DON 1-1

Request:

Please provide a copy of all workpapers supporting the Schedules contained in the Testimony in native format (i.e., WORD and EXCEL or a compatible format). EXCEL workbooks should be provided with all formulas and links intact.

Response:

The Company is providing the following workpapers in support of the Schedules contained in the Testimony:

Appendix 2.1 Program BCA	Attachment DON 1-1-1
Appendix 2.2 Economic Development	Attachment DON 1-1-2
Appendix 4.1 AMF Technology and BCA REDACTED	Attachment DON 1-1-3 (REDACTED)
Appendix 4.2 AMF BCA Methodology	Attachment DON 1-1-4
Appendix 10.1 Revenue Requirement Summaries	Attachment DON 1-1-5
Appendix 10.2 Revenue Requirement Modern Grid, RI only	Attachment DON 1-1-6
Appendix 10.3 Revenue Requirement Modern Grid, Multi Jurisdiction	Attachment DON 1-1-7
Appendix 10.4 Revenue Requirement AMF, RI only	Attachment DON 1-1-8
Appendix 10.5 Revenue Requirement AMF, Multi Jurisdiction	Attachment DON 1-1-9
Appendix 10.6 Revenue Requirement Electric Transportation	Attachment DON 1-1-10
Appendix 10.7 Revenue Requirement Electric Heat	Attachment DON 1-1-11
Appendix 10.8 Revenue Requirement Energy Storage	Attachment DON 1-1-12
Appendix 10.9 Revenue Requirement Solar	Attachment DON 1-1-13
Appendix 10.10 Power Sector Transformation Provision	Attachment DON 1-1-14
Appendix 10.11 Power Sector Transformation Plan, Distribution Adjustment Charge	Attachment DON 1-1-15
Workpaper 3.1 Modern Grid Costs, RI only	Attachment DON 1-1-16
Workpaper 3.2 Modern Grid Costs, Multi Jurisdiction	Attachment DON 1-1-17
Workpaper 4.1 AMF Costs REDACTED	Attachment DON 1-1-18 (REDACTED)
Workpaper 5.1 Electric Transport Costs/Assumptions	Attachment DON 1-1-19
Workpaper 6.1 Electric Heat Costs/Assumptions	Attachment DON 1-1-20
Workpaper 7.1 Energy Storage Costs/Assumptions	Attachment DON 1-1-21
Workpaper 8.1 Solar Costs/Assumptions	Attachment DON 1-1-22

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

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

KPMG

Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models

Reference Document

November 2017

The joint NG-KPMG approach to developing BCAs involved iterating on both quantitative & qualitative benefits

Gather data & key inputs

Review models from other jurisdictions to identify value drivers

- Evaluate relevance to Rhode Island-specific rate case
- Identify and acquire outstanding data

Build initial BCA models

Leverage previous models, RI 4600, and the AESC to develop a RI-specific framework

- Work with project teams to ensure that data is not missing, all benefits are captured, and costs are represented
- Build consistency across models while still allowing for some flexibility where appropriate to project structure

Review with Teams

Review with project teams & get feedback

- Stress test & QA/QC models
- Challenge key assumptions and provide alternative values

Optimize programs

Assist teams with program optimization based on initial BCA results

- Find areas of hidden value
- Reevaluate project configurations and implications (as necessary)
- Include other ratios to provide additional context and points of comparison

Develop Qualitative Analysis

Identify & articulate qualitative benefits

- Discuss how projects align with policy, social and/or economic goals of Rhode Island
- Evaluate benefits that fall outside of the AESC framework, but are still relevant to the state

More tactically, this resulted in the RI BCAs taking into account a broad set of considerations during development

Design Principles

Consistency

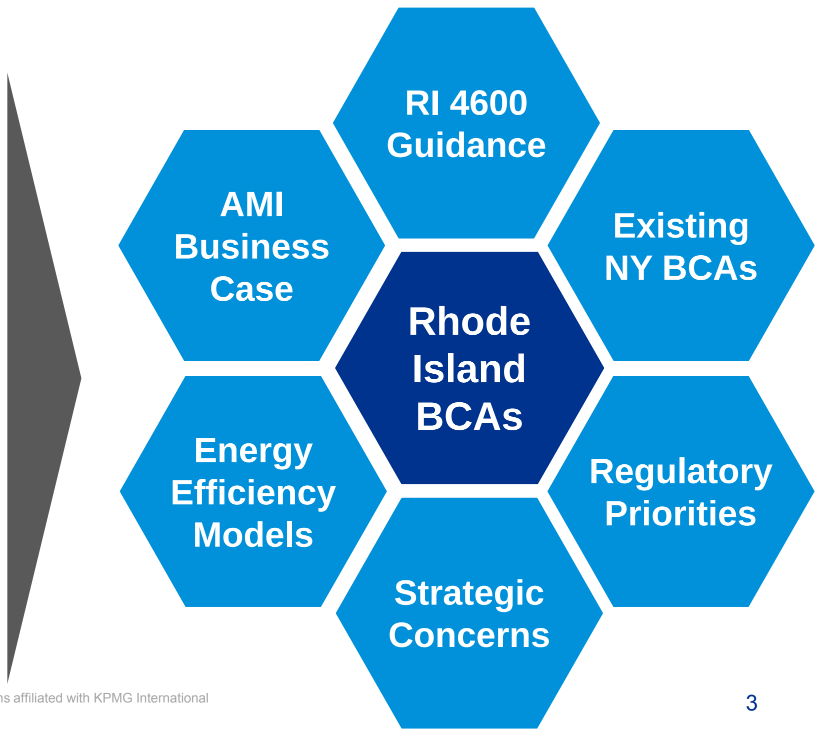
- Where possible, a single method for the same assumption
- Common naming conventions, design and style
- Increased stakeholder agreement on the above

Transparency

- Simple to understand assumptions & calculations
- Adequate documentation and commentary on work

Flexibility

- Design that allows for quick updates of variables with global or local impacts (as appropriate)
- Ability to combine and/or disaggregate future business cases with minimal effort



Benefits were "translated" to Rhode Island accounting for other jurisdictions, precedent and regulatory direction

Benefits & Costs Mapping		Test Applicability			Projects / Elements			
NY Benefit/Cost Category	RI Benefit/Cost Category	SCT	UCT	RIM	Electric Transportation	Electric Heat	Company-Owned Solar	Company-Owned Storage
Avoided Generation Capacity Costs ("AGCC"	Forward Commitment: Capacity Value	✓	✓	✓				
Avoided LBMP	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)	✓	✓	✓				
	REC (Renewable Energy Credit Cost) Cost/Value	✓	✓	✓				
Avoided Transmission Capacity Infrastructur	Electric Transmission Capacity Costs/Value	✓	✓	✓	N/A	N/A	N/A	N/A
Avoided Transmission Losses	Electric Transmission Capacity Costs/Value	✓	✓	✓	N/A	N/A	N/A	N/A
Avoided Ancillary Services	Forward Commitment: Ancillary Services Value			✓	N/A	N/A	N/A	
Wholesale Market Price Impacts	Energy Demand Reduction Induced Price Effect (DRIPE) + Capacity Demand Reduction Induced Price Effect (DRIPE)		✓	✓				
Avoided Distribution Capacity Infrastructure	Distribution Capacity Costs	✓	✓	✓	N/A	N/A	N/A	N/A
Avoided O&M	Distribution Capacity Costs	✓	✓	✓	N/A	N/A	N/A	N/A
Avoided Distribution Losses	Distribution Delivery Costs	✓	✓	✓	N/A	N/A	N/A	N/A
Net Avoided Restoration Costs	Distribution System and Customer Reliability/Resilience Impacts	✓	✓	✓	N/A	N/A	N/A	N/A
Net Avoided Outage Costs	Distribution System and Customer Reliability/Resilience Impacts	✓			N/A	N/A	N/A	N/A
Net Avoided CO2	GHG (Greenhouse Gas) Externality Costs	✓						
Net Avoided SO2 and NOx	Criteria Air Pollutant and Other Environmental Externality Costs	✓					N/A	N/A
Net Non-Energy Benefits	Non-Electric Avoided Fuel Cost	✓					N/A	N/A
Program Administration Costs	Utility/Third Party Developer Renewable Energy, Efficiency, or DER Costs	✓	✓	✓				
Added Ancillary Service Costs	Utility/Third Party Developer Renewable Energy, Efficiency, or		✓	✓	N/A	N/A	N/A	N/A
Incremental T&D and DSP Costs	Electric transmission infrastructure costs for Site Specific	✓	✓	✓	N/A	N/A	N/A	N/A
Participant DER Cost	Utility/Third Party Developer Renewable Energy, Efficiency, or	✓						
Lost Utility Revenue (Cost shift from non-participants to	Program Participant/Prosumer Benefits/Costs		✓	✓				
Net Non-Energy Costs	Non-Energy Costs/Benefits: Economic Development	✓			Not applied	Not applied	Not applied	Not applied

KPMG

The BCAs are collected in a single, consistent tool

Contents

Section	Worksheet	Description
1	Cover	
2	Key Terms	This page provides descriptions of acronyms used across the models
3	Contents	The contents page provides descriptions of and links to the sheets in this model
4	RI BCA Summary	BCA summary and comprehenesive benefits and costs by investment category
5	Electric Vehicles (EV) - BCA	Electric Vehicles BCA Model
5.1	EV - BCA Summary	EV BCA ratios and comprehensive benefits and costs
5.2	EV - Inputs	EV control panel, inputs, and sub-models
5.3	EV - Benefits	Detailed build-up of EV benefits
5.4	EV - Costs	Detailed build-up of EV costs
6	Electric Heat (EH) - BCA	Electric Heat BCA Model
6.1	EH - BCA Summary	EH BCA ratios, comprehensive benefits and costs, and sensitivity analyses
6.2	EH - Inputs	EH control panel, inputs, and sub-models
6.3	EH - Benefits	Detailed build-up of EH benefits
6.4	EH - Costs	Detailed build-up of EH costs
7	Solar (SOL) - BCA	Solar BCA Model
7.1	SOL - BCA Summary	SOL BCA ratios and comprehensive benefits and costs
7.2	SOL - Inputs	SOL control panel, inputs, and sub-models
7.3	SOL - Load & Energy Costs	SOL annual system load and corresponding hourly avoided energy costs
7.4	SOL - Benefits	Detailed build-up of SOL benefits
7.5	SOL - Costs	Detailed build-up of SOL costs
8	Energy Storage (ES) - BCA	Energy Storage BCA Model
8.1	ES - BCA Summary	ES BCA ratios and comprehensive benefits and costs
8.2	ES - Inputs	ES control panel, inputs, and sub-models
8.3	ES - Benefits	Detailed build-up of ES benefits
8.4	ES - Costs	Detailed build-up of ES costs
9	Inputs - General	

- Sections 1-3 represent a general introduction to the model, defining key terms and acronyms as well as providing links to worksheets
- The Table of Contents breaks down the organization of the model and links you to the various worksheets
- Each model includes project specific summary, inputs, benefits and costs tabs

The tool clearly summarizes outcomes while giving project leads the ability to easily drill down into details

The RI BCA Summary tab includes a SCT and RIM score for each investment category

RI National Grid BCA Summary

BCA Summary by Investment Category

Investment Categor	SCT	RIM
Electric Vehicles	1.02	0.13
Electric Heat	1.12	2.42
Solar	0.84	0.62
Energy Storage	0.45	0.49

Electric Heat: Comprehensive Benefits & Costs

	Applicable Cost Test SCT	UCT	RIM	Electric Heat - BCA Ratio		
Benefits	x	x	x	Forward Commitment: Capacity Value	$	277,788
	x	x	x	Energy Supply & Transmission Operating Value of Energy Provided (	$	(1,121,845)
	x	x	x	Avoided Renewable Energy Credit (REC) Cost	$	(99,926)
		x	x	Wholesale Market Price Impacts	$	(5,073)
	x			Greenhouse Gas (GHG) Externality Costs	$	527,088
	x			Criteria Air Pollutant and Other Environmental Costs	$	222
	x			Non-Electric Avoided Fuel Cost	$	4,162,394
	x			Economic Development	$	-
		x	x	Change in Utility Revenue	$	3,552,155
					$	**7,292,803**
Costs	x	x	x	Utility / Third Party Developer Renewable Energy, Efficiency, or DER C	$	1,073,830
	x			Program Participant / Prosumer Benefits / Costs	$	2,275,503
					$	**3,349,332**

- The RI BCA Summary tab also includes a more comprehensive benefits and costs table
- This includes all the modeled benefits and costs for the SCT and RIM (and UCT for reference)
- It also indicates which benefits/costs apply to each type of recognized test

Specific investments also have complete breakdowns

EH - BCA Summary

Societal Cost Test

RI Electric Heat BCA

	Electric Heat - BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	277,788
	Energy Supply & Transmission Operating Value of Energy Provided	$	(1,121,845)
	Avoided Renewable Energy Credit (REC) Cost	$	(99,926)
	0	$	-
	Greenhouse Gas (GHG) Externality Costs	$	527,088
	Criteria Air Pollutant and Other Environmental Costs	$	222
	Non-Electric Avoided Fuel Cost	$	4,162,394
	Economic Development	$	-
	0	$	-
		$	**3,745,721**
Cost	Utility / Third Party Developer Renewable Energy, Efficiency, or	$	1,073,830
	Program Participant / Prosumer Benefits / Costs	$	2,275,503
		$	**3,349,332**

BCA Ratio 1.12

RIM Cost Test

RI Electric Heat BCA

	Electric Heat - BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	277,788
	Energy Supply & Transmission Operating Value of Energy Provided	$	(1,121,845)
	Avoided Renewable Energy Credit (REC) Cost	$	(99,926)
	Wholesale Market Price Impacts	$	(5,073)
	0	$	-
	0	$	-
	0	$	-
	0	$	-
	Change in Utility Revenue	$	3,552,155
		$	**2,603,098**
Cost	Utility / Third Party Developer Renewable Energy, Efficiency, or DER	$	1,073,830
	0	$	-
		$	**1,073,830**

BCA Ratio 2.42

Comprehensive Benefits & Costs

	Applicable Cost Test			Electric Heat - BCA Ratio		
	SCT	UCT	RIM			
Benefits	x	x	x	Forward Commitment: Capacity Value	$	277,788
	x	x	x	Energy Supply & Transmission Operating Value of Energy Provided	$	(1,121,845)
	x	x	x	Avoided Renewable Energy Credit (REC) Cost	$	(99,926)
		x	x	Wholesale Market Price Impacts	$	(5,073)
	x			Greenhouse Gas (GHG) Externality Costs	$	527,088
	x			Criteria Air Pollutant and Other Environmental Costs	$	222
	x			Non-Electric Avoided Fuel Cost	$	4,162,394
	x			Economic Development	$	-
		x	x	Change in Utility Revenue	$	3,552,155
					$	**7,292,803**
Cost	x	x	x	Utility / Third Party Developer Renewable Energy, Efficiency, or DER	$	1,073,830
	x			Program Participant / Prosumer Benefits / Costs	$	2,275,503
					$	**3,349,332**

There is also a list of the comprehensive benefits & costs included in each project's summary tab

Each investment project has its own individual summary which includes the individual benefits & costs segments for the respective cost tests

Inputs are similarly separated into global and project-specific categories to minimize potential errors

To minimize repetition, a general inputs tab is included which contains all global assumptions used across the model

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%	%	

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		

Some examples of globally-defined variables are AESC pricing, emissions assumptions, unit conversions, time assumptions, residential heat pricing, etc.

Economic development benefits all share a common method and application across BCAs as well

Review of Economic Development Method

- Valued the increased GDP in Rhode Island attributable to each of the program investments
- Used the REMI input-output analysis model to measure the increased economic activity created by the program
  - Developed a GDP number resulting from increased incomes and spending
  - Further categorized benefit types for additional analysis (direct vs. indirect vs. induced)
- For a number of reasons it was elected that these not be included directly in evaluation of the BCA results:
  - For many of the proposed initiatives, there are still some outstanding parameters (specific procurement plans, siting characteristics, etc.) that would lower the precision of any economic development measures evaluated
  - GDP output are large relative to the size of the programs under consideration, creating a "masking" effect that makes it more difficult to properly evaluate the investments on their own merits

Methodology Breakdown

1 Program investment → **2** Jobs supported → **3** New income created → **4** GDP increased

Table of Contents – Individual Programs

KPMG

Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models

Transportation

Reference Document

November 2017

1

Project Overview – Transportation

Project Description

- National Grid will invest in the construction of 362 Charging Ports throughout the state of Rhode Island from 2018 to 2020
- Charging stations will be built for use by general consumers as well as fleet and transit vehicles
- National Grid will also build 12 dedicated charging points and adopt 12 heavy duty vehicles into the fleet over 3 years
- The incremental cost of these vehicles will be amortized over the course of their 10-year life
- National Grid will also begin a 3 year pilot program offering a rebate to customers who participate in their Off-peak charging pilot program to drive interest and collect additional data for use in refining future offerings

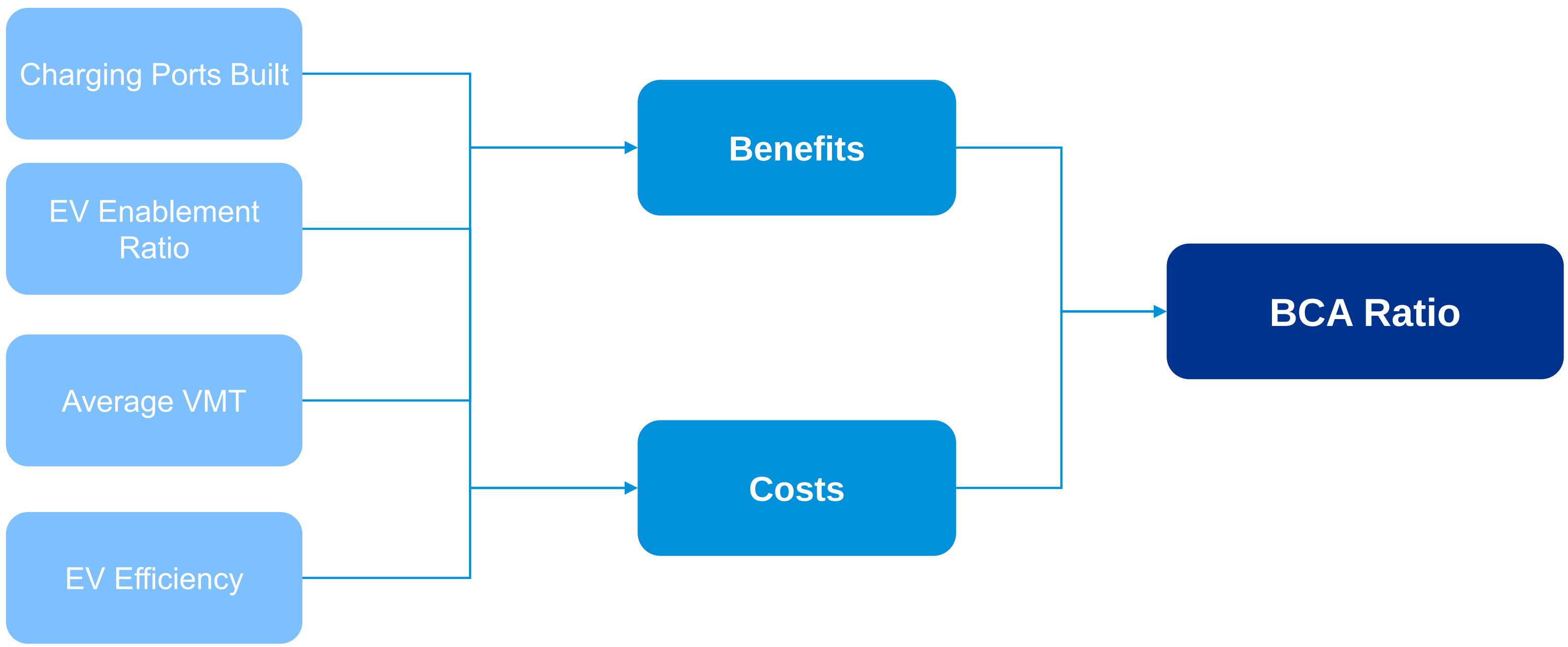
Modeling Overview

- For every charging port built, a given rate of EV adoption results from the mere presence of these charging stations
- In addition, Rhode Island and National data is used to estimate the number of miles these vehicles would travel and efficiency levels
- Using these key inputs, estimations are made on total internal combustion engine vehicle miles displaced, total energy capacity increase, and total energy usage increase
- These numbers are then used to tabulate the total costs and benefits

1

Model Overview

Transportation Model Schematic



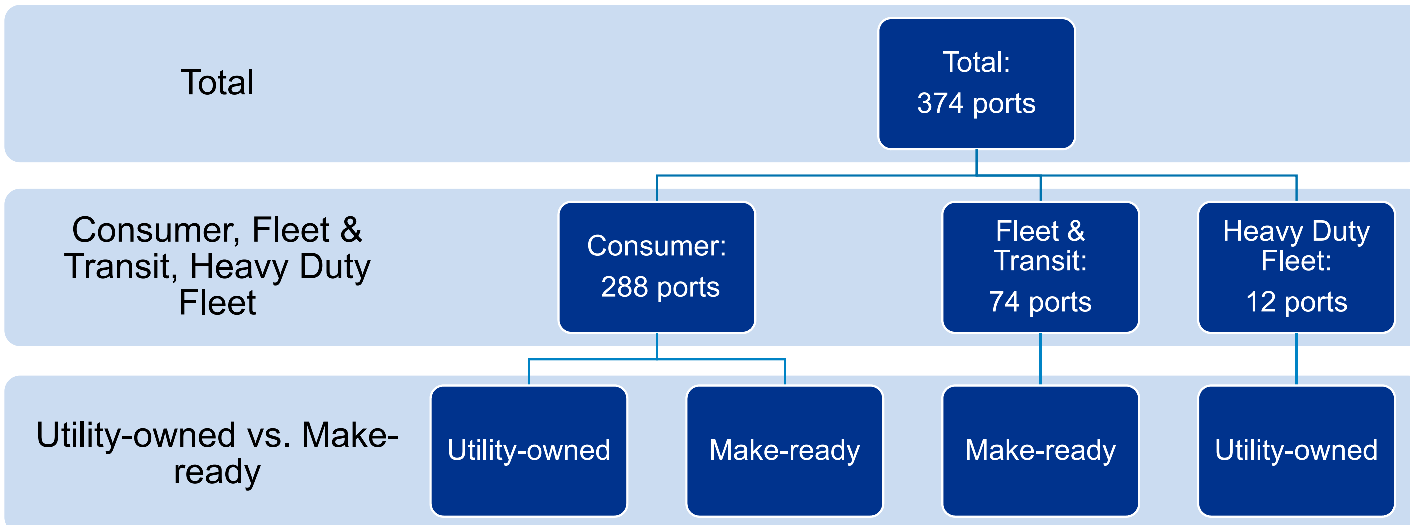
2

Key Inputs Table

Key Inputs	Definition	Model Usage	Source(s)
Charging Ports Built	• Total number of Consumer as well as Fleet & Transit charging ports built (374)	*Used together to approximate the total number of electric vehicles adopted by the program*	• Transportation Initiative - Draft Testimony (Karsten Barde) • CALSTART • Auto Alliance • Alternative Fuels Data Center
EV Enablement Ratios	• Approximation of the number of electric vehicles adopted to the construction of each port • There are different ratios depending on the type of vehicle		
Average VMT	• Average number of miles traveled annually per vehicle • Differs depending on vehicle type	*Used with total vehicles enabled to project the total electricity usage increase and avoided fuel cost attributable to the program*	• RITA • RI DOT • Transportation Initiative - Draft Testimony (Karsten Barde)
Vehicle Efficiency	• For EV's: Average number of miles traveled per kWh of electricity • For internal combustion engine (ICE) vehicles: Average number of miles traveled per gallon of fuel		
BEV	• Battery Electric Vehicle – Make up about 30% of the consumer EV market • Cover 95% of miles on battery power	*Use these specifications to help determine total electricity usage from charging* *These values are also used in fuel displacement cost*	• NY Model Assumptions • Transportation Initiative - Draft Testimony (Karsten Barde)
PHEV	• Plug in Hybrid Electric Vehicle – Make up about 70% of the consumer EV market • Cover 85% of miles on battery power		
BEB	• Battery Electric Bus – Assumed to be 100% of the heavy duty vehicles adopted • Cover 95% of miles on battery power		
HD Fleet PHEV	• Heavy Duty Plug in Hybrid Electric Vehicle – 12 vehicles to be adopted by National Grid • Cover 50% of miles on battery power		

2

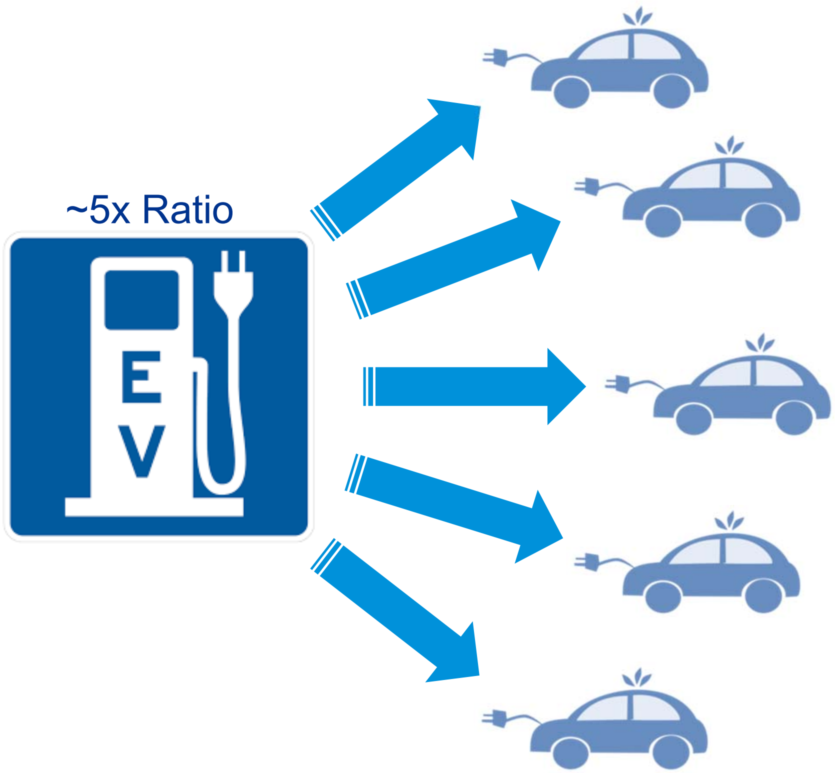
Key Input #1 – Charging Ports Built



- National Grid will be administrating the construction of 374 total charging ports
- Of those, 288 ports will be consumer facing and 78 ports will be for fleet and transit vehicles
- On the consumer side, ~50% will be utility-owned and operated

2

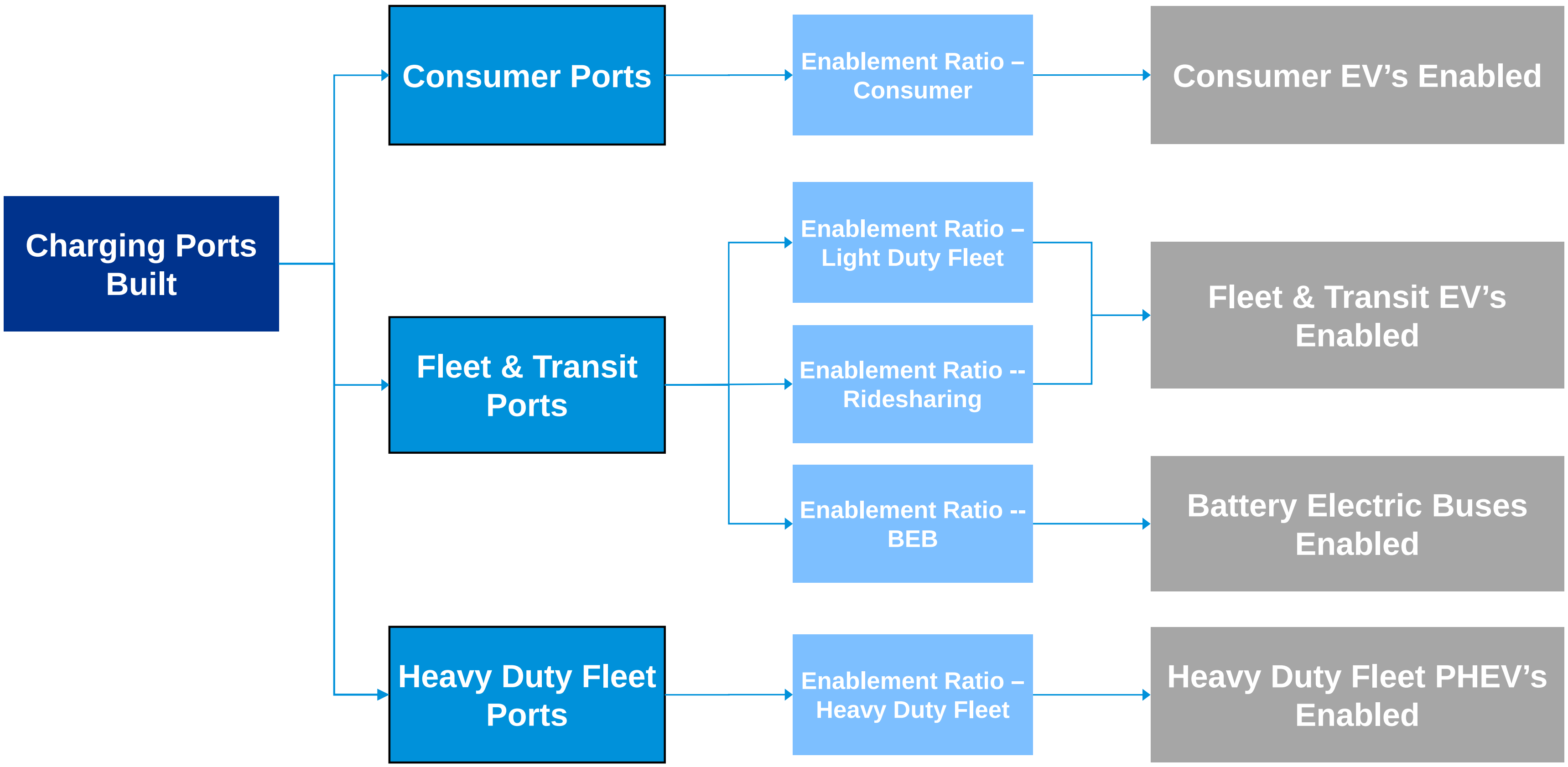
Key Input #2 – EV Enablement Ratios



- Projected # of electric vehicles that will be adopted due to the construction of each port
- Calculated by benchmarking the average # of vehicles per port in other states
- This assumption is still significantly lower than the current national average
- Ratio assumptions
  - Consumer: 5.25 vehicles/port
  - Light Duty Fleet: 2 vehicles/port
  - Ridesharing: 5.25 vehicles/port
  - Heavy Duty Buses: 4 buses/port
  - Heavy Duty Fleet Vehicles: 1 truck/port

2

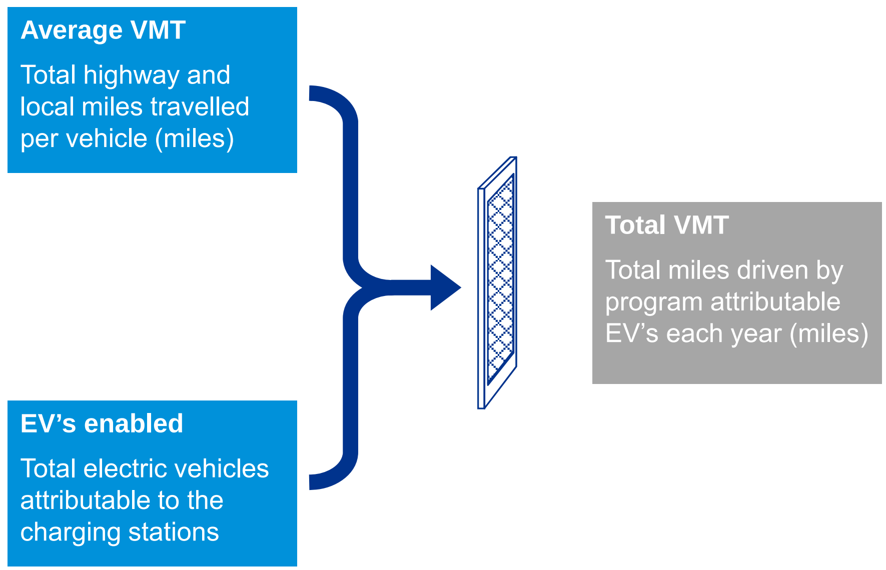
Electric Vehicles Enabled



2

Key Input #3 – Average VMT

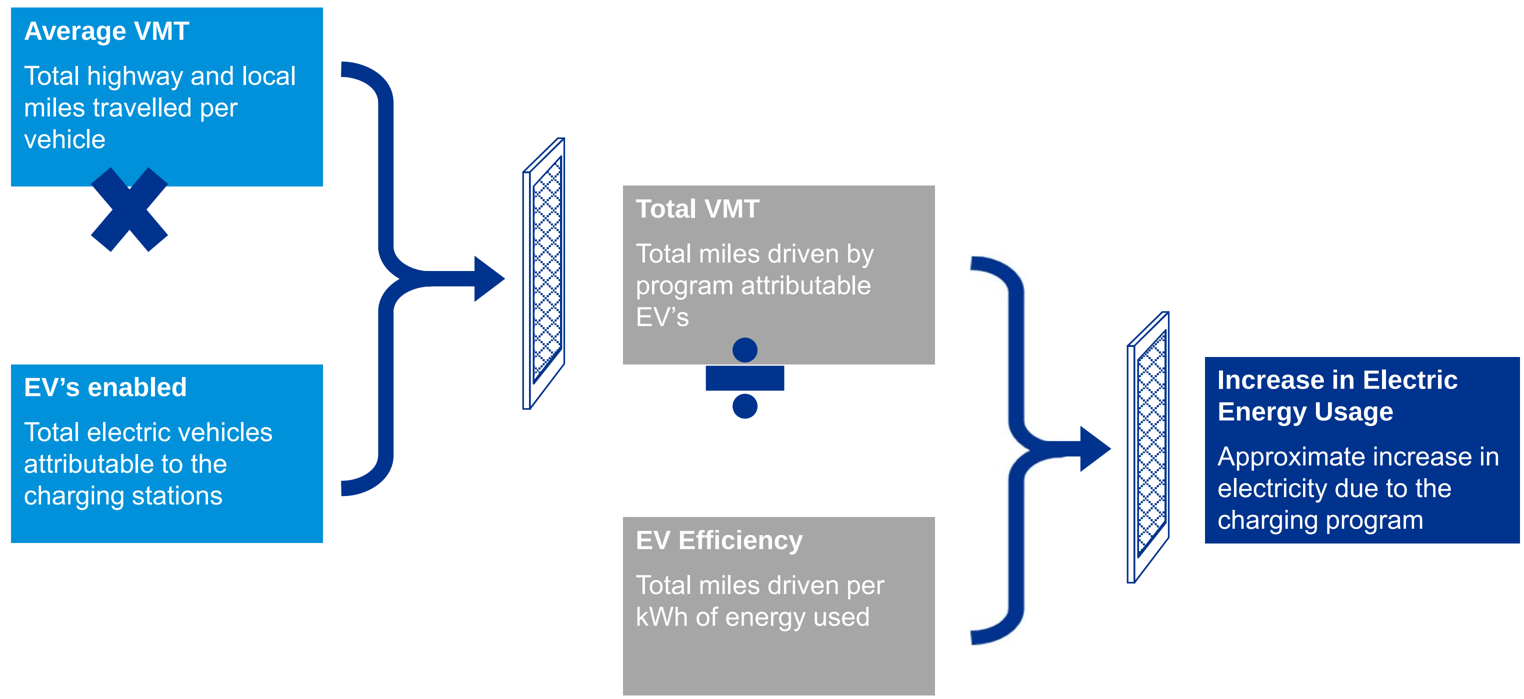
Input Breakdown



- ❑ Average annual miles driven per vehicle in Rhode Island
- ❑ Calculated by leveraging highway and local driving data
- ❑ Average VMT differs depending on vehicle function (i.e. consumer vs. ridesharing)

Key Input #4 – EV Efficiency

Input Breakdown



Dividing Total VMT by average Electric Vehicle Efficiency yields an estimate of the total increase in electric energy usage

3

Benefits – Overview

Benefits Components

Benefits

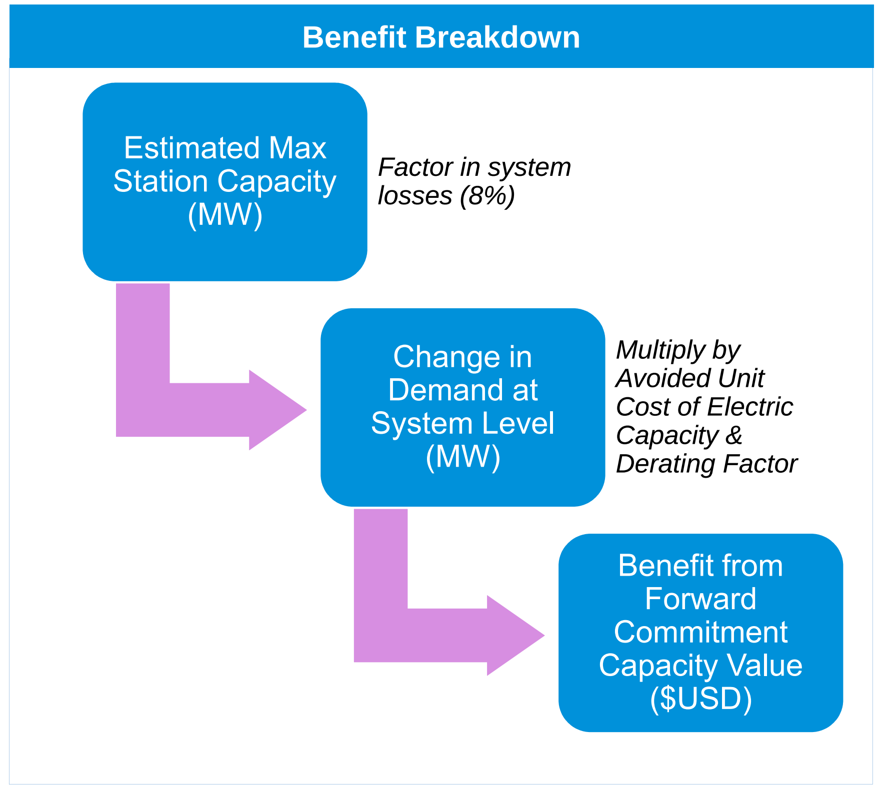
- Forward Commitment Capacity Value
- Energy Supply & Transmission Value of Energy Provided or Saved (ES&T)
- Avoided Renewable Energy Credit (REC) Costs
- Wholesale Market Price Impact
- Environmental Costs
- Non-electric Avoided Fuel Costs

3

Benefits – Forward Commitment Capacity Value

Forward Commitment Capacity Value

- Values the increase or decrease in the total energy demand attributable to the program
- Numbers are delayed by four years because bidding into the forward capacity market takes place 4 years in advance in Rhode Island
- In the case of EV charging stations, the program will lead to an increase in the load demands of the system
- This value is negative, but is accounted for in benefits to maintain consistency across BCAs
- Off-peak rebate cannot participate in the Forward Capacity Market due to its 3-year term; there is a capacity benefit from this program, but not one that can be captured within the AESC framework

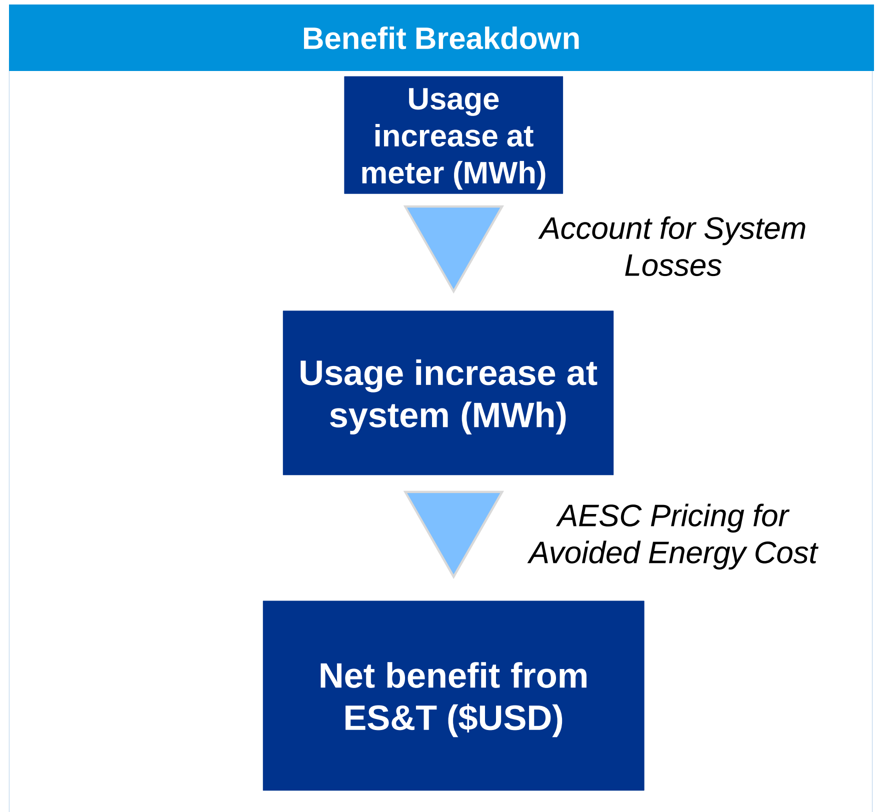


3

Benefits – Energy Supply and Transmission

Energy Supply & Transmission

- ❑ Values the total avoided cost of generating and distributing energy
- ❑ In the case of EV charging stations, the program will lead to a greater level of energy usage
- ❑ In turn, there is an increase in total energy being supplied, meaning that there is an increase in the cost to both generate and transmit this energy



3

Benefits – Avoided REC Costs

Avoided REC Costs

- Despite the increased energy efficiency, there is no qualifying renewable energy being generated by this program
- RECs must be purchased to offset the increased electricity usage
- As a result, this is captured as a negative benefit

Benefit Breakdown

Usage increase at meter (MWh)

÷ 1-System Losses (%)

= Usage increase at system (MWh)

× Avoided REC Cost ($/MWh)

= Total Avoided REC Cost ($USD)

3

Benefits – Wholesale Market Price Impact

Wholesale Market Price Impact

- Values the price changes in the market that are ***directly attributable to the program itself***
- For example, it captures how an increase in the electricity usage impacts the supply and demand
- Uses the AESC Demand Reduction Induced Price Effect to ascribe value to the increase in electricity usage
- Included in RIM test only

Benefit Breakdown

Adjusted Change in Energy Usage (MWh)

× DRIPE ($/MWh)

= Wholesale Market Price Impact ($USD)

3

Benefits – Environmental Costs

Greenhouse Gas Externality Costs

- Measures the monetary value of estimated avoided greenhouse gas emissions
- For transportation, this is calculated by taking the total ICE miles replaced by Electric Vehicles
- This is then multiplied by the average ICE vehicle CO2 emissions rate per mile driven (differs depending on the vehicle)
- The value is then multiplied by the non-embedded cost of CO_2 ($/short ton)
- Calculate the total electricity usage for EVs
- Multiply it by the non-embedded cost of CO2 ($/MWh)
- Net the two values to arrive at the final

Criteria Air Pollutant and Other Environmental Costs

- Attributes value to the avoided emissions of SO2, NOX, and PM2.5
- Uses AESC and EPA prices per ton of avoided emission (by pollutant type)
- Captures the increased environmental and public health benefits of lower particulate emissions
- This captures one of the major benefits of EVs: negligible particulate emissions

3

Benefits – Non-Electric Avoided Fuel Costs

Non-Electric Avoided Fuel Costs

- Values the fuel that is no longer consumed due to the adoption of EV's
- Calculated by taking the total ICE miles replaced by Electric Vehicle miles
- Divide by Average MPG for ICE vehicles to get the total gallons of fuel avoided
- Due to the size of the program and the amount of ICE vehicle miles being displaced, this category offers the most significant benefits

Benefit Breakdown

Total ICE Miles Converted (miles)

÷ Average MPG - ICE vehicle (mpg)

= Total Gallons of Fuel Avoided (gallons)

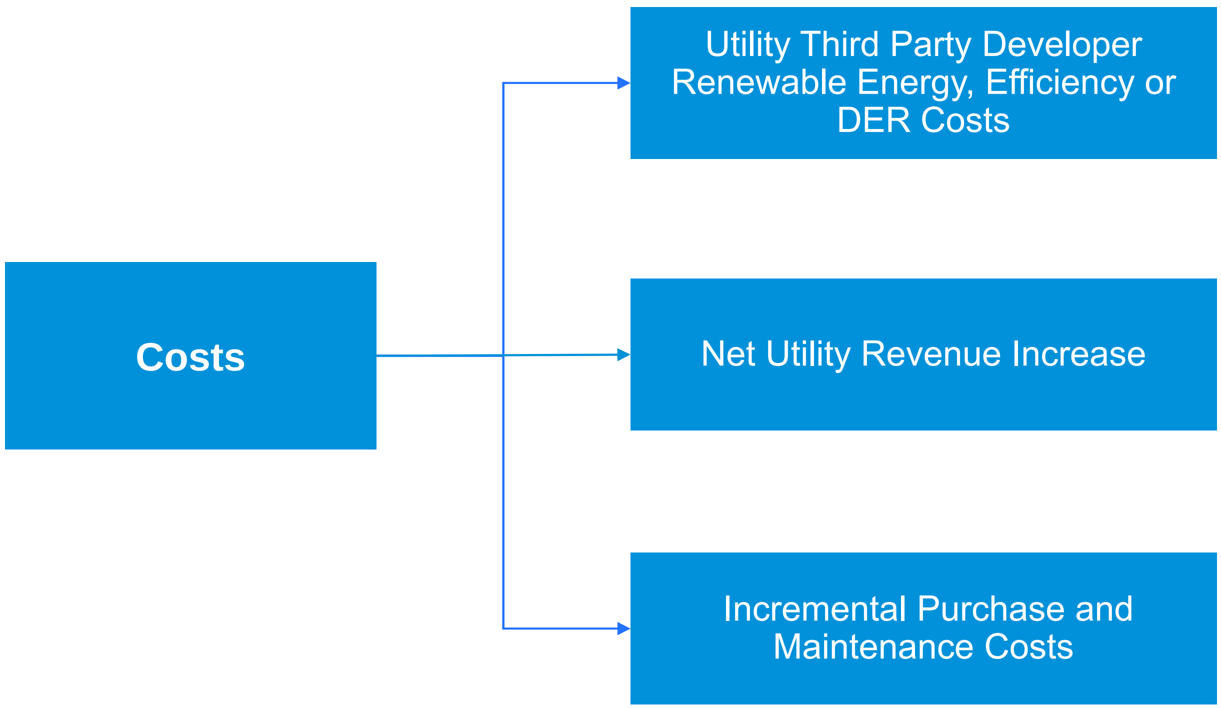
× Average Fuel Price ($USD)

= Non-Electric Avoided Fuel Cost ($USD)

3

Costs – Overview

Costs Components



3

Description of Cost Categories

Utility Third Party Dev. Renewable Energy, Efficiency or DER Costs

Combination of Opex and Capex, less participation payments from station operators

- Differs slightly between Consumer Stations and Fleet & Transit Stations
- Fleet & Transit only have 3 total year of Program Administration Costs
- ~50% of Consumer Stations will be Utility Operated, so a percentage of operating expenditures remain through the life of the program

Net Utility Revenue Increase

Captures National Grid's projected increase in revenue due to the Transportation program

- Uses projected electricity usage for the program and multiplies by the price per kWh
- Only included in the RIM test

Incremental Purchase and Maintenance Costs

Calculates the cost of ownership for consumers

- Incremental purchase price of EV's
- Federal and state tax rebates
- Ongoing maintenance costs for the life of the program

4

Results – Transportation

	Electric Vehicles -- Total		
Benefit	Forward Commitment: Capacity Value	$	(1,016,847)
	Energy Supply & Transmission Operating Value of Energy Provided or Saved	$	(2,005,010)
	Avoided Renewable Energy Credit (REC) Cost	$	(199,162)
	Greenhouse Gas (GHG) Externality Costs	$	4,189,624
	Criteria Air Pollutant and Other Environmental Costs	$	999,129
	Non-Electric Avoided Fuel Cost	$	13,567,821
	Economic Development	$	-
		$	-
	Total	**$**	**15,535,555**
Cost	Total Program Administration Costs	$	10,420,428
	Incremental Purchase and Maintenance Cost	$	4,671,444
		$	-
	Total	**$**	**15,091,871**
	BCA Ratio		**1.03**

GHG Externality Cost is very high because ICE vehicles are being replaced by Electric Vehicles with comparatively low carbon emissions

Non-Electric Avoided Fuel Costs is the largest benefit by a considerable margin because gasoline and diesel powered vehicles are converting to EVs

Incremental Purchase and Maintenance Costs is particularly large for transportation because it accounts for the upfront cost of an ICE vehicle versus an EV

Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models

Electric Heat

Reference Document

November 2017

1

Project Overview – Electric Heat

Project Description

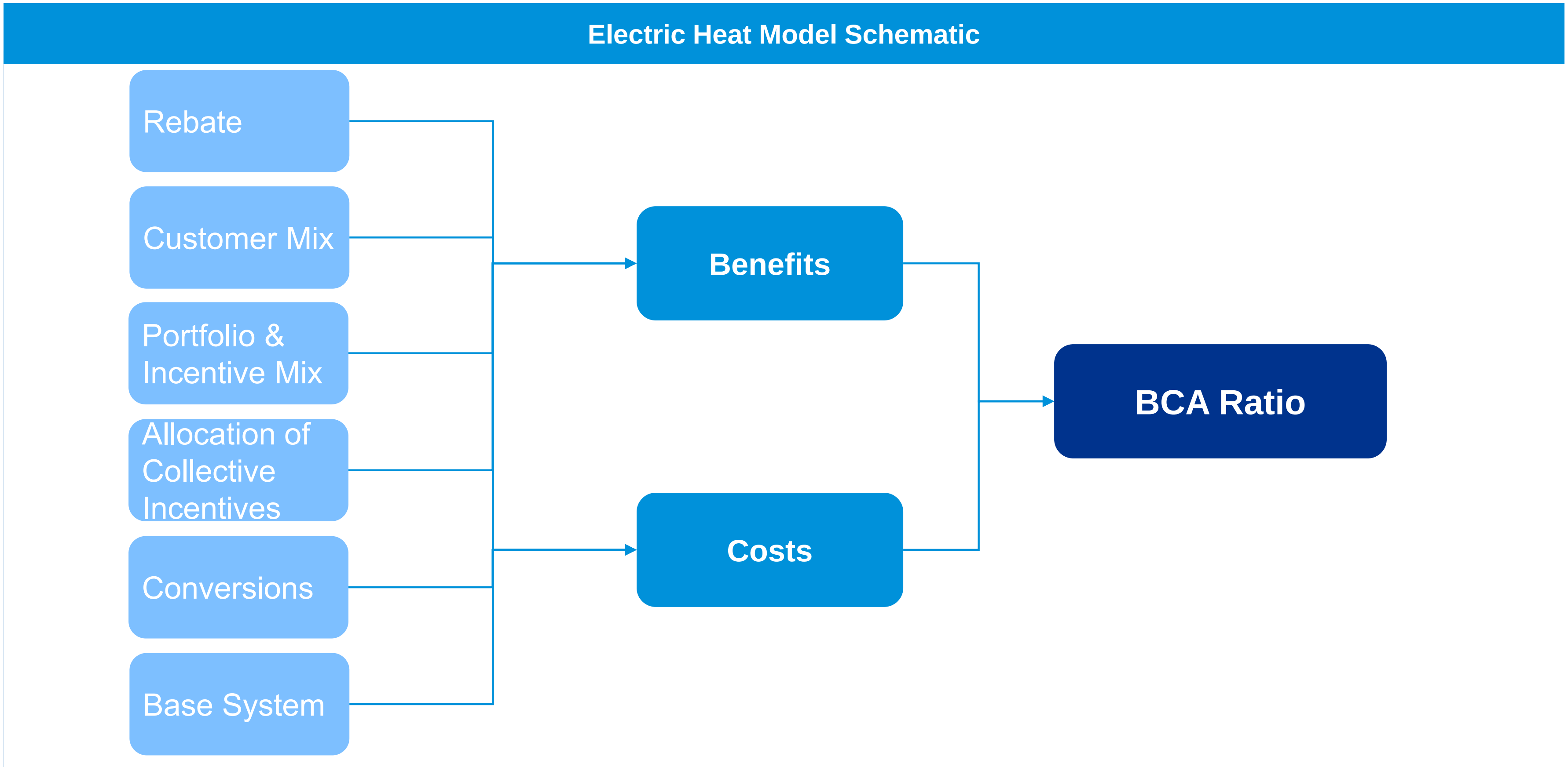
- National Grid is offering equipment incentives to encourage eligible customers to convert from delivered fuels and electric resistance heat to more efficient Air-Source Heat Pumps and Ground-Source Heat Pumps
- In accordance with this program, the company will partner with 2 municipalities annually to set community goals and market heat conversions
- Oil and Propane dealer training programs will also occur to support installation and marketing/sales of staff

Modeling Overview

- Assumptions are made concerning the rebate budget, the portfolio and incentive mix, the customer mix, and the allocation of collective incentives to estimate the number of system conversions for each configuration type
- A base heating and cooling system is then selected to develop a "current state" to compare with the forecasted effects of the conversions

1

Model Overview



2

Key Inputs Table

Key Inputs	Definition	Model Usage	Source(s)
Rebate	• The total budget allotted to incentivize both low income and market customers to switch from their base heating and cooling system to an electric heat pump system • The percentage of the total installation costs that customers will receive by participating in the program is also a major driver A larger rebate percentage leads to fewer conversions	*Involved in determining the total number of conversions*	Mackay Miller and RI testimony
Portfolio and Incentive Mix	• The percentage share of the rebate that goes to low income participants versus market participants • The larger share that goes to market participants, the higher the SCT ratio because they are receiving a much lower rebate %		
Conversions	• The total number of systems converted into electric heat systems • The number of system conversions for each system configuration is a function of the rebate specifications, the allocation of collective incentives, the incentive mix and the customer mix	*A key driver of every benefit category*	Calculated based on information from Mackay Miller and RI testimony
Allocation of Collective Incentives	• Determines the share of total incentives that is allocated towards each system type	*Determines which system configurations will see the most conversions*	Mackay Miller and RI testimony
Customer Mix	• The target level of customers that will be low income versus market participants • The higher percentage that are market participants, the higher the SCT ratio because more conversions will occur	*Contributes to the total number of conversions*	Mackay Miller and RI testimony
Base System	• Defines the system that will be converted to electric heat • Provides the model with a baseline for comparison • Options for Base Heat include Fuel Oil, Propane, Natural Gas, and Electricity • Options for Base Cooling include No AC, Window AC, and Central AC	*Impacts the magnitudes of nearly every benefits category*	Mackay Miller and RI testimony

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2

Control Panel Breakdown

Control Panel - select heating portfolio scenario in table below	
Switch key:	
Select from Drop-down	
Populate Area	

Control Panel Description

- The numbers have been saved as default, agreed-upon values with the project teams. The switches only exist to add a degree of flexibility for the user and the program to test scenarios
- **Select from Drop-down**: There is a set list of options that were predetermined by the National Grid team and KPMG
- **Populate Area**: The user can input any number themselves and it will flow through the model

2

Key Inputs #1-2 – Customer Mix & Rebate Budget

Sensitivity Analysis of Low-Income Participation & Low-Income Rebate %

% Low-Income Customers	50%
Low-Income Rebate %	100%

Low-Income Rebate (%)

Low-Income Customers (% of Total)

1.12	5%	25%	50%	75%	100%
10%	1.31	1.27	1.26	1.26	1.26
20%	1.35	1.25	1.24	1.23	1.23
30%	1.37	1.24	1.21	1.20	1.20
40%	1.39	1.22	1.18	1.17	1.16
50%	1.41	1.21	1.15	1.13	1.12
60%	1.43	1.19	1.11	1.08	1.06
70%	1.44	1.17	1.06	1.02	0.99
80%	1.45	1.14	1.00	0.93	0.89
90%	1.47	1.11	0.93	0.82	0.77
100%	1.48	1.09	0.85	0.71	0.63

Sensitivity Analysis of Low-Income Participation & Rebate Total

% Low-Income Customers	50%
Total Rebate Budget	708,750

Total Rebate ($)

Low-Income Customers (% of Total)

1.12	500,000	708,750	1,000,000	1,250,000	1,500,000
10%	1.16	1.26	1.34	1.38	1.41
20%	1.13	1.23	1.31	1.36	1.39
30%	1.09	1.20	1.29	1.34	1.37
40%	1.05	1.16	1.26	1.31	1.35
50%	1.00	1.12	1.22	1.28	1.32
60%	0.94	1.06	1.17	1.24	1.28
70%	0.87	0.99	1.11	1.18	1.23
80%	0.78	0.89	1.02	1.10	1.16
90%	0.66	0.77	0.90	0.98	1.05
100%	0.52	0.63	0.73	0.81	0.87

Customer Mix: Input the target percentage of customers that are low-income participants. Low-income recipients receive 100% installation rebates. Therefore, the higher the percentage of low income customers, the lower the SCT.

Rebate Budget: Input the total rebate budget. The sensitivity table shows that a larger rebate budget generally leads to a higher SCT because it will drive more conversions.

2

Key Inputs #1,3,4 – Incentives & Rebate %

Portfolio & Incentive Mix

Customer	% of Total
Low-Income	50%
Market	50%
Total	100%

Portfolio and Incentive Mix: Input the allocation percentage of the rebate budget between the Low-income and Market participants.

Allocation of Collected Incentives

System Type	Low-Income	Market
ASHP 3 ton	50%	50%
ASHP 5 ton	0%	0%
GSHP Horizontal Loop 4 ton	50%	50%
GSHP Vertical Loop 82 ton	0%	0%
Total	100%	100%
Check (Sum equal to 100%)	Y	Y

Allocation of Collective Incentives: After selecting the customer segment allocation, the user must input the percentage of the budget the flows toward each type of electric heating system. This drives the model's system adoption logic.

Rebate by Customer Type and System

Customer	System	Tons (per system)	Cost ($/ton)	Rebate ($/ton)	Rebate %
Low-Income	ASHP 3 ton	3	3,200.00	3,200.00	100%
	ASHP 5 ton	5	3,381.00	3,381.00	100%
	GSHP Horizontal Loop 4 ton	4	7,988.24	7,988.24	100%
Market	ASHP 3 ton	3	3,200.00	500.00	16%
	ASHP 5 ton	5	3,381.00	500.00	15%
	GSHP Horizontal Loop 4 ton	4	7,988.24	750.00	9%

Rebate %: Input the rebate percentage for each system type and customer segment to generate economics.

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2

Key Inputs #5,6 – Base System & Conversions

System Technology Selections				Incentive Allocated	Progression Schedule (number of conversions)					
Technology Type	Base Heating	Base Cooling	New System Type	(y/n)	2018	2019	2020	2021	2022	Total Converted
Type A	Fuel Oil	No AC	ASHP 3 ton	Yes	39.00	45.00	50.00	-	-	134.00
Type B	Fuel Oil	No AC	GSHP Horizontal Loop 4 ton	Yes	18.00	20.00	24.00	-	-	62.00
Type C	Fuel Oil	No AC	GSHP Vertical Loop 82 ton	N/A	-	1.00	-	-	-	1.00
Type D	Fuel Oil	No AC	ASHP 5 ton	No	-	-	-	-	-	-
			Total		57.00	66.00	74.00	-	-	197.00

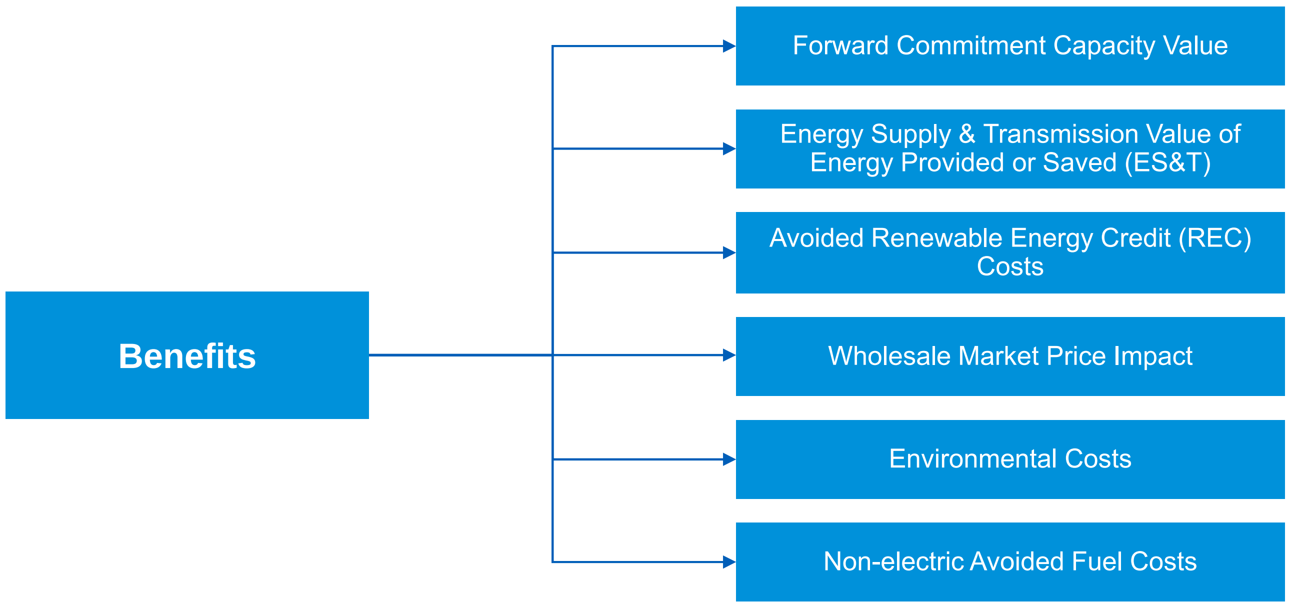
Base System: Select the assumed base system that the customer is switching over from. This will impact the total magnitude of the conversions across the benefits categories

Conversions: The number of conversions from the base system to the electric heating systems is a function of all the other key inputs. After making the previous specifications, the number of conversions for each system type will be determined

3

Benefits – Overview

Benefits Components



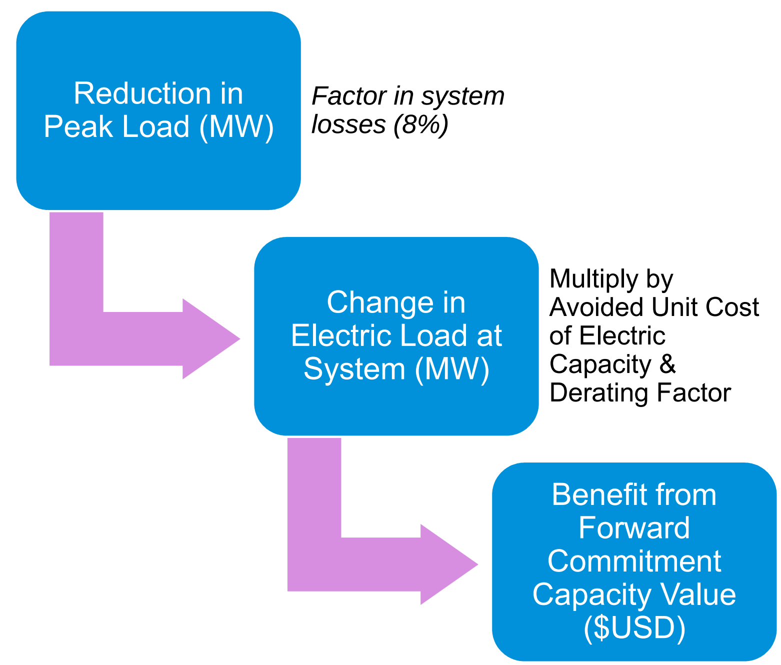
3

Benefits – Forward Commitment Capacity Value

Forward Commitment Capacity Value

- Values the increase or decrease in the total energy demand attributable to the program
- Numbers are delayed by four years because you must bid into the forward capacity market 4 years in advance
- In the case of Electric Heat, the program will lead to an overall decrease in the load demands of the system
- Although the majority of the participants will switch from fossil fuel systems to electric heat pumps, some will switch from highly inefficient electric systems
- This switch will offset any increased load from the heat pumps and yield a net benefit for the program

Benefit Breakdown

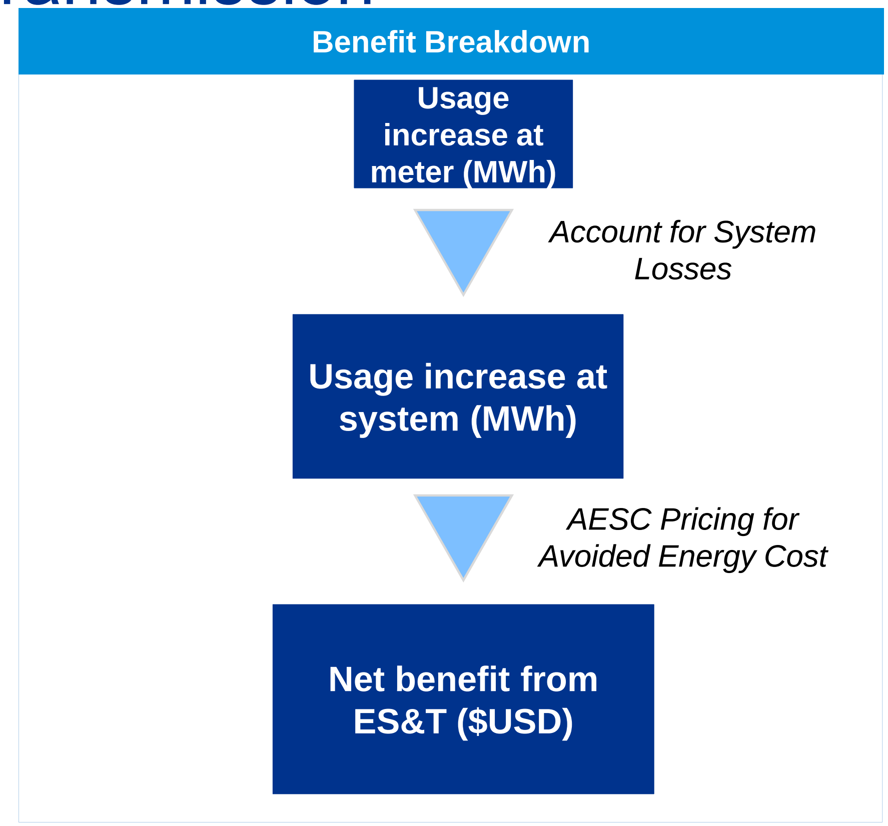


3

Benefits – Energy Supply and Transmission

Energy Supply & Transmission

- Values the total avoided cost of generating and distributing energy
- The electric heat program will lead to a greater level of total electricity usage
- In turn, there is an increase in the cost to generate and transmit this energy



3

Benefits – Avoided REC Costs

Avoided REC Costs

- Despite a large increase in energy efficiency, there is no qualifying renewable energy being generated by this program
- RECs must be purchased to offset the increased electricity usage
- As a result, this is captured as a negative benefit

Benefit Breakdown

Adjusted Change in Energy Usage (MWh)

× Avoided REC Cost ($/MWh)

= Total Avoided REC Cost ($USD)

3

Benefits – Wholesale Market Price Impact

Wholesale Market Price Impact

- Values the price changes in the market that are ***directly attributable to the program itself***
- For example, this value captures how an increase in the electricity usage impacts real-world supply and demand
- Uses the AESC Demand Reduction Induced Price Effect to ascribe value to the increase in electricity usage
- Only included in the RIM test

Benefit Breakdown

Adjusted Change in Energy Usage (MWh)

× DRIPE ($/MWh)

= Wholesale Market Price Impact ($USD)

3

Benefits – Environmental Costs

Greenhouse Gas Externality Costs

- Multiplies the increased electricity usage from the heat pumps by the non-embedded CO2 cost to get the Electricity Added Carbon Benefits

- Multiplies the CO2 emissions per unit by the fossil fuel usage reduction

  -Multiply this number by the non-embedded CO2 cost to Fossil Fuel Carbon Benefits

- Take the net value of Fossil Fuel Carbon Benefits and Electricity Added Carbon Benefits

Criteria Air Pollutant and Other Environmental Costs

- Values the net avoided emissions by switching from a fossil fuel system to an electric heat system

- Uses AESC and EPA prices per ton of avoided emissions

- Captures the increased environmental and public health benefits of lower particulate emissions

Benefits – Non-Electric Avoided Fuel Costs

Non-Electric Avoided Fuel Costs

- Values the fuel not consumed due to the adoption of the electric heating system
- Multiplies the reduction in consumption by the average price of consumption ($/MMBTU)
- This category captures the majority of the benefits of the electric heating system conversions

Benefit Breakdown

Base Fuel Consumption Cost ($USD)

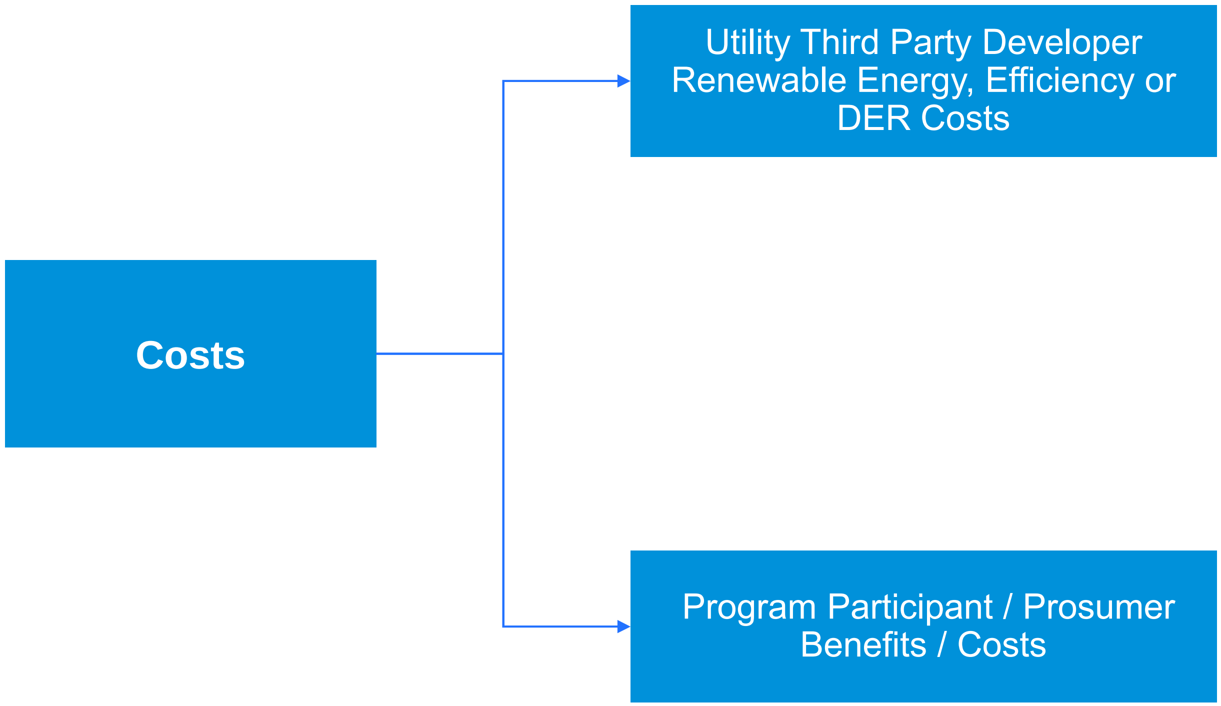
× Base Fuel Reduced Consumption ($USD)

= Non-Electric Avoided Fuel Cost ($USD)

3

Costs – Overview

Costs Components



3

Description of Cost Categories

Utility Third Party Developer Renewable Energy, Efficiency or DER Costs

Incentive costs and program administration costs

- Incentives are for system installations and community programs
- Program administration costs are for community programs and oil dealer training & support

Program Participant / Prosumer Benefits / Costs

Captures participant's net installation costs

- Uses the total installation cost and subtracts any applicable incentives

4

Electric Heat – Results

EH - BCA Summary

Societal Cost Test

RI Electric Heat BCA

	Electric Heat - BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	277,788
	Energy Supply & Transmission Operating Value of Energy Provided	$	(1,121,845)
	Avoided Renewable Energy Credit (REC) Cost	$	(99,926)
	0	$	-
	Greenhouse Gas (GHG) Externality Costs	$	527,088
	Criteria Air Pollutant and Other Environmental Costs	$	222
	Non-Electric Avoided Fuel Cost	$	4,162,394
	Economic Development	$	-
	0	$	-
		$	**3,745,721**
Cost	Utility / Third Party Developer Renewable Energy, Efficiency, or	$	1,073,830
	Program Participant / Prosumer Benefits / Costs	$	2,275,503
		$	**3,349,332**
	BCA Ratio		**1.12**

Non-Electric Avoided Fuel Costs is the largest benefit by a considerable margin because the program results in people switching from a fuel-based heating system to an electric heat pump. This switch generates savings from avoided purchase of fuel oil, natural gas, or propane.

Electric Heat Pumps are much more energy efficient than the base systems, so the major cost to market participants is **installation costs**. This cost category can change based on conversion count and the customer mix.

KPMG

Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models

Solar

Reference Document

November 2017

Project Overview – Solar

Project Description

– National Grid will be constructing solar generation units at three different sites. One 0.25 MW site will be built in 2018, one 0.5 MW site will be built in 2019, and one 1.5 MW site will be built in 2020

– The benefits from these respective sites will come on line one year after they are built

– The two smaller systems are intended to be canopies, and the larger to be a simple rooftop or fixed ground installation (e.g., no advancing tracking hardware/software is planned)

Modeling Overview

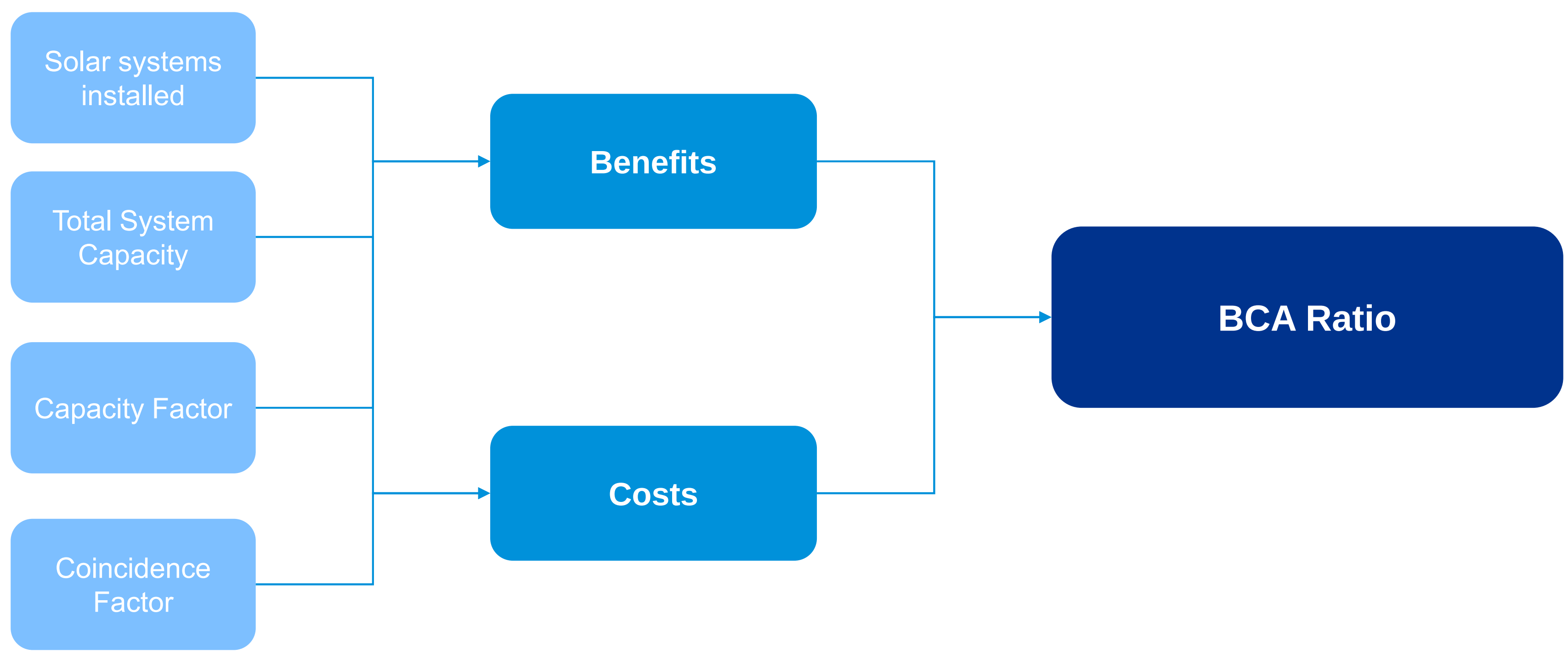
– Total System Capacity and Capacity Factor are used to estimate the total annual energy output from solar generation and derive an Adjusted Peak Load

– These numbers are then used with AESC prices to value the capacity and usage benefits from the solar program

1

Model Overview

Solar Model Schematic



2

Key Inputs Table

Key Inputs	Definition	Model Usage	Source(s)
Systems Built	• The total number of systems built by National Grid and their respective years. • NG is building one 0.25 MW solar canopy in 2018, one 0.5 MW solar canopy in 2019, and a larger 1.5 MW solar unit in 2020	*Used to determine the peak site capacity and the total solar energy generation in a given year*	Calculated based on RI testimony
Total System Capacity	• The peak capacity of the total solar generation system • The sites come on line and start accruing benefits the year after they are built		
Capacity Factor	• The ratio of actual power generation over a year divided by installed capacity • The capacity factor suggests that, over the course of a year, the system is generating energy at 16.1% of its peak operating capacity • Solar has a relatively low capacity factor in comparison to other forms of energy generation	*Used with total system capacity to estimate the average annual output from solar generation*	PV Watts
System Coincidence Factor	• A measure of solar generation capacity during the time of peak energy demand • The amount of energy that it generates during this period informs how much it reduces the peak load of the system • Estimated to be 28.1% • This input is largely determined by system site selection, panel orientation, and the climate of the region – all inputs contributing to the amount of sunlight that gets captured	*Used to calculate the Benefit from Forward Commitment Capacity Value*	Confirmed with project team

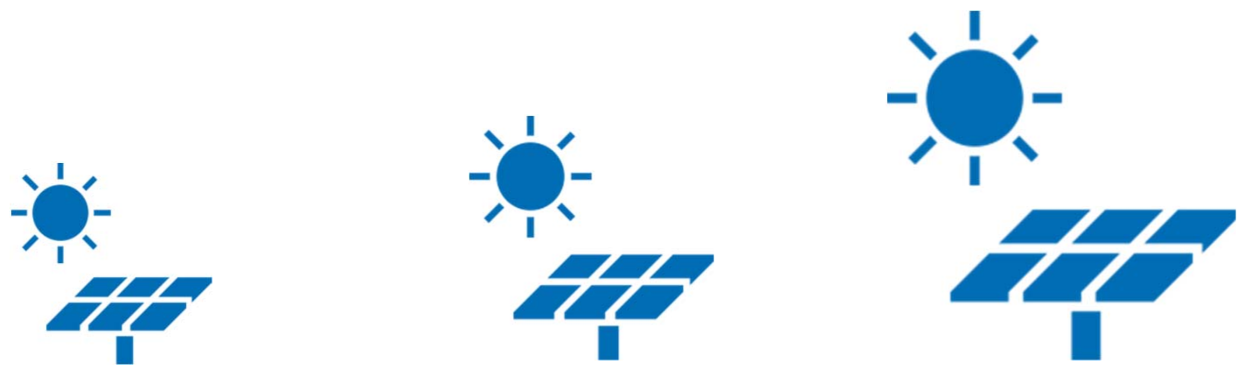
Key Inputs #1/2 – Systems Installed & Capacity

- National Grid will undergo construction of 3 solar sites from 2018 to 2020
- Over this period, the total system capacity will increase from 0.25 MW to 2.25 MW
- These systems all have a useful life of 25 years

2018
- System Type A: 0.25 MW

2019
- System Type B: 0.5 MW

2020
- System Type C: 1.5 MW



2

Key Input #3 – Capacity Factor

Input Breakdown

System Capacity
The peak capacity of the identified system (MW)

Capacity Factor
Average operating capacity as a percent of peak capacity (%)

Energy Output from Solar Generation
Total amount of energy generated from system (MWh)

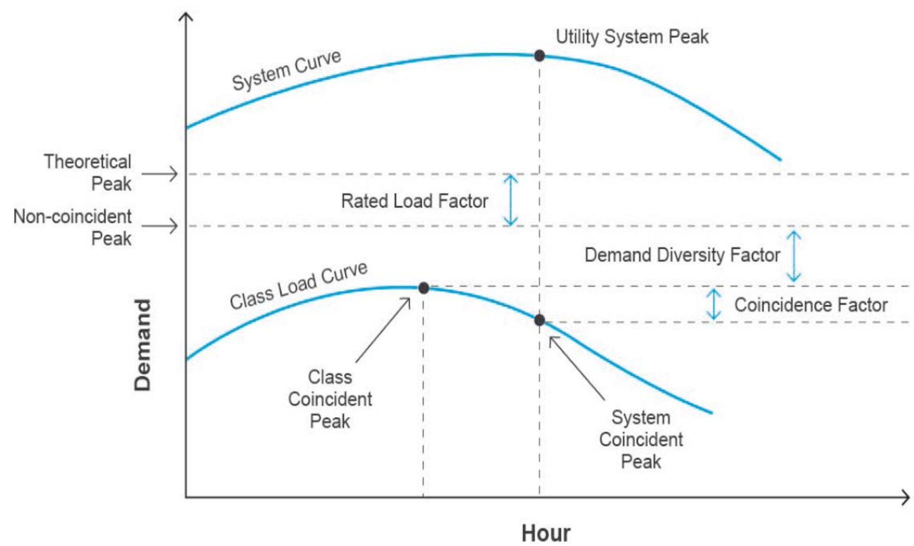
- The capacity factor is a descriptive statistic characterizing the average operating capacity of the systems in question
- This is expressed as a percentage of the peak system capacity
- This is an important metric because it can be used to determine which locations and sites are most suitable for solar
- Used in combination with peak system capacity, it is possible to estimate the average energy output from solar generation

2

Key Input #4 – Coincidence Factor

- The System Coincidence Factor for solar is a measure of the system operating capacity during the utility system peak demand
- It measures how much the peak system load overlaps with periods of strong sunlight absorption
- A key driver for this factor is the amount of sunlight available for conversion into energy
- Used in the calculation for the Forward Commitment Capacity Value

Illustration of System Coincidence Factor

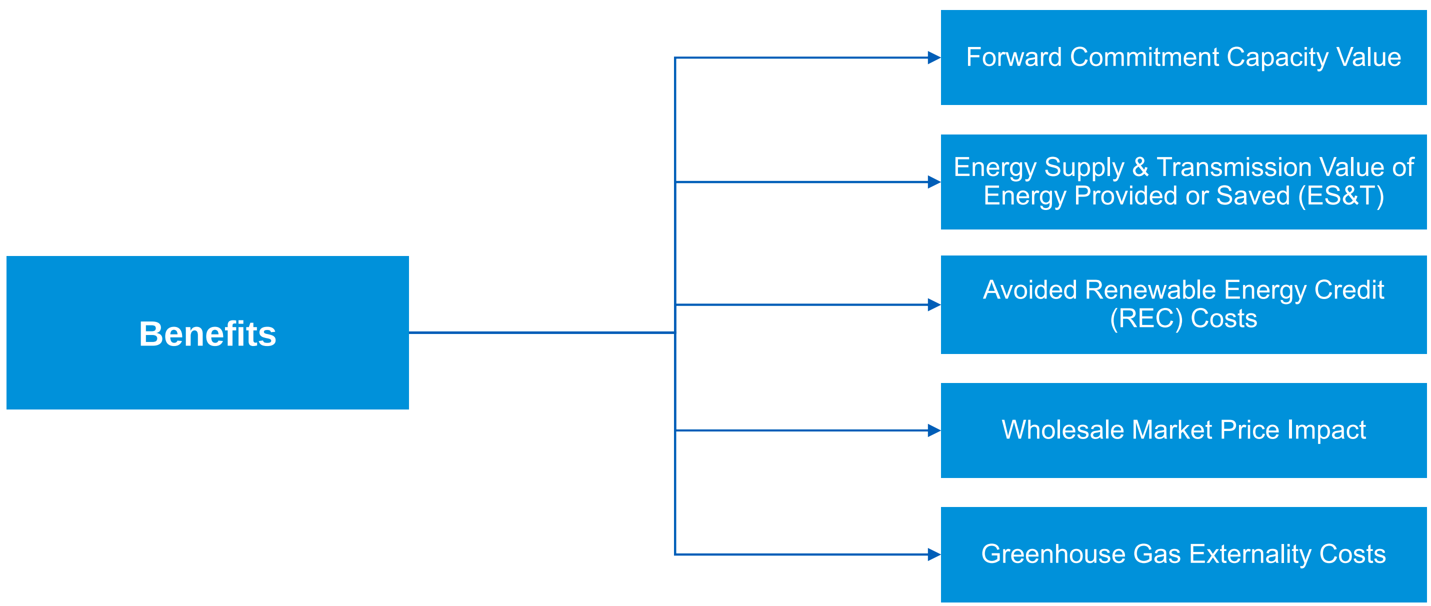


Source: NREL – Peak Demand and Time-Differentiated Energy Savings Cross-Cutting Protocols

3

Benefits Overview

Benefits Components



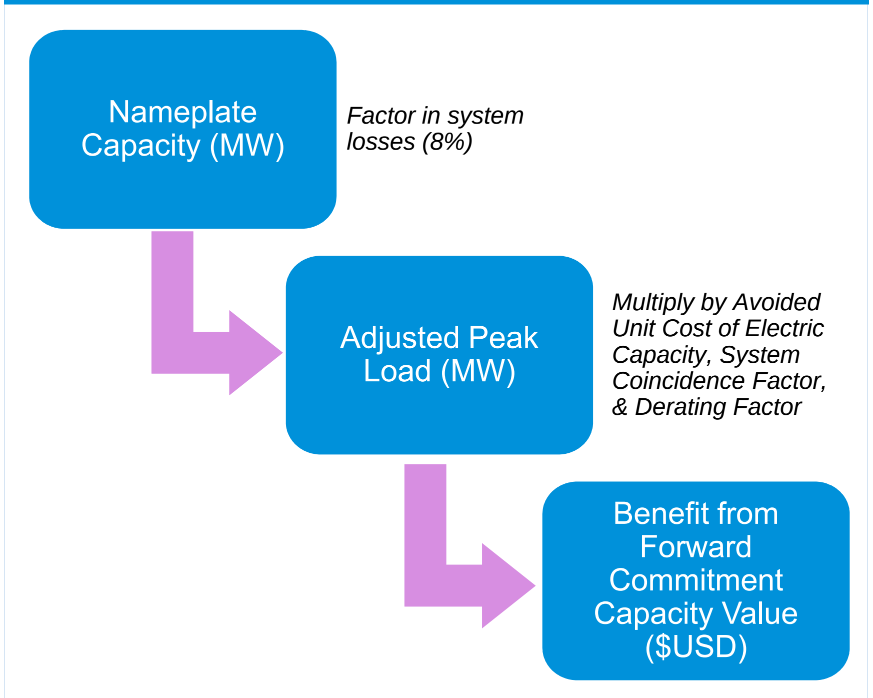
3

Benefit – Forward Commitment Capacity Value

Forward Commitment Capacity Value

- Values the increase or decrease in the total energy demand attributable to the program
- Numbers are delayed by four years because of requirement to bid into the forward capacity market 4 years in advance
- Increased energy generation from Solar helps to lessen the total load demand on the system
- This provides a large benefit for the Solar BCA

Benefit Breakdown

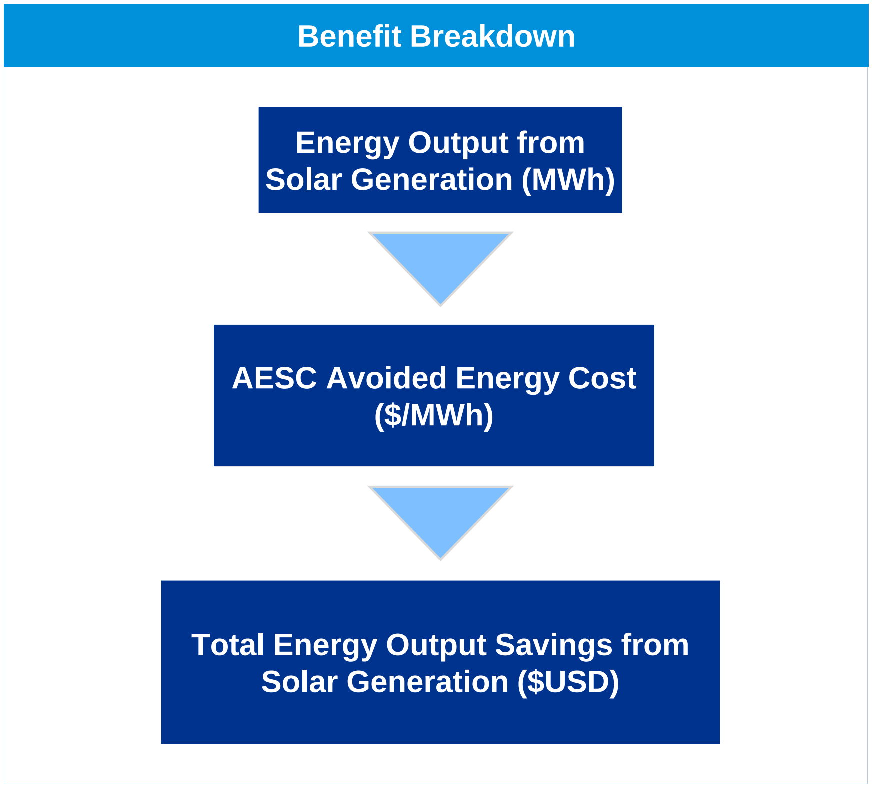


3

Benefit – Energy Supply & Transmission

Energy Supply & Transmission

- ❑ Values the total avoided cost of generating and distributing energy
- ❑ In the case of Solar generation, the program will reduce the amount of energy that needs to be generated and supplied at the system level
- ❑ In turn, the Solar program is attributed the value of this avoided generation and transmission



3

Benefit – Avoided REC Costs

Avoided REC Costs

- For every MWh of power generated by the solar systems, National Grid will receive 1 REC
- These provide tangible value to the company because each REC accrued from generation is one that they can avoid purchasing later (or can offset existing obligations)

Benefit Breakdown

Total Energy Output from Solar Generation (MWh)

× Avoided REC Cost ($/MWh)

= Total Avoided REC Cost ($USD)

3

Benefit – Wholesale Market Price Impact

Wholesale Market Price Impact

- Values the price changes in the market that are ***directly attributable to the program itself***
- For example, it captures how an increase in the electricity usage impacts the supply and demand
  - Uses the AESC Demand Reduction Induced Price Effect to ascribe value to the increase in electricity usage
- Only included in the RIM test

Benefit Breakdown

Total Energy Output from Solar Generation (MWh)

× DRIPE ($/MWh)

= Wholesale Market Price Impact ($USD)

3

Benefit – GHG Externality Cost

Avoided Greenhouse Gas Externality Costs

- Measures the monetary value of estimated avoided greenhouse gas emissions
- For Solar, the resulting energy output from solar generation is assumed to displace the same amount of energy at the system level
- This results in a switch from an emissions generating energy source to a "zero" emissions source
- Therefore, National Grid is avoiding GHG emissions that would have occurred if not for increased solar generation

Benefit Breakdown

Total Energy Output from Solar Generation (MWh)

× Non-embedded CO2 cost ($/MWh)

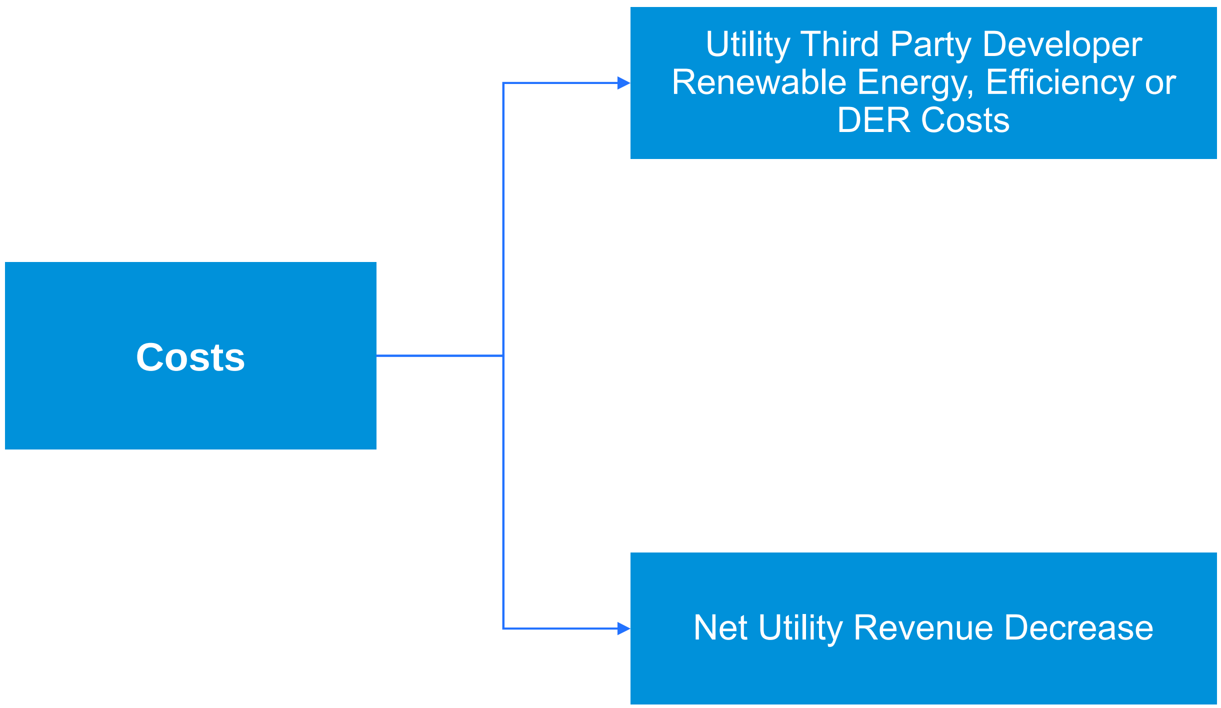
= Greenhouse Gas Externality Cost ($USD)

Source: NREL; Profim

3

Costs Overview

Costs Components



Description of Cost Categories

Utility Third Party Developer Renewable Energy, Efficiency or DER Costs

Combination of Capex and Opex Sub-total, less any relevant tax incentives

- Capex refers to the direct cost of building the sites
- Opex Sub-total includes the ongoing site maintenance costs as well as the inverter leases
- Tax incentives refer to the ITC tax incentive as well as the R&D tax incentive

Net Utility Revenue Decrease

Captures National Grid's projected decrease in revenue attributable to the program

- Accounts for the fact that the utility will not be receiving charges from electricity generation
- This cost is only included in the RIM test

4

Solar – Results

The greatest benefit comes from the avoided generation and transmission of energy.

Solar panels will be replacing an energy source that most often emits far greater amounts of greenhouse gases.

Societal Cost Test

RI Solar BCA

	Solar - BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	1,204,029
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)	$	3,022,542
	Avoided Renewable Energy Credit (REC) Cost	$	213,002
		$	-
	Greenhouse Gas (GHG) Externality Costs	$	1,605,107
	Non-Electric Avoided Fuel Cost	$	-
	Economic Development	$	-
		$	-
		$	**6,044,680**
Costs	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	$	7,093,687
		$	-
		$	**7,093,687**

BCA Ratio **0.85**

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Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models

Energy Storage

Reference Document

November 2017

1

Project Overview – Energy Storage

Project Description

- National Grid proposes constructing 2 energy storage batteries: one ~0.50 MWh battery will be built in 2018, and another ~0.75 MWh battery will be built in 2019
- The storage systems will begin providing benefits one year after they are built
- They will be deployed in areas that maximize the benefits to the transmission system and to customers/partners
- National Grid's preference is to work with a local partner to share in both the costs and benefits and to maximize engagement with the broader community whenever possible

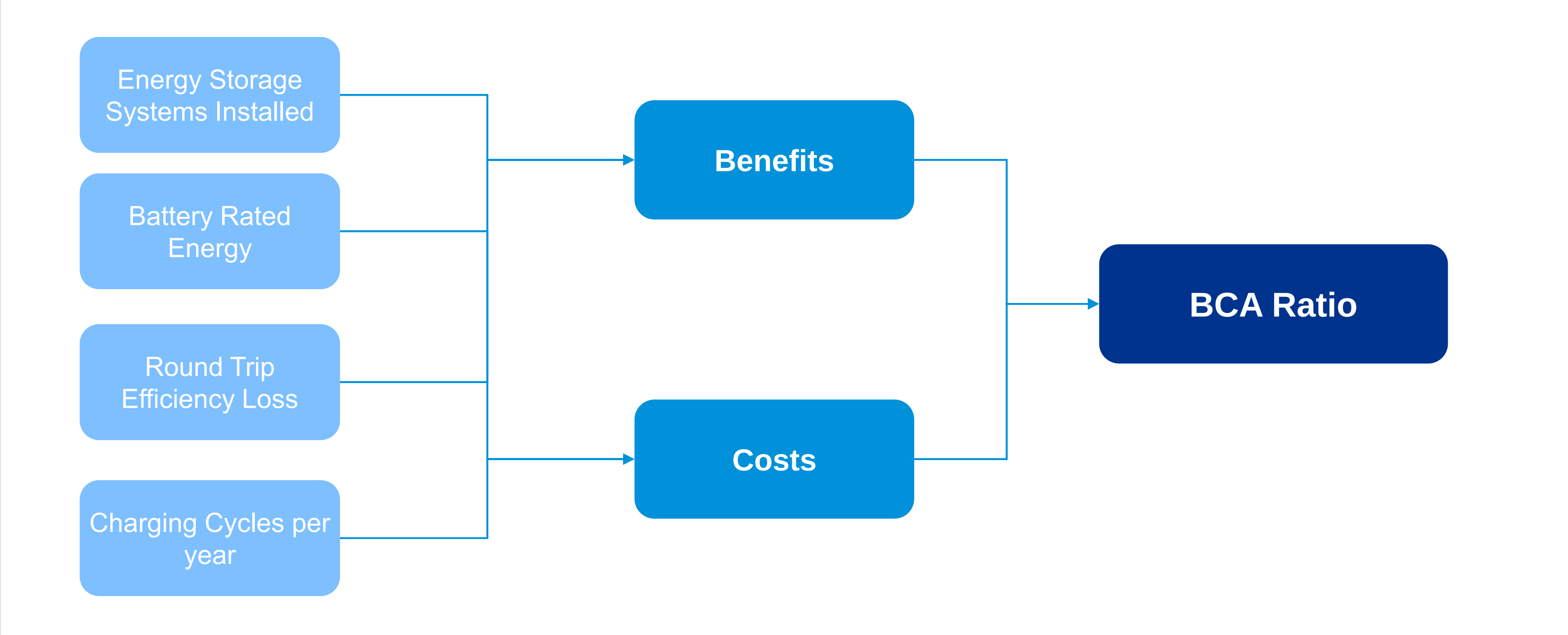
Modeling Overview

- Given rated energy, the difference is calculated between energy displaced from Off-peak to On-peak over a single full charging cycle
- An assumption is then made regarding number of cycles per year as well as the round trip efficiency loss
- Using these factors, it is possible to forecast the total energy displaced annually and the total energy charged annually
- These numbers – along with AESC & ISO-NE market prices – are utilized to calculate usage-related benefits.
- In order to capture the increased capacity benefits, an assumed ratio of capacity to energy can be used to calculate the reduction in the system's peak load

1

Model Overview

Energy Storage Model Schematic



2

Key Inputs

Key Inputs	Definition	Model Usage	Sources
Energy Storage Systems Built	• The total number of systems built by National Grid and their respective years. • NG is building one 0.5 MW battery in 2018, and one 0.75 MW battery in 2019	*Used in order to calculate the amount of energy displaced from On-peak to Off-peak as well as the change in energy load*	RI testimony - October 3rd 2017 -
Battery Rated Energy	• The total amount of energy that the batteries can store • The batteries are assumed to come online and start accruing benefits the year after they are built		
Round Trip Efficiency Loss	• The amount of energy lost when converting from one system to another • Assumed round trip efficiency loss was 10%, meaning that through the process of charging and discharging the batteries lose about 10% of usable energy	*Used in order to calculate the total energy usage increase which is used in all usage related benefits*	Kenmore Energy Storage Project File
Charging Cycles per Year	• The amount of times a battery charges and discharges annually • Assuming 1 discharge per day, 5 days per week	*Used to calculate the total energy displaced and charged annually*	Lazard Levelized Cost of Storage 2.0 Study

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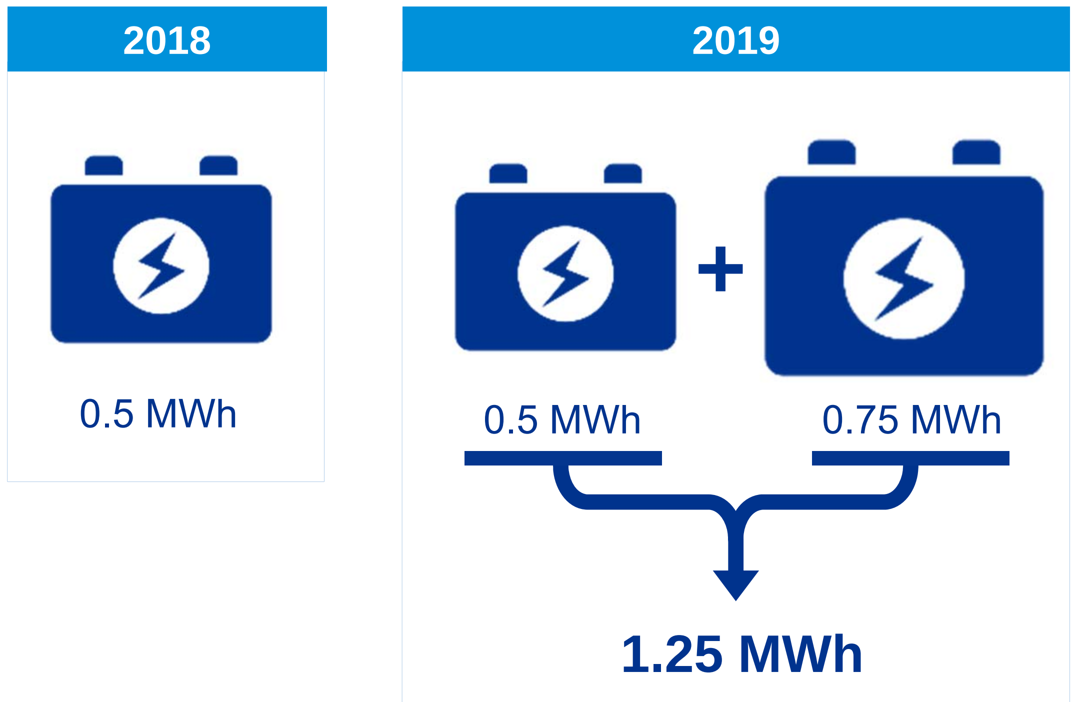
2

Key Input #1-2 – System Builds & Total Energy

- National Grid proposes the construction of 2 energy storage systems in 2018 and 2019
- Over this period, the total storage of the system increases from 0.5 MWh to 1.25 MWh
- Systems are assumed to have a useful life of 12 years
- Benefits begin accruing in the year following the system build



2

Key Input #3 – Round Trip Efficiency Loss

Input Breakdown

Battery Rated Energy
- The amount of MWh hours that the battery is capable of storing (MWh)

Total Energy Displaced
- The amount of energy displaced from On-peak to Off-peak (MWh)

Round Trip Efficiency Loss
- The amount of useful energy lost during conversion (%)

Total Energy Charged
- The amount of energy required to in order to displace a commensurate amount between Off-peak and On-peak (MWh)

- Round trip efficiency loss refers to the ratio of energy stored to energy retrieved
- 10% round trip efficiency loss suggests that if you charge 1.11 MWh Off-peak, ~1 MWh of energy if effectively displaced
- Battery efficiency is quickly approaching (and in some cases surpassing) 90% for standard lithium-ion configurations

2

Key Input #4 – Charging Cycles Per Year

- The total number of charges and discharges annually
- Adjusts energy usage numbers from per cycle basis to an annual basis
- Assumes 1 charge per day, 5 days per week

Charge/Discharge Components

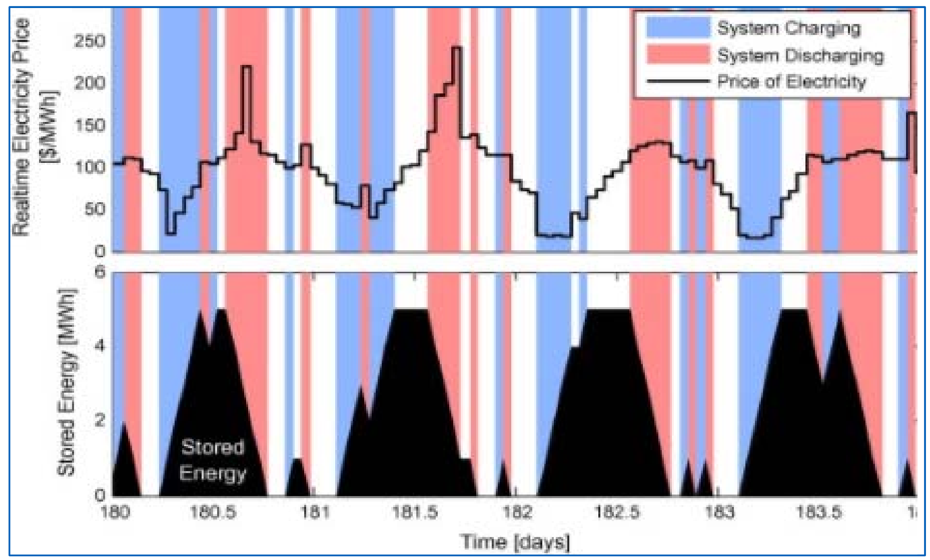
Total Energy Displaced (per cycle) (MWh)
Charging Cycles per Year (#)
System Losses (%)
Depth of Charged (%)

→ Total Energy Displaced Annually (MWh)

Total Energy Charged (per cycle) (MWh)
Charging Cycles per Year (#)
System Losses (%)
Depth of Charge (%)

→ Total Energy Charged Annually (MWh)

Sample Battery Dispatch Profile



Benefits – Overview

Benefits Components

Benefits

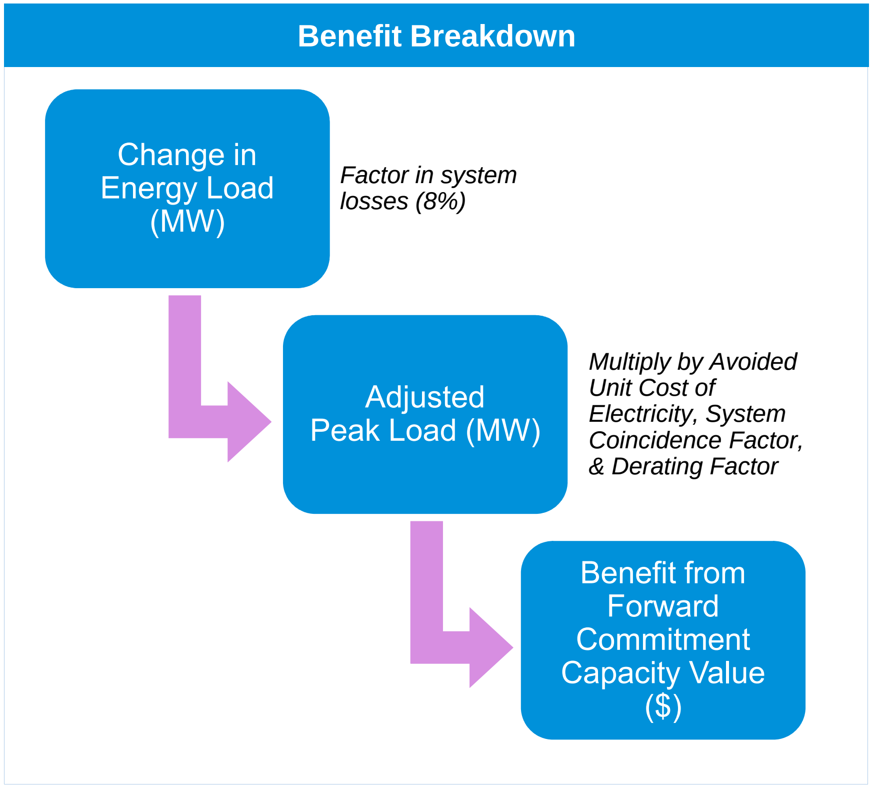
- Forward Commitment Capacity Value
- Energy Supply & Transmission Value of Energy Provided or Saved (ES&T)
- Avoided Renewable Energy Credit (REC) Costs
- Wholesale Market Price Impact
- Greenhouse Gas Externality Costs
- Frequency Regulation

3

Benefits – Forward Commitment Capacity Value

Forward Commitment Capacity Value

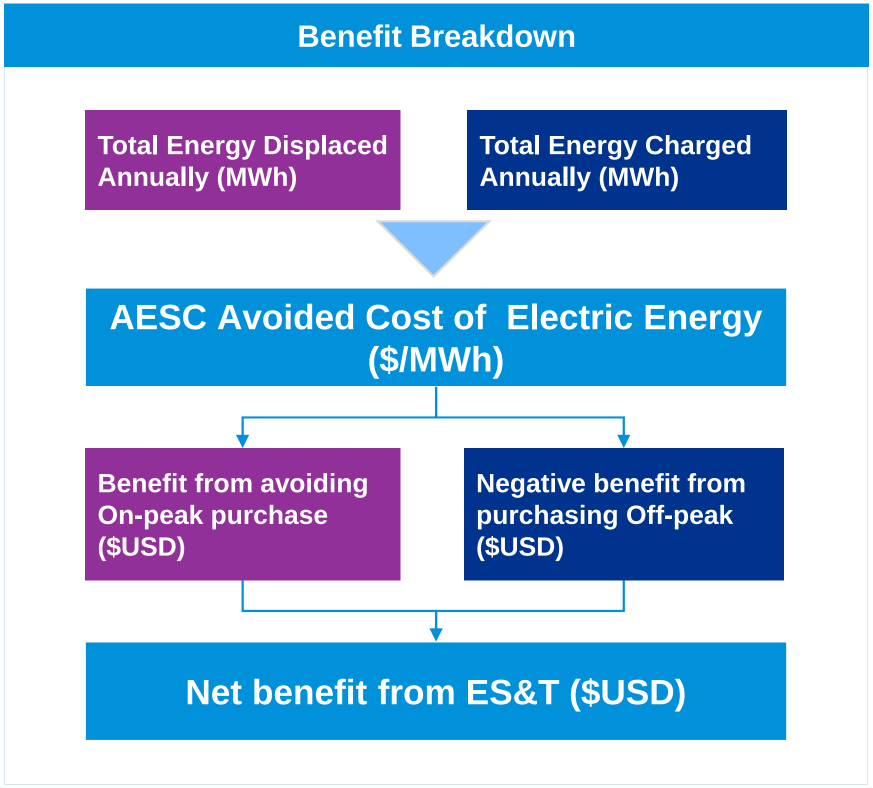
- Values the increase or decrease in the total energy demand attributable to the program
- Numbers are lagged by four years because you must bid into the forward capacity market 4 years in advance (in accordance with AESC guidance)
- The displaced energy from charging Off-peak and discharging On-peak supports the grid during times of peak load
- Capacity is a major benefit of Energy Storage in most jurisdictions, though payment mechanisms vary and are currently in a state of flux



Benefits – Energy Supply & Transmission

Energy Supply & Transmission

- Attributes a monetary value to the total avoided cost of generating and distributing energy
- In the case of Energy Storage, the batteries will charge energy Off-peak and discharge On-peak
- This has a major benefit for capacity but also increases total energy usage due to efficiency loss
- However, the On-peak prices are much higher than Off-peak price, so ES&T becomes a net positive benefit for Energy Storage



3

Benefits – Avoided REC Costs

Avoided REC Costs

- For each MWh of power generated from a renewable energy source, National Grid receives 1 REC
- The Energy Storage program has a negative Avoided REC Cost because they are increasing energy usage and have to purchase RECs to offset usage increase

Benefit Breakdown

Adjusted Change in Energy Usage (MWh)

× Avoided REC Cost ($/MWh)

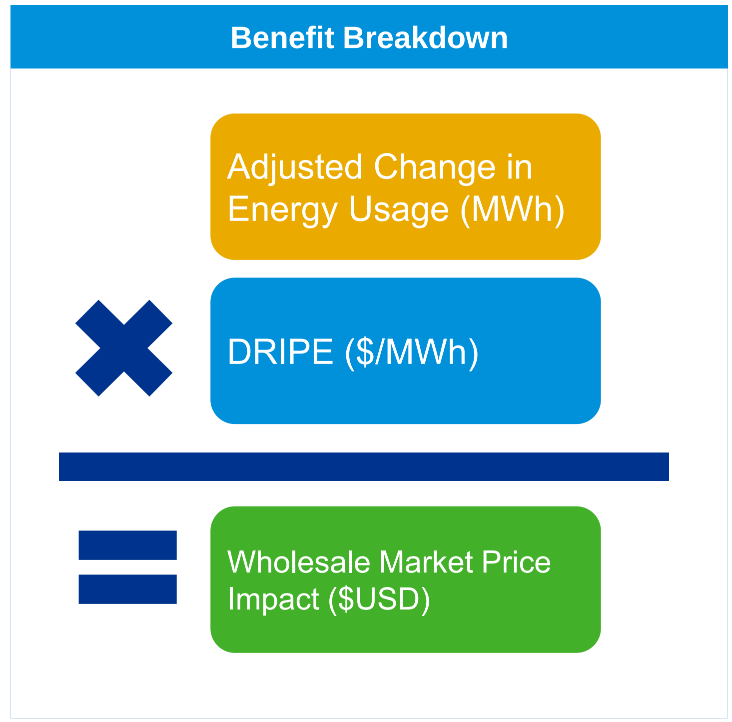
= Total Avoided REC Cost ($USD)

3

Benefits – Wholesale Market Price Impact

Wholesale Market Price Impact

- Values the price changes in the market that are ***directly attributable to the program itself***
- For example, it captures how an increase in the electricity usage impacts actual market supply and demand, and eventually equilibrium prices
- Uses the AESC Demand Reduction Induced Price Effect to ascribe value to the resulting increase in electricity usage

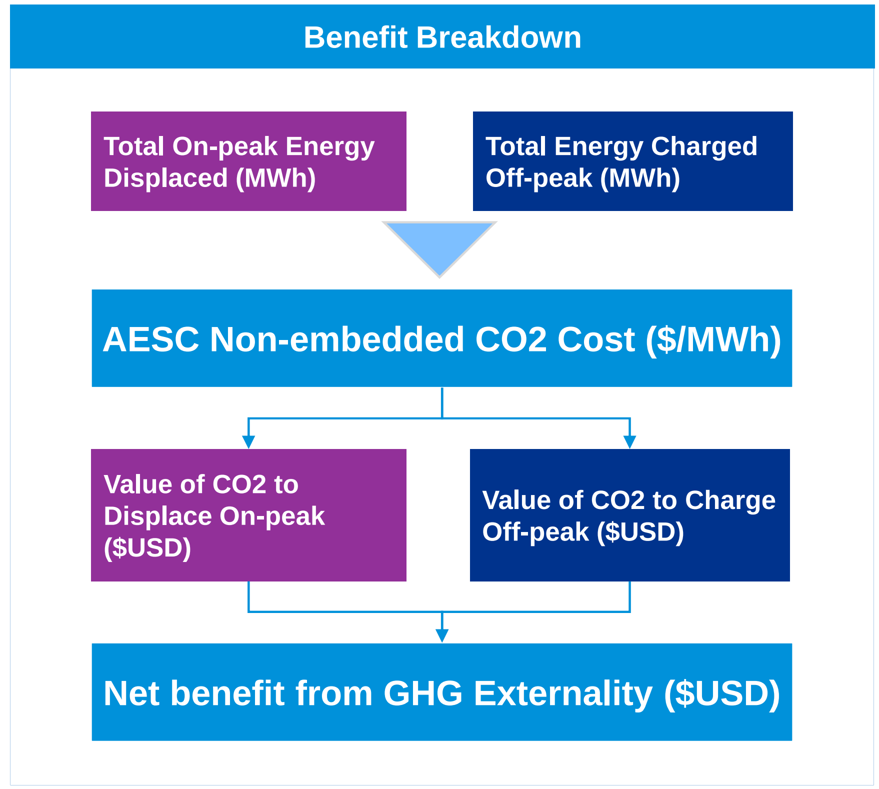


3

Benefits – GHG Externality Costs

Greenhouse Gas Externality Costs

- Measures the monetary value of estimated avoided greenhouse gas emissions
- For Energy Storage, estimates are made for the change in energy usage by subtracting the total energy charged from the total energy displaced
  - This yields a usage increase for energy storage due to efficiency loss
  - However, there is an emissions benefit to using Off-peak energy versus On-peak energy
- The increased energy usage outweighs the benefit to charging Off-peak
- As a result, Greenhouse Gas Externality Cost is a negative benefit in this storage case



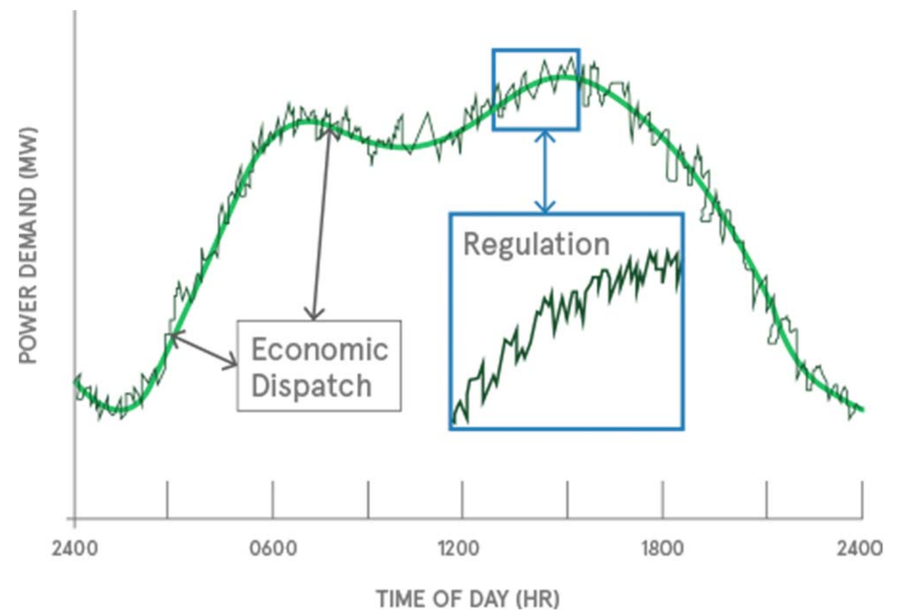
3

Benefits – Frequency Regulation

Frequency Regulation

- Frequency regulation is the second-by-second power adjustments that take place to maintain grid stability
- In ISO NE, participants respond to ISO signals every 4 seconds to increase or decrease their energy output
- This process helps to balance energy supply levels against momentary demand fluctuations
- Frequency regulation market participants are selected by ISO-NE dispatch algorithm and then are credited for (1) regulation capacity and (2) regulation service

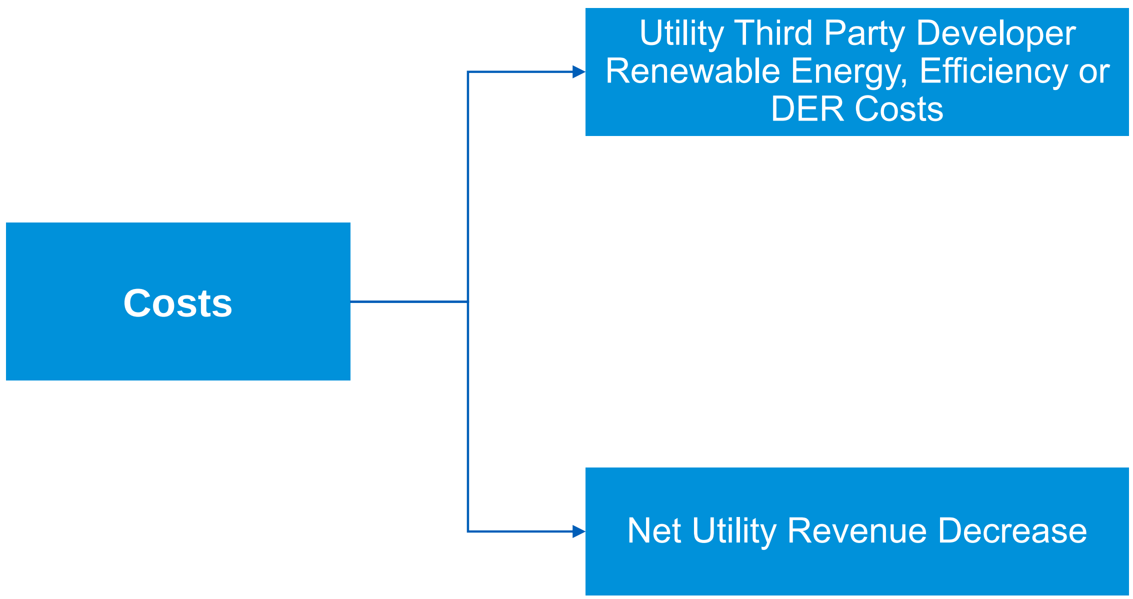
Illustrative Example



3

Costs – Overview

Costs Components



3

Description of Cost Categories

Utility Third Party Developer Renewable Energy, Efficiency or DER Costs

Culmination of Capex and Opex Subtotal, less any relevant tax incentives and cost sharing with a potential partner

- Capex refers to the direct cost of constructing and installing the batteries
- Opex Sub-total includes the ongoing site maintenance costs as well as the lease charge
- R&D tax credit refers to a rebate for a certain percentage of Opex

Net Utility Revenue Decrease

Captures National Grid's projected decrease in revenue attributable to the program

- Accounts for the increased revenue Off-peak and the decreased revenue On-peak
- This results in an overall revenue decrease due to the higher prices during On-peak hours
- Only included in the RIM test

4

Energy Storage – Results

ES - BCA Summary

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Societal Cost Test

RI Energy Storage BCA

	Energy Storage - BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	889,173
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (	$	139,264
	Avoided Renewable Energy Credit (REC) Cost	$	(2,859)
		$	-
	Greenhouse Gas (GHG) Externality Costs	$	(6,674)
	Economic Development	$	-
		$	-
		$	**1,018,904**
Costs	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	$	2,260,660
		$	**2,260,660**
			0.45

The majority of benefits come from the increased capacity offered by the batteries.

Charging during off-peak and displacing avoiding elevated on-peak pricing is an energy-storage specific benefit.

Appendix 2.2 - Economic Development

APPENDIX 2.2: ECONOMIC DEVELOPMENT

For reference, the Company is including a detailed description of the economic development benefits estimated by the Company. As noted in Chapter Two, these benefits are not included in the Company's BCA cost tests for several reasons.

In total, National Grid plans to spend $206 million through 2021 on planning, constructing, installing and implementing five electric utility projects: company-owned solar, storage, electric vehicle service equipment, electric heat pump conversions, and AMI. AMI accounts for the vast majority of the spending, $181 million or 87%.

The impact on Rhode Island Gross Domestic Product (GDP) is highlighted below because this economic development benefit was not included in the Benefit Cost Analyses, but the cost of planning, constructing, installing and implementing the projects was included. Planned investment spending on the projects is expected to increase local Rhode Island demand and raise GDP by $67 million through 2021. Again, the majority of this impact, $48 million, is attributable to AMI. Solar, storage, electric vehicle service equipment and heat pump conversions add $19 million to Rhode Island GDP through 2021.

Table 2.2-1: Total Investment Spending and Economic Impacts by Project Planning through Construction Phase (2018-2021) in Rhode Island

Rhode Island Investment Proposal
Total Investment Spending and Economic Impacts by Project Planning through Construction Phase (2018-2021)

Year	2018	2019	2020	2021	Sum
Spending Plan (Labor & Materials)					
Company-Owned Solar	$1.3	$2.6	$5.4	$0.2	$9.5
Company-Owned Storage	$0.9	$1.4	$0.0	$0.0	$2.4
Electric Vehicle Service Equipment (EVSE)	$1.4	$2.4	$5.3	$0.0	$9.1
Electric Heat Pump Conversions	$1.3	$2.1	$1.6	$0.0	$5.0
AMI Meters*	$0.0	$32.6	$62.3	$85.8	$180.6
Total	$5.0	$41.0	$74.6	$86.0	$206.6
Impact on RI GDP ($m)	**2018**	**2019**	**2020**	**2021**	**Sum**
Company-Owned Solar	$0.7	$1.5	$3.2	$0.5	**$6.0**
Company-Owned Storage	$0.5	$0.8	$0.1	$0.1	**$1.5**
Electric Vehicle Service Equipment (EVSE)	$1.1	$2.3	$5.4	$0.0	**$8.7**
Electric Heat Pump Conversions	$0.7	$1.1	$0.9	$0.0	**$2.7**
AMI Meters	$0.0	$3.8	$16.2	$27.7	**$47.6**
Total	$3.0	$9.5	$25.8	$28.3	**$66.6**

Rhode Island GDP impacts were estimated using the Regional Economic Models, Inc. (REMI) regional economic model of the Rhode Island economy. REMI has been used in the industry for over 30 years to estimate the economic development impact of various projects. REMI has over 150 US and international clients including the Rhode Island Department of Revenue; dozens of other state, federal and local government planning agencies; non-profit research organizations; energy consultants; universities and utilities. National Grid leases a 169 sector version of REMI's Rhode Island model.

Spending on the proposed Power Sector Transformation electric projects is expected to create jobs in construction, engineering, project management, consulting, professional services, and other industries, including secondary jobs in the local service sector as workers spend their income. The result is increased economic activity, as measured by Rhode Island GDP, employment, and income.

Only local spending was considered in the REMI analysis. Spending on materials to be purchased from outside of the region was not included as this will not have a significant impact on Rhode Island economic activity. Spending on specialized labor available only outside of Rhode Island was not included. Spending on local labor was allocated between general construction, electrical contractors, professional services and utility O&M before being input to REMI. The REMI model estimates the proportion of this increase in Rhode Island demand that will be met locally versus from outside of Rhode Island.

In total, spending on the projects is projected to create 679 annual jobs in Rhode Island, from 2018 to 2021, as the projects are planned, constructed, installed and implemented. Moreover, the projects will generate an additional $46 million in Rhode Island personal income and $5.1 million in state and local tax revenues. These impacts are summarized below.

Table 2.2-2: Rhode Island Economic Impact Summary for all Projects

Rhode Island Economic Impact Summary - All Projects

	2018	2019	2020	2021	Sum
Total Jobs*	34	98	265	283	679
GDP ($m)	$3.0	$9.5	$25.8	$28.3	$66.6
Personal Income ($m)	$2.0	$6.1	$17.5	$20.0	$45.5
State and Local Tax Revenue ($m)	$0.2	$0.7	$2.0	$2.2	$5.1
0.112					

* AMI job impact does not include reduced meter reading positions.

The economic developments in the table above reflect the direct, indirect and induced economic impacts of project spending. Direct impacts are tied directly to the projects, for example contractors hired to install solar facilities, storage, electric vehicle service equipment, heat pumps and AMI meters. Indirect jobs are created in the supply chain. This includes local industries supplying tools, equipment and other materials used by project workers. Induced jobs result from the spending of the direct and indirect workers and are felt mostly in the local service sector, for example, retail. Table D-3 below shows the direct, indirect and induced employment impacts for each project. On average, direct jobs account for about 62% of all jobs created; indirect jobs account for 14%; and induced jobs account for 24%.

Table 2.2-3: Job Impacts by Project

Job Impacts - All Projects

	2018	2019	2020	2021	Sum
Direct	21	60	163	174	419
Indirect	4	13	36	38	92
Induced	8	24	66	70	169
Total	34	98	265	283	679

Job Impacts - Non AMI

	2018	2019	2020	2021	Sum
Direct	21	37	58	1	117
Indirect	4	8	12	0	24
Induced	8	15	24	1	49
Total	34	59	94	3	190

Job Impacts - Electric Heat

	2018	2019	2020	2021	Sum
Direct	5	8	6	0	18
Indirect	1	2	1	0	4
Induced	2	3	2	0	7
Total	8	12	9	0	30

Job Impacts - Company Owned Solar

	2018	2019	2020	2021	Sum
Direct	5	10	19	1	35
Indirect	1	2	4	0	7
Induced	2	4	8	1	15
Total	8	16	31	2	57

Job Impacts - Company Owned Storage

	2018	2019	2020	2021	Sum
Direct	3	5	0	0	9
Indirect	1	1	0	0	2
Induced	1	2	0	0	4
Total	6	8	1	0	15

Job Impacts - Electric Vehicles

	2018	2019	2020	2021	Sum
Direct	8	14	33	0	55
Indirect	2	3	7	0	11
Induced	3	6	14	0	22
Total	12	23	53	0	89

Job Impacts - AMI*

	2018	2019	2020	2021	Sum
Direct	0	23	105	173	301
Indirect	0	6	24	38	68
Induced	0	9	42	69	120
Total	0	38	171	280	489

For AMI, results include jobs supported within National Grid for installation of AMI meters, as well as contractors hired to install the meters. On the other hand, meter reading jobs lost is not included in the AMI analysis.

Appendix 4.1

AMF Technology & BCA

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APPENDIX 4.1: AMF TECHNOLOGY AND BCA

1. AMF TECHNOLOGY AND COSTS

The following descriptions of the end to end metering technologies are meant to provide a broad explanation of the capabilities of individual components presented in this document. Descriptions of components and capabilities defined herein do not constitute a complete list, nor are they linked to a specific vendor or vendors. Rather, it is intended to be directional in nature, establishing the order of magnitude of a comprehensive scope of deployment.

The AMF solution under consideration by National Grid will include solid-state meters, interval consumption measurement, radio frequency (RF) mesh and cellular telecommunications, remote firmware upgrades, network ping support and sensors for power quality measurement such as last gasp notifications and voltage fluctuations. Within the meter's functionality are autonomous algorithms for abnormal operation, tamper detection and support for remote connect and disconnect service functionality for electric customers.

The Company proposes to install approximately 515,000 electric AMF meters (this includes meter points that are inactive since January 2016) across its service territory over the eighteen-month meter deployment phase beginning the second half of fiscal year 2021. One-third of the meters are to be deployed in fiscal year 2021 and the remainder in fiscal year 2022. Actual deployment could vary from the proposed schedule based on field conditions and other factors. Meter deployment is closely aligned to the lifecycle replacement of electric AMR meters.

Gas AMF Encoder Receiver Transmitters (ERTs) will be deployed separately from the electric AMF meters as part of the normal Gas AMR ERT replacement cycle as projected in Table 4-1.

Table 4-1: Gas ERT replacement cycle, FY19 – FY29

Deployment Year	Gas ERT Installation
FY 19	7.85%
FY 20	7.85%
FY 21	7.85%
FY 22	7.85%
FY 23	7.85%
FY 24	27.55%
FY 25	7.85%
FY 26	7.85%
FY 27	7.85%
FY 28	7.85%
FY 29	1.80%

Beginning in fiscal year 2019 gas AMR ERTs will be replaced with ERTs that can be configured for either AMR or AMF meter data collection. ERTs installed in areas without AMF infrastructure will initially be configured for AMR, and then reconfigured remotely for AMF once the AMF infrastructure is in place. Since the cost of gas AMF ERT deployment is the same as the cost of the gas AMR ERT replacement program, the AMF business case does not include the costs of gas AMF ERT replacement.

1.1 AMF Meter Equipment and Installation

An electric AMF meter is an electronic device used to measure electric consumption at residential, commercial, and industrial locations. This device digitally communicates the interval data using two-way telecommunications infrastructure and can be equipped to leverage either a cellular radio or a RF mesh network to communicate with back-office systems. The electric meters will be replaced by an AMF solution which possesses a fully self-contained measurement and communication system.

Gas meters are equipped with an external ERT (compatible encoder receiver transmitters) module that records and transmits the gas consumption data measured by the meter. AMF replacement of the ERT will allow the gas meter to communicate with the electric AMI meter or directly with the telecom system, enabling both meters to be read in near real-time (instead of monthly) through the AMF solution.

1.1.1 AMF Electric Meter Equipment and Installation

The AMF electric meters support the following functionality:

- A Flexible Two-Way Communication System.
- Upgradable Firmware: Customizable firmware upgrades with automated roll-back functionality and the ability to create phased firmware packages.
- Bi-Directional Metering: Support for both consumption and generation measurements for distributed generation customers. AMF also provides the functionality to net this usage in the MDM and at the meter level.
- Energy Measurements:
- kWh delivered, received and net.
- kVARh delivered and received.
- kVARh Q1-Q4.
- VAh delivered, received and net.
- Demand Measurements:
- Max Watts delivered and received
- Max VA delivered and received
- Max VAR delivered and received
- VAR Q1, Q2, Q3, Q4
- Min Power Factor.
- Meter Reading: Remotely interrogate register and interval billing data from the AMF meters. Additionally meter events and exceptions will be delivered to the head-end software for detailed analysis.
- Real-Time Meter Event and Alarm Retrieval: Alarms received by the head-end system can be automatically distributed to a specific user or group of users.
- Tamper Detection: Detect and report exceptions for events such as magnetic interference, voltage integrity issues and disruption in service.

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- Remote Disconnect/Reconnect: Integrated functionality allowing remote disconnect and reconnect of electric service.
- Integration & Installation: A self-contained metering solution allows a simple and streamlined field deployment.
- Meter Security: Multiple security protocols with an encrypted file system, secure boot, standard DLMS security, application layer enhanced security and local access signed authorization.
- Adaptive Communications: Supports both RF and Power Line Communication (PLC) for "last gasp" communication. Each meter is assigned a global routable address with meters dynamically selecting the optimal link based on channel conditions and target QoS. The mesh network uses adaptation layers and an RPL routing protocol.
- Radio Specifications: Radio Output Power configured at time of manufacture: – 500mW-1W.
- Possesses the ability to communicate and operate within Home Area Network (HAN) and Business Area Network (BAN) technologies.

This functionality is included in models that are currently available on the market. Meter manufacturers have been working to bring updated models to market that include additional functionality:

- Integration with distributed generation and load control devices
- Improved granularity of voltage and consumption data
- Location awareness and communication with other meters

While we did not account for devices with these capabilities in our analysis, we will be looking to procure the latest technology to maximize value for our customers.

1.1.2 AMF Gas ERT Equipment

The AMF Gas ERT supports the following functionality:

- Continually stores and updates the last 40 days of hourly interval data which can be read via mobile collection and fixed network.
- Continually stores and updates the last 40 days of sub-hourly interval data which can be read via fixed network.
- Operates in bubble-up mode and does not require a license from the Federal Communications Commission (FCC).
- Designed for a 20-year battery based on standard data collection to ensure low operating and maintenance costs.
- Module design makes installation fast and easy, especially when gas is flowing through the meter.
- The compact design and direct engagement with the meter drive assure the unparalleled accuracy that makes gas modules the industry standard.
- The two-way 500G DLN offers improved tilt tamper detection.

1.1.3 AMF Inventory
This cost is for AMF electric meter storage that will support each local operating area to facilitate ongoing day-to-day operations. An inventory level of 2.5% is assumed and will be allocated consistent with the AMF meter deployment schedule.

1.1.4 Support Infrastructure
Deployment of AMF meters will require significant coordination of personnel, meter and CGR staging, dispatching and disposal of legacy AMR meters. While costs are sought to be minimized through coordinated equipment deliveries, supplemental costs will be incurred.

In addition to field operations, additional back office and clerical personnel will be required to support the AMF implementation. Once AMF meters have been deployed efforts are undertaken from the back office to validate meter installation and ensure that the deployment was performed correctly. While existing staff will support these efforts, supplemental personnel will be required to support increased workload during AMF deployment.

1.1.5 AMF Meter Equipment and Installation Cost Summary

Table 4-2: AMF Meter Equipment and Installation Costs ($million) – Rhode Island only

Rhode Island Only Deployment	Deployment Period Capital Cost	20-Year NPV (FY20$)
AMF Electric Meter Equipment and Installation	$89.57	$76.01
AMF Inventory	$1.53	$1.26
Support Infrastructure	$7.37	$6.32
Total	$98.47	$83.58

<u>Multi-Jurisdiction Deployment</u>

Cost synergies reflected in the following multi-jurisdiction deployment table are the result of a lower per unit meter cost attributed to volume efficiencies that could be experienced across the operating companies.

Table 4-3: AMF Meter Equipment and Installation Costs ($million) – Multi Jurisdiction

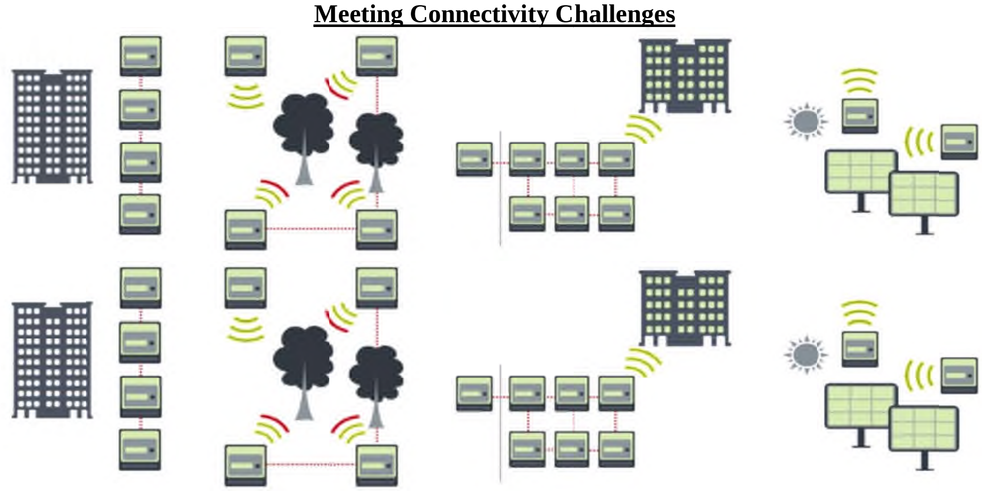
Multi-jurisdiction Deployment	Deployment Period Capital Cost	20-Year NPV (FY20$)
AMF Electric Meter Equipment and Installation	$88.84	$75.11
AMF Inventory	$1.51	$1.25
Support Infrastructure	$7.37	$6.32
Total	$97.92	$82.68

1.2 Communication Network Equipment and Installation

While the Company plans to evaluate alternative options for a shared communications system in the detailed design phase of development, the proposed AMF solution will leverage the evolving technological landscape to create a strong, secure mesh network. This will ensure that obstacles such as high rise buildings, changing RF conditions, meter vaults and low-density conditions will not pose significant restrictions in the new network environment.

Figure 4-1: AMF Communication Network Illustration

Meeting Connectivity Challenges



High Rise Buildings Changing RF Conditions Underground Meter Vaults Low-Density Environments

1.2.1 Network Equipment and Installation

Embedded within each meter is a communications module that enables the meter to communicate with peer meters and back office systems. These modules can either be outfitted with RF or cellular radios depending on various geographical and environmental considerations.

The principal focus of AMF network design is to support accurate and timely meter communications and data collection. However, it's possible the network could be leveraged for other distribution modernization functions which will be considered during detailed design.

A radio frequency mesh network is created by including a low-power, short-range radio in each meter. Each meter can transmit its own load profile as well as a finite collection of data from downstream meters. All meters with this technology dynamically communicate with each other to identify optimal communication pathways back to centralized data collection points. In doing so, these networks of devices can self-identify the most efficient paths on an ongoing basis and dynamically reconfigure to maintain optimal routing in varying operational situations.

For most urban/suburban areas where a sufficient population density exists, National Grid will utilize a radio frequency mesh network to facilitate meter communication with the backhaul system. In areas of low population density or poor RF performance a cellular communication solution will be leveraged by the meter. National Grid has assumed a five percent of the electric AMF meters will utilize cellular communications.

The AMF network will have several characteristics that enable communications efficiency and effectiveness. They are:

- Network components that will dynamically reroute to maintain the most efficient communications pathways across seasons, varying weather conditions and vegetation cycles.
- In the event of a power outage, the field area network will stay up long enough to transmit a power-off notification to alert the outage management system (OMS).
- Multiple device layers will collect and transmit data:
  - CGRs: Large bandwidth devices to manage data transmission to back-office systems;
  - Relays: Devices extend communication range
  - Meters: Small short range communication devices
- Overall network design and configurations implemented in each device will impact transmission speed.

The network will be designed to support low latency meter data collection. The general industry standard for AMF implementations in the United States has been to make bill-quality interval data available within 24 hours of collection. Under the Company's program electric customers will have access to their raw usage data within four to five hours after an interval. Gas customers will have access to this raw usage information within eight hours due to battery limitations. In both cases, customers will have bill quality data within approximately 24 hours of the end of a given interval. The Company expects to engage stakeholders further with respect to their real-time information access needs and can adapt the system to meet evolving needs.

1.2.2 Communication Network Installation Management

During the network installation and meter deployment phase of the program internal Company department resources will be paired with meter vendor resources under the direction of the AMF program management team to manage the communications infrastructure, meter deployments,

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and coordinate the initial stabilizations as appropriate. This team will also be responsible for troubleshooting any meter related issues that occur during this phase. Once the meter deployment phase is complete, these responsibilities will be permanently assigned to the appropriate internal departments.

1.2.3 Backhaul

The backhaul network is a wide area network ("WAN") that is the high-speed, high-bandwidth communications structure between the collectors and the AMF Head-End. The network can either be public or private depending on several factors, including cost (both upfront and reoccurring), security, meter density in the area and distance from the existing fiber network.

Regarding private communication National Grid has a SONET fiber communications system that ties a number of larger transmission substations and other corporate facilities together. In some instances, distribution level substations also leverage this network to send operational data back to our corporate facilities. In addition to fiber optic systems, the Company operates numerous licensed and unlicensed microwave point-to-point links that provide backhaul connectivity for multiple operational and corporate systems.

AMF CGRs will backhaul their data utilizing 4G cellular networks or company private networks when located at substations or other company facilities with private network connectivity.

1.2.4 Communication Network Equipment and Installation Cost Summary

Table 4-4: Communication Network Equipment and Installation Costs ($million) – Rhode Island Only

Rhode Island Only Deployment	Deployment Period Capital Cost	20-Year NPV (FY20$)
Network Equipment and Installation	$2.04	$2.83
Communication Network Installation Management	$2.42	$3.69
Backhaul	-	$1.06
Total	$4.46	$7.58

<u>Multi-Jurisdiction Deployment</u>

Cost synergies reflected in the following multi-jurisdiction deployment table are the result of lower vendor services support costs attributed to volume efficiencies that could be experienced across the operating companies.

Table 4.5: Communication Network Equipment and Installation Costs ($million) – Multi Jurisdiction

Multi-jurisdiction Deployment	Deployment Period Capital Cost	20-Year NPV (FY20$)
Network Equipment and Installation	$2.04	$2.83
Communication Network Installation Management	$2.09	$3.18
Backhaul	-	$1.06
Total	$4.12	$7.06

1.3 IT Platform and Ongoing IT Operations

Five IT platform elements are included as part of the AMF program; AMF Head-end and Meter Data Management Systems, enhancements to the Customer Service System, Customer Engagement Products and Services, IS Infrastructure, and Cyber Security. Each of these elements is described below.

1.3.1 AMF Head-End and Meter Data Management System

The AMF Head-end is the command and control system that integrates the communications infrastructure in the field and the back-office systems. An AMF Head-End communicates with AMF meters to collect meter data, interval readings and events. It also can ping individual meters as necessary and push firmware updates across the network. For electrical systems, it can remotely initiate the connection and disconnection of the service at a meter level. This system serves as the main point bi-direction data transmission across the meter population.

An effective AMF platform also requires a meter data management system (MDMS). The MDMS provides data storage and archival capabilities for meter information. Additionally, the MDMS performs initial validation, editing and estimating of the incoming meter data. Once the raw data has been processed, it can be utilized by back-office systems such as billing, customer service, and data analytics. This data can also be uploaded to the Energy Management portal and Green Button Connect for customer and authorized third party viewing and utilization.

An important function of the MDMS is the validation, editing, and estimating process. During validation, editing, and estimating, the MDMS reviews all incoming data from the AMF meters in an effort to validate data accuracy, estimate data and identify anomalies. Any meter with data that cannot pass initial validation is routed to a "validation queue" which is worked by support staff. From this queue missing data intervals, data integrity issues and configuration errors are resolved to produce billing quality data.

Cost estimates in this area assume the Company contracts with an outside service vendor to host these systems. The arrangement is referred to as Software as a Service.

1.3.2 Service System

The customer service system (CSS) is utilized to manage customer-facing activities. A multitude of processes pull meter data, perform billing and payment processing, support collections and various pricing program rates. As part of the AMF deployment CSS will be modified and configured to support the enhanced data requirements of smart metering. Additional configurations will be made for expanded pricing programs such as time-of-use and critical peak pricing. With such a prominent role in customer interaction, an effective CSS with support for AMF capabilities is critical to maintaining customer satisfaction. Moreover, as distributed energy resource (DER) penetration increases throughout Rhode Island, CSS must be adaptable to the dynamic energy environment.

CSS also possesses capabilities intended to foster our relationship with customers and assist in customer retention through personalized service. The system interfaces with various back-office resources to create personal profiles for customer engagement. CSS can be linked with an interactive voice response (IVR) system to send automated outage response notifications received from AMF meters. Additionally, CSS will present customer history and real-time meter status to the customer services representatives (CSR) providing enhanced customer service. CSRs will also have a new suite of tools to perform meter diagnostics and remote service re-connection.

Contact Center Personalization Engine Tools
The Company is planning on making investments in the technology utilized by Customer Service Representative (CSR) staff operating out of the Contact Center in order to facilitate meaningful interactions with low and medium-income customers.

These enhanced tools will provide staff with necessary customer specific data to provide these customers with information about the most relevant and appropriate programs for their particular situations.

While this solution is currently intended to utilize monthly consumption data, access to the more timely and granular consumption data enabled by AMF would support a more robust solution on multiple levels:

- Enable more timely and specific outbound customer alerting and communications, as these communications would be based on near real-time observations of customer consumption patterns
- Enable Contact Center staff to engage customers about changes to consumption patterns (and likely resulting bill changes) mid-month, while customers would still have an opportunity to take actions to impact an upcoming monthly bill. Access to this information earlier in a customer billing cycle could reduce both the scale of volatility in customer bills as well as the likelihood of a customer receiving an unexpectedly high bill. Both outcomes are drivers of inbound Contact Center call volumes, as well as reduced on-time bill payment performance by customers
- Provide Contact Center staff with more granular, actionable and accurate insights into drivers of customer energy consumption patterns, as well as the likely impact and potential benefits associated with customers' taking behavioral actions or implementing other direct energy efficiency measures. This could be expected to

drive both higher customer satisfaction with Company energy efficiency programs, as well as greater customer adoption of these programs.

1.3.3 Customer Engagement Products and Services

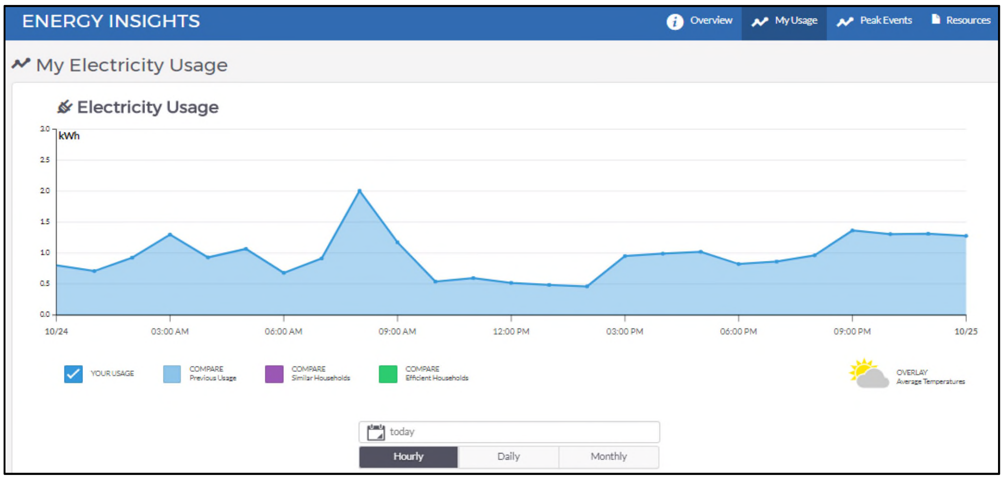
For the benefits of smart meter technology to be fully realized by the customer, the Company must pair AMF technology with proactive customer and market engagement initiatives. As part of the AMF deployment, National Grid will develop and implement an Energy Management Portal and Green Button functionalities (i.e. Green Button Download My Data and Green Button Connect My Data). The cost of these solutions is included in the AMF benefit cost analysis.

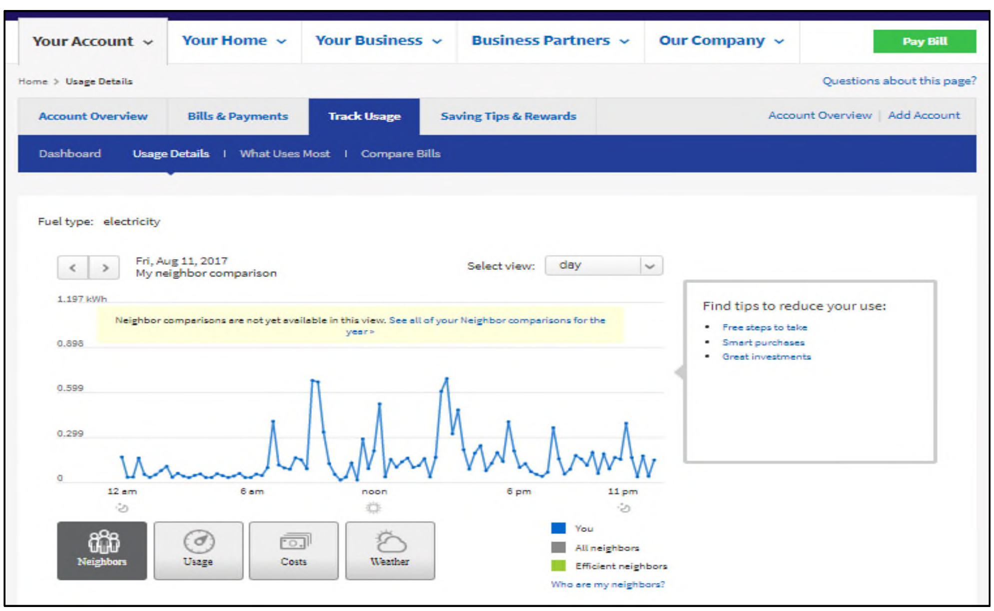
<u>Energy Management Portal & the Customer Engagement Management Platform (CEMP)</u>

As part of the AMF deployment, National Grid will be develop an energy management web portal (hereafter *the Portal*) that will act as a hub for residential, commercial, and industrial customers to view their energy usage, including smart meter interval data. The Portal will allow electric customers to view raw consumption data within four hours of the end of a given billing interval and gas customers within eight hours. Both electric and gas customers will be able to view billing quality data within 24 hours. Additionally, from the Portal customers will have the ability to download and/or share their interval data with qualified third parties via the Green Button Download My Data and Green Button Connect My Data features, respectively.

Access to this granular interval data, paired with personalized insights, will enable customers to make better informed decisions about how and when they use energy, and can help facilitate action that will reduce customers' energy usage and costs, aligning well with the power sector transformation goal of "giving customers more energy choices". The Company already has experience in delivering this type of customer engagement portal through both its ongoing Smart Energy Solutions smart grid pilot programs. Examples of these Portals from the two Smart Energy Solutions pilot programs are included in Figure 4-2. The Company will apply learnings and best practices from these two programs to ensure that customers are provided with a "best in class" portal experience that leverages AMF deployment. In fact, within it Smart Energy Solutions program in Worcester, MA, the Company found that customers who utilized the provided Energy Management Web Portal saved an incremental 10% in peak energy load during critical peak pricing hours, as well as an incremental 3-5% in annual energy savings, compared to those who did not access the Portal.

Figure 4-2: Screenshots of Energy Management Portals from Worcester SES and Clifton Park SES





The Company envisions that this proposed energy management portal will exist as the foundational element of a larger approach denoted as the Customer Energy Management Platform (CEMP). The CEMP aims at providing a "state of the art" platform approach to best provide customers with accurate and personalized energy usage information, as well as various choices and options to enroll in programs and services that can leverage the more granular data provided by AMF deployment. These include programs and services such as energy efficiency programs, demand response, adoption of distributed generation (e.g. solar PV and Electric Vehicles), and other potential time-varying pricing programs that may accompany AMF deployment. From the CEMP, customers can easily and conveniently access a variety of tools and information that will help them conserve energy and better manage their energy usage.

Customers will also be able to access existing educational and safety information, all of which is currently provided to customers on the Company's home webpage. As such, the CEMP will be accessible through that same channel, and will seek to link together a number of existing customer portals and third party websites, with the proposed Energy Management Portal serving as the anchor of the CEMP. An illustrative example of what the CEMP could look like is provided in Figure 4-3, and the Company will continue to refine this design based on stakeholder and customer feedback, as well as on the market evolution of customer offerings, technologies, and solutions.

In the long term, the Company envisions integrating the CEMP with smartphone applications that allow customers to access their data on the go, in addition to being able to create customizable alerts notifying them of grid conditions (including outages, reductions or curtailments), unusual consumption patterns, and bill pay.

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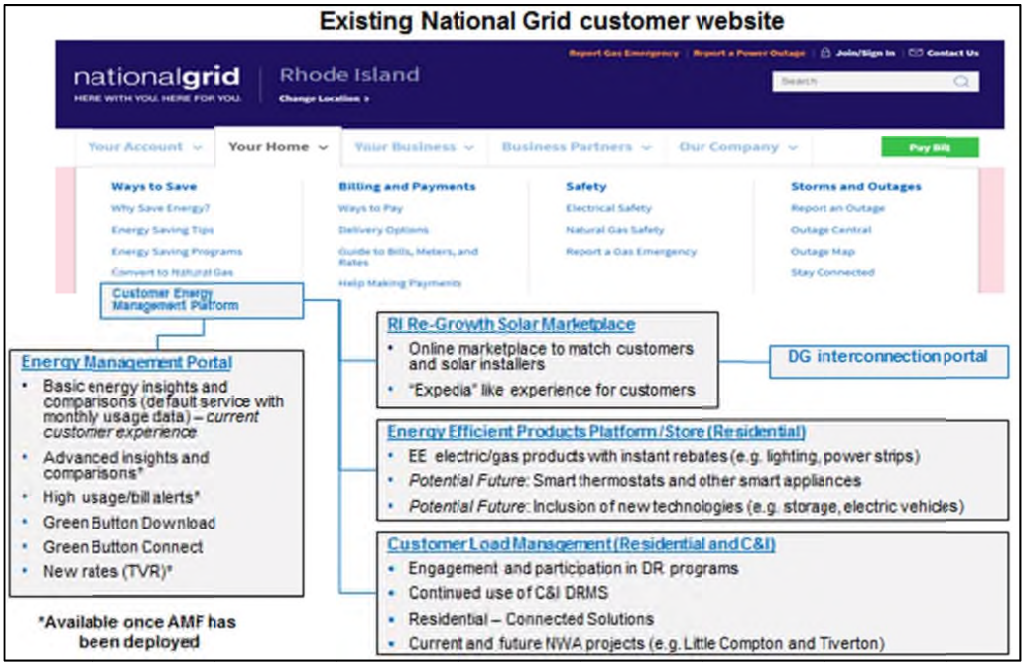
Figure 4-3 – Illustrative Example of Customer Energy Management Platform ("CEMP")



<u>Green Button</u>
Many utilities, including National Grid, have implemented the Green Button Download My Data functionality. This system gives every utility customer the ability to download their personal energy consumption data directly to their computer in a secure manner. Additionally, if customers are interested, they can upload their data to a third-party application.

The Green Button Connect My Data functionality takes this process further by streamlining it to allow utility customers to automate the process. With Green Button Connect My Data customers can securely authorize both National Grid and designated third parties to send and receive data on the customer's behalf as may be seen in Figure A-4. Upon authorization, energy usage data can be transferred as required. Making this data accessible to third parties is critical to animating the market and driving innovation.

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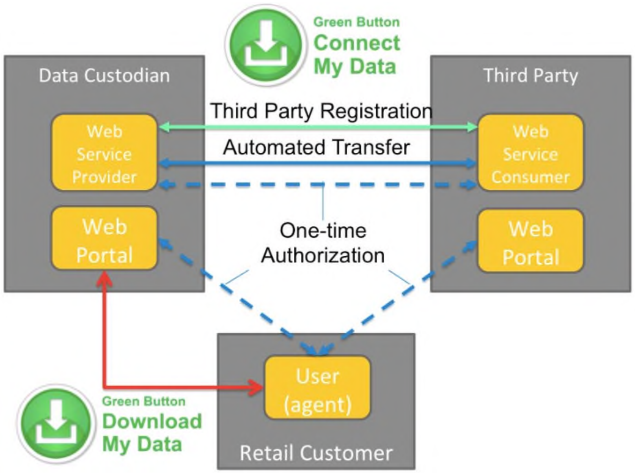
Figure 4-4: Standard communications protocol for Green Button Connect My Data



1.3.4 Information Technology (IT) Infrastructure

The following IT infrastructure capabilities are required to support the AMF systems. These capabilities are further described in Chapter 3 of the Plan, *Investment in a modern Grid.*

- Telecommunications - Enhancements are required to expand existing backhaul capabilities and bandwidth to support data transfer.
- Enterprise Service Bus (ESB) - To implement several of the AMF and ADMS use cases, systems in the new distribution ESB will need to communicate with legacy systems that currently use a corporate ESB.
- Information Management & Advanced Analytics - Costs in this category allow data ingestion, data quality and analytic capabilities to be configured and deployed. The big data analytics capabilities will allow for the analysis of the data gathered from existing and third-party data sources to provide valuable output reflecting current state as well as predictive and prescriptive outcomes.
- Cloud Computing & Data Lake - Rather than hosting these data management capabilities on servers within National Grid data centers, greater efficiencies, redundancies, and security regimes can be cost effectively procured by outsourcing this function. This cost element captures the costs associated with setting up a cloud data lake environment.

While the IS projects described above are a necessary component of the AMF proposal, their use goes beyond AMF. Therefore, to avoid duplication in calculating the total Revenue Requirement for the Plan, the Company has removed the AMF allocation of these projects from the schedule of AMF costs. The full costs of each IS project above are included in Chapter 3: *Investment in a Modern Grid*. However, the Company uses the AMF portion of the IS project costs when computing the AMF benefit-cost analysis.

1.3.5 Cyber Security

The Company understands that in an evolving technology landscape, there are growing cyber security risks. To best secure AMF, National Grid is preparing a comprehensive cyber security plan to ensure protection for both customers and the company. At a high level, this plan will ensure that proper end-to-end security controls are incorporated into all aspects of design, implementation, and deployment of AMF meter technology. These security controls will ensure that all AMF meter devices, communications infrastructure, and back office systems supporting them, along with user portals and other critical infrastructure are fully secured and monitored. Moreover, the plan will also ensure that any data transmitted across this network is properly encrypted using nationally recognized standards and protocols.

The Company will leverage industry-leading best practices to meet the goals of an effective cyber security program. These practices include training, change control, configuration management security, access monitoring, incident management, end-to-end encryption, network segmentation, firewalls and other security controls. The cyber security measures outlined will enable National Grid to maintain confidentiality and integrity to the best of its ability in both the short and long term future of AMF.

All systems, components, and integrations from the AMF Business Case were considered as part of this review in consideration of the following service domains:

- Network Security Services
- Data Security Services
- Identity & Access Management Services
- Threat and Vulnerability Management Services
- Security Operations Center Services
- Host and Endpoint Security Services
- Security Policy Management Services
- Cryptography Services
- Change & Configuration Management Services
- Security Awareness & Training Services
- Application Security Services
- Third Party Assurance Services
- Remote Access Services
- Privacy Services

1.3.6 IT Platform and Ongoing IT Operations Cost Summary

Table 4-6: IT Platform and Ongoing IT Operations Costs ($million) – Rhode Island Only

Rhode Island Only Deployment	Deployment Period Capital Cost	20-Year NPV (FY20$)
AMF Head-end and Meter Data Management Systems*	[redacted]	[redacted]
Customer Service System	[redacted]	[redacted]
Customer Engagement Products and Services	[redacted]	[redacted]
IT Infrastructure	[redacted]	[redacted]
Cyber Security	[redacted]	[redacted]
Total	$88.73	$137.79

* Assumes Software as a Service payments are capitalized and are discounted to 2020 dollars

<u>Multi-Jurisdiction Deployment</u>

Cost synergies reflected in the following multi-jurisdiction deployment table are the result of lower Head-end and Meter Data Management SaaS fees attributed to volume efficiencies, and the sharing of the fixed costs related to development and deployment of supporting computer technologies, that could be experienced across the operating companies.

Table 4-7: IT Platform and Ongoing IT Operations Costs ($million) – Multi Jurisdiction

Multi-jurisdiction Deployment	Deployment Period Capital Cost	20-Year NPV (FY20$)
AMF Head-end and Meter Data Management Systems*	[redacted]	[redacted]
Customer Service System	[redacted]	[redacted]
Customer Engagement Products and Services	[redacted]	[redacted]
IT Infrastructure	[redacted]	[redacted]
Cyber Security	[redacted]	[redacted]
Total	$53.15	$72.78

** Assumes Software as a Service payments are capitalized and are discounted to 2020 dollars*

1.4 Project Management and Ongoing Business Operations

1.4.1 Project Management

AMF Project Management will provide the necessary framework for the successful integration of interdependent technology components and processes through the proposed thirty-six month AMF program. The project management team will consist of internal project management leadership, internal business support and external support.

1.4.2 Equipment and Installation Refresh Cost

This area includes the following cost elements:

- AMF meter replacement cost recognizes that over time meters will need to be replaced for a number of reasons, including damage or failure. While a warranty is provided on meters for a one-year period, after this period expires, it will be National Grid's responsibility to procure replacements.
- A subset of electric meters are located in rural areas with insufficient density to form a stable and consistent mesh. For these locations, a meter with a cellular communication module will be leveraged and will have a corresponding ongoing service fee with public cellular providers.
- AMF meters can communicate with peer meters through RF technology for short range communications but rely on more robust communications to reach back office systems. For this CGRs are leveraged which can aggregate data from local metering mesh clusters and deliver data to the head-end system. Over time, it is expected that these devices will fail and require replacement. This cost element addresses the costs of the replacement equipment and the installation cost associated with replacing failed equipment throughout the duration of the program.
- CGRs used to support electric AMF meters / gas ERTs, also have a corresponding annual service fee allowing them to communicate with the public cellular backhaul. These cost elements are annual cost for operations.

1.4.3 Ongoing Business Management

AMF deployment will require additional operational support to monitor and manage system performance and oversee numerous AMF processes such as validation, editing, and estimating, meter and communication mitigation, field area network performance and firmware deployments. The Company's pilot experience is used to estimate these costs.

1.4.4 Customer Engagement Cost

A robust customer education and outreach effort will be needed to support the AMF rollout. The objective of the Customer Engagement plan is to build customer awareness and interest in both, the grid modernization and the AMF that will enable it, in order to eliminate potential adoption barriers, encourage participation and facilitate transition to AMF meters. The line item captures costs related to multi-channel marketing content development and implementation, community outreach, surveys to test communications effectiveness and satisfaction, and additional support staff.

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1.4.5 Project Management and Ongoing Business Operations Cost Summary

Table 4-8: Project Management and Ongoing Business Operations Costs ($million) – Rhode Island Only

Rhode Island Only Deployment	Deployment Period Capital Cost	20-Year NPV (FY20$)
Project Management	$5.58	$13.25
Equipment and Installation Refresh Cost	$0.12	$2.98
Ongoing Business Management	-	$6.27
Customer Engagement Cost	-	$8.30
Total	$5.70	$30.80

Multi-Jurisdiction Deployment

Cost synergies reflected in the following multi-jurisdiction deployment table are the result of lower project management support costs as well as lower per unit meter costs attributed to volume efficiencies that could be experienced across the operating companies.

Table 4-9: Project Management and Ongoing Business Operations Costs ($million) – Multi Jurisdiction

Multi-jurisdiction Deployment	Deployment Period Capital Cost	20-Year NPV (FY20$)
Project Management	$4.47	$11.58
Equipment and Installation Refresh Cost	$0.11	$2.94
Ongoing Business Management	-	$6.27
Customer Engagement Cost	-	$8.30
Total	$4.58	$29.09

2. AMF BENEFITS

2.1 AVOIDED O&M COSTS

2.1.1 AMR Meter Reading

National Grid currently has a fleet of AMR meters covering its electric and gas service territory. These AMR meters have monthly reads that are acquired through radio frequency technology. These collections are done by a fleet of service vans which meter readers drive along routes to allow communication with each meter. Starting in the second half of fiscal year 2021, National Grid will replace its current electric AMR meters with AMF meters thereby reducing the need for AMR meter readers, associated vehicles and annual AMR meter reading equipment maintenance costs.

2.1.2 Meter Investigation

Smart meters will provide auto and on-demand meter reads and diagnostics to alert and inform the Company about anomalous situations that in-turn allows for the reduction of visits to the meter for manual meter investigations. This will reduce labor and vehicle costs. The types of manual meter investigations that can be avoided in part include Use on Inactive Electric Meter Investigations, Meter On/Off and Meter Reads.

2.1.3 Remote Connect and Disconnect

Advanced Metering provides the ability to connect and disconnect electric service remotely and in near real-time. This capability can be used in various service situations to avoid initial and in some cases repeat visits to the meter for manual meter connects and disconnects. The estimated savings assumes the Company would need to continue manual field connects and disconnects for dual fuel customers. With respect to collections related disconnects, the Company will comply with all requirements per Title 39 of the State of Rhode Island General Laws and the Rules and Regulations promulgated by the PUC and the Rhode Island Division of Public Utilities and Carriers regarding termination of service, including visits to the customer premises. Avoided meter visits will reduce labor and vehicle costs.

2.1.4 Reduction in Damage Claims

In the course of business, despite efforts for mindfulness and safety consciousness, accidents occasionally occur. In certain circumstances arising from driving to/from service orders, routine meter reading routes, or other day to day activities, damage to third party property can occur. As discussed during some of the previous AMF benefits, the advanced metering technologies will allow for remote interaction that will keep metering service reps off of the road and away from customers' premises. The reduction of opportunities for accidents and damage to occur will reduce damage claims.

2.1.5 Storm OMS Benefit

The Company spends millions of dollars annually on storm restoration efforts to include procurement of external crews, meals and lodging, and overtime. AMF would increase visibility during major and minor storms due to the ability to contact meters remotely and determine outage status. This enhanced situational awareness creates efficiencies with crew management and deployment as well as the avoidance of false outages, thereby reducing costs.

2.1.6 FCS Meter Reading

The Field Collection System (FCS) is currently utilized to perform manual and AMR meter reading for both residential and commercial customers. With the implementation of AMF meters the FCS back-office costs will be phased out as the AMF system utilizes different back office systems to manage data collection and processing.

2.1.7 Interval Meter Reading

The AMF system will replace the current MV90 system. The MV90 system currently supports electric interval metering reading for Narragansett Electric, Niagara Mohawk, and Massachusetts Electric. A benefit has been developed and allocated to Narragansett Electric for the costs that will be avoided, including MV90 licensing and IS support, and avoided field visit costs.

2.1.8 Avoided O&M Costs Summary

Table 4-10: Avoided O&M Costs ($million)

Avoided O&M Costs	20-Year NPV (FY20$)
AMR Meter Reading	$14.75
Meter Investigation	$6.20
Remote Connect and Disconnect	$26.90
Reduction in Damage Claims	$2.61
Storm OMS Benefit	$1.88
FCS Meter Reading	$0.28
Interval Meter Reading	$0.02
Total	$52.64

2.2 Avoided AMR Costs

2.2.1 Capital

The AMF program will avoid the need and associated capital costs of the life-cycle replacement program for the existing electric AMR meters. The AMR life-cycle replacement program includes many of the same capital activities as the AMF program such as electric meter installation, communication equipment upgrades, and project management. The avoided cost of these similar activities are estimated as part of, and consistent with, the AMF model.

2.2.2 Operations & Maintenance

The AMF program will avoid the need and associated O&M costs of the life-cycle replacement program for the existing electric AMR meters. The AMR life-cycle replacement program includes many of the same O&M activities as the AMF program such as call center calls, customer communications, and project management. The avoided cost of these similar activities are estimated as part of, and consistent with, the AMF model.

2.2.3 Avoided AMR Costs Summary

Table 4-11: Avoided AMR Costs ($million)

Avoided AMR Costs	20-Year NPV (FY20$)
Capital	$60.52
Operations & Maintenance	$5.97
Total	$66.49

2.3 CUSTOMER BENEFITS

2.3.1 Volt-VAR Optimization ("VVO")

The more granular and frequent data from AMF meters enhances the effectiveness of this program. In particular, a subset of AMF meters can act as end of line sensors that provide real-time information to centralized control systems to adjust grid operational characteristics. More granular metering information can also define more precise load models of individual circuits with adjustments for time of day and year or temperature correlation. For the purposes of this business case, the Company recognizes VVO benefits that would be considered incremental to those achieved by Grid Modernization.

2.3.2 Energy Insights/High Usage Alerts

Through the deployment of AMF smart meters and associated back-office infrastructure, the Company will have access to customer usage data in near real-time, with granularity at sub-hour reading intervals. National Grid will be building an Energy Management Portal that will act as a hub for residential, commercial, and industrial customers to view their energy usage, including the smart meter interval data. This platform will allow electric customers to have access to their raw, not validated, edited and estimated usage data within four hours after an interval, and gas customers will have access to raw usage information within eight hours[1]. Customers will subsequently be able to view billing quality data within 24 hours. In addition to allowing customers to view their energy consumption in near real-time, the Energy Management Portal will allow customers to compare their usage and costs against certain variables such as weather, historic consumption at the same time and dates, and neighbors' usage to understand factors that may be driving their energy use.

Armed with this information, customers can take action using the functionality that the Energy Management Portal provides. This could include enrollment in the Company's energy efficiency and demand response, as well as any pricing programs that are implemented as a part of or subsequent to the AMF deployment. In addition, customers can access the Energy Management Portal for energy savings programs and personalized energy tips and strategies to reduce their energy usage and save money. The Energy Management Portal can also be customized with alerts, notifying customers of high use or events on the electric system such as an outage.

[1] Gas customers will receive monthly register reads until such time that Gas ERTs are installed and interval metering becomes available.

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As described in a report issued by the Electric Power Research Institute (EPRI)2, there is a range of potential savings that can be achieved by empowering customers with personalized energy insights. The EPRI report cites savings achieved during 35 pilot projects in the range of zero to twenty-five percent. To address the potential uncertainty of the benefit estimate for the Energy Management Portal, the Company has calculated a low and high benefit of one percent and three percent, respectively. The low savings estimate will be included with the low TVP pricing options and the high savings with the high TVP pricing options in the Company's BCA analysis.

2.3.3 Time Varying Pricing ("TVP")

AMF technology will allow National Grid to collect utility customers' energy usage in greater detail than previous technologies will allow[3]. This time-stamped data is the foundation by which new pricing programs can be implemented. Through the provision of more granular, time-variant price signals, customers will have new opportunities to reduce energy consumption and/or shift usage from high cost periods to lower cost periods, while also creating system savings.

The Company has evaluated an opt-out scenario where, by default, a large percentage of customers will be enrolled in time variant pricing programs, as well as an opt-in scenario, in which customers must choose to enroll on the rate. Through educational initiatives and pricing signals designed to encourage efficient consumption behavior, over time customers will proactively shift portions of their energy consumption to times of day where energy rates are lower, thereby resulting in reductions in their electric bills. In addition to incentivizing customers' savings, consumers shifting their energy usage will flatten the overall load curve. This shift, combined with other programs such as VVO and energy efficiency, will lower energy peaks, thus reducing expenditures on generation capacity.

Creating an optimal TVP program that maximizes the net benefits to the system could be achieved over years of phase-ins or introductions of new rate designs, software tools, data availability and customer education. This means an optimal design will likely evolve over time, while the concepts described in this business case are intended to be illustrative of how such programs could be implemented. The conceptual TVP program described in our BCA analysis consists of two supply pricing components:

Time of Use – supply prices will vary by specific times of day, every month, with peak (higher price) and off-peak (lower price) periods defined. In response to time of use rates, customers save by reducing consumption during higher cost peak periods and/or shifting use from peak to off-peak periods.

Critical Peak Pricing– supply prices will increase further by time of day on a limited number of specific days (typically during high demands on the electrical system, where customers are notified in advance) designated as critical peak pricing events. Critical peak pricing is designed

[2] Electric Power Research Institute (EPRI), *Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments*, July 2008.
[3] Section 3.4 provides an overview of why AMR technology is insufficient to deliver the Company's TVR program

to recover most of the costs for generation capacity in the hours that have the greatest need for peak capacity. When customers avoid consumption during the highest peak loads of the year, future generation capacity costs, as determined through ISO-NE's Forward Capacity Market auction, are reduced relative to what they otherwise might have been, resulting in capacity cost savings that are included in supply rates for customers. CPP events would be limited to a specific number of days and during specific hours of the day, which gives customers a greater level of flexibility relative to a set critical peak price period.

The benefits from the Company's illustrative TVP program will result from savings in generation capacity costs described above as well as savings in energy costs[4]. Energy cost savings result from a reduction in energy consumption during higher-cost peak periods, and the resulting reduction in the hourly marginal generation cost.

The level of benefits achieved will be directly related to the 1) number of enrolled customers and 2) the level of customer response to the new price signals and the resulting peak and energy savings. National Grid recognizes that customers will require a substantial amount of education, training and access to tools that will enable them to become active participants in TVP programs. For example, customers will need to fully understand the cost implications of consuming electricity during hot summer days, as compared to a springtime morning, as well as how specific technology and program offerings can help them manage their energy costs. With this in mind, the Company evaluated both "High" and "Low" scenarios that vary assumptions about peak reductions and reduction in on-peak energy use.

Energy and capacity savings were calculated for four scenarios: 1) Opt-in TVP with low customer responsiveness; 2) Opt-in TVP with high customer responsiveness; 3) Opt-out TVP with low customer responsiveness; and 4) Opt-out TVP with high customer responsiveness.

<u>Key Assumptions</u>

Key assumptions used to estimate potential savings for the four scenarios are summarized in Table 4-12. These assumptions leverage multiple sources to include:

- Smart Grid Investment Grant Program[5];
- Price Responsiveness Survey[6]; and
- Experiences from National Grid's Smart Energy Solutions smart grid pilot program in Worcester, MA

For our illustrative rate program, National Grid assumed all residential customers would have the ability to participate in the TVP program. Customers would have the ability to Opt-out of TVP, and for this analysis, the Company assumed that 15% of the customers would do so. This 15% opt-out assumption is conservative, as the Company has experienced a less than 10% opt-out in

[4] The assumptions on the value of avoided capacity cost savings and avoided energy cost savings are based on the 2017 update to the 2015 New England Avoided Energy Supply Cost Study.

[5] American Recovery and Reinvestment Act of 2009, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies*, November 2016.

[6] The Brattle Group Economists (Submitted to EDI Quarterly), *The Discovery of Price Responsiveness – A Survey of Experiments involving Dynamic Pricing of Electricity*, March 2012.

the Smart Energy Solutions smart grid pilot program in Worcester, MA, as well as a 98% customer participation retention rate over the Pilot's first two years.

Customer participation is also dependent on the pace of meter deployment, which is assumed to be 33% during the second half of FY21, and 67% in FY22. Steady state enrollment in the TVP is assumed to occur after year 10. This acknowledges and assumes that while all meters scheduled to be deployed as of a given year become operational, customer behaviors are slower to change, implying lower capacity and energy savings in the early years of the program. As customers become familiar with the new TVP program, more customers will become reliability active in delivering CPP load reductions. Different levels of customer engagement and responsiveness to the rates are captured in the low and high scenarios.

Table 4-12: Assumptions to estimate savings from time varying rates

Program Type	Scenario	Customer Participation	Meter Deployment Rate/Year	Years to Steady State	CPP Peak Load Reduction	TOU OnPeak Energy Reduction
Opt-In	Low	20%	33.33%/66.67%	10	8%	4%
Opt-In	High	20%	33.33%/66.67%	10	18%	8%
Opt-Out	Low	85%	33.33%/66.67%	10	6%	3%
Opt-Out	High	85%	33.33%/66.67%	10	13.5%	6%

Forecasted Savings

A summary of the total savings over 20 years is shown in Table 4-13. The savings represent net savings as they are offset by the costs to market and administer the TVP program (i.e. assumed to be 20% of the gross benefits). The range of savings is from a low of $8.4 million to a high of $57.4 million (with a discount rate of 7.51%).

Table 4-13: Summary of Total TVP Savings over 20 Years ($million)

	WACC (after tax)	
NPV ($millions)	**7.51%**	
Opt-In	**Low**	**High**
CPP Savings	$4.6	$10.3
TOU Savings	$3.8	$7.7
Total Savings	$8.4	$18.0
Opt-Out	**Low**	**High**
CPP Savings	$14.6	$32.9
TOU Savings	$12.3	$24.5
Total Savings	$26.9	$57.4

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2.3.4 Electric Vehicle Pricing

The Company expects the introduction of AMF and TVP to enable demand savings and avoided energy charges. The estimate for the electric vehicle integration benefit assumes a certain percentage of electric vehicle charging is done during peak periods and can be displaced, thereby generating both system demand (kw) reductions/savings and avoided energy costs by charging at off-peak versus peak rates.

2.3.5 Customer Benefits Summary

Table 4-14: Customer Benefits ($million)

Customer	20-Year NPV (FY20$)
Volt-VAR Optimization	$13.73
Energy Insights/High Usage Alerts*	$22.02
Time Varying Pricing*	$8.43
Electric Vehicle Pricing	$24.81
Total	$68.99

* Opt-In Low Savings Scenario

2.4 SOCIETAL BENEFITS

2.4.1 Reduction in Greenhouse Emissions

AMF will produce societal benefits through the reduction of greenhouse gas emissions. Reductions will occur as a result of energy conservation enabled by AMF, including enhanced access to usage information and usage alerts, education, and pricing programs. Greenhouse gas emissions will also be reduced due to load reductions enabled by AMF/VVO integration and by eliminating the need for vehicle trips to read meters, connect and disconnect service, and investigate service anomalies.

2.4.2 Societal Benefits Summary

Table 4-15: Societal Benefits ($million)

Societal (CO2 Emission Reductions)	20-Year NPV (FY20$)
AMR Meter Reading	$0.02
Meter Investigations	$0.01
Remote Connect and Disconnect	$0.17
Energy Insights/High Usage Alerts	$7.88
Time Varying Pricing	$2.86
Volt-VAR Optimization	$5.65
Total	$16.40

2.5 Revenue Benefits

2.5.1 Reduction in Theft of Service

Smart meter technology combines greater frequency of readings with sophisticated algorithms to ensure that electric and gas consumption is accurate. AMF provides tamper alarms after detecting usage that attempts to bypass the meter, and also produces customer level data that can be analyzed for reasonableness in order to identify unusual patterns that may reflect theft of service. If discrepancies are proven to be theft, the Company can take action to address the situation, thus minimizing a cost that would normally be socialized across the customer base, thereby saving other customers money.

Per a report from the Electric Power Research Institute (EPRI)[7], today's well managed utilities with proactive revenue protection programs will experience average revenue losses from all non-technical sources (excluding bad debt) of 1.5%, with 3% representing the higher end of the range. This same report explains that AMF with meter data management can mitigate many of the factors contributing to these losses. For the purposes of this business case, we have utilized a conservative assumption that AMF implementation will reduce non-technical revenue losses (excluding bad debt) by .25%.

2.5.2 Reduction in Write-offs

Bad debt is incurred when National Grid customers are unable or unwilling to pay their billing obligations. National Grid makes every reasonable attempt to collect those outstanding bills. Eventually, this unrealized revenue is classified as a loss and is written off and spread across all customers. A smart meter's ability to remotely disconnect service, within the existing approved parameters and in consideration of all consumer protection processes, will reduce these socialized costs. Although the smart meters cannot entirely eliminate bad debt write-offs, the remote disconnect function can reduce the period between when an electric customer defaults on payment to when their meter is actually disconnected, thus reducing the loss incurred. In time the impact of this functionality will prompt a change in customer behavior, resulting in a significant reduction in overall bad debt and operational expense. This will improve the customer experience due to fewer collection activities such as mailings, phone calls, and field visits.

2.5.3 Electromechanical Meter

The majority (i.e. approx. 70%) of electric meters currently deployed in the Rhode Island service territory are electromechanical by design. Electromechanical meters operate by counting the rotation of an internal metal disk, and various studies have shown that the accuracy of this count begins to decline over time. The net effect of the reduced accuracy is to understate usage, thereby decreasing revenue. The electromechanical meter benefit recognizes the ability to increase revenue through the introduction of AMF and related solid state technology which mitigates the impact of declining meter reading accuracy over time.

[7] Electric Power Research Institute, *Advance Metering Infrastructure Technology – Limiting Non-Technical Distribution Losses in the Future*, December 2008, Pages 1-6, 1-14.

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2.5.4 Revenue Benefits Summary

Table 4-16: Revenue Benefits ($million)

Revenue Benefits	20-Year NPV (FY20$)
Reduction in Theft of Service	$26.95
Reduction in Write-offs	$6.15
Electromechanical Meter	$15.98
Total	$49.08

2.6 Additional Synergies/Coordination Benefits

The components, capabilities, costs, and benefits articulated in the prior sections all align to the core vision of AMF for near-term implementation. Other capabilities and use cases were also contemplated but were determined to be out of scope. As such, no costs or benefits have been defined for these capabilities. However, as AMF deploys, stabilizes, and matures, the preliminary vision can be expanded upon in the following ways.

2.6.1 Water Utility/Municipality Revenue Opportunities with Joint Use

Electric utilities have pursued the concept of "Joint Use" for many years through the use of shared infrastructure like utility poles that support electric, telephone, and cable television lines. Applied to metering technology, the technical umbrella of National Grid's proposed infrastructure could be leveraged to support the metering efforts that overlap with water utilities. While water meters themselves could likely be procured and installed by the respective water agency, wireless radios, backhaul, and back-office validation systems could be owned by National Grid but provided as "Metering-As-A-Service" to interested jurisdictions. In this way, the concepts of greater customer information and empowered decision making can be expanded as a more holistic capability for Rhode Island customers.

2.6.2 AMF for Streetlights and Ancillary Devices

Many metering technology vendors, in addition to numerous lighting control technology applications, offer metering capabilities for street light infrastructure which complements the other proposed metering capabilities. Street lights have a universal, industry standard receptacle for a light sensitive photoelectric control that is used to facilitate the changing dusk to dawn operating schedule throughout the year. This lighting control can be replaced with a new control device that incorporates dedicated solid state AMF meter chip technology. At a minimum, this control device can integrate with the metering mesh to transition street lighting from an unmetered to a metered billing application.

The increasing customer demand for this metering functionality is being fostered by the instant on/off and dimming capabilities of solid state lighting technology (i.e. light emitting diode (LED's)) to provide customized, variable operating schedules and illumination levels based on application needs. The additional energy savings of these tailored usage applications beyond the savings achieved through conversion from legacy lighting technologies cannot be realized through the use of limited fixed operating schedules that conform to present analytic billing methods. Additionally, these devices provide additional communication contact nodes to reinforce and strengthen data routing. Further, by virtue of the inherent elevation and location

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logistics, the additional nodes can also reduce communication hop counts and minimize the urban concrete canyon effects by increasing the number of direct communications to the nearest wireless router.

Street Light AMF also has several benefits independent of the broader metering platform. These include:

- Preemptive maintenance based on:
  - Luminaire diagnostics used to identify imminent failure characteristics for; lamps, ignitor, ballast, surge suppression and photocontrol sensor for timely repairs to avoid "outages" or "day-burners";
  - Circuitry diagnostics used to identify electric operating conditions;
  - Detection of errant (stray) voltage conditions and inadequate grounding capacity;
  - Minimizes customer/company interaction for operation condition reporting;
- Promotes the application and accurate energy metering of advanced technologies such as; WiFi, surveillance and detection cameras (e.g. license plate, parking space, "red light", etc.), sensors (e.g. Motion, temperature, humidity, hazardous chemicals, radiation, etc.), distributed antenna and small cell technology, interactive parking meters, vehicle charging stations and other emergency notification systems;
- Establishes a real-time, global position for all street lighting and ancillary device locations;
- Supports active asset management of street lighting and associated infrastructure for accurate inventory and billing requirements; and
- Enhances customer accessibility of street lighting /device information through a secure interactive internet interface for: inventory information, operational scheduling/dimming, installation/removal/relocation requests and scheduling, maintenance service reporting and performance
  - Enables customer control of advanced lighting technologies facilitating dynamic use of the lights while experiencing actual energy consumption billing optimizing all energy efficiencies.

2.6.3 Gas Remote Service Valve

Gas remote service shutoff valves can be integrated with the AMF solution. Remote service valves with flood sensors that automatically shut off gas to structures that experience flooding and provide an accurate count of services impacted by the flooding - will enable improved emergency response in the event of flooding. This targeted approach shuts down only the services affected by flooding (as opposed to the larger gas service districts) and sends alerts to the customers impacted, isolating the system and alerting the Company of the loss of service to our customers in real time. This will enable improved management of storm restoration with specific focus on the affected customers. This program will also facilitate swift decision making focused upon affected regions, thus generating efficient execution of service restoration work and allowing improved customer satisfaction while further ensuring the safety and reliability of the system. Remote Service Shutoff Valves without flood sensors can also be installed, allowing for remote disconnect for safety reasons such as residential methane detection alarms, gas leaks, and customer natural gas calls.

2.6.4 Residential Methane Detectors

Residential Methane Detectors (RMD) equipped with communication devices, also known as Smart Residential Methane Devices, are currently in research and development in support of deployment. The RMD can be integrated with the AMF solution. Smart RMD's will be able to send a notification to National Grid in the event the device senses methane at a customer location through a fixed communication network, allowing National Grid to respond with or without a customer call. In conjunction with the remote service valve, National Grid will have the ability to turn off a customer service remotely when methane is detected, ensuring safety prior to a potential leak being investigated. Systematic methane detection across multiple customer locations in a common area in the event multiple devices sense methane can be investigated as well. Due to an RMD's nature to detect any type of methane, any type of leak within the residence will be detected, including customer owned equipment and piping. This is especially critical in multiple unit dwellings (i.e.-apartment buildings, multistory structures, etc.).

2.6.5 Outage Management

An additional benefit of core smart meter technology is the ability to report an outage in near real time. Although individual smart meters are electrically powered, they have enough battery life to signal the network and operational systems of a power loss. This ability has several advantages over the current system of monitoring substations for very large power changes that would indicate an outage and rely on customer calls to pinpoint. Smart meters near real-time power outage notification allow the system operators to assess outage characteristics more quickly, have more extensive situational awareness, and take steps to restore power more efficiently. Furthermore, once power has been restored, smart meters can be dynamically pinged to assess whether the entire outage has been restored or if additional work needs to be done to restore nested outages.

2.7 ECONOMIC DEVELOPMENT BENEFITS

Economic Impact offers additional benefits not captured in the Benefit Cost Calculation. The AMF program provides a positive benefit to the Rhode Island economy through a number of channels. First, the planned investment spending on this program is expected to increase local Rhode Island GDP by $47.6 million, generate $3.7 million in state and local taxes, and create 489 jobs. Moreover, the program will create $32.8 million in labor income and help build a workforce with the skills and experience required to underpin Rhode Island's future as a clean energy economy.

Table 4-17: Rhode Island Economic Impact: Years 1-4 Total

Measure	Value
Rhode Island GDP	$47.6 Million
Jobs Created	489 Job Years
Labor Income	$32.8 Million
State & Local Taxes	$3.67 Million

In addition to spending generated benefits, the AMF program will stimulate economic activity in other ways. These include the impact of reductions in customers' energy bills, as demonstrated in the National Grid Smart Energy Solutions Pilot program. Additional bill savings are made possible through AMF's enablement of distributed energy resources (DER) and third-party energy management products. These savings will be redirected to spending in other sectors of the Rhode Island economy; generating additional jobs, output, labor income, and tax revenues. The introduction of AMI also improves National Grid's ability to manage the distribution system. Cost savings, efficiency improvements, reliability and resiliency gains all translate into economic benefits for Rhode Island as resources are allocated in an efficient manner.

APPENDIX 4.2 - AMF BCA METHODOLOGY

APPENDIX 4.2: AMF BCA METHODOLOGY

The following document provides detailed descriptions and calculation methodologies of the cost and benefit line items in the AMF model. Each item is identified with a number that corresponds to the AMF model.

2 – Benefit from Eliminated AMR Meter Readers

Description: National Grid currently has a fleet of automatic meter reading (AMR) meters covering its electric and gas service territory. These AMR meters have monthly reads that are acquired through radio frequency technology. These collections are done by a fleet of service vans which meter readers drive along routes to allow communication with each meter.

Starting in fiscal year 2021, National Grid will replace its current AMR meters with advanced metering functionality (AMF) meters. National Grid has estimated that the vast majority of AMF meters will utilize a built-in low-power, short-range radio to digitally communicate interval data using a two-way communication structure. This data will be communicated from meter to meter until it reaches a centralized data collection point, at which point it will be passed up to an AMF Head-End and various back-office systems. This radio frequency based communication path is referred to as a “mesh network”.

Due to topographical limitations etc., it is also expected that a small percentage of AMF meters will utilize internal cellular radios to communicate with the wireless communications infrastructure. Ultimately, utilization of the new AMF technology to include both the radio frequency mesh network and cellular communications would avoid the need for AMR meter readers. National Grid would also avoid the annual maintenance cost for the AMR meters being replaced.

Calculation Overview: This benefit calculation takes the annual cost per AMR Meter Reader and multiplies it by the number of AMR meter readers that will be eliminated, and also adds in the Annual AMR meter maintenance bill for upstate NY.

Source References: RI AMF ID: 1007, 1008

Cost/Benefit Group: AMR Meter Reading

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	33%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

3 – Benefit from Eliminated AMR Meter Reader Vehicle Costs

Description: As described under Benefit 2 and starting in fiscal year 2021, National Grid will replace its current AMR meters with AMF meters. In addition to avoiding the need for the AMR meter readers as a result of the new technology, National Grid will also be able to reduce the number of related company vehicles formerly utilized by this function.

Calculation Overview: This benefit calculation multiplies the number of full-time meter reader employee reductions by the vehicle cost per employee.

Source References: RI AMF ID: 1007

Cost/Benefit Group: AMR Meter Reading

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	33%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

4 – CO2 Benefit from Eliminated AMR Vehicle Emissions

Description: As described under Benefits 2 and 3, use of the new AMF technology will eliminate the need for meter readers to perform drive-by readings while leveraging company vehicles. The reduction in company vehicles will in turn reduce diesel fuel consumption, which reduces CO2 emissions.

Calculation Overview: This benefit generally takes the AMR reading miles driven and multiplies this total by the cost of CO2.

Source References: RI AMF ID: 1009, 1010, 1019

Cost/Benefit Group: AMR Meter Reading (CO2)

CapEx/OpEx/Other: Emissions

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	33%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

5 – Benefit from Reduction of Meter Investigations

Description: AMF meters will provide auto and on-demand meter reads and diagnostics to alert and inform the Company about anomalous situations that in-turn allows for the reduction of visits to the meter for manual meter investigations. This will reduce labor and vehicle costs. The types of manual meter investigations that can be avoided in part include Use on Inactive Electric Meter Investigations, Meter On/Off and Meter Reads.

Calculation Overview: This benefit calculation is generally comprised of two parts:

- Reduction of labor associated with performing investigations
- Reduction of vehicle costs associated with performing investigations

In aggregate, the labor and vehicle cost reductions are added together.

Source References: RI AMF ID: 1008, 1011, 1012

Cost/Benefit Group: Meter Investigations

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	33%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

6 – Benefit from Remote Metering Capabilities

Description: Advanced Metering provides the ability to connect and disconnect electric service remotely and in near real-time. This capability can be used in various service situations to avoid initial and in some cases repeat visits to the meter for manual meter connects and disconnects. The estimated savings assumes the Company would need to continue manual field connects and disconnects for dual fuel customers. With respect to collections related disconnects, the company will comply with all requirements per Title 39 of the State of Rhode Island General Laws including visits to the customer premise. Avoided meter visits will reduce labor and vehicle costs.

Calculation Overview: This benefit calculation is generally comprised of two parts:

- Reduction of vehicle costs associated with certain meter disconnects and reconnects
- Reduction of labor costs associated with certain meter disconnects and reconnects

In aggregate, these two cost reduction components are added together.

Source References: RI AMF ID: 1008, 1011, 1012

Cost/Benefit Group: Remote Connect and Disconnect

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	33%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

9 – Benefit from improvement in bad debt write-offs

Description: Bad debt is incurred when National Grid customers are unable or unwilling to pay their billing obligations. National Grid makes every reasonable attempt to collect those outstanding bills. Eventually, this unrealized revenue is classified as a loss and is written off and spread across all customers. A smart meter's ability to remotely disconnect service, within the existing approved parameters and in consideration of all consumer protection processes, will reduce these socialized costs. Although the smart meters cannot entirely eliminate bad debt write-offs, the remote disconnect function can reduce the period between when an electric customer defaults on payment to when their meter is actually disconnected, thus reducing the loss incurred. In time the impact of this functionality will prompt a change in customer behavior, resulting in a significant reduction in overall bad debt and operational expense. This will improve the customer experience due to fewer collection activities such as mailings, phone calls, and field visits.

Calculation Overview: This benefit calculation takes the cumulative AMF Deployment and multiplies it by the Total Residential and Commercial Growth in bad debt mitigation attributable to AMF data to get the total annual bad debt mitigation.

Source References: RI AMF ID: 1016

Cost/Benefit Group: Reduction in Write-Offs

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

11 - Benefit from mitigation / reduction of damage claims

Description: In the course of business, despite efforts for mindfulness and safety consciousness, accidents occasionally occur. In certain circumstances arising from driving to/from service orders, routine meter reading routes, or other day to day activities, damage to third party property can occur. As discussed during some of the previous AMF benefits, the advanced metering technologies will allow for remote interaction that will keep metering service reps off of the road and away from customers' premises. The reduction of opportunities for accidents and damage to occur will reduce damage claims.

Calculation Overview: This benefit calculation determines an approximate number of meters for Electric, and then multiplies this by the # of claims per meter, the value of damage claims and the % reduction due to AMF Meters.

Source References: RI AMF ID: 1005, 1006

Cost/Benefit Group: Reduction in Damage Claims

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

13 - Benefit from Reduction of AMR Theft / Undermetering

Description: Smart meter technology combines greater frequency of readings with sophisticated algorithms to ensure that electric and gas consumption is accurate. AMF provides tamper alarms after detecting usage that attempts to bypass the meter, and also produces customer level data that can be analyzed for reasonableness in order to identify unusual patterns that may reflect theft of service. If discrepancies are proven to be theft, the Company can take action to address the situation, thus minimizing a cost that would normally be socialized across the customer base, thereby saving other customers money.

Calculation Overview: This benefit calculation generally takes projected RI annual customer revenue and multiplies it by the percentage of revenue loss due to theft avoided by AMF.

Source References: RI AMF ID: 1023

Cost/Benefit Group: Reduction in Theft of Service

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	33%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

14 – Benefit from VVO/AMF Integration

Description: The more granular and frequent data from AMF meters enhances the effectiveness of the VVO program. In particular, a subset of AMF meters can act as end of line sensors that provide real-time information to centralized control systems to adjust grid operational characteristics. More granular metering information can also define more precise load models of individual circuits with adjustments for time of day and year or temperature correlation. For the purposes of this business case, the Company recognizes VVO benefits that would be considered incremental to those achieved by Grid Modernization.

Calculation Overview: This benefit calculation takes the cumulative pre-CVR load on circuits where CVR is to be deployed and multiplies it by the % improvement due to CVR attributable to AMF data, and then multiplies it by the cost per megawatt hour.

Source References: RI AMF ID: 1020, 1021, 1022

Cost/Benefit Group: Volt-VAR Optimization

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	2%	2%	3%	3%	3%	4%	4%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
5%	5%	6%	6%	7%	8%	9%	9%	10%	11%

15 – CO2 Benefit from VVO/AMF Integration

Description: As described under benefit 14, the deployment of AMF meters enhances the effectiveness of the VVO program. In particular, a subset of AMF meters can act as end of line sensors that provide real-time information to centralized control systems to adjust grid operational characteristics. These VVO benefits will lead to a reduction in CO2 emissions.

Calculation Overview: This benefit calculation takes the cumulative pre-CVR load on circuits where CVR is to be deployed and multiplies it by the % improvement due to CVR attributable to AMF data, and then multiplies it by the price of carbon.

Source References: RI AMF ID: 1019, 1020, 1021

Cost/Benefit Group: Volt-VAR Optimization (CO2)

CapEx/OpEx/Other: Losses

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	33%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

16 – Benefit from Energy Insights/High Usage Alerts

Description: Through the deployment of AMF smart meters and associated back-office infrastructure, the Company will have access to customer usage data in near real-time, with granularity at sub-hour reading intervals. National Grid will be building an Energy Management Portal that will act as a hub for residential, commercial, and industrial customers to view their energy usage, including the smart meter interval data. This platform will allow electric customers to have access to their raw, not validated, edited and estimated ("VEE") usage data within four hours after an interval, and gas customers will have access to raw usage information within eight hours. Customers will subsequently be able to view billing quality data within 24 hours. In addition to allowing customers to view their energy consumption in near real-time, the Energy Management Portal will allow customers to compare their usage and costs against certain variables such as weather, historic consumption at the same time and dates, and neighbors' usage to understand factors that may be driving their energy use.

Armed with this information, customers can take action using the functionality that the Energy Management Portal provides. This could include enrollment in the Company's energy efficiency and demand response, as well as any pricing programs that are implemented as a part of or subsequent to the AMF deployment. In addition, customers can access the Energy Management Portal for energy savings programs and personalized energy tips and strategies to reduce their energy usage and save money. The Energy Management Portal can also be customized with alerts, notifying customers of high use or events on the electric system such as an outage.

As described in a report issued by the Electric Power Research Institute (EPRI), there is a range of potential savings that can be achieved by empowering customers with personalized energy insights. The EPRI report cites savings achieved during 35 pilot projects in the range of zero to twenty-five percent. To address the potential uncertainty of the benefit estimate for the Energy Management Portal, the Company has calculated a low and high benefit of one percent and three percent, respectively. The low savings estimate will be included with the low TVP pricing options and the high savings with the high TVP pricing options in the Company's BCA analysis.

Calculation Overview: This benefit calculation is generally comprised of two parts:

- Calculate reduction of GWh consumed
- Calculate value of avoided energy based on annual reduction

In aggregate, the electric and gas fuel savings are added together.

Source References: RI AMF ID: 1017, 1019, 1026

Cost/Benefit Group: Energy Insights/High Usage Alerts

CapEx/OpEx/Other: Revenue

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	100%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

17 – CO2 Benefit from Energy Insights/High Usage Alerts

Description: As described under benefit 16, the deployment of AMF meters can enable more granular consumption data and high usage alerts etc. to be made available to customers. It is anticipated that these personalized energy insights will drive reduced consumption which in turn, will lead to a reduction in CO2 emissions.

This cost element leverages MWh energy reductions calculated in element 16 as the basis for avoided CO2 valuation in this calculation.

Calculation Overview: This benefit calculation multiplies the forecasted load reduction in MWh calculated in benefit 16 multiplied by the CO2 value in $/MWh.

Source References: RI AMF ID: 1019

Cost/Benefit Group: Energy Insights/High Usage Alerts (CO2)

CapEx/OpEx/Other: Losses

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	100%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

18 – CO2 Benefit from Reduction of Meter Investigations

Description: As previously stated in benefit 5, AMF meters will provide auto and on-demand meter reads and diagnostics to alert and inform the Company about anomalous situations that in-turn allows for the reduction of visits to the meter for manual meter investigations. The reduction in visits will lead to a corresponding reduction in diesel fuel consumption, which in turn will lead to a decrease in CO2 emissions.

Calculation Overview: This benefit generally takes the meter investigation miles driven which can be avoided and multiplies it by the cost of CO2.

Source References: RI AMF ID: 1007, 1010, 1011, 1015, 1019

Cost/Benefit Group: Meter Investigation (CO2)

CapEx/OpEx/Other: Emissions

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	33%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

19 – CO2 Benefit from Remote Metering Capabilities

Description: As previously described under benefit 6, Advanced Metering provides the ability to connect and disconnect electric service remotely and in near real-time. This capability can be used in various service situations to avoid initial and in some cases repeat visits to the meter for manual meter connects and disconnects. This decrease in the number of times field employees have to drive out to meters to manually connect or disconnect them, reduces diesel fuel consumption which in turn decreases CO2 emissions.

Calculation Overview: This benefit generally takes the annual meter service stop miles that can be avoided and multiplies it by the cost of CO2.

Source References: RI AMF ID: 1007, 1010, 1015, 1019

Cost/Benefit Group: Remote Connect and Disconnect (CO2)

CapEx/OpEx/Other: Emissions

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	33%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

20 – Outage Management Operational Benefit

Description: The Company spends millions of dollars annually on storm restoration efforts to include procurement of external crews, meals and lodging, and overtime. AMF would increase visibility during major and minor storms due to the ability to contact meters remotely and determine outage status. This enhanced situational awareness creates efficiencies with crew management and deployment as well as the avoidance of false outages, thereby reducing costs.

Calculation Overview: This calculation takes the annual RI storm restoration costs and multiplies by the % improvement attributed to AMF deployment.

Source References: RI AMF ID: 1028

Cost/Benefit Group: Storm OMS Benefit

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

25 – Benefit from Electric Vehicle TVP

Description: The Company expects the introduction of AMF and TVP to enable demand savings and avoided energy charges. The estimate for the electric vehicle integration benefit assumes a certain percentage of electric vehicle charging is done during peak periods and can be displaced, thereby generating both system demand (kw) reductions/savings and avoided energy costs by charging at off-peak versus peak rates.

Calculation Overview: The below cited reference contains a model which calculates and sums the avoided demand cost from reduced demand billing rates and the avoided energy cost from shifts to off-peak charging.

Source References: RI AMF ID: 1027

Cost/Benefit Group: Electric Vehicle Pricing

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

26 – Benefit from Critical Peak Pricing (CPP) peak shaving

Description: Supply prices will increase further by time of day on a limited number of specific days (typically during high demands on the electrical system, where customers are notified in advance) designated as CPP events. CPP is designed to recover most of the costs for generation capacity in the hours that have the greatest need for peak capacity. When customers avoid consumption during the highest peak loads of the year, future generation capacity costs, as determined through ISO-NE's Forward Capacity Market auction, are reduced relative to what they otherwise might have been, resulting in capacity cost savings that are included in supply rates for customers. CPP events would be limited to a specific number of days and during specific hours of the day, which gives customers a greater level of flexibility relative to a set critical peak price period.

The benefits from the Company's illustrative TVP program will result from savings in generation capacity costs described above as well as savings in energy costs. Energy cost savings result from a reduction in energy consumption during higher-cost peak periods, and the resulting reduction in the hourly marginal generation cost.

Calculation Overview: This benefit calculation is generally comprised of a multiplication of forecasted annual peak load multiplied by an achievable load reduction percentage (based on AMF deployment and CPP adoption) multiplied by an anticipated CPP Capacity Payment $ per MW avoided.

Source References: RI AMF ID: 1018

Cost/Benefit Group: Time Varying Pricing

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	33%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

27 – Benefit from Avoided Energy due to Time-of-Use Program

Description: Supply prices will vary by specific times of day, every month, with peak (higher price) and off-peak (lower price) periods defined. In response to TOU rates, customers save by reducing consumption during higher cost peak periods and/or shifting use from peak to off-peak periods.

Calculation Overview: This benefit calculation is generally comprised of a multiplication of forecasted load during peak hours multiplied by achievable load reduction percentage (based on AMF deployment and TOU adoption) multiplied by avoided average fuel costs per MWh of generation.

Source References: RI AMF ID: 1018

Cost/Benefit Group: Time Varying Pricing

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	33%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

28 – CO2 Benefit from Avoided Energy due to Time-of-Use Program

Description: As described under Benefit 27, supply prices will vary by specific times of day, every month, with peak (higher price) and off-peak (lower price) periods defined. In response to TOU rates, customers save by reducing consumption during higher cost peak periods and/or shifting use from peak to off-peak periods. Based on the annual MWh reductions, a CO2 benefit can be applied.

Calculation Overview: This benefit calculation multiplies the Total benefit from Avoided Energy due to Time-of-Use Program calculated in benefit item 27 by the price of CO2 in nominal $ per MWh.

Source References: RI AMF ID: 1018, 1019

Cost/Benefit Group: Time Varying Pricing (CO2)

CapEx/OpEx/Other: Emissions

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	33%	100%	100%	100%	100%	100%	100%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

30 – Benefit from Electromechanical Meter Accuracy

Description: The majority (i.e. approx. 70%) of electric meters currently deployed in the Rhode Island service territory are electromechanical by design. Electromechanical meters operate by counting the rotation of an internal metal disk, and various studies have shown that the accuracy of this count begins to decline over time. The net effect of the reduced accuracy is to understate usage, thereby decreasing revenue. The electromechanical meter benefit recognizes the ability to increase revenue through the introduction of AMF and related solid state technology which mitigates the impact of declining meter reading accuracy over time.

Calculation Overview: The below cited reference contains a model which calculates the average customer consumption and multiplies this amount by the increased accuracy percentage to derive increased revenue.

Source References: RI AMF ID: 1031

Cost/Benefit Group: Electromechanical Meter

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	29%	60%	32%	30%	27%	25%	23%	21%	18%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
16%	14%	12%	10%	8%	5%	3%	0%	0%	0%

100 – AMF electric meter equipment cost

Description: This element covers the cost of Advanced Metering equipment to be installed at electric metering locations. For electric, this equipment consists of the electric meter itself which includes all capabilities natively within the device.

The functions included in the configuration that National Grid is considering include technologies to measure interval consumption, telecommunications to interface with Advanced Metering Mesh, solid-state memory and processing allowing (for firmware upgrades, consumption recording, ping support, etc), sensors for power quality measurement (last gasp notifications, voltage violations, etc.), autonomous algorithms for abnormal operation (to identify tamper detection, improper measurement, etc.), and the ability to remotely connect and/or disconnect electrical service for customers

Calculation Overview: This cost calculation determines an approximate number of meters for residential and C&I customers and then multiplies this by the known cost per electric metering unit.

Source References: RI AMF ID: 1005, 1035, 1036, 1042

Cost/Benefit Group: AMF Electric Meter Equipment and Installation

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	67%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

102 – AMF electric meter installation cost – CapEx portion

Description: In addition to the cost of electric metering units themselves, additional costs must be incurred for labor associated with installation. These efforts include labor time to travel to a given premise, remove the existing meter, install the new meter at the customer premises, and make note of all appropriate inventory and activation information.

Calculation Overview: This cost calculation is generally comprised of a multiplication of total number of electric meters by the approximate cost per each electric meter installation.

Source References: RI AMF ID: 1005, 1007, 1038

Cost/Benefit Group: AMF Electric Meter Equipment and Installation

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	67%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

104 – AMF failed meter equipment replacement cost

Description: This element recognizes that over time, meters will fail. While a warranty is provided on meters for a one-year period, after this period expires, it will be National Grid's responsibility to procure replacements.

Calculation Overview: This cost calculation determines incremental AMF equipment costs and multiplies it by the annual failure rate.

Source References: RI AMF ID: 1005, 1033

Cost/Benefit Group: Equipment and Installation Refresh Cost

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	100%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

105 – AMF Demonstration Period Cost

Description: This element recognizes that a pilot deployment is a best practice undertaken by many utilities throughout the industry. Through the pilot, processes and capabilities can be undertaken and improved with a smaller volume of meters to minimize negative customer experiences. Once refined, the tools, processes, and staff are better prepared to perform the expected business functions on a larger scale.

Calculation Overview: This cost calculation sums various estimated pilot program costs (e.g. System Testing Strategy, Implementation, and Infrastructure).

Source References: RI AMF ID: 1039

Cost/Benefit Group: AMF Electric Meter Equipment and Installation

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
100%	0%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

110 – AMF network engineering, design, contracting cost

Description: As a first step for implementing the AMF network, various efforts must be undertaken to engineer and design the network to ensure that it is fit for purpose and will operate efficiently and effectively. This design activity includes identification of preliminary CGR locations, access points, backhaul gateways, as well as core backhaul network design.

Calculation Overview: Sourced directly from Meter Telecom estimate.

Source References: RI AMF ID: 1041

Cost/Benefit Group: Network Equipment and Installation

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
100%	0%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

111 – Network communications equipment cost, Electric Meters

Description: Advanced meters communicate with each other through mesh technologies for local communications but rely on more robust communications equipment for backhaul to back office systems. The core piece of equipment to perform this function is a Connected Grid Router (CGR) which can aggregate data from local metering mesh clusters and convey pertinent data through publicly available cellular wireless. This cost component considers the cost of CGRs to support electric advanced metering.

Calculation Overview: This cost calculation multiplies the number of CGRs required to support Electric Meters by the known cost per CGR unit.

Source References: RI AMF ID: 1005, 1006, 1035, 1042, 1043

Cost/Benefit Group: Network Equipment and Installation

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	67%	0%	0%	0%	0%	0%	0%	0%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

112 – Network communications equipment cost, Gas Meters

Description: Advanced meters communicate with each other through mesh technologies for local communications but rely on more robust communications equipment for backhaul to back office systems. The core piece of equipment to perform this function is a Connected Grid Router (CGR) which can aggregate data from local metering mesh clusters and convey pertinent data through publicly available cellular wireless. This cost component considers the cost of CGRs to support gas advanced metering.

Calculation Overview: This cost calculation multiplies the number of CGRs required to support the expected quantity of Gas meters by the known cost per CGR unit.

Source References: RI AMF ID: 1035, 1043

Cost/Benefit Group: Network Equipment and Installation

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	67%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

113 – Network communications installation cost, Electric Meters

Description: For Connected Grid Routers (CGRs) used to support Electric Advanced Meters (documented in cost element 111), each device must be configured and installed to properly support necessary communications. This cost element considers the installation costs.

Calculation Overview: This cost calculation multiplies the number of CGRs required to support the expected quantity of electric meters calculated in cost item 111 by the known cost per CGR unit installation.

Source References: RI AMF ID: 1041

Cost/Benefit Group: Network Equipment and Installation

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	67%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

114 – Network communications installation cost, Gas Meters

Description: For Connected Grid Routers (CGRs) used to support Gas Advanced Meters (documented in cost element 112), each device must be configured and installed to properly support necessary communications. This cost element considers the installation costs.

Calculation Overview: This cost calculation multiplies the number of CGRs required to support the expected quantity of gas meters calculated in cost item 111 by the known cost per CGR unit installation.

Source References: RI AMF ID: 1041

Cost/Benefit Group: Network Equipment and Installation

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	67%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

115 – Network communications LTE backhaul cost, Electric Meters

Description: For Connected Grid Routers (CGRs) used to support Electric Advanced Meters (documented in cost element 111), each device has a corresponding, annual service fee allowing it to communicate with the public cellular backhaul. This cost element considers this annual cost for operations.

Calculation Overview: This cost calculation multiplies the number of CGRs required to support the expected quantity of electric meters calculated in cost item 111 by the annual LTE service charge per CGR.

Source References: RI AMF ID: 1041

Cost/Benefit Group: Backhaul

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	100%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

116 – Network communications LTE backhaul cost, Gas Meters

Description: For Connected Grid Routers (CGRs) used to support Gas Advanced Meters (documented in cost element 112), each device has a corresponding, annual service fee allowing it to communicate with the public cellular backhaul. This cost element considers this annual cost for operations.

Calculation Overview: This cost calculation multiplies the number of CGRs required to support the expected quantity of gas meters calculated in cost item 112 by the annual LTE service charge per CGR.

Source References: RI AMF ID: 1041

Cost/Benefit Group: Backhaul

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	16%	24%	31%	39%	67%	75%	82%	90%	98%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

117 – AMF meter cellular service cost, Electric Meters

Description: A subset of electric meters will be located in rural areas with insufficient density to form a stable and consistent mesh. For these electric metering locations, an electric meter with a cellular radio will be installed instead of one with a mesh radio. The difference in technology will alter the cost per meter, as seen in cost element 100. In addition, electric meters that use a cellular radio for communication do have a corresponding service fee with public cellular providers to ensure timely delivery of meter reads.

Calculation Overview: This cost calculation determines an approximate number of advanced electric meters then multiplies this by an estimated % of meters which directly use public cellular backhaul multiplied by an annual cost of service per meter.

Source References: RI AMF ID: 1005, 1006, 1041, 1042

Cost/Benefit Group: Equipment and Installation Refresh Cost

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	100%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

118 – Network Communications Equipment Cost Upgrade

Description: As stated in cost elements 111 and 112, advanced meters communicate with each other through mesh technologies for local communications but rely on more robust communications equipment for backhaul to back office systems. The core piece of equipment to perform this function is a Connected Grid Router (CGR) which can aggregate data from local metering mesh clusters and convey pertinent data through publicly available cellular wireless. This cost component considers the equipment and installation cost associated with a one-time CGR upgrade to support electric and gas advanced metering.

Calculation Overview: This cost calculation is equal to the CGR equipment and installation costs for electric and gas established in cost element 111, 112, 113 and 114.

Source References: RI AMF ID: Calculated

Cost/Benefit Group: Network Equipment and Installation

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	0%	0%	0%	0%	0%	0%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

119 – AMF communications failed equipment replacement cost

Description: Advanced meters communicate with each other through mesh technologies for local communications but rely on more robust communications equipment for backhaul to back office systems. The core piece of equipment to perform this function is a Connected Grid Router (CGR) which can aggregate data from local metering mesh clusters and convey pertinent data through publicly available cellular wireless. Cost elements 111 and 112 define the costs incurred for initial deployment of these devices.

Over time, it is expected that these devices will fail and require replacement. This cost element addresses the costs of the replacement equipment and the installation cost associated with replacing failed equipment throughout the duration of the program.

Calculation Overview: This cost calculation multiplies the total number of CGRs (supporting both electric and gas metering) by the replacement cost per CGR by an annual failure rate necessitating replacement.

Cost/Benefit Group: Equipment and Installation Refresh Cost

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	33%	100%	100%	100%	100%	100%	100%	100%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

120 – AMF communications equipment O&M cost (outside warranty)

Description: Advanced meters communicate with each other through mesh technologies for local communications but rely on more robust communications equipment for backhaul to back office systems. The core piece of equipment to perform this function is a Connected Grid Router (CGR) which can aggregate data from local metering mesh clusters and convey pertinent data through publicly available cellular wireless. Cost elements 111 and 112 define the costs incurred for initial deployment of these devices.

Over time, various efforts must be undertaken to investigate and maintain these devices through their lifecycle. These costs are captured as part of this line item.

Calculation Overview: This cost calculation multiplies the total value of CGRs (supporting both electric and gas metering) by an annual operations and maintenance cost to for continued operation.

Source References: RI AMF ID: 1039

Cost/Benefit Group: Equipment and Installation Refresh Cost

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

121 – AMF External Project Management Labor Cost - CapEx portion

Description: Advanced Metering requires numerous components and systems which must be designed, configured, tested, deployed and managed. National Grid expects to augment internal efforts through external Project Management to advance project objectives. This cost element captures the external cost of contract labor to facilitate and support National Grid staff through the requisite program lifecycle.

Calculation Overview: This cost calculation multiplies the total number of external resources used for AMF project staff augmentation by an external resource annual salary.

Cost/Benefit Group: Project Management

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	50%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

123 – Cost from call center and AMO, implementation

Description: Deployment of advanced meter physical infrastructure is eventually accompanied by downstream customer impacts. Some customers may have questions about how TOU or CPP pricing works, some may have questions about changes to their bill, some may be curious about how to access their detailed consumption data on the web portal, and others may just be curious to better understand the program. National Grid fully believes that supporting customers with a robust change management program is vital to the overall successful adoption of this program. The most personal point of contact for many customers will be a call to the National Grid call center to ask these questions. It is expected that the call volumes will increase during the deployment years of the program, but will eventually return to the current, steady-state volume. A portion of this cost element addresses the incremental cost associated with increased call volumes across various call center facilities.

Installation of the AMF meters in the field will also require parallel back office support to ensure timeliness and accuracy of the initial billing on the new meter as well as regular maintenance with meter changes, new customer connections and rate programs. In addition, with the ability for AMF to detect losses or theft, the Account Maintenance team works with Revenue Assurance to backbill any lost revenue of customers in accordance with tariff regulations. National Grid has found in recent pilots that proactive review and assurance of meter installation to the point of first bill accuracy creates a successful customer program. It is expected that account maintenance resources largely increase during the installation of the meters and then begin to ramp back down after all customers are on the new meters.

Calculation Overview: This cost calculation is derived from our call center model (see cited source reference) with scaling to account for account maintenance activities.

Source References: RI AMF ID: 1046

Cost/Benefit Group: Project Management

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	37%	63%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

124 – AMF Internal Project Management Leadership Staff – CapEx portion

Description: Advanced Metering requires numerous components and systems which must be designed, configured, tested, deployed and managed. National Grid expects to have internal employees dedicated to advancing project objectives. This cost element captures the cost of National Grid Leadership Staff that will manage the program through its lifecycle.

Calculation Overview: This calculation takes the number of annual full-time National Grid employees that will be Project Management Leadership Staff and multiplies it by the internal resource annual salary.

Source References: RI AMF ID: 1040

Cost/Benefit Group: Project Management

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	100%	100%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

125 – AMF Internal Project Management Business Support – CapEx portion

Description: Advanced Metering requires numerous components and systems which must be designed, configured, tested, deployed and managed. National Grid expects to have internal employees dedicated to advancing project objectives. This cost element captures the cost of company employee labor that will support the program through its lifecycle.

Calculation Overview: This calculation takes the sum of all full-time National Grid employees that will be used for Project Management Business Support and multiplies it by the internal resource annual salary.

Source References: RI AMF ID: 1040

Cost/Benefit Group: Project Management

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
46%	50%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

126 – AMF Electric Meter Installation Cost – COR portion

Description: As previously stated in cost element 102, additional costs must be incurred for labor associated with installation of electric meters. These efforts include labor time to travel to a given premise, remove the existing meter, installing the new meter at the customer premises, and make note of all appropriate inventory and activation information. Cost element 102 captures the capital portion of the electric meter installation cost, while this cost element captures the cost to remove the existing meter.

Calculation Overview: Multiplies the AMF electric meter installation cost subtotal calculated in cost element 102 by the % of the AMF electric meter installation cost that is associated with cost of removal.

Source References: RI AMF ID: 1038

Cost/Benefit Group: AMF Electric Meter Equipment and Installation

CapEx/OpEx/Other: COR

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	67%	0%	0%	0%	0%	0%	0%	0%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

128 – AMF External Project Management Labor Cost – OpEx portion

Description: Advanced Metering Functionality requires numerous components and systems which must be designed, configured, tested, deployed and managed. National Grid expects to augment internal efforts through external Project Management to advance project objectives. This cost element captures the external cost of contract labor to facilitate and support National Grid staff through the requisite program lifecycle.

Calculation Overview: This cost calculation multiplies the total number of external resources used for AMF project staff augmentation by an external resource annual salary.

Cost/Benefit Group: Project Management

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
50%	0%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

129 – AMF Internal Project Management Leadership Staff – OpEx portion

Description: Advanced Metering requires numerous components and systems which must be designed, configured, tested, deployed and managed. National Grid expects to have internal employees dedicated to advancing project objectives. This cost element captures the cost of National Grid Leadership Staff that will manage the program through its lifecycle.

Calculation Overview: This calculation takes the number of annual full-time National Grid employees that will be Project Management Leadership Staff and multiplies it by the internal resource annual salary.

Source References: RI AMF ID: 1040

Cost/Benefit Group: Project Management

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
100%	0%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

130 – AMF Internal Project Management Business Support – OpEx portion

Description: Advanced Metering requires numerous components and systems which must be designed, configured, tested, deployed and managed. National Grid expects to have internal employees dedicated to advancing project objectives. This cost element captures the cost of company employee labor that will support the program through its lifecycle.

Calculation Overview: This calculation takes the sum of all full-time National Grid employees that will be used for Project Management Business Support and multiplies it by the internal resource annual salary.

Source References: RI AMF ID: 1040

Cost/Benefit Group: Project Management

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
50%	0%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

134 – AMF Inventory Equipment Cost

Description: This cost item captures the cost of electric meters that will be maintained in inventory during the meter deployment stage.

Calculation Overview: This cost calculation takes the total AMF electric meter equipment cost calculated in cost element 101 and multiplies it by a percentage of AMF equipment that needs to be held in inventory.

Source References: RI AMF ID: 1037

Cost/Benefit Group: AMF Inventory

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	67%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

135 – Professional Services – Field Deployment Support Workstream cost

Description: National Grid has decided to contract to host several IS systems, most notably the Meter Data Management System (MDMS), AMF Head End System and the Network Management System. This cost element covers resources that will oversee meter and field area network deployment, as well as assist in determining the best location for CGRs. The specific resources included in this cost element are an installation manager with technical team and field engineering support.

Calculation Overview: This cost includes the sum of all Professional Services – Field Deployment costs as quoted by an external vendor.

Source References: RI AMF ID: 5003

Cost/Benefit Group: Communication Network Installation Management

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	11%	50%	40%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

136 – Professional Services – Field Deployment Support Workstream Travel Expenses cost

Description: National Grid has decided to contract to host several IS systems, most notably Meter Data Management System (MDMS), Advanced Meter Interface Head End System (AMF HE) and the Network Management System (NMS). This cost element covers travel expenses for resources that will oversee meter and field area network deployment, as well as assist in determining the best location for CGRs. The specific resources included in this cost element are an installation manager with technical team and field engineering support.

Calculation Overview: This cost calculation multiplies the sum of all Professional Services – Field Deployment costs by the travel expenses percentage.

Source References: RI AMF ID: 5003

Cost/Benefit Group: Communication Network Installation Management

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	11%	50%	40%	0%	0%	0%	0%	0%	0%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

203 – CMS Deployment Center, Facility cost

Description: Deployment of Advance Meters will require the coordination of a large number of personnel, dispatch activities, new meter staging, new CGR staging, and deposition of removed legacy AMR meters to facilitate disposal. While facility costs are sought to be minimized through equipment just-in time deliveries, some facility costs will be incurred as captured through this line item.

Calculation Overview: This calculation takes the annual value of facility costs and applies them to the years of meter deployment.

Source References: RI AMF ID: 1008

Cost/Benefit Group: Support Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	67%	33%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

204 – CMS Back Office & Clerical cost

Description: Deployment of Advance Meters will require additional staff to support back office and clerical functions associated with deployed meter characteristics, retired meter characteristics, data cleanup, asset management / customer deployment details. While some existing staff will assist with these efforts, insufficient bandwidth exists for the increased volume of activity during deployment; additional staff is required as captured through this line item.

Calculation Overview: This cost calculation determines an aggregate number of additional back office and clerical FTEs needed per year then multiplies this by the corresponding annual salary and then multiplies this by the number of years to deploy meters.

Source References: RI AMF ID: 1008

Cost/Benefit Group: Support Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	67%	33%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

205 – Service Representative Tools / Uniform cost

Description: Staff deploying Advance Meters will require additional tools to support Meter Asset Management activities to document meter ID numbers and locational details. Further, dedicated uniforms are anticipated for meter replacement crews to identify staff performing meter replacements. These cost estimates are captured through this line item.

Calculation Overview: This calculation takes the total cost of tools and uniforms and allocates across the meter deployment period.

Source References: RI AMF ID: 1008

Cost/Benefit Group: Support Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	72%	28%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

206 – Installed Meter Quality Assurance / Quality Check cost

Description: Once Advanced Meters have been deployed efforts are undertaken from the back office to ping meters and ensure that the deployment was performed correctly. This quality control check confirms that meters are able to communicate with central systems by reporting interval reads, alerts, and other functions as could be expected to be called upon through its useful life. These quality assurance labor cost estimates are captured through this line item.

Calculation Overview: This calculation multiplies the annual FTEs required for quality assurance/quality checks by the annual quality assurance salary by the number of years for meter deployment.

Source References: RI AMF ID: 1008

Cost/Benefit Group: Support Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	67%	33%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

207 – CMS Deployment Coordination Labor cost

Description: Teams of Advance Meter installers will require supervision and coordination. These teams will be spread throughout the service territory. The coordination labor cost is captured within this line item.

Calculation Overview: This calculation multiplies the annual Chief Foreman FTEs required for coordination by the annual Chief Foreman salary by the number of years for meter deployment.

Source References: RI AMF ID: 1008

Cost/Benefit Group: Support Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	67%	33%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

208 – CMS Field Installer Initial Training

Description: Teams of Advanced Meter installers will require training prior to meter deployment. This line item captures the cost of training field installers required to install AMF electric meters.

Calculation Overview: This calculation takes the number of Field Installers and multiplies it by the initial training cost per field installer.

Source References: RI AMF ID: 1007, 1008

Cost/Benefit Group: Support Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
50%	50%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

209 – CMS Cellular Communication Cost

Description: Staff deploying Advanced Meters will require cell phones to communicate with each other, the office and authorities for safety and to ask for assistance when encountering issues. The cost of cell phones and cellular data is captured through this line item.

Calculation Overview: This calculation takes the annual cellular communication cost and multiplies it by the number of years to deploy meters.

Source References: RI AMF ID: 1008

Cost/Benefit Group: Support Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	67%	33%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

210 – Handheld Devices Cost

Description: Staff deploying Advance Meters will require handheld devices to support meter installation activities. This item captures the cost these handheld devices.

Calculation Overview: Multiply the number of full-time field installers who need handheld devices by the cost per handheld device.

Source References: RI AMF ID: 1007

Cost/Benefit Group: Support Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	100%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

300 – AMF Additional Meter Data Services labor cost

Description: Deployment of new Advanced Meters will result in more meter data that needs to be validated, estimated, and edited to support the meter to cash process. Past experience with pilots has shown that extra labor is required to support this effort for timely data processing. This extra labor is captured within this line item.

Calculation Overview: This cost calculation multiplies the incremental Meter Data Services FTEs by the internal resource annual salary.

Source References: RI AMF ID: 1030

Cost/Benefit Group: Ongoing Business Management

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	50%	100%	50%	50%	50%	50%	50%	50%	50%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
50%	50%	50%	50%	50%	50%	50%	50%	50%	50%

301 – Billing System Development Testing

Description: Deployment of new Advanced Meters will likely result in increased questions about bill validity. Past experience with pilots has shown that extra labor is required to support this effort for timely data processing. This extra labor is captured within this line item.

Calculation Overview: This cost calculation multiplies the incremental Billing System Development Testing FTEs by the internal resource annual salary.

Source References: RI AMF ID: 1030

Cost/Benefit Group: Ongoing Business Management

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	50%	100%	50%	50%	50%	50%	50%	50%	50%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
50%	50%	50%	50%	50%	50%	50%	50%	50%	50%

302 – MDS System Development Testing

Description: During the initial years of the program, internal Meter Data Services staff will need to be dedicated to the project team to assist in reviewing configurations, testing deployed back office integrations, and overall capabilities. This extra labor is captured within this line item.

Calculation Overview: This cost calculation multiplies the incremental Meter Data Services System Development Testing FTEs by the internal resource annual salary.

Source References: RI AMF ID: 1039

Cost/Benefit Group: Support Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
75%	25%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

400 – Customer Engagement Plan Cost

Description: A robust customer education and outreach effort will be needed to support the AMF rollout. The objective of the Customer Engagement plan is to build customer awareness and interest in both grid modernization and the AMF that will enable it, in order to eliminate potential adoption barriers, encourage participation and facilitate transition to AMF meters. This line item captures costs related to multi-channel marketing content development and implementation, community outreach, surveys to test communications effectiveness and satisfaction, and additional support staff.

Calculation Overview: This cost calculation is derived from our customer engagement model (see cited source reference).

Source References: RI AMF ID: 1045

Cost/Benefit Group: Customer Engagement Cost

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
8%	31%	18%	9%	8%	6%	5%	4%	4%	4%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

501 – CSS Enhancements CapEx Cost

Description: The customer service system (CSS) is utilized to manage customer-facing activities. A multitude of processes pull meter data, perform billing and payment processing, support collections and various pricing program rates. As part of the AMF deployment CSS will be modified and configured to support the enhanced data requirements of smart metering. Additional configurations will be made for expanded pricing programs such as Time-of-use (TOU) and critical peak pricing (CPP). With such a prominent role in customer interaction, an effective CSS with support for AMF capabilities is critical to maintaining customer satisfaction. Moreover, as distributed energy resource (DER) penetration increases throughout Rhode Island, CSS must be adaptable to the dynamic energy environment.

CSS also possesses capabilities intended to foster our relationship with customers and assist in customer retention through personalized service. The system interfaces with various back-office resources to create personal profiles for customer engagement. CSS can be linked with an interactive voice response (IVR) system to send automated outage response notifications received from AMF meters. Additionally, CSS will present customer history and real-time meter status to the customer services representatives (CSR) providing enhanced customer service. CSRs will also have a new suite of tools to perform meter diagnostics and remote service re-connection.

Calculation Overview: This cost calculation multiplies the sum of all CSS enhancement costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5001

Cost/Benefit Group: Customer Service System

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
66%	34%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

502 – Professional Services – Head End/MDM Solution Program Management cost

Description: National Grid has decided to contract to host several IS systems, most notably the Meter Data Management System (MDMS), AMF Head End and the Network Management System. This cost element covers program management resources associated with the hosted system. The specific resources included in this cost element are a solution architect, security specialist resources, a project liaison for coordination between project teams and a software-as-a-service team upon the conclusion of the Systems Implementation Workstream (cost element 518). This cost element also covers continuous management across workstreams, as well as coordination with all National Grid program management processes.

Calculation Overview: This cost calculation multiplies the sum of all Professional Services – Solution Program Management costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5003

Cost/Benefit Group: AMF Head-end and Meter Data Management Systems

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
11%	50%	40%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

503 – Energy Monitoring Portal OpEx Cost

Description: Through the deployment of AMF smart meters and associated back-office infrastructure, the Company will have access to customer usage data in near real-time, with granularity at sub-hour reading intervals. National Grid will be building an Energy Management Portal that will act as a hub for residential, commercial, and industrial customers to view their energy usage, including the smart meter interval data. This platform will allow electric customers to have access to their raw, not validated, edited and estimated ("VEE") usage data within four hours after an interval, and gas customers will have access to raw usage information within eight hours[1]. Customers will subsequently be able to view billing quality data within 24 hours. In addition to allowing customers to view their energy consumption in near real-time, the Energy Management Portal will allow customers to compare their usage and costs against certain variables such as weather, historic consumption at the same time and dates, and neighbors' usage to understand factors that may be driving their energy use.

Calculation Overview: This cost calculation multiplies the sum of Energy Monitoring Portal costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5004

Cost/Benefit Group: Customer Engagement Products and Services

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
5%	1%	0%	0%	6%	6%	6%	6%	6%	6%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
6%	6%	6%	6%	6%	6%	6%	6%	6%	0%

[1] Gas customers will receive monthly register reads until such time that Gas ERTs are installed and interval metering becomes available.

504 – Green Button Connect CapEx Cost

Description: Many utilities, including National Grid, have implemented the Green Button Download My Data functionality. This system gives every utility customer the ability to download their personal energy consumption data directly to their computer in a secure manner. Additionally, if customers are interested, they can upload their data to a third-party application.

The Green Button Connect My Data functionality takes this process further by streamlining it to allow utility customers to automate the process. With Green Button Connect My Data customers can securely authorize both National Grid and designated third parties to send and receive data on the customer's behalf. Upon authorization, energy usage data can be transferred as required. Making this data accessible to third parties is critical to animating the market and driving innovation.

Calculation Overview: This cost calculation multiplies the sum of Green Button Connect costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5006

Cost/Benefit Group: Customer Engagement Products and Services

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
75%	25%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

513 – Telecom CapEx Cost

Description: National Grid is enhancing several of its capabilities e.g. AMF, ADMS, substation automation among others. All of these enhancements will require National Grid's network to install new backhaul and enhance its existing bandwidth to support transfer of the new data.

Calculation Overview: This cost calculation multiplies the sum of telecom costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5007

Cost/Benefit Group: IS Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
50%	25%	25%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

514 – ESB CapEx Cost

Description: A platform such as AMF will have highly complex data exchanges. Throughout the industry, systems integration is supported by an enabling technology known as an Enterprise Service Bus (ESB), which helps facilitate the exchange of standardized data elements between all impacted systems.

Calculation Overview: This cost calculation multiplies the sum of ESB costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5009

Cost/Benefit Group: IS Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
19%	30%	5%	0%	15%	0%	0%	0%	0%	15%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	15%	0%	0%	0%	0%	0%

516 – Information Management CapEx Cost

Description: In addition to the data lake functionalities described by Cost Item 517, the next level capability is to process available data to identify trends and other insights which could indicate potential areas where actions can be taken to create value for both the customers and National Grid. In some cases, algorithms to process this data may come in pre-packed software suites, while in other cases proprietary National Grid-specific approaches can be pursued. Costs in this category allow data ingestion, data quality and analytic capabilities to be configured and deployed. The big data analytics capabilities will allow for the analysis of the data gathered from existing and third-party data sources to provide valuable output reflecting current state as well as predictive and prescriptive outcomes.

Calculation Overview: This cost calculation multiplies the sum of Information Management costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5013

Cost/Benefit Group: IS Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
29%	33%	20%	4%	1%	1%	1%	1%	1%	1%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
1%	1%	1%	1%	1%	1%	1%	1%	1%	0%

517 – Data Lake CapEx Cost

Description: Various data management capabilities will be leveraged by the overall grid modernization program. A data lake repository will be established, with a scalable enterprise data warehouse, of all National Grid data. This will include not only Internal Data like the necessary asset and meter data, but External Data, including Remote Sensing, Land Development, Weather, and Real Estate data. The data lake will empower employees with capabilities to analyze data, create a 360 degree customer view, make data accessible to customers and external parties; not doing so will cause National Grid to lose their ability to extract value from their value chain.

Rather than hosting these data management capabilities on servers within National Grid data centers, greater efficiencies, redundancies, and security regimes can be cost effectively procured by outsourcing this function. This cost element captures the costs associated with setting up a cloud data lake environment.

Calculation Overview: This cost calculation multiplies the sum of Data Lake costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5011

Cost/Benefit Group: IS Infrastructure

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
100%	0%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

518 – Professional Services –Head End/MDM Systems Implementation Workstream cost

Description: National Grid has decided to contract to host several IS systems, most notably the Meter Data Management System (MDMS), AMF Head End and the Network Management System. This cost element covers systems implementation resources associated with the hosted system. The specific resources included in this cost element are a project manager for systems, a consulting team for business/tech consulting and testing and integration of four environments (pro, DR, dev and test).

Calculation Overview: This cost calculation multiplies the sum of all Professional Services – Head End/MDM Systems Implementation costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5003

Cost/Benefit Group: AMF Head-end and Meter Data Management Systems

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
87%	13%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

519 – SaaS Setup Fees – One Time Setup (Version upgrade and scale-up existing system) cost

Description: National Grid has decided to contract to host several IS systems, most notably the Meter Data Management System (MDMS), AMF Head End and the Network Management System. This cost element covers the initial cost to complete a version upgrade and to scale-up the existing hosted system.

Calculation Overview: This cost calculation multiplies the sum of all version upgrade costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5003

Cost/Benefit Group: AMF Head-end and Meter Data Management Systems

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
100%	0%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

520 – SaaS Fees – Headend Software (OWOCCM, OWOC PM, IEE MDM, IoT FND, FDM) cost

Description: The AMF Head-end is the command and control system that integrates the communications infrastructure in the field and the back-office systems. An AMF Head-End communicates with AMF meters to collect meter data, interval readings and events. It also can ping individual meters as necessary and push firmware updates across the network. For electrical systems, it can remotely initiate the connection and disconnection of the service at a meter level. This system serves as the main point bi-direction data transmission across the meter population.

An effective AMF platform also requires a meter data management system (MDMS). The MDMS provides data storage and archival capabilities for meter information. Additionally, the MDMS performs initial validation, editing and estimating (VEE) of the incoming meter data. Once the raw data has been processed, it can be utilized by back-office systems such as billing, customer service, and data analytics. This data can also be uploaded to the Energy Management portal and Green Button Connect for customer and authorized third party viewing and utilization.

An important function of the MDMS is the VEE process. During VEE, the MDMS reviews all incoming data from the AMF meters in an effort to validate data accuracy, estimate data and identify anomalies. Any meter with data that cannot pass initial validation is routed to a "validation queue" which is worked by support staff. From this queue missing data intervals, data integrity issues and configuration errors are resolved to produce billing quality data.

Cost estimates in this area assume the Company contracts with an outside service vendor to host these systems. The arrangement is referred to as Software as a Service ("SaaS").

Calculation Overview: This cost calculation multiplies the sum of all SaaS Fees – Headend Software costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5003

Cost/Benefit Group: AMF Head-end and Meter Data Management Systems

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	33%	100%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

521 – Professional Services – System and Meter Firmware Upgrade cost

Description: National Grid has decided to contract to host several IS systems, most notably the Meter Data Management System (MDMS), AMF Head End and the Network Management System. This element covers a one-time cost to upgrade key software-as-a-service applications to cloud-optimized architecture. In particular, this includes an upgrade of the entire hosted system as well as a meter firmware upgrade.

Calculation Overview: This cost calculation multiplies the sum of all Professional Services – System and Meter Firmware Upgrade costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5003

Cost/Benefit Group: AMF Head-end and Meter Data Management Systems

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

522 – Telecom OpEx Cost

Description: National Grid is enhancing several of its capabilities e.g. AMF, ADMS, substation automation among others. All of these enhancements will require National Grid's network to install new backhaul and enhance its existing bandwidth to support transfer of the new data.

Calculation Overview: This cost calculation multiplies the sum of telecom costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5007

Cost/Benefit Group: IS Infrastructure

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
50%	25%	25%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

523 – Telecom RTB Cost

Description: National Grid is enhancing several of its capabilities e.g. AMF, ADMS, substation automation among others. All of these enhancements will require National Grid's network to install new backhaul and enhance its existing bandwidth to support transfer of the new data.

Calculation Overview: This cost calculation multiplies the sum of telecom costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5007

Cost/Benefit Group: IS Infrastructure

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	3%	4%	6%	6%	6%	6%	6%	6%	6%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
6%	6%	6%	6%	6%	6%	6%	6%	6%	0%

524 – ESB OpEx Cost

Description: A platform such as AMF will have highly complex data exchanges. Throughout the industry, systems integration is supported by an enabling technology known as an Enterprise Service Bus (ESB), which helps facilitate the exchange of standardized data elements between all impacted systems.

Calculation Overview: This cost calculation multiplies the sum of ESB costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5009

Cost/Benefit Group: IS Infrastructure

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
36%	50%	14%	0%	0%	0%	0%	0%	0%	0%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

525 – ESB RTB Cost

Description: A platform such as AMF will have highly complex data exchanges. Throughout the industry, systems integration is supported by an enabling technology known as an Enterprise Service Bus (ESB), which helps facilitate the exchange of standardized data elements between all impacted systems.

Calculation Overview: This cost calculation multiplies the sum of ESB costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5009

Cost/Benefit Group: IS Infrastructure

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	3%	5%	6%	6%	6%	6%	6%	6%	6%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
6%	6%	6%	6%	6%	6%	6%	6%	6%	0%

526 – Data Lake OpEx Cost

Description: Various data management capabilities will be leveraged by the overall grid modernization program. A data lake repository will be established, with a scalable enterprise data warehouse, of all National Grid data. This will include not only Internal Data like the necessary asset and meter data, but External Data, including Remote Sensing, Land Development, Weather, and Real Estate data. The data lake will empower employees with capabilities to analyze data, create a 360 degree customer view, make data accessible to customers and external parties; not doing so will cause National Grid to lose their ability to extract value from their value chain.

Rather than hosting these data management capabilities on servers within National Grid data centers, greater efficiencies, redundancies, and security regimes can be cost effectively procured by outsourcing this function. This cost element captures the costs associated with setting up a cloud data lake environment.

Calculation Overview: This cost calculation multiplies the sum of Data Lake costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5011

Cost/Benefit Group: IS Infrastructure

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
4%	4%	5%	5%	6%	6%	6%	6%	6%	6%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
6%	6%	6%	6%	6%	6%	6%	6%	6%	0%

527 – Professional Services – Head End/MDM Solution Program Management Travel Expenses cost

Description: National Grid has decided to contract to host several IS systems, most notably the Meter Data Management System (MDMS), AMF Head End and the Network Management System. This cost element covers travel expenses for the program management resources associated with the hosted system.

Calculation Overview: This cost calculation multiplies the sum of all Professional Services – Head End/MDM Solution Program Management costs by the travel expenses percentage.

Source References: RI AMF ID: 5003

Cost/Benefit Group: AMF Head-end and Meter Data Management Systems

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
11%	50%	40%	0%	0%	0%	0%	0%	0%	0%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

528 – Professional Services – Head End/MDM Systems Implementation Workstream Travel Expenses cost

Description: National Grid has decided to contract to host several IS systems, most notably the Meter Data Management System (MDMS), AMF Head End and the Network Management System. This cost element covers the travel expenses for systems implementation resources associated with the hosted system.

Calculation Overview: This cost calculation multiplies the sum of all Professional Services – Head End/MDM Systems Implementation Workstream costs by the travel expenses percentage.

Source References: RI AMF ID: 5003

Cost/Benefit Group: AMF Head-end and Meter Data Management Systems

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
87%	13%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

529 – Green Button Connect OpEx Cost

Description: Many utilities, including National Grid, have implemented the Green Button Download My Data functionality. This system gives every utility customer the ability to download their personal energy consumption data directly to their computer in a secure manner. Additionally, if customers are interested, they can upload their data to a third-party application.

The Green Button Connect My Data functionality takes this process further by streamlining it to allow utility customers to automate the process. With Green Button Connect My Data customers can securely authorize both National Grid and designated third parties to send and receive data on the customer's behalf. Upon authorization, energy usage data can be transferred as required. Making this data accessible to third parties is critical to animating the market and driving innovation.

Calculation Overview: This cost calculation multiplies the sum of Green Button Connect costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5006

Cost/Benefit Group: Customer Engagement Products and Services

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
52%	32%	0%	0%	0%	0%	0%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

530 – Information Management OpEx Cost

Description: In addition to the data lake functionalities described by Cost Item 517, the next level capability is to process available data to identify trends and other insights which could indicate potential areas where actions can be taken to create value for both the customers and National Grid. In some cases, algorithms to process this data may come in pre-packed software suites, while in other cases proprietary National Grid-specific approaches can be pursued. Costs in this category allow data ingestion, data quality and analytic capabilities to be configured and deployed. The big data analytics capabilities will allow for the analysis of the data gathered from existing and third-party data sources to provide valuable output reflecting current state as well as predictive and prescriptive outcomes.

Calculation Overview: This cost calculation multiplies the sum of Information Management costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5013

Cost/Benefit Group: IS Infrastructure

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
3%	4%	4%	4%	6%	6%	6%	6%	6%	6%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
6%	6%	6%	6%	6%	6%	6%	6%	6%	0%

531 – Information Management RTB Cost

Description: In addition to the data lake functionalities described by Cost Item 517, the next level capability is to process available data to identify trends and other insights which could indicate potential areas where actions can be taken to create value for both the customers and National Grid. In some cases, algorithms to process this data may come in pre-packed software suites, while in other cases proprietary National Grid-specific approaches can be pursued. Costs in this category allow data ingestion, data quality and analytic capabilities to be configured and deployed. The big data analytics capabilities will allow for the analysis of the data gathered from existing and third-party data sources to provide valuable output reflecting current state as well as predictive and prescriptive outcomes.

Calculation Overview: This cost calculation multiplies the sum of Information Management costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5013

Cost/Benefit Group: IS Infrastructure

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	4%	5%	6%	6%	6%	6%	6%	6%	6%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
6%	6%	6%	6%	6%	6%	6%	6%	6%	0%

532 – Energy Monitoring Portal RTB Cost

Description: Through the deployment of AMF smart meters and associated back-office infrastructure, the Company will have access to customer usage data in near real-time, with granularity at sub-hour reading intervals. National Grid will be building an Energy Management Portal that will act as a hub for residential, commercial, and industrial customers to view their energy usage, including the smart meter interval data. This platform will allow electric customers to have access to their raw, not validated, edited and estimated ("VEE") usage data within four hours after an interval, and gas customers will have access to raw usage information within eight hours[2]. Customers will subsequently be able to view billing quality data within 24 hours. In addition to allowing customers to view their energy consumption in near real-time, the Energy Management Portal will allow customers to compare their usage and costs against certain variables such as weather, historic consumption at the same time and dates, and neighbors' usage to understand factors that may be driving their energy use.

Calculation Overview: This cost calculation multiplies the sum of Energy Monitoring Portal costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5004

Cost/Benefit Group: Customer Engagement Products and Services

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	6%	6%	6%	6%	6%	6%	6%	6%	6%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
6%	6%	6%	6%	6%	6%	6%	6%	6%	0%

[2] Gas customers will receive monthly register reads until such time that Gas ERTs are installed and interval metering becomes available.

533 – CSS Enhancements OpEx Cost

Description: The customer service system (CSS) is utilized to manage customer-facing activities. A multitude of processes pull meter data, perform billing and payment processing, support collections and various pricing program rates. As part of the AMF deployment CSS will be modified and configured to support the enhanced data requirements of smart metering. Additional configurations will be made for expanded pricing programs such as Time-of-use (TOU) and critical peak pricing (CPP). With such a prominent role in customer interaction, an effective CSS with support for AMF capabilities is critical to maintaining customer satisfaction. Moreover, as distributed energy resource (DER) penetration increases throughout Rhode Island, CSS must be adaptable to the dynamic energy environment.

CSS also possesses capabilities intended to foster our relationship with customers and assist in customer retention through personalized service. The system interfaces with various back-office resources to create personal profiles for customer engagement. CSS can be linked with an interactive voice response (IVR) system to send automated outage response notifications received from AMF meters. Additionally, CSS will present customer history and real-time meter status to the customer services representatives (CSR) providing enhanced customer service. CSRs will also have a new suite of tools to perform meter diagnostics and remote service re-connection.

Calculation Overview: This cost calculation multiplies the sum of all CSS enhancement costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5001

Cost/Benefit Group: Customer Service System

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
2%	64%	15%	7%	7%	2%	2%	0%	0%	0%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

534 – CSS Enhancements RTB Cost

Description: The customer service system (CSS) is utilized to manage customer-facing activities. A multitude of processes pull meter data, perform billing and payment processing, support collections and various pricing program rates. As part of the AMF deployment CSS will be modified and configured to support the enhanced data requirements of smart metering. Additional configurations will be made for expanded pricing programs such as Time-of-use (TOU) and critical peak pricing (CPP). With such a prominent role in customer interaction, an effective CSS with support for AMF capabilities is critical to maintaining customer satisfaction. Moreover, as distributed energy resource (DER) penetration increases throughout Rhode Island, CSS must be adaptable to the dynamic energy environment.

CSS also possesses capabilities intended to foster our relationship with customers and assist in customer retention through personalized service. The system interfaces with various back-office resources to create personal profiles for customer engagement. CSS can be linked with an interactive voice response (IVR) system to send automated outage response notifications received from AMF meters. Additionally, CSS will present customer history and real-time meter status to the customer services representatives (CSR) providing enhanced customer service. CSRs will also have a new suite of tools to perform meter diagnostics and remote service re-connection.

Calculation Overview: This cost calculation multiplies the sum of all CSS enhancement costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5001

Cost/Benefit Group: Customer Service System

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	1%	2%	4%	5%	7%	10%	7%	7%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
7%	7%	7%	7%	7%	7%	7%	7%	7%	0%

535 – Green Button Connect RTB Cost

Description: Many utilities, including National Grid, have implemented the Green Button Download My Data functionality. This system gives every utility customer the ability to download their personal energy consumption data directly to their computer in a secure manner. Additionally, if customers are interested, they can upload their data to a third-party application.

The Green Button Connect My Data functionality takes this process further by streamlining it to allow utility customers to automate the process. With Green Button Connect My Data customers can securely authorize both National Grid and designated third parties to send and receive data on the customer's behalf. Upon authorization, energy usage data can be transferred as required. Making this data accessible to third parties is critical to animating the market and driving innovation.

Calculation Overview: This cost calculation multiplies the sum of Green Button Connect costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5006

Cost/Benefit Group: Customer Engagement Products and Services

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	6%	6%	6%	6%	6%	6%	6%	6%	6%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
6%	6%	6%	6%	6%	6%	6%	6%	6%	0%

536 – Data Lake RTB Cost

Description: Various data management capabilities will be leveraged by the overall grid modernization program. A data lake repository will be established, with a scalable enterprise data warehouse, of all National Grid data. This will include not only Internal Data like the necessary asset and meter data, but External Data, including Remote Sensing, Land Development, Weather, and Real Estate data. The data lake will empower employees with capabilities to analyze data, create a 360 degree customer view, make data accessible to customers and external parties; not doing so will cause National Grid to lose their ability to extract value from their value chain.

Rather than hosting these data management capabilities on servers within National Grid data centers, greater efficiencies, redundancies, and security regimes can be cost effectively procured by outsourcing this function. This cost element captures the costs associated with setting up a cloud data lake environment.

Calculation Overview: This cost calculation multiplies the sum of Data Lake costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5011

Cost/Benefit Group: IS Infrastructure

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	4%	6%	6%	6%	6%	6%	6%	6%	6%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
6%	6%	6%	6%	6%	6%	6%	6%	6%	0%

540 – Avoided FCS Costs

Description: The Field Collection System (FCS) is currently utilized to perform manual and AMR meter reading for both residential and commercial customers. With the implementation of AMF meters the FCS back-office costs will be phased out as the AMF system utilizes different back office systems to manage data collection and processing.

Calculation Overview: The calculation generally assumes the percentage of annual FCS maintenance costs allocated to RI (forecasted for historical inflation).

Source References: RI AMF ID: 1030

Cost/Benefit Group: FCS Meter Reading

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	33%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

541 – Avoided Interval Meter Reading Costs

Description: The AMF system will replace the current MV90 system. The MV90 system currently supports electric interval metering reading for Narragansett Electric, Niagara Mohawk, and Massachusetts Electric. A benefit has been developed and allocated to Narragansett Electric for the costs that will be avoided, including MV90 licensing and IS support, and avoided field visit costs.

Calculation Overview: This calculation includes avoided vendor and IS maintenance costs in addition to avoided internal meter reading service orders.

Source References: RI AMF ID: 1008, 1012, 1030

Cost/Benefit Group: Interval Meter Reading

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	100%	100%	100%	100%	100%	100%	100%	100%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

600 –Cyber Security Project CapEx Initial

Description: Advanced Metering and other grid modernization capabilities include many systems and components which each pose potential vulnerabilities to cyber threats. Various proactive and reactive capabilities are envisioned to provide protection to this new corporate infrastructure. Certain capital costs are to be incurred in the early years to establish this collection of services which include but are not limited to: Network Security Services, Data Security Services, Threat and Vulnerability Management Services, Identity & Access Management Services, etc.

Calculation Overview: This cost calculation multiplies the sum of Cyber Security Project costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5015

Cost/Benefit Group: Cyber Security

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
53%	30%	17%	0%	0%	0%	0%	0%	0%	0%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

601 –Cyber Security Project OpEx (initial)

Description: Advanced Metering and other grid modernization capabilities include many systems and components which each pose potential vulnerabilities to cyber threats. Various proactive and reactive capabilities are envisioned to provide protection to this new corporate infrastructure. Certain operating expenses are to be incurred in parallel with the capital costs documented in cost element 600 during the early years to establish this collection of services. These include but are not limited to: Network Security Services, Data Security Services, Threat and Vulnerability Management Services, Identity & Access Management Services, etc.

Calculation Overview: This cost calculation multiplies the sum of Cyber Security Project costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5015

Cost/Benefit Group: Cyber Security

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
56%	28%	16%	0%	0%	0%	0%	0%	0%	0%
FY 30	**FY 31**	**FY 32**	**FY 33**	**FY 34**	**FY 35**	**FY 36**	**FY 37**	**FY 38**	**FY 39**
0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

602 –Cyber Security Project RTB O&M

Description: Advanced Metering and other grid modernization capabilities include many systems and components which each pose potential vulnerabilities to cyber threats. Once operational, additional costs must be incurred on an annual basis to ensure that the functions are effectively staffed, used, and maintained to run the business (RTB). These include but are not limited to: Network Security Services, Data Security Services, Threat and Vulnerability Management Services, Identity & Access Management Services, etc.

Calculation Overview: This cost calculation multiplies the sum of Cyber Security Project costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5015

Cost/Benefit Group: Cyber Security

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
6%	5%	5%	7%	4%	5%	7%	4%	4%	7%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
5%	4%	7%	4%	4%	7%	4%	4%	7%	8%

603 –Cyber Security Refresh / Removal Capital

Description: Advanced Metering and other grid modernization capabilities include many systems and components which each pose potential vulnerabilities to cyber threats. Over time, hardware and software (capital costs) must be refreshed to reflect recent advances in protective approaches and dynamics. These refresh efforts are targeted at, but are not limited to: Network Security Services, Data Security Services, Threat and Vulnerability Management Services, Identity & Access Management Services, etc.

Calculation Overview: This cost calculation multiplies the sum of Cyber Security Refresh costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5015

Cost/Benefit Group: Cyber Security

CapEx/OpEx/Other: CapEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	9%	0%	12%	9%	1%	0%	9%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
12%	0%	10%	2%	0%	20%	5%	1%	9%	9%

604 –Cyber Security Refresh/Removal OpEx

Description: Advanced Metering and other grid modernization capabilities include many systems and components which each pose potential vulnerabilities to cyber threats. Over time, hardware and software must be refreshed to reflect recent advances in protective approaches and dynamics (see cost element 603). Additional operations and maintenance activities must occur to support decommissioning, disposal, and other activities applicable to the following functions: Network Security Services, Data Security Services, Threat and Vulnerability Management Services, Identity & Access Management Services, etc.

Calculation Overview: This cost calculation multiplies the sum of Cyber Security Refresh costs by an allocation factor for costs attributable to AMF.

Source References: RI AMF ID: 5015

Cost/Benefit Group: Cyber Security

CapEx/OpEx/Other: OpEx

Cash Flow Impact:

FY 20	FY 21	FY 22	FY 23	FY 24	FY 25	FY 26	FY 27	FY 28	FY 29
0%	0%	0%	3%	0%	27%	3%	0%	0%	3%
FY 30	FY 31	FY 32	FY 33	FY 34	FY 35	FY 36	FY 37	FY 38	FY 39
27%	0%	3%	0%	0%	30%	0%	0%	3%	3%

The Narragansett Electric Company
d/b/a National Grid
Power Sector Transformation (PST)
Rhode Island Renewable Energy
Annual Revenue Requirement Summary
including shared AMI and Grid Mod

Line No.		Six Months Ended March 31, 2019	PST Year Ending March 31, 2020	PST Year Ending March 31, 2021	PST Year Ending March 31, 2022
1	Grid Mod - Electric	$943,000	$3,460,063	$6,091,736	$7,977,872
2	AMI - Electric	$2,000,000	$5,336,627	$10,992,547	$23,186,638
3	Electric Transportation	$350,000	$926,126	$1,514,562	$2,609,868
4	Electric Heat	$100,000	$383,093	$406,193	$454,646
5	Energy Storage	$100,000	$119,178	$281,112	$437,491
6	Solar	$100,000	$84,218	$388,650	$1,002,620
7	**Total Electric**	**$3,593,000**	**$10,309,305**	**$19,674,801**	**$35,669,134**
8	Grid Mod - Gas	$0	$1,433,572	$2,206,703	$3,138,758
9	AMI - Gas	$0	$1,709,697	$968,010	$1,325,454
10	**Total Gas**	**$0**	**$3,143,269**	**$3,174,712**	**$4,464,212**
11	**Total Gas and Electric**	**$3,593,000**	**$13,452,574**	**$22,849,513**	**$40,133,346**

The Narragansett Electric Company
d/b/a National Grid
Power Sector Transformation (PST)
Rhode Island Renewable Energy
Annual Revenue Requirement Summary
including standalone RI AMI and Grid Mod

Line No.		Six Months Ended March 31, 2019	Fiscal Year Ending March 31, 2020	Fiscal Year Ending March 31, 2021	Fiscal Year Ending March 31, 2022
1	Grid Mod - Electric	$943,000	$8,969,264	$14,213,747	$17,913,152
2	AMI - Electric	$2,000,000	$9,395,171	$13,436,950	$26,262,967
3	Electric Transportation	$350,000	$926,126	$1,514,562	$2,609,868
4	Electric Heat	$100,000	$383,093	$406,193	$454,646
5	Energy Storage	$100,000	$119,178	$281,112	$437,491
6	Solar	$100,000	$84,218	$388,650	$1,002,620
7	**Total Electric**	**$3,593,000**	**$19,877,050**	**$30,241,214**	**$48,680,743**
8	Grid Mod - Gas	$0	$4,427,536	$6,619,647	$8,538,141
9	AMI - Gas	$0	$4,673,719	$5,861,568	$5,065,625
10	**Total Gas**	**$0**	**$9,101,255**	**$12,481,215**	**$13,603,766**
11	**Total Gas and Electric**	**$3,593,000**	**$28,978,305**	**$42,722,429**	**$62,284,509**

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Grid Mod - Electric Projects and IS Electric and IS Gas Projects
Annual Revenue Requirement Summary

Line No.			Fiscal Year Ending March 31, 2020 (a)	Fiscal Year Ending March 31, 2021 (b)	Fiscal Year Ending March 31, 2022 (c)
	Electric Operation and Maintenance (O&M) Expenses:				
1	System Data Portal		$ 700,000	$ 700,000	$ 700,000
2	Feeder Monitoring Sensors		$ -	$ 5,000	$ 10,000
3	RTU Separation		$ 60,000	$ 60,000	$ 60,000
4	GIS Data Enhancement		$ -	$ 1,028,000	$ 1,028,000
5	DSCADA & ADMS		$ -	$ 58,311	$ 87,467
6	GIS Data Enhancement		$ -	$ -	$ -
7	Enterprise Service Bus		$ 518,968	$ 1,264,701	$ 1,326,251
8	Data Lake		$ 546,180	$ 786,551	$ 1,063,852
9	PI Historian		$ 33,691	$ 1,329,491	$ 1,329,491
10	Advanced Analytics		$ 69,973	$ 874,017	$ 1,029,513
11	Telecommunications		$ -	$ 1,263,405	$ 1,895,108
12	Cybersecurity		$ 5,423,571	$ 2,736,730	$ 2,182,127
13	**Total Electric O&M costs**	Sum of Lines 1 through 12	**$ 7,352,383**	**$ 10,106,205**	**$ 10,711,808**
	Gas Operation and Maintenance (O&M) Expenses:				
14	DSCADA & ADMS		$ -	$ 31,689	$ 47,534
15	GIS Data Enhancement		$ -	$ -	$ -
16	Enterprise Service Bus		$ 282,032	$ 687,299	$ 720,749
17	Data Lake		$ 296,820	$ 427,449	$ 578,148
18	PI Historian		$ 18,309	$ 722,509	$ 722,509
19	Advanced Analytics		$ 38,027	$ 474,983	$ 559,487
20	Telecommunications		$ -	$ 686,595	$ 1,029,893
21	Cybersecurity		$ 2,947,429	$ 1,487,270	$ 1,185,873
22	**Total Gas O&M costs**	Sum of Lines 14 through 21	**$ 3,582,618**	**$ 4,517,795**	**$ 4,844,192**
23	**Total O&M Expenses**	Line 13 + Line 22	**$ 10,935,000**	**$ 14,624,000**	**$ 15,556,000**
24	Electric Capital Investment:				
25	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2020 Capital Investment		$1,616,881	$3,087,366	$2,784,565
26	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2021 Capital Investment			$1,020,176	$1,983,581
27	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2022 Capital Investment				$2,433,198
28	Total Electric Capital Investment Component of Revenue Requirement	Sum of Lines 25 through Line 27	$1,616,881	$4,107,542	$7,201,344
29	Gas Capital Investment:				
30	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2020 Capital Investment		$844,919	$1,594,730	$1,433,305
31	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2021 Capital Investment			$507,122	$960,550
32	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2022 Capital Investment				$1,300,094
33	Total Gas Capital Investment Component of Revenue Requirement	Sum of Lines 30 through Line 32	$844,919	$2,101,852	$3,693,950
34	**Total Electric Revenue Requirement**	Line 13 + Line 28	**$8,969,264**	**$14,213,747**	**$17,913,152**
35	**Total Gas Revenue Requirement**	Line 22 + Line 33	**$4,427,536**	**$6,619,647**	**$8,538,141**
36	**Total Electric & Gas Revenue Requirement**	Line 34 + Line 35	**$ 13,396,800**	**$ 20,833,394**	**$ 26,451,293**

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
RI Only Grid Mod - IS
Annual Grid Mod RI Only Electric Revenue Requirement Summary

Line No.			Fiscal Year Ending March 31, 2020 (a)	Fiscal Year Ending March 31, 2021 (b)	Fiscal Year Ending March 31, 2022 (c)
	Operation and Maintenance (O&M) Expenses:				
1	System Data Portal		$700,000	$700,000	$700,000
2	Feeder Monitoring Sensors		$0	$5,000	$10,000
3	RTU Separation		$60,000	$60,000	$60,000
4	GIS Data Enhancement		$0	$1,028,000	$1,028,000
5	**Total O&M Expenses**	Sum of Lines 1 through 4	**$760,000**	**$1,793,000**	**$1,798,000**
	Capital Investment:				
6	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2020 Capital Investment		$62,145	$152,900	$147,136
7	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2021 Capital Investment			$87,020	$216,071
8	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2022 Capital Investment				$40,891
9	**Total Capital Investment Component of Revenue Requirement**	Sum of Lines 6 through 8	**$62,145**	**$239,920**	**$404,099**
10	**Total Electric Revenue Requirement**	Line 5 + Line 9	**$822,145**	**$2,032,920**	**$2,202,099**

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Revenue Requirement on Estimated Electric Capital Investment 12 months ending March 31, 2020
RI Only Grid Mod - Electric

Line No.				Fiscal Year Ending March 31, 2020 (a)	Fiscal Year Ending March 31, 2021 (b)	Fiscal Year Ending March 31, 2022 (c)
	Estimated Capital Investment					
1	Feeder Monitor Sensors			$455,000	$0	$0
2	RTU Separation			$570,000	$0	$0
3	Total Estimated Capital Investment	Line 1 + Line 2		$1,025,000	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$1,025,000	$0	$0
5	Retirements	Line 4 * 0%		$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b and c) = Prior Year Line 6		$1,025,000	$1,025,000	$1,025,000
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 3		$1,025,000	$0	$0
8	Cost of Removal			$0	$0	$0
9	**Total Net Plant in Service Including Cost of Removal**	**Line 6 + Line 8**		**$1,025,000**	**$1,025,000**	**$1,025,000**
	Tax Depreciation					
10	Vintage Year Tax Depreciation:					
11	FY 2020 Spend	Page 4 of 21, Line 21		$260,414	$57,346	$53,040
12	Cumulative Tax Depreciation	Prior Year Line 12 + Current Year Line 11		$260,414	$317,760	$370,800
	Book Depreciation					
13	Composite Book Depreciation Rate	As filed per R.I.P.U.C. Docket No. 4770		2.89%	2.89%	2.89%
14	Book Depreciation	Column (a) = Line 1 * Line 13 * 50% ; Column (b and c) = Line 1 * Line 13		$6,575	$13,150	$13,150
15	Cumulative Book Depreciation	Prior Year Line 15 + Current Year Line 14		$6,575	$19,724	$32,874
16	Composite Book Depreciation Rate	As filed per R.I.P.U.C. Docket No. 4770		2.09%	2.09%	2.09%
17	Book Depreciation	Column (a) = Line 2 * Line 16 * 50% ; Column (b and c) = Line 2 * Line 16		$5,957	$11,913	$11,913
18	Cumulative Book Depreciation	Prior Year Line 18 + Current Year Line 17		$5,957	$17,870	$29,783
19	Total Cumulative Book Depreciation	Line 18 + Line 15		$12,531	$37,594	$62,656
	Deferred Tax Calculation:					
20	Cumulative Book / Tax Timer	Line 12 - Line 19		$247,883	$280,166	$308,144
21	Effective Tax Rate			35.00%	35.00%	35.00%
22	Deferred Tax Reserve	Line 20 * Line 21		$86,759	$98,058	$107,850
23	Less: FY 2020 Federal NOL			$ -	$ -	$ -
24	Less: Proration Adjustment	Col (a) = Page 9 of 21, Line 40; Col (b) = Page 10 of 21, Line 40; Col (c) = Page 11 of 21, Line 40		$ (47,103)	$ (6,135)	$ (5,316)
25	Net Deferred Tax Reserve	Sum of Lines 22 through 24		$39,656	$91,924	$102,534
	Rate Base Calculation:					
26	Cumulative Incremental Capital Included in Rate Base	Line 9		$ 1,025,000	$ 1,025,000	$ 1,025,000
27	Accumulated Depreciation	- Line 19		($12,531)	($37,594)	($62,656)
28	Deferred Tax Reserve	- Line 25		($39,656)	($91,924)	($102,534)
29	Year End Rate Base	Sum of Lines 26 through 28		$ 972,813	$895,483	$859,810
	Revenue Requirement Calculation:					
30	Average Rate Base	Column (a) = Current Year Line 29 ÷ 2; Column (b and c) = (Prior Year Line 29 + Current Year Line 39) ÷ 2		$486,407	$934,148	$877,646
31	Pre-Tax ROR		1/	10.20%	10.20%	10.20%
32	Return and Taxes	Line 30 * Line 31		$49,613	$95,283	$89,520
33	Book Depreciation	Line 14 - Line 17		$12,531	$25,063	$25,063
34	Property Taxes	Tax Rate 3.176% MAL-7 - Columns (b & c) Line 9 * 3.176%		$0	$32,554	$32,554
35	**Annual Revenue Requirement**	**Sum of Lines 32 through 34**		**$62,145**	**$152,900**	**$147,136**

1/ Weighted Average Cost of Capital as file in R.I.P.U.C. Docket No. 4770, Schedule MAL-1-ELEC

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	48.47%	4.69%	2.27%		2.27%
Short Term Debt	0.45%	1.76%	0.01%		0.01%
Preferred Stock	0.11%	4.50%	0.00%		0.00%
Common Equity	50.97%	10.10%	5.15%	2.77%	7.92%
	100.00%		7.43%	2.77%	10.20%

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Calculation of Tax Depreciation and Repairs Deduction on Fiscal Year 2020 Electric Capital Investments
RI Only Grid Mod - Electric

Line No.			Fiscal Year Ending March 31, 2020 (a)	Fiscal Year Ending March 31, 2021 (b)	Fiscal Year Ending March 31, 2022 (c)
	Capital Repairs Deduction				
1	Plant Additions	Page 3 of 21, Line 3	$1,025,000		
2	Capital Repairs Deduction Rate	Per Tax Department	0.00%		
3	Capital Repairs Deduction	Line 1 * Line 2	$0		
	Bonus Depreciation				
4	Plant Additions	Line 1	$1,025,000		
5	Less Capital Repairs Deduction	Line 3	$0		
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	$1,025,000		
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	100.00%		
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7	$1,025,000		
9	Bonus Depreciation Rate (April 2019- December 2019)	1 * 75% * 30%	22.50%		
10	Bonus Depreciation Rate (January 2020 - Mar 2020)	1 * 25% * 00%	0.00%		
11	Total Bonus Depreciation Rate	Line 9 + Line 10	22.50%		
12	Bonus Depreciation	Line 8 * Line 11	$230,625		
	Remaining Tax Depreciation				
13	Plant Additions	Line 1	$1,025,000		
14	Less Capital Repairs Deduction	Line 3	$0		
15	Less Bonus Depreciation	Line 12	$230,625		
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$794,375	$794,375	$794,375
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946	3.750%	7.219%	6.677%
18	Remaining Tax Depreciation	Line 16 * Line 17	$29,789	$57,346	$53,040
19	FY20 Loss incurred due to retirements	Per Tax Department	$0	$0	$0
20	Cost of Removal	Page 3 of 21, Line 8	$0		
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, and 20	$260,414	$57,346	$53,040

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Revenue Requirement on Estimated Electric Capital Investment 12 months ending March 31, 2021
RI Only Grid Mod - Electric

Line No.				Fiscal Year Ending March 31, 2021 (a)	Fiscal Year Ending March 31, 2022 (b)
	Estimated Capital Investment				
1	Feeder Monitor Sensors			$455,000	
2	RTU Separation			$950,000	
3	Total Estimated Capital Investment	Line 1 + Line 2		$1,405,000	$0
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$1,405,000	$0
5	Retirements	Line 4 * 0%		$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$1,405,000	$1,405,000
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$1,405,000	$0
8	Cost of Removal			$0	$0
9	**Total Net Plant in Service Including Cost of Removal**	**Line 6 + Line 8**		**$1,405,000**	**$1,405,000**
	Tax Depreciation				
10	Vintage Year Tax Depreciation:				
11	FY 2021 Spend	Page 6 of 21, Line 21		$52,688	$101,427
12	Cumulative Tax Depreciation	Prior Year Line 12 + Current Year Line 11		$52,688	$154,115
	Book Depreciation				
13	Composite Book Depreciation Rate	As filed per R.I.P.U.C. Docket No. 4770		2.89%	2.89%
14	Book Depreciation	Column (a) = Line 1 * Line 13 * 50% ; Column (b) = Line 1 * Line 13		$6,575	$13,150
15	Cumulative Book Depreciation	Prior Year Line 15 + Current Year Line 14		$6,575	$19,724
16	Composite Book Depreciation Rate	As filed per R.I.P.U.C. Docket No. 4770		2.09%	2.09%
17	Book Depreciation	Column (a) = Line 2 * Line 16 * 50% ; Column (b) = Line 2 * Line 16		$9,928	$19,855
18	Cumulative Book Depreciation	Prior Year Line 18 + Current Year Line 17		$9,928	$29,783
19	Total Cumulative Book Depreciation	Line 18 + Line 15		$16,502	$49,507
	Deferred Tax Calculation:				
20	Cumulative Book / Tax Timer	Line 12 - Line 19		$36,186	$104,608
21	Effective Tax Rate			35.00%	35.00%
22	Deferred Tax Reserve	Line 20 * Line 21		$12,665	$36,613
23	Less: FY 2021 Federal NOL			$0	$0
24	Less: Proration Adjustment	Col (a) = Page 10 of 21, Line 40; Col (b) = Page 11 of 21, Line 40		($6,876)	($13,002)
25	Net Deferred Tax Reserve	Sum of Lines 22 through 24		$5,789	$23,611
	Rate Base Calculation:				
26	Cumulative Incremental Capital Included in Rate Base	Line 9		$ 1,405,000	$1,405,000
27	Accumulated Depreciation	- Line 19		($16,502)	($49,507)
28	Deferred Tax Reserve	- Line 25		($5,789)	($23,611)
29	Year End Rate Base	Sum of Lines 26 through 28		$ 1,382,709	$1,331,882
	Revenue Requirement Calculation:				
30	Average Rate Base	Column (a) = Current Year Line 29 ÷ 2; Column (b) = (Prior Year Line 29 + Current Year Line 29) ÷ 2		$691,354.43	$1,357,296
31	Pre-Tax ROR		1/	10.20%	10.20%
32	Return and Taxes	Line 30 * Line 31		$70,518	$138,444
33	Book Depreciation	Line 14 + Line 17		$16,502	$33,005
34	Property Taxes	Tax Rate 3.176% MAL-7 - Columns (b) Line 9 * 3.176%		$0	$44,623
35	**Annual Revenue Requirement**	**Sum of Lines 32 through 34**		**$87,020**	**$216,071**

1/ Weighted Average Cost of Capital as file in R.I.P.U.C. Docket No. 4770, Schedule MAL-1-ELEC

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	48.47%	4.69%	2.27%		2.27%
Short Term Debt	0.45%	1.76%	0.01%		0.01%
Preferred Stock	0.11%	4.50%	0.00%		0.00%
Common Equity	50.97%	10.10%	5.15%	2.77%	7.92%
	100.00%		7.43%	2.77%	10.20%

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Calculation of Tax Depreciation and Repairs Deduction on Fiscal Year 2021 Electric Capital Investments
RI Only Grid Mod - Electric

Line No.			Fiscal Year Ending March 31, 2021 (a)	Fiscal Year Ending March 31, 2022 (b)
	Capital Repairs Deduction			
1	Plant Additions	Page 5 of 21, Line 3	$1,405,000	
2	Capital Repairs Deduction Rate	Per Tax Department	0.00%	
3	Capital Repairs Deduction	Line 1 * Line 2	$0	
	Bonus Depreciation			
4	Plant Additions	Line 1	$1,405,000	
5	Less Capital Repairs Deduction	Line 3	$0	
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	$1,405,000	
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	100.00%	
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7	$1,405,000	
9	Bonus Depreciation Rate (April 2020- December 2020)	0%	0.00%	
10	Bonus Depreciation Rate (January 2021 - Mar 2021)	0%	0.00%	
11	Total Bonus Depreciation Rate	Line 9 + Line 10	0.00%	
12	Bonus Depreciation	Line 8 * Line 11	$0	
	Remaining Tax Depreciation			
13	Plant Additions	Line 1	$1,405,000	
14	Less Capital Repairs Deduction	Line 3	$0	
15	Less Bonus Depreciation	Line 12	$0	
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$1,405,000	$1,405,000
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946	3.750%	7.219%
18	Remaining Tax Depreciation	Line 16 * Line 17	$52,688	$101,427
19	FY21 Loss incurred due to retirements	Per Tax Department	$0	$0
20	Cost of Removal	Page 5 of 21, Line 8	$0	$0
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20	$52,688	$101,427

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Revenue Requirement on Estimated Electric Capital Investment 12 months ending March 31, 2022
RI Only Grid Mod - Electric

Line No.			Fiscal Year Ending March 31, 2022 (a)
	Estimated Capital Investment		
1	Feeder Monitor Sensors		$455,000
2	RTU Separation		$190,000
3	Total Estimated Capital Investment	Line 1 + Line 2	$645,000
	Depreciable Net Capital Included in Rate Base		
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3	$645,000
5	Retirements	Line 4 * 0%	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5	$645,000
	Change in Net Capital Included in Rate Base		
7	Capital Included in Rate Base	Line 3	$645,000
8	Cost of Removal		$0
9	**Total Net Plant in Service Including Cost of Removal**	**Line 6 + Line 8**	**$645,000**
	Tax Depreciation		
10	Vintage Year Tax Depreciation:		
11	FY 2022 Spend	Page 8 of 21, Line 21	$24,188
12	Cumulative Tax Depreciation	Prior Year Line 12 + Current Year Line 13	$24,188
	Book Depreciation		
13	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4770	2.89%
14	Book Depreciation	Column (a) = Line 1* Line 13 * 50%	$6,575
15	Cumulative Book Depreciation	Current Year Line 14	$6,575
16	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4770	2.09%
17	Book Depreciation	Column (a) = Line 2* Line 16 * 50%	$1,986
18	Cumulative Book Depreciation	Current Year Line 16	$1,986
19	Total Cumulative Book Depreciation	Line 15 + Line 18	$8,560
	Deferred Tax Calculation:		
20	Cumulative Book / Tax Timer	Line 12 - Line 19	$15,628
21	Effective Tax Rate		35.00%
22	Deferred Tax Reserve	Line 20 * Line 21	$5,470
23	Less: FY 2022 Federal NOL		$0
24	Less: Proration Adjustment	Col (a) = Page 11 of 21, Line 40	($2,970)
25	Net Deferred Tax Reserve	Sum of Lines 22 through 24	$2,500
	Rate Base Calculation:		
26	Cumulative Incremental Capital Included in Rate Base	Line 9	$ 645,000
27	Accumulated Depreciation	- Line 19	($8,560)
28	Deferred Tax Reserve	- Line 25	($2,500)
29	Year End Rate Base	Sum of Lines 26 through 28	$ 633,940
	Revenue Requirement Calculation:		
30	Average Rate Base	Column (a) = Current Year Line 29 ÷ 2	$316,970
31	Pre-Tax ROR		1/ 10.20%
32	Return and Taxes	Line 30 * Line 31	$32,331
33	Book Depreciation	Line 14 + Line 17	$8,560
34	Property Taxes	Tax Rate 3.176% MAL-7	$0
35	**Annual Revenue Requirement**	**Sum of Lines 32 through 34**	**$40,891**

1/ Weighted Average Cost of Capital as file in R.I.P.U.C. Docket No. 4770, Schedule MAL-1-ELEC

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	48.47%	4.69%	2.27%		2.27%
Short Term Debt	0.45%	1.76%	0.01%		0.01%
Preferred Stock	0.11%	4.50%	0.00%		0.00%
Common Equity	50.97%	10.10%	5.15%	2.77%	7.92%
	100.00%		7.43%	2.77%	10.20%

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Calculation of Tax Depreciation and Repairs Deduction on Fiscal Year 2022 Electric Capital Investments
RI Only Grid Mod - Electric

Line No.			Fiscal Year Ending March 31, 2022 (a)
	Capital Repairs Deduction		
1	Plant Additions	Page 7 of 21, Line 3	$645,000
2	Capital Repairs Deduction Rate	Per Tax Department	0.00%
3	Capital Repairs Deduction	Line 1 * Line 2	$0
	Bonus Depreciation		
4	Plant Additions	Line 1	$645,000
5	Less Capital Repairs Deduction	Line 3	$0
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	$645,000
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	100.00%
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7	$645,000
9	Bonus Depreciation Rate (April 2021- December 2021)	0.00%	0.00%
10	Bonus Depreciation Rate (January 2022 - Mar 2022)	0.00%	0.00%
11	Total Bonus Depreciation Rate	Line 9 + Line 10	0.00%
12	Bonus Depreciation	Line 8 * Line 11	$0
	Remaining Tax Depreciation		
13	Plant Additions	Line 1	$645,000
14	Less Capital Repairs Deduction	Line 3	$0
15	Less Bonus Depreciation	Line 12	$0
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$645,000
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946	3.750%
18	Remaining Tax Depreciation	Line 16 * Line 17	$24,188
19	FY22 Loss incurred due to retirements	Per Tax Department	$0
20	Cost of Removal	Page 7 of 21, Line 8	$0
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20	$24,188

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Calculation of Fiscal Year 2020 Net Deferred Tax Reserve Electric Proration
RI Only Grid Mod - Electric

Line No.	Deferred Tax Subject to Proration		(a)= Column (b) Total	(b) Vintage Year March 31, 2020
1	Book Depreciation	Page 3 of 21, Line 14 + Line 17	$12,531	$12,531
2	Bonus Depreciation	Page 4 of 21, Line 12	($230,625)	($230,625)
3	Remaining MACRS Tax Depreciation	Page 4 of 21, Line 18	($29,789)	($29,789)
4	FY20 tax (gain)/loss on retirements	Page 4 of 21, Line 19	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($247,883)	($247,883)
6	Effective Tax Rate		35.00%	35.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($86,759)	($86,759)
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	Page 4 of 21, Line 3	$0	$0
9	Cost of Removal	Page 4 of 21, Line 20	$0	$0
10	Book/Tax Depreciation Timing Difference at 3/31/2020		$0	$0
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0
12	Effective Tax Rate		35.00%	35.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($86,759)	($86,759)
15	Net Operating Loss	Page 3 of 21, Line 23	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($86,759)	($86,759)
	Allocation of FY 2020 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($247,883)	($247,883)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($247,883)	($247,883)
20	Total FY 2020 Federal NOL	Page 3 of 21, Line 23 / 35%	$0	$0
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0
22	Allocated FY 2020 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0
23	Effective Tax Rate	Per Tax Department	35.00%	35.00%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($86,759)	($86,759)

Line	Proration Calculation	(i) Number of Days in Month	(j) Proration Percentage	(k)= Sum of (l)	(l)
26	April 2019	30	91.78%	($6,636)	($6,636)
27	May 2019	31	83.29%	($6,022)	($6,022)
28	June 2019	30	75.07%	($5,427)	($5,427)
29	July 2019	31	66.58%	($4,813)	($4,813)
30	August 2019	31	58.08%	($4,199)	($4,199)
31	September 2019	30	49.86%	($3,605)	($3,605)
32	October 2019	31	41.37%	($2,991)	($2,991)
33	November 2019	30	33.15%	($2,397)	($2,397)
34	December 2019	31	24.66%	($1,783)	($1,783)
35	January 2020	31	16.16%	($1,169)	($1,169)
36	February 2020	28	8.49%	($614)	($614)
37	March 2020	31	0.00%	$0	$0
38	Total	365		($39,656)	($39,656)
39	Deferred Tax Without Proration	Line 25		($86,759)	($86,759)
40	Proration Adjustment	Line 38 - Line 39		$47,103	$47,103

Column Notes:

(j) Sum of remaining days in the year (Col (i)) ÷ 365
(l) through (r) = Current Year Line 25 ÷ 12 * Current Month Col (j)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Calculation of Fiscal Year 2021 Net Deferred Tax Reserve Electric Proration
RI Only Grid Mod - Electric

Line No.			(a)=Sum of (b) through (c) Total	(b) Vintage Year March 31, 2021	(c) Vintage Year March 31, 2020
	Deferred Tax Subject to Proration				
1	Book Depreciation	Col (b) = Page 5 of 21, Line 14 + Line 17 ;Col (c) = Page 3 of 21, Line 14 + Line 17	$41,565	$16,502	$25,063
2	Bonus Depreciation	Page 6 of 21, Line 12	$0	$0	
3	Remaining MACRS Tax Depreciation	Col (b) = Page 6 of 21, Line 18 ;Col (c) = Page 4 of 21, Line 18	($110,034)	($52,688)	($57,346)
4	FY21 tax (gain)/loss on retirements	Col (b) = Page 6 of 21, Line 19 ;Col (c) = Page 4 of 21, Line 19	$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($68,469)	($36,186)	($32,284)
6	Effective Tax Rate	Per Tax Department	35.00%	35.00%	35.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($23,964)	($12,665)	($11,299)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	Page 8 of 21, Line 3	$0	$0	
9	Cost of Removal	Page 8 of 21, Line 20	$0	$0	
10	Book/Tax Depreciation Timing Difference at 3/31/2021		$0	$0	
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0	
12	Effective Tax Rate		35.00%	35.00%	
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0	
14	Total Deferred Tax Reserve	Line 7 + Line 13	($23,964)	($12,665)	($11,299)
15	Net Operating Loss	Page 5 of 21, Line 23	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($23,964)	($12,665)	($11,299)
	Allocation of FY 2021 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($36,186)	($36,186)	
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($36,186)	($36,186)	
20	Total FY 2021 Federal NOL	Col (b) = Page 5 of 21, Line 23 / 35%	$0	$0	
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0	
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0	
23	Effective Tax Rate	Per Tax Department	35.00%	35.00%	
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0	
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($23,964)	($12,665)	($11,299)

Line No.	**Proration Calculation**	(i) Number of Days in Month	(j) Proration Percentage	(k)= Sum of (l) through (m)	(l)	(m)
26	April 2020	30	91.78%	($1,833)	($969)	($864)
27	May 2020	31	83.29%	($1,663)	($879)	($784)
28	June 2020	30	75.07%	($1,499)	($792)	($707)
29	July 2020	31	66.58%	($1,330)	($703)	($627)
30	August 2020	31	58.08%	($1,160)	($613)	($547)
31	September 2020	30	49.86%	($996)	($526)	($470)
32	October 2020	31	41.37%	($826)	($437)	($390)
33	November 2020	30	33.15%	($662)	($350)	($312)
34	December 2020	31	24.66%	($492)	($260)	($232)
35	January 2021	31	16.16%	($323)	($171)	($152)
36	February 2021	28	8.49%	($170)	($90)	($80)
37	March 2021	31	0.00%	$0	$0	$0
38	Total	365		($10,954)	($5,789)	($5,165)
39	Deferred Tax Without Proration	Line 25		($23,964)	($12,665)	($11,299)
40	Proration Adjustment	Line 38 - Line 39		$13,011	$6,876	$6,135

Column Notes:
(j) Sum of remaining days in the year (Col (i)) ÷ 365
(l) through (r) = Current Year Line 25 ÷ 12 * Current Month Col (j)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Calculation of Fiscal Year 2022 Net Deferred Tax Reserve Electric Proration
RI Only Grid Mod - Electric

Line No.			(a)=Sum of (b) through (d) Total	(b) Vintage Year March 31, 2022	(c) Vintage Year March 31, 2021	(d) Vintage Year March 31, 2020
	Deferred Tax Subject to Proration					
1	Book Depreciation	Col (b) = Page 7 of 21, Line 14 + Line 17; Col (c) = Page 5 of 21, Line 14 + Line 17; Col (d) = Page 3 of 21, Line 14 + Line 17	$66,627	$8,560	$33,005	$25,063
2	Bonus Depreciation	Page 6 of 21, Line 12	$0	$0		
3	Remaining MACRS Tax Depreciation	Col (b) = Page 8 of 21, Line 18; Col (c) = Page 6 of 21, Line 18; Col (d) = Page 4 of 21, Line 18	($178,655)	($24,188)	($101,427)	($53,040)
4	FY22 tax (gain)/loss on retirements	Col (b) = Page 8 of 21, Line 19; Col (c) = Page 6 of 21, Line 19; Col (d) = Page 4 of 21, Line 19	$0	$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($112,028)	($15,628)	($68,423)	($27,978)
6	Effective Tax Rate	Per Tax Department	35.00%	35.00%	35.00%	35.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($39,210)	($5,470)	($23,948)	($9,792)
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction	Page 8 of 21, Line 3	$0	$0		
9	Cost of Removal	Page 8 of 21, Line 20	$0	$0		
10	Book/Tax Depreciation Timing Difference at 3/31/2022		$0	$0		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0		
12	Effective Tax Rate		35.00%	35.00%		
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0		
14	Total Deferred Tax Reserve	Line 7 + Line 13	($39,210)	($5,470)	($23,948)	($9,792)
15	Net Operating Loss	Page 7 of 21, Line 23	$0	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($39,210)	($5,470)	($23,948)	($9,792)
	Allocation of FY 2022 Estimated Federal NOL					
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($15,628)	($15,628)		
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0		
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($15,628)	($15,628)		
20	Total FY 2022 Federal NOL	Col (b) = Page 7 of 21, Line 23 / 35%	$0	$0		
21	Allocated FY 2022 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0		
22	Allocated FY 2022 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0		
23	Effective Tax Rate	Per Tax Department	35.00%	35.00%		
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0		
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($39,210)	($5,470)	($23,948)	($9,792)

Line	**Proration Calculation**	(i) Number of Days in Month	(j) Proration Percentage	(k)= Sum of (l) through (n)	(l)	(m)	(n)
26	April 2021	30	91.78%	($2,999)	($418)	($1,832)	($749)
27	May 2021	31	83.29%	($2,721)	($380)	($1,662)	($680)
28	June 2021	30	75.07%	($2,453)	($342)	($1,498)	($613)
29	July 2021	31	66.58%	($2,175)	($303)	($1,329)	($543)
30	August 2021	31	58.08%	($1,898)	($265)	($1,159)	($474)
31	September 2021	30	49.86%	($1,629)	($227)	($995)	($407)
32	October 2021	31	41.37%	($1,352)	($189)	($826)	($338)
33	November 2021	30	33.15%	($1,083)	($151)	($662)	($271)
34	December 2021	31	24.66%	($806)	($112)	($492)	($201)
35	January 2022	31	16.16%	($528)	($74)	($323)	($132)
36	February 2022	28	8.49%	($278)	($39)	($169)	($69)
37	March 2022	31	0.00%	$0	$0	$0	$0
38	Total	365		($17,922)	($2,500)	($10,946)	($4,476)
39	Deferred Tax Without Proration	Line 25		($39,210)	($5,470)	($23,948)	($9,792)
40	Proration Adjustment	Line 38 - Line 39		$21,288	$2,970	$13,002	$5,316

Column Notes:
(j) Sum of remaining days in the year (Col (i)) ÷ 365
(l) through (r) = Current Year Line 25 ÷ 12 * Current Month Col (j)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
RI Only Grid Mod - IS
Annual Grid Mod RI Only IS Revenue Requirement Summary

Line No.			Fiscal Year Ending March 31, 2020 (a)	Fiscal Year Ending March 31, 2021 (b)	Fiscal Year Ending March 31, 2022 (c)
	IS Electric Operation and Maintenance (O&M) Expenses:				
1	DSCADA & ADMS		$ -	$ 58,311	$ 87,467
2	GIS Data Enhancement		$ -	$ -	$ -
3	Enterprise Service Bus		$ 518,968	$ 1,264,701	$ 1,326,251
4	Data Lake		$ 546,180	$ 786,551	$ 1,063,852
5	PI Historian		$ 33,691	$ 1,329,491	$ 1,329,491
6	Advanced Analytics		$ 69,973	$ 874,017	$ 1,029,513
7	Telecommunications		$ -	$ 1,263,405	$ 1,895,108
8	Cybersecurity		$ 5,423,571	$ 2,736,730	$ 2,182,127
9	**Total IS Electric O&M costs**	Sum of Lines 1 through 8	**$ 6,592,383**	**$ 8,313,205**	**$ 8,913,808**
	IS Gas Operation and Maintenance (O&M) Expenses:				
10	DSCADA & ADMS		$ -	$ 31,689	$ 47,534
11	GIS Data Enhancement		$ -	$ -	$ -
12	Enterprise Service Bus		$ 282,032	$ 687,299	$ 720,749
13	Data Lake		$ 296,820	$ 427,449	$ 578,148
14	PI Historian		$ 18,309	$ 722,509	$ 722,509
15	Advanced Analytics		$ 38,027	$ 474,983	$ 559,487
16	Telecommunications		$ -	$ 686,595	$ 1,029,893
17	Cybersecurity		$ 2,947,429	$ 1,487,270	$ 1,185,873
18	**Total IS Gas O&M costs**	Sum of Lines 10 through 17	**$ 3,582,618**	**$ 4,517,795**	**$ 4,844,192**
19	**Total IS O&M Expenses**	Line 9 + Line 18	**$ 10,175,000**	**$ 12,831,000**	**$ 13,758,000**
	IS Electric Capital Investment:				
20	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2020 Capital Investment		$1,554,737	$2,934,466	$2,637,429
21	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2021 Capital Investment			$933,156	$1,767,510
22	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2022 Capital Investment				$2,392,307
23	Total IS Electric Capital Investment Component of Revenue Requirement	Sum of Lines 20, 21, and 22	$1,554,737	$3,867,622	$6,797,245
	IS Gas Capital Investment:				
24	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2020 Capital Investment		$844,919	$1,594,730	$1,433,305
25	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2021 Capital Investment			$507,122	$960,550
26	Estimated Revenue Requirement on Fiscal Year Ending March 31, 2022 Capital Investment				$1,300,094
27	Total IS Gas Capital Investment Component of Revenue Requirement	Sum of Lines 20, 21, and 22	$844,919	$2,101,852	$3,693,950
28	**Total IS Electric Revenue Requirement**	Line 9 + Line 23	**$8,147,119**	**$12,180,827**	**$15,711,053**
29	**Total IS Gas Revenue Requirement**	Line 18 + Line 27	**$ 4,427,536**	**$6,619,647**	**$8,538,141**
30	**Total IS Electric & Gas Revenue Requirement**	Line 29 + Line 28	**$12,574,655**	**$18,800,474**	**$24,249,194**

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Appendix 10.2 - Grid Mod Stand Alone
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THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Revenue Requirement on Estimated IS Capital Investment 12 months ending March 31, 2020
RI Only Grid Mod - IS

Line No.			Fiscal Year Ending March 31, 2020 (a)	Fiscal Year Ending March 31, 2021 (b)	Fiscal Year Ending March 31, 2022 (c)
	Estimated Capital Investment				
1	Grid Mod IS Investments		$20,720,000	$0	$0
2	Total Estimated Capital Investment	Sum of Line 1	$20,720,000	$0	$0
	Depreciable Net Capital Included in Rate Base				
3	Total Allowed Capital Included in Rate Base in Current Year	Line 2	$20,720,000	$0	$0
4	Retirements	Line 4 * 0%	$0	$0	$0
5	Net Depreciable Capital Included in Rate Base	Column (a) = Line 3 - Line 4; Column (b and c) = Prior Year Line 5	$20,720,000	$20,720,000	$20,720,000
	Change in Net Capital Included in Rate Base				
6	Capital Included in Rate Base	Line 2	$20,720,000	$0	$0
7	Cost of Removal		$0	$0	$0
8	**Total Net Plant in Service Including Cost of Removal**	**Line 6 + Line 7**	$20,720,000	$20,720,000	$20,720,000
	Tax Depreciation				
9	Vintage Year Tax Depreciation:				
10	FY 2020 Spend	Page 14 of 21, Line 21	$10,014,131	$7,137,781	$2,378,190
11	Cumulative Tax Depreciation	Prior Year Line 11 + Current Year Line 10	$10,014,131	$17,151,912	$19,530,102
	Book Depreciation				
12	Composite Book Depreciation Rate	As filed per R.I.P.U.C. Docket No. 4770	14.29%	14.29%	14.29%
13	Book Depreciation	Column (a) = Line 1 * Line 12 * 50% ; Column (b and c) = Line 1 *	$1,480,000	$2,960,000	$2,960,000
14	Cumulative Book Depreciation	Prior Year Line 14 + Current Year Line 13	$1,480,000	$4,440,000	$7,400,000
15	Total Cumulative Book Depreciation	Line 14	$1,480,000	$4,440,000	$7,400,000
	Deferred Tax Calculation:				
16	Cumulative Book / Tax Timer	Line 11 - Line 15	$8,534,131	$12,711,912	$12,130,102
17	Effective Tax Rate		35.00%	35.00%	35.00%
18	Deferred Tax Reserve	Line 16 * Line 17	$2,986,946	$4,449,169	$4,245,536
19	Less: FY 2020 Federal NOL		$0	$0	$0
20	Less: Proration Adjustment	Col (a) = Page 19 of 21, Line 40; Col (b) = Page 20 of 21, Line 40; Col (c) = Page 21 of 21, Line 40	($1,621,680)	($793,874)	$110,557
21	Net Deferred Tax Reserve	Sum of Lines 18 through 20	$1,365,266	$3,655,295	$4,356,093
	Rate Base Calculation:				
22	Cumulative Incremental Capital Included in Rate Base	Line 8	$20,720,000	$20,720,000	$20,720,000
23	Accumulated Depreciation	- Line 15	($1,480,000)	($4,440,000)	($7,400,000)
24	Deferred Tax Reserve	- Line 21	($1,365,266)	($3,655,295)	($4,356,093)
25	Year End Rate Base	Sum of Lines 22 through 24	$17,874,734	$12,624,705	$8,963,907
	Revenue Requirement Calculation:				
26	Average Rate Base	Column (a) = Current Year Line 25 ÷ 2; Column (b and c) = (Prior Year Line 25 + Current Year Line 25) ÷ 2	$8,937,366.94	$15,249,719	$10,794,306
27	Pre-Tax ROR	Weighted Average Cost of Capital as file in R.I.P.U.C. Docket No. 4770, Workpaper MAL-6	10.29%	10.29%	10.29%
28	Return and Taxes	Line 26 * Line 27	$919,655	$1,569,196	$1,110,734
29	Book Depreciation	Line 13	$1,480,000	$2,960,000	$2,960,000
30	**Annual Revenue Requirement**	**Line 28 + Line 29**	**$2,399,655**	**$4,529,196**	**$4,070,734**

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Calculation of Tax Depreciation and Repairs Deduction on Fiscal Year 2020 IS Capital Investments
RI Only Grid Mod - IS

Line No.			Fiscal Year Ending March 31, 2020 (a)	Fiscal Year Ending March 31, 2021 (b)	Fiscal Year Ending March 31, 2022 (c)
	Capital Repairs Deduction				
1	Plant Additions	Page 13 of 21, Line 2	$20,720,000		
2	Capital Repairs Deduction Rate	Per Tax Department	0.00%		
3	Capital Repairs Deduction	Line 1 * Line 2	$0		
	Bonus Depreciation				
4	Plant Additions	Line 1	$20,720,000		
5	Less Capital Repairs Deduction	Line 3	$0		
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	$20,720,000		
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	100.00%		
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7	$20,720,000		
9	Bonus Depreciation Rate (April 2019- December 2019)	1 * 75% * 30%	22.50%		
10	Bonus Depreciation Rate (January 2020 - Mar 2020)	1 * 25% * 0%	0.00%		
11	Total Bonus Depreciation Rate	Line 9 + Line 10	22.50%		
12	Bonus Depreciation	Line 8 * Line 11	$4,662,000		
	Remaining Tax Depreciation				
13	Plant Additions	Line 1	$20,720,000		
14	Less Capital Repairs Deduction	Line 3	$0		
15	Less Bonus Depreciation	Line 12	$4,662,000		
16	Remaining Plant Additions Subject to 3 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$16,058,000	$16,058,000	$16,058,000
17	3 YR MACRS Tax Depreciation Rates	Per IRS Publication 946	33.330%	44.450%	14.810%
18	Remaining Tax Depreciation	Line 16 * Line 17	$5,352,131	$7,137,781	$2,378,190
19	FY20 Loss incurred due to retirements		$0	$0	$0
20	Cost of Removal	Page 13 of 21, Line 7	$0	$0	$0
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, and 20	$10,014,131	$7,137,781	$2,378,190

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Revenue Requirement on Estimated IS Capital Investment 12 months ending March 31, 2021
RI Only Grid Mod - IS

Line No.			Fiscal Year Ending March 31, 2021 (a)	Fiscal Year Ending March 31, 2022 (b)
	Estimated Capital Investment			
1	Grid Mod IS Investments		$12,305,000	
2	Total Estimated Capital Investment	Sum of Lines 1	$12,305,000	$0
	Depreciable Net Capital Included in Rate Base			
3	Total Allowed Capital Included in Rate Base in Current Year	Line 2	$12,305,000	$0
4	Retirements	Line 4 * 0%	$0	$0
5	Net Depreciable Capital Included in Rate Base	Column (a) = Line 3 - Line 4; Column (b and c) = Prior Year Line 5	$12,305,000	$12,305,000
	Change in Net Capital Included in Rate Base			
6	Capital Included in Rate Base	Line 2	$12,305,000	$0
7	Cost of Removal		$0	$0
8	**Total Net Plant in Service Including Cost of Removal**	**Line 5 + Line 7**	**$12,305,000**	**$12,305,000**
	Tax Depreciation			
9	Vintage Year Tax Depreciation:			
10	FY 2021 Spend	Page 16 of 21, Line 21	$4,101,257	$5,469,573
11	Cumulative Tax Depreciation	Prior Year Line 11 + Current Year Line 10	$4,101,257	$9,570,830
	Book Depreciation			
12	Composite Book Depreciation Rate	As filed per R.I.P.U.C. Docket No. 4770	14.29%	14.29%
13	Book Depreciation	Column (a) = Line 1 * Line 12 * 50% ; Column (b) = Line 1 * Line 12	$878,929	$1,757,857
14	Cumulative Book Depreciation	Prior Year Line 14 + Current Year Line 13	$878,929	$2,636,786
15	Total Cumulative Book Depreciation	Line 14	$878,929	$2,636,786
	Deferred Tax Calculation:			
16	Cumulative Book / Tax Timer	Line 11 - Line 14	$3,222,328	$6,934,044
17	Effective Tax Rate		35.00%	35.00%
18	Deferred Tax Reserve	Line 16 * Line 17	$1,127,815	$2,426,916
19	Less: FY 2021 Federal NOL		$0	$0
20	Less: Proration Adjustment	Col (a) = Page 20 of 21, Line 40; Col (b) = Page 21 of 21, Line 40	($612,316)	($705,311)
21	Net Deferred Tax Reserve	Sum of Lines 18 through 20	$515,499	$1,721,605
	Rate Base Calculation:			
22	Cumulative Incremental Capital Included in Rate Base	Line 8	$12,305,000	$12,305,000
23	Accumulated Depreciation	- Line 15	($878,929)	($2,636,786)
24	Deferred Tax Reserve	- Line 21	($515,499)	($1,721,605)
25	Year End Rate Base	Sum of Lines 22 through 24	$10,910,572	$7,946,610
	Revenue Requirement Calculation:			
26	Average Rate Base	Column (a) = Current Year Line 25 ÷ 2; Column (b) = (Prior Year Line 25 + Current Year Line 25) ÷ 2	$5,455,286.22	$9,428,591
27	Pre-Tax ROR	Weighted Average Cost of Capital as file in R.I.P.U.C. Docket No. 4770, Workpaper MAL-6	10.29%	10.29%
28	Return and Taxes	Line 26 * Line 27	$561,349	$970,202
29	Book Depreciation	Line 13	$878,929	$1,757,857
30	**Annual Revenue Requirement**	**Line 28 + Line 29**	**$1,440,278**	**$2,728,059**

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Calculation of Tax Depreciation and Repairs Deduction on Fiscal Year 2021 IS Capital Investments
RI Only Grid Mod - IS

Line No.			Fiscal Year Ending March 31, 2021 (a)	Fiscal Year Ending March 31, 2022 (b)
	Capital Repairs Deduction			
1	Plant Additions	Page 15 of 21, Line 2	$12,305,000	
2	Capital Repairs Deduction Rate	Per Tax Department	0.00%	
3	Capital Repairs Deduction	Line 1 * Line 2	$0	
	Bonus Depreciation			
4	Plant Additions	Line 1	$12,305,000	
5	Less Capital Repairs Deduction	Line 3	$0	
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	$12,305,000	
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	100.00%	
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7	$12,305,000	
9	Bonus Depreciation Rate (April 2020- December 2020)	0%	0.00%	
10	Bonus Depreciation Rate (January 2021 - Mar 2021)	0%	0.00%	
11	Total Bonus Depreciation Rate	Line 9 + Line 10	0.00%	
12	Bonus Depreciation	Line 8 * Line 11	$0	
	Remaining Tax Depreciation			
13	Plant Additions	Line 1	$12,305,000	
14	Less Capital Repairs Deduction	Line 3	$0	
15	Less Bonus Depreciation	Line 12	$0	
16	Remaining Plant Additions Subject to 3 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$12,305,000	$12,305,000
17	3 YR MACRS Tax Depreciation Rates	Per IRS Publication 946	33.330%	44.450%
18	Remaining Tax Depreciation	Line 16 * Line 17	$4,101,257	$5,469,573
19	FY21 Loss incurred due to retirements	Per Tax Department	$0	$0
20	Cost of Removal	Page 15 of 21, Line 7	$0	$0
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20	$4,101,257	$5,469,573

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Revenue Requirement on Estimated IS Capital Investment 12 months ending March 31, 2022
RI Only Grid Mod - IS

Line No.			Fiscal Year Ending March 31, 2022 (a)
	Estimated Capital Investment		
1	Grid Mod IS Investments		$31,546,000
2	Total Estimated Capital Investment	Sum of Line 1	$31,546,000
	Depreciable Net Capital Included in Rate Base		
3	Total Allowed Capital Included in Rate Base in Current Year	Line 2	$31,546,000
4	Retirements	Line 4 * 0%	$0
5	Net Depreciable Capital Included in Rate Base	Column (a) = Line 3 - Line 4	$31,546,000
	Change in Net Capital Included in Rate Base		
6	Capital Included in Rate Base	Line 2	$31,546,000
7	Cost of Removal		$0
8	**Total Net Plant in Service Including Cost of Removal**	**Line 6 + Line 8**	**$31,546,000**
	Tax Depreciation		
9	Vintage Year Tax Depreciation:		
10	FY 2022 Spend	Page 18 of 21, Line 21	$10,514,282
11	Cumulative Tax Depreciation	Current Year Line 10	$10,514,282
	Book Depreciation		
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4770	14.29%
13	Book Depreciation	Column (a) = Line 2* Line 12 * 50%	$2,253,286
14	Cumulative Book Depreciation	Current Year Line 13	$2,253,286
15	Total Cumulative Book Depreciation	Line 14	$2,253,286
	Deferred Tax Calculation:		
16	Cumulative Book / Tax Timer	Line 11 - Line 15	$8,260,996
17	Effective Tax Rate		35.00%
18	Deferred Tax Reserve	Line 16 * Line 17	$2,891,349
19	Less: FY 2022 Federal NOL		$0
20	Less: Proration Adjustment	Col = Page 21 of 21, Line 40	($1,569,778)
21	Net Deferred Tax Reserve	Sum of Lines 18 through 20	$1,321,571
	Rate Base Calculation:		
22	Cumulative Incremental Capital Included in Rate Base	Line 8	$31,546,000
23	Accumulated Depreciation	- Line 15	($2,253,286)
24	Deferred Tax Reserve	- Line 21	($1,321,571)
25	Year End Rate Base	Sum of Lines 22 through 24	$27,971,143
	Revenue Requirement Calculation:		
26	Average Rate Base	Column (a) = Current Year Line 25 ÷ 2	$13,985,571.74
27	Pre-Tax ROR	Weighted Average Cost of Capital as file in R.I.P.U.C. Docket No. 4770, Workpaper MAL-6	10.29%
28	Return and Taxes	Line 26 * Line 27	$1,439,115
29	Book Depreciation	Line 13	$2,253,286
30	**Annual Revenue Requirement**	**Line 28 + Line 29**	**$3,692,401**

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Calculation of Tax Depreciation and Repairs Deduction on Fiscal Year 2022 IS Capital Investments
RI Only Grid Mod - IS

Line No.			Fiscal Year Ending March 31, 2022 (a)
	Capital Repairs Deduction		
1	Plant Additions	Page 17 of 21, Line 2	$31,546,000
2	Capital Repairs Deduction Rate	Per Tax Department	0.00%
3	Capital Repairs Deduction	Line 1 * Line 2	$0
	Bonus Depreciation		
4	Plant Additions	Line 1	$31,546,000
5	Less Capital Repairs Deduction	Line 3	$0
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	$31,546,000
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	100.00%
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7	$31,546,000
9	Bonus Depreciation Rate (April 2020- December 2020)	0%	0.00%
10	Bonus Depreciation Rate (January 2021 - Mar 2021)	0%	0.00%
11	Total Bonus Depreciation Rate	Line 9 + Line 10	0.00%
12	Bonus Depreciation	Line 8 * Line 11	$0
	Remaining Tax Depreciation		
13	Plant Additions	Line 1	$31,546,000
14	Less Capital Repairs Deduction	Line 3	$0
15	Less Bonus Depreciation	Line 12	$0
16	Remaining Plant Additions Subject to 3 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$31,546,000
17	3 YR MACRS Tax Depreciation Rates	Per IRS Publication 946	33.33%
18	Remaining Tax Depreciation	Line 16 * Line 17	$10,514,282
19	FY22 Loss incurred due to retirements	Per Tax Department	$0
20	Cost of Removal	Page 17 of 21, Line 7	$0
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20	$10,514,282

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
Power Sector Transformation (PST)
Calculation of Fiscal Year 2020 Net Deferred Tax Reserve IS Proration
RI Only Grid Mod - IS

Line No.	Deferred Tax Subject to Proration		(a)= Column (b) Total	(b) Vintage Year March 31, 2020
1	Book Depreciation	Page 13 of 21, Line 13	$1,480,000	$1,480,000
2	Bonus Depreciation	Page 14 of 21, - Line 12	($4,662,000)	($4,662,000)
3	Remaining MACRS Tax Depreciation	Page 14 of 21, - Line 18	($5,352,131)	($5,352,131)
4	FY20 tax (gain)/loss on retirements	Page 14 of 21, - Line 19	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($8,534,131)	($8,534,131)
6	Effective Tax Rate	Per Tax Department	35.00%	35.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($2,986,946)	($2,986,946)
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	Page 14 of 21, Line 3	$0	$0
9	Cost of Removal	Page 14 of 21, Line 20	$0	$0
10	Book/Tax Depreciation Timing Difference at 3/31/2020		$0	$0
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0
12	Effective Tax Rate		35.00%	35.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($2,986,946)	($2,986,946)
15	Net Operating Loss	Page 13 of 21, Line 19	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($2,986,946)	($2,986,946)
	Allocation of FY 2020 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($8,534,131)	($8,534,131)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($8,534,131)	($8,534,131)
20	Total FY 2020 Federal NOL	Page 13 of 21, Line 19 / 35%	$0	$0
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0
22	Allocated FY 2020 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0
23	Effective Tax Rate	Per Tax Department	35.00%	35.00%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($2,986,946)	($2,986,946)

	Proration Calculation	(i) Number of Days in Month	(j) Proration Percentage	(k)= Sum of (l)	(l)
26	April 2019	30	91.78%	($228,454)	($228,454)
27	May 2019	31	83.29%	($207,313)	($207,313)
28	June 2019	30	75.07%	($186,855)	($186,855)
29	July 2019	31	66.58%	($165,714)	($165,714)
30	August 2019	31	58.08%	($144,574)	($144,574)
31	September 2019	30	49.86%	($124,115)	($124,115)
32	October 2019	31	41.37%	($102,975)	($102,975)
33	November 2019	30	33.15%	($82,516)	($82,516)
34	December 2019	31	24.66%	($61,376)	($61,376)
35	January 2020	31	16.16%	($40,235)	($40,235)
36	February 2020	28	8.49%	($21,140)	($21,140)
37	March 2020	31	0.00%	$0	$0
38	Total	365		($1,365,266)	($1,365,266)
39	Deferred Tax Without Proration	Line 25		($2,986,946)	($2,986,946)
40	Proration Adjustment	Line 38 - Line 39		$1,621,680	$1,621,680

Column Notes:
(j) Sum of remaining days in the year (Col (i)) ÷ 365
(l) through (r) = Current Year Line 25 ÷ 12 * Current Month Col (j)

The Narragansett Electric Company
d/b/a National Grid
Power Sector Transformation (PST)
Calculation of Fiscal Year 2021 Net Deferred Tax Reserve IS Proration
RI Only Grid Mod - IS

Line No.			(a)=Sum of (b) through (c) Total	(b) Vintage Year March 31, 2021	(c) Vintage Year March 31, 2020
	Deferred Tax Subject to Proration				
1	Book Depreciation	Col (b) = Page 15 of 21, Line 13; Col (c) = Page 13 of 21, Line 13	$3,838,929	$878,929	$2,960,000
2	Bonus Depreciation	Page 16 of 21, Line 12	$0	$0	
3	Remaining MACRS Tax Depreciation	Col (b) = Page 16 of 21, Line 18; Col (c) = Page 14 of 21, Line 18	($11,239,038)	($4,101,257)	($7,137,781)
4	FY21 tax (gain)/loss on retirements	Col (b) = Page 16 of 21, Line 19; Col (c) = Page 14 of 21, Line 19	$0	$0	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($7,400,109)	($3,222,328)	($4,177,781)
6	Effective Tax Rate	Per Tax Department	35.00%	35.00%	35.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($2,590,038)	($1,127,815)	($1,462,223)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	Page 16 of 21, Line 3	$0	$0	
9	Cost of Removal	Page 16 of 21, Line 20	$0	$0	
10	Book/Tax Depreciation Timing Difference at 3/31/2021		$0	$0	
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0	
12	Effective Tax Rate		35.00%	35.00%	
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0	
14	Total Deferred Tax Reserve	Line 7 + Line 13	($2,590,038)	($1,127,815)	($1,462,223)
15	Net Operating Loss	Col (b) = Page 15 of 21, Line 19; Col (c) = Page 13 of 21, Line 19	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($2,590,038)	($1,127,815)	($1,462,223)
	Allocation of FY 2021 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($7,400,109)	($3,222,328)	($4,177,781)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($7,400,109)	($3,222,328)	($4,177,781)
20	Total FY 2021 Federal NOL	Col (b) = Page 15 of 21, Line 19; Col (c) = Page 13 of 21, Line 19 / 35%	$0	$0	$0
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0	$0
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0	$0
23	Effective Tax Rate		35.00%	35.00%	35.00%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($2,590,038)	($1,127,815)	($1,462,223)

		(i) Number of Days in Month	(j) Proration Percentage	(k)= Sum of (l) through (m)	(l)	(m)
	Proration Calculation					
26	April 2020	30	91.78%	($198,097)	($86,260)	($111,837)
27	May 2020	31	83.29%	($179,765)	($78,278)	($101,488)
28	June 2020	30	75.07%	($162,025)	($70,553)	($91,472)
29	July 2020	31	66.58%	($143,694)	($62,571)	($81,123)
30	August 2020	31	58.08%	($125,363)	($54,588)	($70,774)
31	September 2020	30	49.86%	($107,623)	($46,864)	($60,759)
32	October 2020	31	41.37%	($89,291)	($38,881)	($50,410)
33	November 2020	30	33.15%	($71,551)	($31,157)	($40,395)
34	December 2020	31	24.66%	($53,220)	($23,174)	($30,046)
35	January 2021	31	16.16%	($34,889)	($15,192)	($19,697)
36	February 2021	28	8.49%	($18,331)	($7,982)	($10,349)
37	March 2021	31	0.00%	$0	$0	$0
38	Total	365		($1,183,849)	($515,499)	($668,350)
39	Deferred Tax Without Proration	Line 25		($2,590,038)	($1,127,815)	($1,462,223)
40	Proration Adjustment	Line 38 - Line 39		$1,406,190	$612,316	$793,874

Column Notes:
(j) Sum of remaining days in the year (Col (i)) ÷ 365
(l) through (r) = Current Year Line 25 ÷ 12 * Current Month Col (j)

The Narragansett Electric Company
d/b/a National Grid
Power Sector Transformation (PST)
Calculation of Fiscal Year 2022 Net Deferred Tax Reserve IS Proration
RI Only Grid Mod - IS

Line No.			(a)=Sum of (b) through (d) Total	(b) Vintage Year March 31, 2022	(c) Vintage Year March 31, 2021	(d) Vintage Year March 31, 2020
	Deferred Tax Subject to Proration					
1	Book Depreciation	Col (b) = Page 17 of 21, Line 13; Col (c) = Page 15 of 21, Line 13; Col (d) = Page 13 of 21, Line 13	$6,971,143	$2,253,286	$1,757,857	$2,960,000
2	Bonus Depreciation	Page 18 of 21, Line 12	$0	$0		
3	Remaining MACRS Tax Depreciation	Col (b) = Page 18 of 21, Line 18; Col (c) = Page 16 of 21, Line 18; Col (d) = Page 14 of 21, Line 18	($18,362,045)	($10,514,282)	($5,469,573)	($2,378,190)
4	FY22 tax (gain)/loss on retirements	Col (b) = Page 18 of 21, Line 19; Col (c) = Page 16 of 21, Line 19; Col (d) = Page 14 of 21, Line 19	$0	$0		
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($11,390,902)	($8,260,996)	($3,711,716)	$581,810
6	Effective Tax Rate	Per Tax Department	35.00%	35.00%	35.00%	35.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($3,986,816)	($2,891,349)	($1,299,101)	$203,634
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction	Page 18 of 21, Line 3	$0	$0		
9	Cost of Removal	Page 18 of 21, Line 20	$0	$0		
10	Book/Tax Depreciation Timing Difference at 3/31/2022		$0	$0		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0		
12	Effective Tax Rate		35.00%	35.00%		
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0		
14	Total Deferred Tax Reserve	Line 7 + Line 13	($3,986,816)	($2,891,349)	($1,299,101)	$203,634
15	Net Operating Loss	Col (b) = Page 17 of 21, Line 19; Col (c) = Page 15 of 21, Line 19; Col (c) = Page 13 of 21, Line 19	$0	$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($3,986,816)	($2,891,349)	($1,299,101)	$203,634
	Allocation of FY 2022 Estimated Federal NOL					
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($11,390,902)	($8,260,996)	($3,711,716)	$581,810
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($11,390,902)	($8,260,996)	($3,711,716)	$581,810
20	Total FY 2022 Federal NOL	Col (b) = Page 17 of 21, Line 19; Col (c) = Page 15 of 21, Line 19; Col (c) = Page 13 of 21, Line 19 / 35%	$0	$0	$0	$0
21	Allocated FY 2022 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0	$0	$0
22	Allocated FY 2022 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0	$0	$0
23	Effective Tax Rate	Per Tax Department	35.00%	35.00%	35.00%	35.00%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($3,986,816)	($2,891,349)	($1,299,101)	$203,634

		(i) Number of Days in Month	(j) Proration Percentage	(k)= Sum of (l) through (n)	(l)	(m)	(n)
	Proration Calculation						
26	April 2021	30	91.78%	($304,928)	($221,142)	($99,360)	$15,575
27	May 2021	31	83.29%	($276,710)	($200,678)	($90,166)	$14,133
28	June 2021	30	75.07%	($249,404)	($180,874)	($81,268)	$12,739
29	July 2021	31	66.58%	($221,186)	($160,410)	($72,073)	$11,297
30	August 2021	31	58.08%	($192,969)	($139,947)	($62,879)	$9,856
31	September 2021	30	49.86%	($165,662)	($120,143)	($53,981)	$8,461
32	October 2021	31	41.37%	($137,445)	($99,679)	($44,786)	$7,020
33	November 2021	30	33.15%	($110,138)	($79,875)	($35,888)	$5,625
34	December 2021	31	24.66%	($81,921)	($59,411)	($26,694)	$4,184
35	January 2022	31	16.16%	($53,704)	($38,947)	($17,499)	$2,743
36	February 2022	28	8.49%	($28,217)	($20,464)	($9,195)	$1,441
37	March 2022	31	0.00%	$0	$0	$0	$0
38	Total	365		($1,822,284)	($1,321,571)	($593,790)	$93,076
39	Deferred Tax Without Proration	Line 25		($3,986,816)	($2,891,349)	($1,299,101)	$203,634
40	Proration Adjustment	Line 38 - Line 39		$2,164,531	$1,569,778	$705,311	($110,557)

Column Notes:

(j) Sum of remaining days in the year (Col (i)) ÷ 365

(l) through (r) = Current Year Line 25 ÷ 12 * Current Month Col (j)