u>Division 10-22</u>

<u>Request</u>:

Regarding the Interconnection Support – Average Days to System Modification incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

    i. The expected benefits of achieving the annual targets

    ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

e. Please explain why the allocated basis points for this incentive are reasonable.

<u>Response</u>:

a. through e.

For the Company's response to parts a. through e. of this request, please see the Company's response to Division 10-21.

(This response is identical to the Company's response to Division 3-22 in Docket No. 4780.)

Division 10-23

Request:

Regarding the Interconnection Support – Estimate versus Actual Costs incentive and the annual targets contained in Appendix 10.10 (as R.I.P.U.C. No. 2205, Sheet 15, Appendix A):

a. Please describe the actions, investments, and activities that the Company expects to undertake to achieve the targets.

b. Please explain how the costs associated with (a) will be recovered from customers, if at all. For example, will these costs be included in the PST Plan and recovered through the PST Factors?

c. Has the Company or its consultants conducted a cost-benefit analysis associated with achieving the targets?

d. If the answer to (c) is yes, please provide the cost-benefit analysis in machine readable format with all formulas intact. If not, please provide the following in machine-readable format with all formulas intact:

    i. The expected benefits of achieving the annual targets

    ii. The expected costs associated with achieving the targets, not including the financial incentives paid to the Company for achieving the targets.

e. Please explain why the allocated basis points for this incentive are reasonable.

Response:

For the Company's response to parts a. through e. above, please see the Company's response to Division 10-21.

(This response is identical to the Company's response to Division 3-23 in Docket No. 4780.)

Division 10-24

Request:

Please describe the factors considered by the Company when developing its proposed allocation of basis point incentives across the various performance incentive mechanisms, and how those factors resulted in the proposed allocations.

Response:

The discussion in Schedule PST-1, Chapter 9, Section 3, Pages 6-7 (Bates Pages 167-168 of PST Book 1), describes the Company's approach to developing performance incentive mechanisms and allocating basis points. As the Company notes in that discussion, values assigned to individual performance incentive mechanisms were "based on a combination of (1) relevance to developing a foundation for transforming the power sector in the near term, and (2) the associated benefits or savings to customers due the activity encouraged by the incentive. The Company has supported the proposed values for individual incentives using analyses of benefits and costs where possible. Where quantification is not possible, the Company has provided a qualitative description of the most significant benefits and costs."

(This response is identical to the Company's response to Division 3-24 in Docket No. 4780.)

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Division 10-25

Request:

Please identify each instance where the achievement of one PIM target might also contribute to the achievement of another PIM target; i.e., where there is overlap among the PIMs.

Response:

Many of the performance incentive mechanisms will either directly or indirectly provide some support toward the achievement of the Forward Capacity Market Peak Demand Reduction and Monthly Transmission Peak Demand Reduction metrics. However, these performance incentive mechanisms are included in the Company's portfolio because they are geared toward the achievement of either additional or separate policy goals, and, therefore, provide other distinct benefits that justify their value. Conversely, multiple performance incentive mechanisms may support the same broad policy goal but also support independent objectives. The Company sought to propose a set of performance incentive mechanisms that is complementary but not redundant, and which will collectively provide incentives for the Company to effectively support achievement of state policy goals.

For example, achievement of the Off-Peak Charging Rebate Participation targets will result in a modest contribution toward the two peak reduction targets. However, that particular performance incentive mechanism is important in that it is focused on customer engagement, a priority in both Docket 4600 and Power Sector Transformation; and supportive of the State's ZEV and CO_2 near-term goals as it provides a timely means to reward off-peak charging by many electric vehicle drivers during the period before time-varying rates are implemented.

The Demand Response participation performance incentive mechanisms will similarly support the peak reduction metrics. As with the Off-Peak Charging Rebate, the Company emphasized the policy goal of customer engagement in developing these performance incentive mechanisms.

The two energy storage performance incentive mechanisms will also provide some support for peak reduction if targets are achieved. However, they link directly to the Power Sector Transformation goal of building a flexible distribution system to integrate more clean energy generation in support of the State's CO_2 reduction goals and Governor Raimondo's goal of 1000 MW of clean energy by 2020. The Behind the Meter Storage performance incentive mechanism also directly supports the Docket 4600 goal of fostering customer investment in their facilities.

The Electric Heat Initiative and Electric Vehicles performance incentive mechanisms provide direct support of the State's CO_2 reduction goals. The Electric Vehicles performance incentive mechanism provides support for the State's ZEV goals. The Electric Heat Initiative may provide a modest contribution to annual peak reduction that has been accounted for in setting the

Forward Capacity Market Peak Demand Reduction targets. The Electric Heat Initiative also supports local economic development.

The DG-Friendly Substation Transformers and three Interconnection performance incentive mechanisms will all serve to expedite the interconnection of distributed generation. The DG-Friendly Substation Transformers performance incentive mechanism is a complement to the Interconnection performance incentive mechanisms, as completion of the system investments associated with the substation transformer targets will mean that customers can more readily benefit from expedited interconnection timelines. The three Interconnection performance incentive mechanisms each focus on different aspects of the interconnection process, such that their benefits will not be overlapping. All of these performance incentive mechanisms provide support for the State's clean energy and CO_2 goals, and will help to support economic development in the State of Rhode Island.

The Volt/VAR Optimization (VVO) Pilot Impacts performance incentive mechanism targets would imply a small contribution to the Forward Capacity Market and Monthly Transmission peak demand reduction targets. However, this performance incentive mechanism is intended to support outstanding delivery of the pilot, which will ultimately provide lessons that inform and ensure more efficient realization of benefits from broader AMF deployment and grid modernization efforts.

Because of the Company's proposed timeline for AMF deployment, the AMF Customer Engagement and Deployment performance incentive mechanisms targets are unlikely to impact the achievement of other performance incentive mechanisms.

(This response is identical to the Company's response to Division 3-25 in Docket No. 4780.)

Division 10-26

Request:

Please explain how the Company incorporates the value of peak load reduction when evaluating the need for additional “Distribution”, “Transmission”, or “Generation” capacity. Please provide specific examples where such an analysis was performed.

Response:

For distribution, peak load reductions are included in two ways. First, the Company’s forecast includes state wide peak load reductions due to energy efficiency and distributed generation. Table 1 demonstrates the forecast peak reductions.

Table 1 (2017 Electric Peak Forecast)

Rhode Island SUMMER Peak (MW) and Energy Efficiency (EE)/PV Impacts						Total	
	------------- SYSTEM PEAK (50/50) -------------			------ EE/DG REDUCTIONS ----		EE % of	PV % of
Calendar Year	Reconstituted (before reductions)	Final Forecast w/ EE Reduction only	Final Forecast (after all reductions)	EE Reduction Forecast	PV Reduction Forecast	'Reconstituted' Deliveries	'Reconstituted' Deliveries
2003	1,788	1,783	1,783	5	0	0.3%	0.0%
2004	1,848	1,832	1,832	16	0	0.9%	0.0%
2005	1,787	1,760	1,760	27	0	1.5%	0.0%
2006	1,826	1,789	1,789	38	0	2.1%	0.0%
2007	1,898	1,849	1,849	49	0	2.6%	0.0%
2008	1,845	1,786	1,786	59	0	3.2%	0.0%
2009	1,889	1,816	1,816	73	0	3.9%	0.0%
2010	1,836	1,749	1,749	88	0	4.8%	0.0%
2011	1,937	1,836	1,836	101	0	5.2%	0.0%
2012	1,944	1,826	1,826	118	0	6.1%	0.0%
2013	1,980	1,837	1,835	142	2	7.2%	0.1%
2014	1,932	1,755	1,752	177	3	9.2%	0.2%
2015	2,058	1,843	1,839	215	5	10.5%	0.2%
2016	2,039	1,791	1,782	248	9	12.2%	0.4%
2017	2,093	1,817	1,793	276	24	13.2%	1.1%
2018	2,125	1,826	1,783	299	43	14.1%	2.0%
2019	2,149	1,828	1,780	320	49	14.9%	2.3%
2020	2,173	1,832	1,780	341	52	15.7%	2.4%
2021	2,200	1,839	1,786	361	53	16.4%	2.4%
2022	2,228	1,848	1,794	379	54	17.0%	2.4%
2023	2,255	1,858	1,804	397	55	17.6%	2.4%
2024	2,281	1,868	1,812	414	55	18.1%	2.4%
2025	2,307	1,877	1,821	430	56	18.6%	2.4%
2026	2,332	1,887	1,830	445	57	19.1%	2.4%
2027	2,357	1,897	1,840	459	57	19.5%	2.4%
2028	2,381	1,908	1,850	473	58	19.9%	2.4%
2029	2,405	1,919	1,861	486	58	20.2%	2.4%
2030	2,429	1,931	1,872	498	59	20.5%	2.4%
2031	2,453	1,943	1,883	510	60	20.8%	2.4%

Second, the Company reduces peaks on a distribution feeder basis, as necessary, when conducting an area study. Reductions are made when the distributed generation peak reduction amounts aggregate to a level significant in identifying study issues. Table 2 demonstrates a case within the Central Rhode Island East (CRIE) Area Study where the distributed generation information was collected but no feeder reductions were made. The reduction would not have changed issue identification, plan development, or recommendations.

Table 2 - Existing and Proposed Distributed Generation within Study Area (CRIE Study Appendix 9.11)

Feeder	Proposed Capacity (kW)	Existing Capacity (kW)	Fuel Type	DG Type
14F1	0	3.5	Solar	Inverter Based - PV
14F1	0	5.5	Solar	Inverter Based - PV
14F3	0	225	Hydro	Synchronous
14F4	308	0	Solar	Inverter Based - PV
27F2	500	0	Solar	Inverter Based - PV
27F3	0	300	Solar	Inverter Based - PV
27F4	224	0	Solar	Inverter Based - PV
72F2	0	5.16	Solar	Inverter Based - PV
72F5	5	0	Solar	Inverter Based - PV
83F2	495	0	Solar	Inverter Based - PV
87F1	100	0	Wind	Wind Turbine
87F1	220.8	0	Solar	Inverter Based - PV
87F5	0	3.5	Solar	Inverter Based - PV
TOTAL	1,853	543		

Table 3 demonstrates a case in the ongoing South County East (SCE) Area Study where the accumulated distributed generation is more substantial and feeder peaks are reduced.

Table 3 – Draft Existing and Proposed Distributed Generation within Study Area (SCE Study)

Circuit	Status	Name Plate (MW)	DG Type	Study Credit	
				MW	%
West Kingston Substation					
3307/3308	Existing	30.00	Inverter Based - Wind	6.00	20%
3307/3308	Pending	2.20	Inverter Based - PV	0.73	33%
3307/3308	Pending	0.90	Inverter Based - PV	0.30	33%
3307/3308	Pending	3.78	Inverter Based - PV	1.25	33%
SUB-TOTAL		**36.88**		**8.27**	
Davisville Substation					
84T3	Pending	3.06	Inverter Based - PV	1.01	33%
84T4	Existing	12.50	Cogen-Natural Gas	12.50	100%
84T3	Existing	8.00	Cogen-Natural Gas	8.00	100%
83F2	Existing	0.50	Inverter Based - PV	0.16	33%
SUB-TOTAL		**24.06**		**21.67**	
Kent County Substation					
30F1	Existing	1.50	synchronous - Wind	0.00	0%
SUB-TOTAL		**1.50**		**0.00**	
115kV Supplied Stations					
46F4	Pending	1.00	Inverter Based - PV	0.33	33%
46F4	Existing	2.00	Inverter Based - PV	0.60	30%
88F1	Pending	0.88	Inverter Based - PV	0.29	33%
88F1	Pending	0.89	Inverter Based - PV	0.29	33%
SUB-TOTAL		**4.77**		**1.51**	
TOTAL		**67.20**		**31.46**	**47%**

For transmission, National Grid utilizes a ten-year load forecast issued by ISO New England (the Forecast Report of Capacity, Energy, Loads, and Transmission), which takes into account load reduction attributed to energy efficiency, demand response, and distributed generation sources. Ultimately, these factors result in an overall reduction of the net load experienced on the system, and this is reflected in the loadflow models used in transmission reliability planning studies. A recent example of this is documented in ISO New England's, *Southeastern Massachusetts and Rhode Island Area 2026 Needs Assessment* report issued in May, 2016. Specific reference to the load forecast along with load reduction components is discussed in sections 3.1.6 and 3.1.7 of that report. This report contains Critical Energy Infrastructure Information and can be obtained by making a specific request with ISO New England.

With respect to generation, National Grid does not perform generation adequacy studies because this is a market function that is performed by ISO New England.

(This response is identical to the Company's response to Division 3-26 in Docket No. 4780.)

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