

The Narragansett Electric Company

d/b/a National Grid

INVESTIGATION AS TO THE  
PROPRIETY OF PROPOSED TARIFF  
CHANGES

Testimony and Schedules of:

Power Sector Transformation Panel

Book 1 of 3

November 27, 2017

Submitted to:  
Rhode Island Public Utilities Commission  
RIPUC Docket No. 4770

Submitted by:

nationalgrid



**PRE-FILED DIRECT TESTIMONY**  
**OF**  
**THE POWER SECTOR TRANSFORMATION PANEL**

**Kayte O'Neill**

**Robert D. Sheridan**

**John O. Leana**

**Carlos A. Nouel**

**Timothy R. Roughan**

**Meghan McGuinness**

**Mackay Miller**

**James Perkinson**

**Melissa Little**

**Dated: November 27, 2017**

1 **I. Introduction**

2 **Q. Please introduce the members of the Power Sector Transformation Panel.**

3 A. The Power Sector Transformation (PST) Panel (Panel) consists of Kayte O'Neill, Robert  
4 D. Sheridan, John O. Leana, Carlos A. Nouel, Timothy R. Roughan, Meghan  
5 McGuinness, Mackay Miller, James Perkinson, and Melissa Little. The Panel will be  
6 testifying on behalf of The Narragansett Electric Company d/b/a National Grid (the  
7 Company).

8  
9 **Q. Please briefly state the topics that the Panel will discuss in this testimony.**

10 A. The Panel is supporting the Company's Power Sector Transformation Vision and  
11 Implementation Plan (Plan) which includes National Grid's vision regarding the  
12 advancement of Power Sector Transformation efforts in Rhode Island. It also provides  
13 evidence supporting the following PST proposals: (1) grid modernization enabling  
14 investments (2) advanced metering infrastructure; (3) beneficial electrification proposals,  
15 including an electric heat initiative and an electric transportation initiative; (4) utility-  
16 owned energy storage and solar demonstration program; and (5) a rewards program for  
17 income-eligible customers. In support of these proposals, the Plan also includes proposed  
18 performance incentive mechanisms, a PST Provision designed to recovery the  
19 Company's incremental costs associated with PST investments, and a description of the  
20 revenue requirement associated with the Plan.

21 These topics are included in the Plan in the following chapters:

- 1 (1) Chapters One -National Grid’s Vision for a Transformed Power Sector in Rhode  
2 Island
- 3 (2) Chapter Two Advancement of State Goals and Evaluation of Benefits and Costs
- 4 (3) Chapter Three- Grid Modernization Investments;
- 5 (4) Chapter Four- Advanced Metering Functionality (AMF) Investments;
- 6 (5) Chapter Five- Beneficial Electrification Investments (Electric Transportation  
7 Initiative)
- 8 (6) Chapter Six- Beneficial Electrification Investments (Electric Heat Initiative)
- 9 (7) Chapter Seven- Energy Storage System Investments
- 10 (8) Chapter Eight- Enabling Income Eligible Customers (Company-Owned Solar  
11 Facilities and Income Eligible Rewards Program);
- 12 (9) Chapter Nine- Driving Outcomes for Customers: the Role of Performance  
13 Incentive Mechanisms; and
- 14 (10) Chapter Ten- Funding the Transformation (Cost Recovery and Revenue  
15 Requirements for PST Investments).

16 The witnesses sponsoring these chapters are presented below in turn.

17

18 **II. Presentation of PST Panel**

19

*Kayte O’Neill*

20 **Q. Ms. O’Neill, please state your name and business address.**

21 A. My name is Kayte O’Neill. My business address is 40 Sylvan Road, Waltham,

22 Massachusetts 02451.

1 **Q. By whom are you employed and in what position?**

2 A. I am employed by National Grid USA Service Company, Inc. (National Grid USA). My  
3 current position is Vice President of Regulatory Strategy for National Grid. My  
4 responsibilities include developing and coordinating development of a consolidated  
5 United States regulatory policy for National Grid's state and federally regulated  
6 businesses. I am responsible for a small team (10) of regulatory analysts and regulatory  
7 affairs professionals focused on shaping external policy priorities into successful business  
8 and regulatory strategies. I provide strategic direction and coordinated regulatory  
9 guidance over topics including United States-wide regulatory trends, incentive and  
10 performance based regulation, renewable and non-renewable energy development  
11 policies, distributed generation, energy efficiency, legislation, and the evolution of the  
12 energy system in the 21st century. I also lead on regulatory proceedings relating to  
13 regulatory frameworks for the changing energy system, including New York Reforming  
14 the Energy Vision, Massachusetts Grid Modification and Rhode Island Power Sector  
15 Transformation.

16

17 **Q. Please describe your educational background and professional experience.**

18 A. I received a Bachelor of Arts with Honors in Business Economics in 2002. I joined  
19 National Grid in 2002 and have held various positions of increasing responsibility in the  
20 areas of United Kingdom Electric Transmission and Gas Distribution Regulation,  
21 Customer Strategy and Customer Services, Advisory services to the Executive, and  
22 Corporate Strategy. I assumed my current role in May 2016.

1 **Q. Have you previously testified before the Rhode Island Public Utilities Commission**  
2 **or any other regulatory agencies?**

3 A. I have not testified before the Rhode Island Public Utilities Commission (PUC).  
4

5 **Q. What sections of the PST Plan are you supporting?**

6 A. I am supporting Chapters One and Two, which describe the Company's vision for PST  
7 investments in Rhode Island and the Company's perspective on the scope of a modern  
8 electric grid in this state.  
9

10 *Robert D. Sheridan*

11 **Q. Mr. Sheridan, please state your name and business address.**

12 A. My name is Robert D. Sheridan. My business address is 40 Sylvan Road, Waltham,  
13 Massachusetts 02451.  
14

15 **Q. By whom are you employed and in what capacity?**

16 A. I am employed by National Grid, and currently hold the position of Director, Grid  
17 Modernization Strategy. I lead a team of two direct individuals responsible for the  
18 development of electric grid modernization plans in NY, MA and RI.  
19

20 **Q. Please describe your educational background and professional experience.**

21 A. I received a Bachelor of Science in Electrical Engineering degree from the University of  
22 South Florida in Tampa, Florida and a Masters of Business Administration from Bentley

1 College in Waltham Massachusetts. I am a licensed Professional Engineer in the  
2 Commonwealth of Massachusetts.

3 I joined National Grid in 1988 as an Associate Engineer in the Distribution Engineering  
4 department of Massachusetts Electric Company. In 1995, I became a District  
5 Engineering Manager for Massachusetts Electric and took on a similar role in Rhode  
6 Island for the Company in 1998. In 2002, I was appointed to the position of Vice  
7 President of Distribution Planning and Engineering for the Company's New England  
8 jurisdictions. In 2008, I took on the role of Director, Distribution Asset Management for  
9 both New York and New England jurisdictions and in 2013 I became Director, Utility of  
10 the Future and worked on the Company's grid modernization plans in Massachusetts and  
11 New York's Reforming the Energy Vision submittals.

12 Prior to National Grid, I was employed by General Dynamics Electric Boat Division as  
13 an engineer in Groton, Connecticut from 1987-1988.

14  
15 **Q. Have you previously testified before the PUC or any other regulatory commissions?**

16 A. Yes, I have provided testimony in previous ISR proceedings before the PUC. I have also  
17 testified before the Massachusetts Department of Public Utilities and the New Hampshire  
18 Public Utilities Commission on various topics related to engineering, operations and  
19 capital investment issues as well as before the NY Public Service Commission in an  
20 ongoing rate case for the Company's affiliate in upstate NY.

21  
22 **Q. What section of the PST Plan are you supporting?**



1 A. I am supporting Chapters Three and Four of the PST Plan, which describe the Company's  
2 proposals for advanced grid modernization investments, and advanced metering  
3 functionality, for Rhode Island, respectively.

4

5 *John O. Leana*

6 **Q. Mr. Leana, please state your name and business address.**

7 A. My name is John O. Leana. My business address is 300 Erie Boulevard West, Syracuse,  
8 New York 13202.

9

10 **Q. By whom are you employed and in what capacity?**

11 A. I am employed by National Grid USA, and currently hold the position of Director,  
12 Performance and Strategy New York. My responsibilities include supporting the New  
13 York Jurisdictional President on business strategy and energy policy issues, including  
14 activities in the Reforming the Energy Vision proceeding currently before the New York  
15 State Public Service Commission. I am currently responsible for leading the  
16 development of Niagara Mohawk Power Corporation d/b/a National Grid's (Niagara  
17 Mohawk) AMI program and representing the Company on the Joint Utility Distributed  
18 System Platform Provider implementation activities.

19

20 **Q. Please describe your educational background and professional experience.**

21 A. I received a Bachelor of Science in Electrical Engineering from Clarkson University in  
22 1988 and a Master in Electric Engineering from that same institution in 1989. In 1998, I

1 received a Master of Business Administration from Oswego State University. I joined  
2 National Grid in 1989 and have held various positions of increasing responsibility in the  
3 areas of Transmission Planning, Corporate Planning, Finance, Credit and Collections,  
4 Meter Data Services, Merger/Restructuring, and Executive Support. I assumed my  
5 current role in April 2012.

6

7 **Q. Have you previously testified before the PUC or any other regulatory agencies?**

8 A. I have not testified before the PUC. However, I have testified before the New York  
9 Public Service Commission on behalf of Niagara Mohawk.

10

11 **Q. What sections of the PST Plan are you supporting?**

12 A. Together with Messrs. Nouel, Sheridan and Roughan, I am supporting Chapter Four of  
13 the PST Plan, which describes the Company's proposal for AMF investments in Rhode  
14 Island.

15

16 *Carlos A. Nouel*

17 **Q. Mr. Nouel, please state your name and business address.**

18 A. My name is Carlos A. Nouel. My business address is 40 Sylvan Road, Waltham,  
19 Massachusetts 02451.

20

21 **Q. By whom are you employed and in what capacity?**

22 A. I am employed by National Grid and currently hold the position of Vice President, New

1 Energy Solutions. My responsibilities include developing and launching innovative  
2 energy solutions and technologies that deliver value for National Grid's customers and  
3 communities and accelerate progress toward a sustainable energy future.

4

5 **Q. Please describe your educational background and professional experience.**

6 A. I received a Bachelor of Science in Industrial Engineering from the Andres Bello  
7 Catholic University in Caracas, Venezuela in 2003 and a Master in Business and  
8 Administration from Hult International Business School in Cambridge, Massachusetts in  
9 2009. I also hold an Executive Certificate in Strategy and Innovation from the  
10 Massachusetts Institute of Technology in Cambridge, Massachusetts. I joined National  
11 Grid in 2009 and have held various positions of increasing responsibility in the areas of  
12 Supply Chain, Project Management, Energy Efficiency, Smart Grid, Strategy and  
13 Partnerships. I assumed my current role in May 2016.

14

15 **Q. Have you previously testified before the PUC or any other regulatory commissions?**

16 A. I have not testified before the PUC. However, I have testified before the New York  
17 Public Service Commission on behalf of Niagara Mohawk

18

19 **Q. What sections of the PST Plan are you supporting?**

20 A. Together with Messrs. Sheridan, Leana and Roughan, I am supporting Chapter Four of  
21 the PST Plan, which describes the Company's proposal for AMF investments in Rhode  
22 Island. I am also supporting Chapter Five of the PST Plan, addressing the Company's

1 Electric Transportation initiatives. Finally, along with Mr. Perkinson, I am supporting  
2 Chapters Seven and Eight of the PST Plan, which describe the Company's storage and  
3 solar initiatives, respectively.

4

5 *Timothy R. Roughan*

6 **Q. Mr. Roughan, please state your name and business address.**

7 A. My name is Timothy R. Roughan. My business address is 40 Sylvan Road, Waltham,  
8 Massachusetts 02451.

9

10 **Q. By whom are you employed and in what capacity?**

11 A. I am employed by National Grid, Inc. as the Director of Energy and Environmental  
12 Policy. My responsibilities include providing regulatory and policy direction on issues  
13 relative to grid modernization activities. I have worked on policies regarding new  
14 metering technologies as it relates to distributed generation (i.e. reporting ISO  
15 settlements, wireless metering options, etc.), and other metering pilots for National Grid  
16 subsidiaries.

17

18 **Q. Please describe your educational background and professional experience.**

19 A. I am a 1982 graduate of Worcester Polytechnic Institute with a Bachelor of Science in  
20 Mechanical Engineering and have worked for the Service Company or its predecessors  
21 for 35 years in multiple roles.

22

1 **Q. Have you previously testified before the PUC or any other regulatory commissions?**

2 A. Yes, I have testified before the PUC in many dockets; most recently in Docket 4563 (the  
3 revenue neutral rate case from 2015), and the Company's recent rate case, System  
4 Reliability and Procurement Plan. I have also participated in the stakeholder process  
5 before the PUC in connection with the Changing Distribution System, Docket No. 4600,  
6 and most currently in the Power Sector Transformation initiative that the Rhode Island  
7 Division of Public Utilities and Carriers is leading.

8  
9 **Q. What sections of the PST Plan are you supporting?**

10 A. Together with Messrs. Leana, Nouel and Sheridan, I am supporting the Company's AMF  
11 Infrastructure proposal set forth in the Chapter Four of the PST Plan. I am also  
12 supporting the Company's Performance Incentive Mechanism proposal together with Ms.  
13 McGuinness, presented in Chapter Nine.

14  
15 *Mackay Miller*

16 **Q. Mr. Miller, please state your name and business address.**

17 A. My name is Mackay Miller and my business address is 40 Sylvan Road, Waltham,  
18 Massachusetts 02451.

19  
20 **Q. By whom are you employed and in what capacity?**

21 A. I am employed by National Grid as a Principal Analyst in the U.S. Strategy Division. In  
22 this position, I support development of low-carbon business models for National Grid.

1 **Q. Please describe your educational background and professional experience.**

2 I received a Bachelor of Arts degree from Brown University in International Relations  
3 and a Masters of Business Administration from the University of Colorado.

4 Prior to my employment at National Grid starting in 2015, I spent six years at the  
5 National Renewable Energy Laboratory. This experience includes a 2015 assignment to  
6 the U.S. Department of Energy to support development of international climate and clean  
7 energy policies in the lead-up to the Paris Accords.

8

9 **Q. Have you previously testified before the PUC or any other regulatory commissions?**

10 A. No.

11

12 **Q. What sections of the PST Plan are you supporting?**

13 A. I will be supporting the Company's Electric Heat Initiative proposal set forth in Chapter  
14 Six of the PST Plan.

15

16 *James R. Perkinson*

17 **Q. Mr. Perkinson, please state your full name and business address.**

18 A. My name is James Robert Perkinson and my business address is 40 Sylvan Rd, Waltham,  
19 Massachusetts, 02451.

20

21 **Q. By whom are you employed and what capacity?**

1 A. I am employed by National Grid as an Engineering Manager for the New Grid Offerings  
2 Team with the “New Energy Solutions” group. Our group is tasked with assessing grid-  
3 focused technology strategies, new technology pilots and demonstrations, and improved  
4 asset data management.

5

6 **Q. Please describe your educational background and training.**

7 A. I graduated with a BSEE in 2003 and obtained a master’s degree in Electrical  
8 Engineering in 2005, both from Northeastern University in Boston. Most of my career  
9 was spent as an engineering manager at Satcon, a utility-scale Solar inverter manufacture  
10 located in Boston. I was extensively involved in the technical details of the product  
11 design, and its application within utility electric systems. Between 2004 and 2012 I held  
12 several positions, as Senior Director of Product Management, Director of Applications  
13 and Field Engineering, Software Group Leader, as well as an individual contributing  
14 engineer. In addition, I participated in Satcon’s Research and Development efforts  
15 focusing on next generation inverter control technologies to assist with grid integration.  
16 From 2012-2013, I was employed at Fraunhofer’s Center for Sustainable Energy as a  
17 Member of Technical Staff, group lead for Distributed Energy Systems. During this  
18 time, I was extensively involved with their Department of Energy Sunshot funding for  
19 Residential Plug and Play Photo Voltaics. I joined National Grid in December of 2013 as  
20 the Manager of the Utility of the Future Advanced Grid Engineering Team for two years,  
21 before transitioning to the New Energy Solutions organization.

22

1 **Q. Have you previously testified before the PUC or any other regulatory commissions?**

2 A. Yes, I recently testified in Dkt. 4682, regarding the Company's Electric ISR.

3

4 **Q. What sections of the PST Plan are you supporting?**

5 A. Along with Mr. Nouel, I will be supporting the Company's storage proposal set forth in  
6 Chapter Seven of the PST Plan and the Company's utility-owned solar proposal  
7 described in detail in Chapter Eight of the PST Plan.

8

9 *Meghan McGuinness*

10 **Q. Ms. McGuinness, please state your name and business address.**

11 A. My name is Meghan McGuinness. My business address is 40 Sylvan Road, Waltham,  
12 Massachusetts 02451.

13

14 **Q. By whom are you employed and in what position?**

15 A. I am employed by National Grid USA. My current position is Principal Analyst,  
16 Regulatory Strategy. In this position, I support the development of regulatory strategy on  
17 matters related to grid modernization and utility business models reform.

18

19 **Q. Please describe your educational background and professional experience.**

20 A. I received a Bachelor of Arts in Economics and Environmental Studies from Middlebury  
21 College in 2000, and a Master of Science in Technology and Policy from Massachusetts  
22 Institute of Technology in 2008. Prior to joining National Grid in 2016, I worked on



1 energy and environmental policy and regulatory issues affecting utilities for a number of  
2 organizations, including the Bipartisan Policy Center, NERA Economic Consulting,  
3 MIT's Center for Energy and Environmental Policy Research, and the United States  
4 Environmental Protection Agency.

5

6 **Q. Have you previously testified before the Rhode Island Public Utilities Commission**  
7 **or any other regulatory agencies?**

8 A. No.

9

10 **Q. What sections of the PST Plan are you supporting?**

11 A. Along with Mr. Roughan, I am supporting the Company's Performance Incentive  
12 Mechanism proposal set forth in Chapter Nine of the PST Plan.

13

14 *Melissa A. Little*

15 **Q. Ms. Little, please state your name and business address.**

16 A. My name is Melissa A. Little, and my business address is 40 Sylvan Road, Waltham,  
17 Massachusetts 02451.

18

19 **Q. By whom are you employed and in what position?**

20 A. I am Director, New England Revenue Requirements for National Grid. The Service  
21 Company provides engineering, financial, administrative, corporate, management, and  
22 other technical support to direct and indirect subsidiary companies of National Grid. My

1 current duties include revenue requirement responsibilities for National Grid's electric  
2 and gas distribution activities in New England, including the electric and gas operations  
3 of the Company.

4  
5 **Q. Please describe your educational background and experience.**

6 A. In 2000, I earned a Bachelor of Science degree in Accounting Information Systems from  
7 Bentley College (now Bentley University) in Waltham, Massachusetts. In September  
8 2000, I joined PricewaterhouseCoopers LLP in Boston, Massachusetts, where I worked  
9 as an associate in the Assurance practice. In November 2004, I joined National Grid as  
10 an analyst in the general accounting group. After the merger of National Grid and  
11 KeySpan Corporation in 2007, I joined the Regulation and Pricing department as a senior  
12 analyst in the Regulatory Accounting function and also supported the revenue  
13 requirement team for the Company's upstate New York affiliate, Niagara Mohawk Power  
14 Corporation. I joined the New England revenue requirement team in 2011 and was  
15 promoted to Lead Specialist in the Regulation and Pricing department where my duties  
16 included revenue requirement responsibilities for National Grid's electric and gas  
17 distribution activities in New England, including the Company's electric and gas  
18 operations. In August 2017, I was promoted to my current position.

19  
20 **Q. Have you ever testified before the PUC or other regulatory bodies?**

21 A. Yes. Among other testimony, I submitted pre-filed testimony to support the Company's  
22 revenue requirement (1) for the Company's electric operations, in the Company's Fiscal

1 Year 2018 Electric Infrastructure, Safety, and Reliability (ISR) Plan filing in Docket  
2 No. 4682; and (2) for the Company's gas operations, in the Company's Gas ISR Plan and  
3 reconciliation filings for Fiscal Year 2016 in Docket No. 4540 and Fiscal Year 2017 in  
4 Docket No. 4590, and the Company's Gas ISR Plan filing for Fiscal Year 2018 in Docket  
5 No. 4678.

6  
7 **Q. What section of the PST Plan are you supporting?**

8 A. I am supporting the calculation of the revenue requirement associated with the  
9 Company's PST Plan, as presented in Chapter 10.

10  
11 **III. Purpose of Testimony**

12 **Q. What is the purpose of the Panel's testimony?**

13 A. As briefly listed above, the Panel has prepared the PST Plan which sets forth five key  
14 components and the associated cost recovery, including a calculation of associated  
15 revenue requirements and a Performance Incentive Mechanism proposal. The Panel  
16 consists of the subject matter experts that will support each component during this  
17 proceeding. These components are as follows:

18 **PST Initiatives**

- 19 1. **Grid Modernization**: As part of the PST Plan, the Company is also proposing a  
20 portfolio of investments and efforts that are designed to evolve the electric grid.  
21 These foundational grid modernization investments will enhance reliability and  
22 operational efficiency, and will effectively integrate and utilize distributed energy

1 resources (DER). These investments include investments in foundational  
2 information system and cybersecurity, a system data portal, distribution feeder  
3 monitoring, data system control system enhancements and geographic  
4 information system enhancements. These investments are in addition to the  
5 investments in AMI infrastructure which will also enable the evolution of the  
6 grid.

7 2. Advanced Metering Functionality: The AMF component of the PST Plan will  
8 develop a detailed plan for the deployment of electric AMI meters and AMI-  
9 compatible encoder receiver transmitters (ERTs) for its gas meters in Rhode  
10 Island. Specifically, AMF witnesses on the Panel will explain why AMF has the  
11 potential to modernize the Company's electric and gas systems, and advance the  
12 goals and objectives as set forth in the PST initiative. To that end, the Panel  
13 presents a conceptual business case and benefits-cost analysis (BCA) that  
14 demonstrates the viability of AMF and ERT deployment in Rhode Island. The  
15 Panel's AMF witnesses also describe the potential customer, societal, safety, and  
16 operational benefits of AMF, if deployed.

17 3. Electric Transportation Initiative: The Electric Transportation Initiative is a  
18 multi-year, multi-part proposal that will meaningfully accelerate electrification in  
19 Rhode Island through near-term investment while also demonstrating multiple  
20 market-development strategies. This Initiative includes the following  
21 components: (a) a Charging Station Demonstration Program offering a portfolio  
22 of charging station services; (b) a Residential Off-Peak Charging Rebate that will

1 incentivize customers to charge during lower-cost times of day while also  
2 providing the Company with important data regarding customer charging  
3 behavior; (c) a rate discount for DC Fast Charging Station Accounts in order to  
4 encourage third-party charging station development; (d) Transportation  
5 Education and Outreach for residential and commercial customers; (e) investment  
6 in electrification of the Company's own vehicle fleet; and (f) an evaluation plan  
7 in order to evaluate each component and share the results of this Initiative with  
8 stakeholders and industry participants.

9 4. Electric Heat Initiative: The Company is developing a multi-year, multi-part  
10 Electric Heat Initiative in response to 2015 State Energy Plan, the 2016 SIRI  
11 Vision Document, the greenhouse gas emissions reductions targets as established  
12 in the Resilient Rhode Island Act, and the 2017 Power Sector Transformation  
13 stakeholder process. The purpose of this proposal is to meaningfully accelerate  
14 efficient heat electrification in Rhode Island through multiple market  
15 development strategies. The Electric Heat Initiative is comprised of four  
16 components: (a) equipment incentives to encourage Income-Eligible residential  
17 customers to convert to efficient cold-climate Air Source Heat Pumps or Ground-  
18 Source Heat Pump systems; (b) community based marketing; (c) oil/propane  
19 dealer training programs; and (d) a ground-source heat pump program.

20 5. Utility Owned Energy Storage and Solar Demonstration Projects: (a) a  
21 demonstration program to deploy and own approximately 2MWh of energy  
22 storage in one or two locations for the benefit of the community through

1 educational outreach and partnering entities; and (b) a demonstration program to  
2 deploy and own up to 3.75 MW of solar generation, consisting of multiple  
3 projects, for the benefit of Income Eligible customers through the setup of an  
4 Income Eligible Customer Rewards Program

5 **Costs and Cost Recovery**

6 6. Performance Incentive Mechanisms: The Company has included a Performance  
7 Incentive Mechanisms proposal in support of the PST Plan in order to support  
8 advancement of the policy priorities identified by stakeholders through Docket  
9 4600 and the PST initiative led by the Office of Energy Resources. Carefully  
10 designed performance incentives can aid efficient delivery of state policy goals  
11 and provide broad new benefits to customers. Therefore, the Company is  
12 proposing to develop Performance Incentive Mechanisms for the following  
13 categories of implementation of the Plan: (a) system efficiency; (b) distributed  
14 energy resources; and (c) network support services.

15 7. Revenue Requirement: The Company has calculated the revenue requirement  
16 associated with the Plan, using the Company's proposed budget and cost  
17 estimates. For Fiscal Years 2020, 2021 and 2022, the revenue requirement is  
18 illustrative. The Company's proposed PST revenue requirement for those fiscal  
19 years will be calculated annually in the Company's annual PST cost recovery  
20 filings.

21 8. PST Provision: The Company is proposing a PST Provision for recovery of the  
22 costs associated with the PST Plan. The PST factors will allow for recovery of

1 the cumulative revenue requirement as approved by the PUC in the Company's  
2 annual PST filings and will be applicable for the twelve month period  
3 commencing on April 1 of each year. In order to allow the PUC sufficient time  
4 in calendar year 2018 to review and approve the PST Plan, the Company is  
5 proposing that cost recovery for Fiscal Year 2019 be truncated to a six month  
6 period commencing October 1, 2018 and ending March 31, 2019. In order to be  
7 eligible for recovery, PST costs must (a) be pre-authorized by the PUC;  
8 (b) include PST investment; (c) be incremental; and (d) be prudently incurred.  
9 The PST Provision also allows for recovery of associated operations and  
10 maintenance (O&M) expense. The PST Factors will be reconciled through an  
11 August reconciliation filing subject to the PUC's approval.

12 The additional details for each of these components are set forth in the PST Plan.

13  
14 **Q. How does the PST Plan meet the objectives of Docket 4600 regarding proposals to**  
15 **advance the electric power system?**

16 A. Docket 4600 identified the following goals for proposals designed to advance the electric  
17 power system, such as those included in the Company's PST Plan:

- 18 • Provide reliable, safe, clean, and affordable energy;
- 19 • Strengthen the Rhode Island economy through support of economic  
20 competitiveness and retention and creation of jobs;
- 21 • Address the challenges of climate change and other pollution;

- 1           •       Prioritize and facilitate increased customer investments in facilities where
- 2                       such investment will provide recognizable net benefits;
- 3           •       Appropriately compensate distributed energy resources for the value the
- 4                       provide to the distribution system, customers and society;
- 5           •       Appropriately charge customers for the costs they impose on the grid;
- 6           •       Appropriately compensate the distribution utility for the services they
- 7                       provide;
- 8           •       Align distribution utility, customer and policy objectives and interests
- 9                       through the regulatory framework including rate design, cost recovery and
- 10                      incentives.

11           The Company’s PST Plan includes detailed explanations for how each component of the  
12           Plan is consistent with these objectives. This discussion includes details regarding the  
13           costs and benefits associated with each component pursuant to the framework adopted by  
14           the PUC as Appendix A to the PUC’s Docket 4600 Guidance Document.

15  
16   **IV.   Conclusion**

17   **Q.   Please summarize the Panel’s testimony.**

18   A.   The Company has developed a PST Plan that will ensure resiliency, efficiency, and  
19           openness of the electric distribution grid today and for the future. The PST Plan is  
20           designed to create a platform that will empower the Company’s customers and support  
21           the transition to an affordable, sustainable clean energy future for Rhode Island. The



1 Company's PST Plan has been specifically designed to achieve these goals and to be  
2 consistent with the objectives set forth by the PUC.

3

4 **Q. Does this conclude the Panel's testimony?**

5 A. Yes.



## Index of Schedules

Schedule PST-1	PST Plan
Appendix 2.1	Program BCA
Appendix 2.2	Economic Development

### **The following Appendices located in PST Book 2 of 3 Redacted**

Appendix 4.1	AMF Technology and BCA REDACTED
Appendix 4.2	AMF BCA Methodology
Appendix 10.1	Revenue Requirement Summaries
Appendix 10.2	Revenue Requirement Modern Grid, RI only
Appendix 10.3	Revenue Requirement Modern Grid, Multi Jurisdiction
Appendix 10.4	Revenue Requirement AMF, RI only
Appendix 10.5	Revenue Requirement AMF, Multi Jurisdiction
Appendix 10.6	Revenue Requirement Electric Transportation
Appendix 10.7	Revenue Requirement Electric Heat
Appendix 10.8	Revenue Requirement Energy Storage
Appendix 10.9	Revenue Requirement Solar
Appendix 10.10	Power Sector Transformation Provision
Appendix 10.11	Power Sector Transformation Plan, Distribution Adjustment Charge

### **The following Workpapers are located in PST Book 3 of 3 Redacted**

Workpaper 3.1	Modern Grid Costs, RI only
Workpaper 3.2	Modern Grid Costs, Multi Jurisdiction
Workpaper 4.1	AMF Costs REDACTED
Workpaper 5.1	Electric Transport Costs/Assumptions
Workpaper 6.1	Electric Heat Costs/Assumptions
Workpaper 7.1	Energy Storage Costs/Assumptions
Workpaper 8.1	Solar Costs/Assumptions
Workpaper 9.1	Peak Demand Reduction Targets
Workpaper 9.2	Electric Heat Initiative Targets
Workpaper 9.3	Electric Vehicle Targets
Workpaper 9.4	Incentive Benefits





Schedule PST – 1

Chapter 1 - Introduction

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## CHAPTER ONE: OUR VISION FOR A TRANSFORMED POWER SECTOR IN RHODE ISLAND

### 1. INTRODUCTION

*Rhode Island is striving to transform its power sector, to control long term system costs, enhance customer choice and unleash third party innovation and integrate more clean energy into the electric grid.* National Grid is privileged to be part of Rhode Island's energy transformation and is pleased to submit this Vision and Implementation Plan (the Plan) in support of it.

*Across the U.S. and globally, the energy landscape is changing.* Energy supply is becoming more diverse and less carbon-intensive, and decentralization and digitization are accelerating, driven by advances in technology and new business models. Against this backdrop there is a real and immediate opportunity to transform the energy industry. For its part, National Grid can create a more efficient energy delivery system that meets the evolving needs of customers and nurtures a vibrant, clean, and participatory energy landscape.

*National Grid is proud to fulfill a unique role in Rhode Island.* Our hard-working and dedicated employees bring energy to life for customers in homes and business across the state. Given National Grid's unique position, and the ambitions of legislators, regulators, and policy makers, the time is right to roll up our sleeves and work together to build a nation-leading model for energy transformation.

### 2. OUR VISION

By ensuring the **resiliency, efficiency, and openness** of the electric distribution grid today and for the future, we will create a powerful platform for **empowering our customers** and **supporting the transition to an affordable, sustainable clean energy system** for Rhode Island. We will know we have achieved our vision when:

- **All customers have knowledge, choice, and control**, enabled by easy access to information, useful insights on energy options, and thriving markets for innovative new services.
- **Large scale and distributed clean energy resources are commonplace and distributed energy resources are accessible to all**, enabled by affordable distributed solar and storage, effectively and efficiently integrated into a modern electric grid.
- **Efficiency and low-carbon fuels are the affordable, everyday choice**, enabled by robust markets, third party product and service offerings, resilient infrastructure, and well-designed regulatory incentives.

### 3. OUR PRINCIPLES

Given the scale and pace of the transformation ahead of us, successful execution of our vision will demand a holistic, rigorous and structured response, and clarity on exactly what we are seeking to achieve. With this in mind we propose four clarifying principles that underlie our vision:

- **Empower all our customers** by ensuring choice and control over their energy services.
- Cultivate an **efficient and resilient** grid that can adapt to the evolving paradigms of two-way power flows, responsive demand, and customer participation.
- Support the state of Rhode Island in achieving its **clean energy** objectives, including an 80% reduction in greenhouse gas (GHG) emissions by 2050.
- **Maximize the effectiveness of performance incentives** in driving these important outcomes for Rhode Island and its citizens.

Each of these principles is explored more fully below:

### 3.1 Customer Empowerment

Customers are at the heart of National Grid’s proposals for Rhode Island and our focus on empowerment reflects our commitment to meet their changing needs while recognizing the diversity of our customer base. New functionalities provided by advanced meters are designed to afford customers new levels of information and insight about their energy usage, while the future introduction of time-varying rates and the overlay of third-party applications programs are designed to allow customers to exercise new levels of control and choice. In addition to our Advanced Metering Functionality proposals, we are placing particular emphasis on our Income Eligible customers, both by using a reward program to support greater control and choice, and through a new solar program that focuses on providing Income Eligible customers with the benefits of distributed energy resources.

### 3.2 Resiliency and Efficiency

As we reflect on the need for resiliency and efficiency it is important to note that we are building from an already strong foundation. The Company’s electric system has consistently achieved high levels of reliability in Rhode Island as a result of investments that are currently funded through base rates and the Company’s Infrastructure, Safety and Reliability (ISR) plan. National Grid’s proposals in this filing go a step further, anticipating and responding to the impact that decarbonization, decentralization, and digitization will have on the way in which the grid is used and the demands that are placed on it. The Company has identified crucial elements of a modern grid and has proposed investments in those areas that are foundational to ensuring continued reliability, resiliency and efficiency, and effective integration of distributed energy resources. The aim of the Company is to continue to evolve towards modern, participatory electric grid that can strategically and efficiently integrate clean energy resources, and in doing so enable Rhode Islanders to take advantage of new clean energy technologies.



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### **3.3 Transition to a sustainable clean energy future**

The Company’s proposals directly seek to advance the state’s ambitions to realize a cleaner, more sustainable energy future, including specifically the state’s commitment to reduce carbon emissions 80% by 2050 under the Resilient Rhode Island Act (2014), the Rhode Island Zero Emission Vehicle Draft Plan (2015), and the Executive Climate Change Coordinating Council’s GHG Emissions Reduction Plan (2016). The Company is proposing beneficial electrification and DER programs to leverage emerging clean energy technologies including electric vehicle service equipment, ground and air source heat pumps, distributed solar, and energy storage. These programs will generate momentum in nascent sectors, test new business models, reduce system-wide energy costs, provide customer choice, and help meet the state’s emissions reduction goals.

### **3.4 Maximizing the effectiveness of performance incentives**

While the core purpose of the electric utility (to provide safe, reliable, and affordable electricity service) has remained relatively constant over the past several decades, additional objectives related to resiliency and efficiency, customer empowerment, and sustainability will require utilities to innovate with new policies, regulations, technologies, business practices, and customer offerings. To that end, well designed performance incentives that give utilities a clear signal and economic rationale to pursue innovation can create significant new value for customers. The Company’s plan describes a portfolio of performance incentive mechanisms in the areas of system efficiency, distributed energy resources and network support services, and introduces new incentives to improve the efficiency of our capital investments as part of a continuous effort to strike the appropriate balance between capital cost incentives and operations and maintenance cost incentives.

These four principles complement our core commitment to the safe, reliable, and affordable delivery of energy services. Importantly, they also align closely with the state’s goals for Power Sector Transformation and, taken as a whole, reflect the changing role of the utility in the context of this transformation. As we work with policy makers, regulators, and stakeholders to refine and execute our plan, these principles also serve as useful ‘guardrails’ for staying on track to deliver the outcomes we seek for our customers and the state as a whole.

## **4. POWER SECTOR TRANSFORMATION BUILDS ON A FOUNDATION OF ENERGY INNOVATION**

Rhode Island has already made great strides in combining policies and legislation—for the energy industry as a whole, and for specific sectors—with proactive, purposeful efforts to engage interested stakeholders on key regulatory issues.

Recent years have seen a surge in innovative state-level policies, such as “Energy 2035,” the “Rhode Island Renewable Thermal Market Development Strategy,” the “Zero Emission Vehicle Action Plan,” and the “City of Providence Executive Order,” which together create a new framework for transforming Rhode Island’s energy landscape. This framework is unique in the country in that it addresses carbon commitments on a statewide and economy-wide basis, and is overlaid with sector-specific policies designed to ensure that the transportation and heat sectors

play their part. State policy makers are demonstrating genuine commitment to a clean and sustainable future.

In support of these efforts, the Rhode Island Division of Public Utilities and Carriers (The Division), Rhode Island Public Utilities Commission (PUC), and Office of Energy Resources (OER) have worked to bring together interested parties from within and outside Rhode Island to align utility regulation with the state's clean energy objectives. This means examining and adjusting the complex regulatory and legislative frameworks that exist today in an effort to remove barriers, create clarity on desired outcomes for customers, and develop a more dynamic regulatory framework for the future. Significant progress has been made through forums such as the Energy Efficiency Resource Management Council, Distributed Generation Board, System Integration Rhode Island and proceedings such as Docket 4600.

Building from that foundation, in March 2017 Governor Gina Raimondo laid out a new challenge: to create "a more nimble electric grid that can strategically integrate clean energy resources and enable Rhode Islanders to take advantage of new clean energy technologies." The state's initiative in response to this challenge became known as Power Sector Transformation. Stakeholders to the Power Sector Transformation effort have addressed a series of questions related to utility business models, beneficial electrification, connectivity, and distribution system planning. Published in November 2017, the state's "*Rhode Island Power Sector Transformation, Phase One Report to Governor Gina M. Raimondo*" (hereafter the PST Phase One Report) sets out goals and recommended actions for consideration in 2018.

National Grid has played an important and active role in all of these efforts, and most recently has worked very closely with state agencies and other parties to inform the Power Sector Transformation process. The Company is directionally well aligned with the state on many of the recommendations arising from that work and looks forward to ongoing stakeholder participation and input to inform and support achievement of our shared power sector transformation goals.

Transforming Rhode Island's power sector is a journey that must be undertaken in a thoughtful and strategic manner. It has the potential to create significant benefits for customers but these benefits cannot be realized without thoughtful investment today. Pace and momentum will be critical to success and must be carefully balanced with the Company's responsibility to create value and manage overall cost to customers. With this in mind, the Company is pleased to present a robust and balanced Vision and Implementation Plan that represents its initial three-year plan to further power sector transformation in Rhode Island.

## **5. STRUCTURE OF THE PLAN**

Chapter Two: Summarizes the Company's Plan and how its proposals advance the state's goals for a new electric system

Chapter Three: Proposes specific investments as part of the next phase of grid modernization in Rhode Island

Chapter Four: Sets out the Company's proposal to deploy advanced metering functionality (AMF) for customers in Rhode Island.

Chapters Five, Six, and Seven: Outline a portfolio of clean energy investments in electric transport, electric heat, and energy storage

Chapter Eight: Develops proposals for income eligible customers

Chapter Nine: Describes a new performance incentives designed to incentivize utility innovation and focus in delivering outcomes that customers' value

Chapter 10: Estimates the revenue requirement associated with proposed investments in years one, two, and three of the plan and recommends a new cost recovery mechanism, the PST Provision.



Schedule PST - 1,  
Chapter 2 - 4600 Goals/Framework

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## CHAPTER TWO: ADVANCEMENT OF STATE GOALS AND BENEFIT CREATION

### 1. INTRODUCTION

*“By ensuring the **resiliency, efficiency, and openness** of the electric distribution grid today and for the future, we will create a powerful platform for **empowering our customers and supporting the transition to an affordable, sustainable clean energy system for Rhode Island**”*

Delivery of the Company’s vision for power sector transformation in Rhode Island (set out above) will require a holistic, rigorous, and structured approach over a number of years. The Company’s Plan is prioritized and sized to ensure tangible progress toward this vision, recognizing the need to accelerate value creation balanced against bill impacts for customers.

The Company’s four guiding principles of customer empowerment, resiliency and efficiency, transition to a clean energy future, and effective performance incentives have informed the creation of the Plan. The April 2015 *Docket 4600 Stakeholder Working Group Process Report to the Rhode Island Public Utilities Commission*<sup>1</sup> (hereafter Docket 4600) has provided additional direction in the form of clear goals for the electric system in Rhode Island and a framework for evaluating the costs and benefits of proposed investments.

Consistent with *The Public Utilities Commission Guidance on Goals, Principles and Values for Matters Involving the Narragansett Electric Company d/b/a National Grid*<sup>2</sup> (hereafter Docket 4600 guidance), this chapter summarizes where the Company’s proposals are expected to advance the goals set out in Docket 4600 and explains how the Company has evaluated the costs and benefits of its proposals, using the framework set out in Docket 4600, along with a report by the US Department of Energy (DOE) titled *Modern Distribution Grid: A Decision Guide Volume III*<sup>3</sup> (hereafter DOE report). Chapters three, four, five, six and seven of the Plan provide more detail on the advancement of state goals and the evaluation of program costs and benefits.

Investments proposed in the Company’s Plan build on investments funded via existing mechanisms including base rates and the infrastructure, safety, and reliability (ISR) plan. Given the scale of the transformation required and the pace of industry change, the Company proposes a new cost recovery tariff, similar to the ISR, that enables plans to be submitted by the Company annually for approval by the Commission. Chapter Ten of the Plan sets out the cost recovery mechanism and tariff. It also provides the revenue requirement for the period Sept 1 2018 to March 31 2019, and illustrative revenue requirements for the fiscal years 2020, 2021 and 2022.

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<sup>1</sup> See Stakeholder Working Group Process Report, issued in Rhode Island Docket number 4600, April 5 2017: [http://www.ripuc.org/eventsactions/docket/4600-WGReport\\_4-5-17.pdf](http://www.ripuc.org/eventsactions/docket/4600-WGReport_4-5-17.pdf)

<sup>2</sup> See Docket 4600-A Guidance Document, October 27 2017: <http://www.ripuc.org/eventsactions/docket/4600A-GuidanceDocument-Final-Clean.pdf>

<sup>3</sup> See Modern Distribution Grid: A Decision Guide Volume III, issued by Department of Energy Office of Electricity Delivery and Energy Reliability, June 28 2017: <http://doe-dsp.org/wp-content/uploads/2017/06/Modern-Distribution-Grid-Volume-III.pdf>

## 2. ADVANCING DOCKET 4600 GOALS

Docket 4600 articulates several distinct goals for the electric system in Rhode Island:

- i. Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels);
- ii. Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures;
- iii. Address the challenge of climate change and other forms of pollution;
- iv. Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits;
- v. Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society;
- vi. Appropriately charge customers for the cost they impose on the grid;
- vii. Appropriately compensate the distribution utility for the services it provides;
- viii. Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.

These goals have been critical to the development of the Plan, providing a reference against which to evaluate programs individually and as a portfolio. For each proposed investment included in the Plan, the Company includes an explanation of how that investment advances, detracts from, or is neutral with respect to the achievement of the state's goals for a new electric system. Table 2-1 summarizes where the Company's proposals are expected to advance those goals.

**Table 2-1: Proposals in the Plan that are expected to advance Docket 4600 goals**

<b>GOALS FOR “NEW” ELECTRIC SYSTEM</b>	Modern Grid	AMF	Electric Transport	Electric Heat	Storage	Solar	Income Eligible
Provide reliable, safe, clean, and affordable energy	Y	Y	Y	Y	Y	Y	Y
Strengthen the Rhode Island economy	Y	Y	Y	Y	Y	Y	Neutral
Address climate change and other forms of pollution	Y	Y	Y	Y	Y	Y	Y
Prioritize and facilitate increasing customer investment in their facilities	Y	Y	Y	Y	Y	Y	Neutral
Appropriately compensate distributed energy resources	Y	Y	Y	Y	Y	Neutral	Neutral
Appropriately charge customers for the cost they impose on the grid	Y	Y	Y	Neutral	Neutral	Neutral	Y
Appropriately compensate the distribution utility	Neutral	Y	Y	Neutral	Neutral	Neutral	Neutral
Align distribution utility, customer, and policy objectives and interests	Y	Y	Y	Y	Neutral	Neutral	Y

**3. EVALUATING COSTS AND BENEFITS OF PROPOSALS INCLUDED IN THE PLAN**

The Company’s Plan proposes a broad suite of investments to respond to the impact of decentralization, decarbonization, and digitization. These investments include grid-side investments to enable distributed energy resources (DER), deployment of advanced metering functionality (AMF), beneficial electrification programs in transportation and heating, and investments in energy storage and solar. While all of these investments fall under the umbrella term “grid modernization,” the differing nature of the investments warrants a different benefit-cost evaluation approach in each case.

The U.S. Department of Energy is working with state regulators, the utility industry, energy services companies and technology developers to determine the functional requirements for a modern distribution grid that are needed to enhance reliability, resiliency and operational efficiency, and integrate and utilize DER. The Modern Distribution Grid Report is a three-volume set that is intended to develop a consistent understanding of requirements to inform investments in grid modernization. Volume III of the DOE Report is a “Decision Guide” that



presents considerations for the rational implementation of advanced distribution system functionality.

As discussed in the DOE report, there is an identified need for a common framework for evaluating costs and benefits associated with grid modernization investments. Developing such a framework is complex due to the various uses of these investments and the different approaches that can be taken to implementation<sup>4</sup>.

The DOE report allocates investments in a modern grid into four categories, where each category is treated differently for purposes of evaluating benefits and costs. The DOE categories are:

**Category 1—Traditional Utility Infrastructure Investments.** This category includes grid expenditures to replace aging infrastructure, new customer service connections, relocation of infrastructure for roadwork or the like, and storm damage repairs.

**Category 2—DER Enabling Investments.** This category includes grid expenditures that are required to maintain reliable operations in a grid with much higher levels of DER connected behind and in front of the customer meter; these expenditures may be socialized across all customers.

**Category 3—DER Integration Investments.** This category includes grid expenditures that enable public policy objectives and/or provide incremental system and societal benefits to be paid by all customers.

**Category 4— Self-Support or Direct Charge Investments.** This category includes expenditures that will be paid directly by customers who participate in DER programs via a self-supporting, margin-neutral, opt-in DER tariff, or as part of project-specific incremental interconnection costs, for example.

The proposed treatment of the categories is as follows:

**Categories 1 and 2: A *best-fit/least-cost assessment*** is the most practical approach to evaluating traditional utility infrastructure and core platform investments. This includes investments in:

- Planning tools and models
- Physical infrastructure (e.g., wires, transformers, switches, etc.)
- Advanced protection and controls
- Sensing and situational awareness
- Operational communications

For investments in this category, the first step is to assess the “fit” against the “need” with respect to pre-determined customer and policy objectives. This best-fit assessment is applied to grid technology solutions to narrow the potential options. Afterwards, the least-cost option can be identified through various means. Most typically, this determination is the result of a competitive procurement, although states have varying approaches to assessing least-cost, best-fit options, which may also be assessed in terms of expected cost and risk.

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<sup>4</sup> See Modern Distribution Grid: A Decision Guide Volume III, p39, Section 3.4.1 Cost-Effectiveness Framework

**Category 3:** Where the benefits of DER deployment are being directly considered in the evaluation of project alternatives or other investments that integrate DERs into the power system, *a societal benefit-cost analysis* may be useful to evaluate the cost-effectiveness of certain grid investments in relation to the value potential from enabling customer DER integration and/or DER utilization.

**Category 4:** For work charged directly to customers or DER developers, there is no need to go through a benefit-cost assessment as the *customer will determine if there are sufficient benefits* before providing a contribution in aid of construction (CIAC) payment for the agreed work.

The DOE report was developed in collaboration with state regulators, the utility industry, energy services companies, and technology developers; National Grid support the findings of the report as it relates to evaluation of grid modernization costs and benefits.

As such, grid-side investments to enable DER (presented in Chapter 3), are recommended based on a best-fit/least-cost assessment. Proposals are presented with conceptual cost estimates; a competitive procurement process will be used to ensure that project needs are addressed at the lowest cost possible prior to commencing work.

Proposals relating to AMF deployment, beneficial electrification programs in transportation and heating, and investments in storage and solar have more quantifiable benefits that can be assessed through a detailed benefit-cost analysis. For these investments, the Company has developed a Rhode Island specific benefit-cost analysis (BCA) methodology consistent with the state's Docket 4600 guidance. Further details on the Rhode Island methodology are provided in the section that follows.

#### **4. BENEFIT-COST ANALYSIS USED IN RHODE ISLAND**

National Grid, in collaboration with KPMG LLP, and in discussion with the Rhode Island Division and Tim Woolf, developed a Rhode Island specific BCA methodology to evaluate many of the investments proposed in this Plan.

In developing the methodology, the Company took a multifaceted approach that leveraged guidance provided in the Rhode Island Docket 4600 Benefit Cost Analysis Framework, including the benefit and cost categories included in Appendix 2.1. Vetted BCA models from the Company's Massachusetts and New York operating companies were also reviewed to identify project value drivers and evaluate their relevance to the projects proposed for Rhode Island. Lastly, this approach integrates already well-established assumptions and methodologies relied on for energy efficiency program BCAs in Rhode Island. Avoided energy, capacity, RECs, and environmental compliance and externality cost values, as well as wholesale market price impact assumptions and general methodology for their application were taken from the Avoided Energy Supply Costs (AESC) in New England: 2015 Report<sup>5</sup>. The AESC study is

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<sup>5</sup> The AESC 2015 Report was sponsored by a group of electric utilities, gas utilities, and other efficiency program administrators including National Grid (collectively, "program administrators"). The sponsors, along with non-utility parties and their consultants, formed an AESC 2015 Study Group to oversee design & execution of the report

sponsored and overseen by a group of New England electric and gas utilities, other efficiency program administrators, non-utility parties, and consultants, and is used by the Company and other utilities throughout New England to evaluate energy efficiency programs.

Principles of consistency, transparency, and flexibility were applied in developing the BCA methodology. As such, benefits and costs have been calculated consistently, using the same methodologies and assumptions across all projects.

The Company tested the cost-effectiveness of each category three proposal using a societal cost test (SCT) and also has included results of a ratepayer impact measure (RIM) to present the monetary benefits to all customers relative to associated costs. In particular, the RIM calculation is of interest when evaluating the electric vehicle and electric heat proposals as the RIM captures increases in utility revenue that can ultimately reduce costs to ratepayers but that would not be reflected in a societal cost test.

BCA results, and associated benefit and cost categories and values, are presented in Chapters Four, Five, Six, Seven and Eight, for the AMF, electric transportation, electric heat, storage, and solar programs respectively.

In addition to a quantitative evaluation of benefits and costs, the Plan also includes discussion of qualitative benefits for each project—for example, to identify benefits that are difficult or impossible to quantify or monetize given currently available data and methods. For simplicity and consistency these non-quantifiable benefits have been summarized under the headings societal, economic, educational, and environmental benefit. Where relevant, the Plan also discusses benefits that fall outside the scope of the defined cost tests<sup>6</sup>. In the case of the proposed AMF program, the Company also identifies a number of potential synergies / coordination benefits that were considered outside the scope of this analysis at this time, but that could become relevant as AMF is deployed, stabilizes, and matures.

*A note on economic development benefits:* The Docket 4600 BCA framework includes consideration of economic development benefits and notes that such benefits can be reflected via a qualitative assessment or, alternatively, can be quantified through detailed economic modelling. For the purposes of the Plan, the Company undertook an initial qualitative assessment of economic development benefits, and also worked with KPMG to undertake a relatively high-level quantification exercise. The values calculated in that analysis have not been included in the cost tests as they are large and create a “masking” effect that makes it more difficult to properly evaluate the investments on their own merits. Significantly more work would be required to more accurately model the impacts of the programs and to ensure no double counting / overlap with other cost tests. Appendix 2.2 provides an overview of the methods and assumptions used to analyze economic development and the resulting values for each program, for consideration as part of a holistic evaluation of benefits and costs.

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<sup>6</sup> For example, an investment may result in a desirable social or economic impact that represents a net transfer within the economy and is therefore not included in the SCT.



Schedule PST - 1,  
Chapter 3 - Modern Grid

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**CHAPTER THREE: INVESTMENT IN A MODERN GRID**

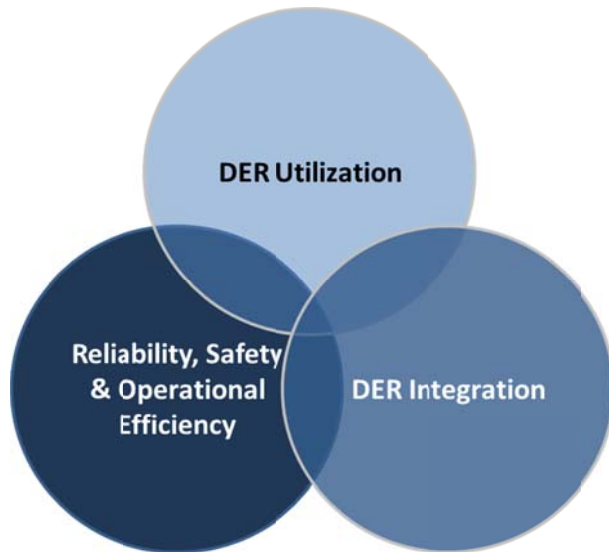
**1. INTRODUCTION**

The one way electric power system, designed to deliver electricity generated at large central power plants through transmission lines and distribution networks to serve customers’ instantaneous energy needs at their individual premises, has served utility customers and the economy well for decades. However, advances in technology, changing customer needs, and public policy related to resource diversity, clean energy, and system efficiency are changing the way the grid is used and the demands that are placed on it.

The U.S. Department of Energy (DOE), in its recent report, *Modern Distribution Grid: A Decision Guide Volume III*<sup>1</sup>, notes that:

*Together, these changes are driving the need for grid modernization across three dimensions: 1) reliability, resiliency, safety and operational efficiency, 2) integration of DER, and 3) DER utilization for bulk power system and / or distribution operational services or infrastructure deferral. Investments may be primarily associated with one of the three dimensions, but also enable functions in the other two.*

**Figure 3-1: Dimensions of a Modern Grid**



The concept of multiple dimensions of grid modernization is not new to Rhode Island. Through the System Integration Rhode Island (SIRI) working group and Docket 4600 “Investigation Into the Changing Distribution System”, the state has clearly articulated objectives in relation to resiliency and efficiency, distributed energy resource (DER) integration, and investment deferral.

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<sup>1</sup> U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability, “Modern Distribution Grid, Decision Guide, Volume III”, June 28, 2017. Available at: <http://doe-dsp.org/sample-page/modern-distribution-grid-report/>.

Most recently, through Power Sector Transformation, state agencies have recognized the impacts of grid modernization on both planning and operations, and have developed further principles and recommendations to guide the transition:

*The emerging complexity of distribution grid power flows now needs real-time situational awareness to keep the lights on, increase renewable energy usage, and minimize procurement and distribution costs for ratepayers. Technologies are required that can (1) exchange information between all generating and consuming energy resources; (2) perform system-management using programmable controls; (3) integrate data from ubiquitous sensors and computer-based analytics; and (4) interface with increasingly intelligent devices within the home to help system operators manage peaks. The underlying foundation beneath all of these capabilities is network connectivity.<sup>2</sup>*

Grid modernization is also not new to National Grid. National Grid USA (National Grid) and its affiliates have engaged in grid modernization discussions through initiatives in both Massachusetts and New York. Our experience in those states has informed the Company's proposals for Rhode Island, and, where their goals and objectives are consistent, our proposed investments in all three jurisdictions are consistent. A coordinated deployment of certain investments in which system synergies can be achieved could produce significant cost savings for customers; thus, for the purposes of this Plan, we highlight the cost (where relevant) of making investments solely for Rhode Island, while also presenting a view that highlights potential synergies if investments are made in the Company's New York affiliate on a consistent timeframe<sup>3</sup>. The customer benefits that could be realized from rolling out grid modernization in more than one jurisdiction have informed our proposed cost recovery mechanism for power sector transformation.

The definition and scope of 'grid modernization' is broad and has implications for customers, DER providers, and the Company as grid owner and operator. National Grid's view of and plans for grid modernization align with the DOE Report, which was developed in collaboration with state regulators, the utility industry, energy services companies, and technology developers. The DOE report lays out the functional requirements of a modern distribution grid that are needed to enhance reliability and operational efficiency and integrate and utilize distributed energy resources, and serves as a useful reference to illustrate the Company's proposed approach to grid modernization in Rhode Island.

There are several functional areas in which the Company is already delivering enhanced capabilities that are featured as part of grid modernization, and a number of areas the Company proposes to move forward on as part of the plan. Figure 3-2, which is adapted from the DOE Report, is color coded to depict different phases of our proposal for grid modernization in Rhode Island. The blue elements represent areas where the Company is already implementing grid modernization investments that have previously been included in the Company's infrastructure,

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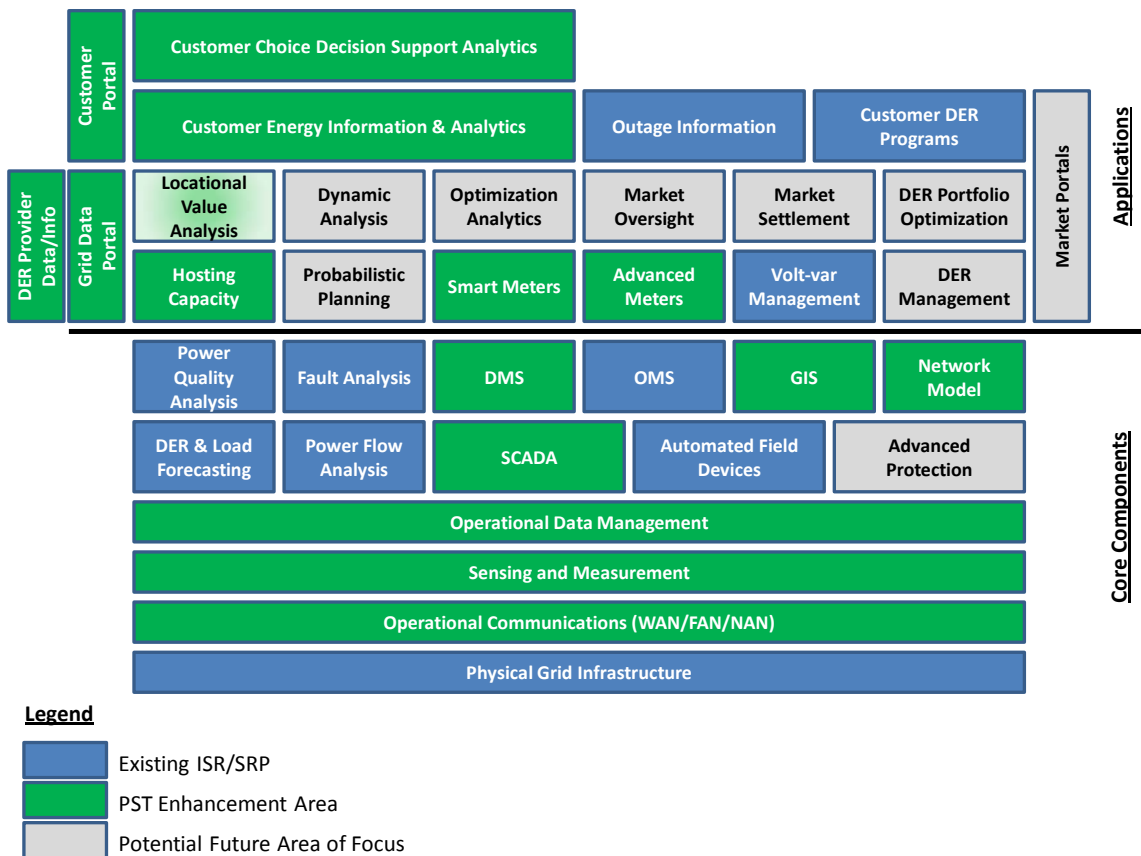
<sup>2</sup> Rhode Island Division of Public Utilities and Carriers, "Grid Connectivity and Meter Functionality Principles and Recommendations", October 13, 2017.

<sup>3</sup> The Company has chosen to analyze the potential synergies of a Rhode Island / New York deployment due to the likely alignment in deployment timeframes.

safety, and reliability (ISR) annual plans. By contrast, green elements represent areas of focus for near-term activities included in this Plan and gray elements represent possible future enhancements, the timing of which will be influenced by the pace of DER integration and the development of new market-based products and services.

It is worth noting that while this color scheme helps to illustrate when new functionalities will be introduced, each functionality or application will continue to evolve over multiple years with respect to level of penetration and advanced capabilities.

**Figure 3-2: Grid Modernization Project Proposals for Rhode Island**



The primary focus of this Plan is on the functionalities shaded in green. However, a brief discussion regarding the on-going activities shaded in blue is also presented for completeness. The areas shaded gray describe longer-term modernization opportunities, which may warrant future action depending on the degree of DER development and the evolution of new products and services. These areas are beyond the scope of this Plan.



## **2. ON-GOING GRID MODERNIZATION ACTIVITIES**

### **2.1 Physical Grid Infrastructure**

The physical grid will continue to be necessary to connect customers with the cost-effective electric power they need. However, the existing grid infrastructure is aging and a well thought-out grid modernization strategy may foster the efficient implementation of new functionalities necessary to operate in environments with high penetration of DER. An integrated grid may provide the interconnections necessary for customers to enjoy reliable power, in an efficient manner, utilizing a wide range of local and remote generating sources. To the extent possible, the Company's infrastructure projects will take advantage of the latest proven technologies and will be integrated with various grid modernization elements proposed in this Plan if approved by the PUC.

### **2.2 Automated Field Devices**

Electronic reclosers can be used to interrupt fault currents and automatically restore service after momentary outages. The Company has been deploying electronic reclosers for many years to enhance reliability. The majority of these reclosers are equipped with cellular communications that permit remote monitoring and control. In addition, the Company is now providing remote monitoring and control of "smart grid" devices (i.e., capacitor banks, voltage regulators voltage monitoring devices) through its volt-var optimization (VVO) program. VVO uses these smart grid devices, AMF (if available), and optimization software to optimally managing distribution level voltage and reactive power to reduce system losses, peak demand, and/or energy consumption. These smart grid devices are also integrated with the Company's Supervisory Control and Data Acquisition (SCADA) system for monitoring and control by system operators.

### **2.3 Power Flow Analysis and Fault Analysis**

The Company's distribution planners utilize a number of power flow analysis software tools to perform long-term system planning, fault and protection analysis, and interconnection studies. Currently, the network models used in this suite of tools tend to be manually created for the specific individual studies they support.

### **2.4 DER & Load Forecasting**

As part of its distribution system planning process, the Company develops a 15-year peak demand forecast. The forecast considers econometric variables that will influence load growth, as well as state policy objectives that will influence DER adoption. This load and DER forecast forms the basis of future distribution system planning capacity evaluations and associated capital investment recommendations.

### **2.5 Power Quality Analysis**

The Company strives to continuously deliver power within defined service quality standards and to respond to identified deviations from those standards in a timely fashion. New technologies, such as intermittent DER, can create new power quality challenges, but new technologies such as power electronic voltage regulators and smart inverters also offer new tools for addressing power

quality issues. The Company will continue to utilize new technologies, including those being introduced in this plan, to analyze and deliver power within service quality standards.

## **2.6 Outage Management System and Outage Information**

The Company utilizes a state of the art outage management system (OMS) as part of its suite of tools in the operations control center. This system receives and analyzes customer interruption and trouble calls, predicts or confirms the extent of an outage, and tracks restoration efforts. In near real time, OMS information is presented for public review and query via the “Outage Central” application on the Company’s website.

## **2.7 Volt-var Management**

Enhanced volt-var optimization (VVO) benefits customers by reducing demand and energy use through conservation voltage reduction (CVR). The Company recently completed an initial VVO/CVR deployment on seven feeders in the Putnam Pike and Tower Hill areas. Results on this pilot project exceeded the anticipated 3% reduction in energy and peak demand on the targeted feeders. Customer benefits are realized through reduced commodity costs for energy and demand, which result in lower bills. Deployment on an additional 40 feeders is planned, through the Company’s future ISR Plan filings, over the coming four years based on these initial positive results.

## **2.8 Customer DER Programs**

The Company continues to screen all transmission and distribution needs to assess the feasibility of implementing non-wires alternative (NWA) solutions when the projects are initiated. When a future need is identified, the Company conducts a detailed analysis so that potential solutions (both wires and non-wires) can be conceptualized and compared. If the Company determines that a NWA solution is feasible, it is fully developed and then proposed through the system reliability procurement (SRP) report. After a NWA project is initiated DER providers are invited to propose solutions for either all or a portion of the peak MW reduction target. In the 2012 SRP Report Supplement<sup>4</sup>, a NWA load curtailment pilot project was proposed in Tiverton and Little Compton, Rhode Island. Recently, in the 2018 SRP Report<sup>5</sup>, the Company proposed a new NWA project called the Little Compton Battery Storage Project, which includes a 1,000kWh/250kW (continuous) battery storage system that would be installed in Little Compton for peak load relief. Both the initial pilot and the proposed project are intended to defer the \$2.9 million cost of a substation upgrade. The Company will continue to analyze its current NWA screening and development processes to determine how customer DER programs might be best considered as complete or partial solutions.

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<sup>4</sup> The Narragansett Electric Company dba National Grid, “2012 System Reliability Plan Report - Supplement”, February 1, 2012. RIPUC Docket No. 4296.

<sup>5</sup> The Narragansett Electric Company dba National Grid, “2018 System Reliability Procurement Report”, November 1, 2017. RIPUC Docket No. 4756.

### 3. NEW GRID MODERNIZATION ACTIVITIES IN THE PLAN

While the Company has taken steps towards grid modernization as discussed above, higher levels of DER penetration warrant a transformational change in grid capabilities; therefore, this Plan proposes investment in several new areas. The elements shaded green on the chart in Figure3-2 represent key grid modernization elements that comprise seven new investment areas proposed in this Plan:

1. **System Data Portal**—DER provider data/information, grid data portal, locational value analysis, hosting capacity
2. **Advanced Metering Functionality**—customer portal, customer choice decision support analytics, customer energy information and analytics, smart meters, advanced meters.
3. **Feeder Monitoring Sensors**—sensing and measurement
4. **Control Center Enhancements**—Distribution Management System, GIS, network model, SCADA
5. **Operational Data Management**
6. **Telecommunications**—operational communications
7. **Cybersecurity**

The sections that follow provide a discussion of these new investment areas. Workpapers 3.1 and 3.2 provide additional detail on the costs for each investment, both in a Rhode Island only deployment scenario and in a multi jurisdiction deployment scenario where the Company has considered the potential synergies available from deploying systems in alignment with its affiliates in New York or Massachusetts.

#### 3.1 System Data Portal

DER providers desire access to transparent system data to facilitate the integration of DER into distribution system planning and operations. To facilitate the sharing of information with DER providers, and others, the Company is proposing to develop a system data portal and populate it with information intended to facilitate DER integration in the most advantageous locations and as cost-effectively as possible. The system data portal will be a web-based application that provides relevant distribution planning information and distribution system data that have been identified to be of interest by DER providers and other interested parties during power sector transformation stakeholder engagement and similar work in National Grid's New York jurisdiction.<sup>6</sup> The portal will provide access in one common location for documents such as

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<sup>6</sup> For example, as part of their written comments to the PST Distribution System Planning work stream, the Northeast Clean Energy Council (NECEC) and Advanced Energy Economy Institute (AEE Institute) stated "A well-designed data portal, developed iteratively with increasing automation, can provide a valuable conduit for information – making it available to solution providers and customers, and enabling the utility to incorporate third party solutions and customer choices into distribution system planning." and "The portal could ultimately help to accelerate collaboration between utilities and solutions providers to address areas of greatest interest and economic value." (NECEC and AEEI Letter; Re: Initial Proposals for Distribution System Planning Improvements and Request for Stakeholder Comment; September 1, 2017)

regulatory filings, load and DER forecasts, and distribution planning criteria. In addition, system data, such as circuit loading, hosting capacity analysis, and heat maps of beneficial DER locations, will be provided via interactive geographic maps. The functionality and the look and feel of the portal will be similar to a system data portal recently deployed in National Grid's New York jurisdiction. Although utilization details continue to evolve in New York, best practices and lessons learned will be used to refine efforts in Rhode Island to the furthest extent possible.

DER developers are the target audience for the system data portal. Through a series of stakeholder discussions in Rhode Island DER developers have expressed an interest in using system data to improve planning efforts associated with efficiently deploying their products and services. Moreover they have noted transparency concerning distribution system planning processes, system needs, DER opportunities, and pertinent data to inform potential interconnection requirements as key.

The need for a system data portal has been the topic of considerable stakeholder engagement within the distribution system planning working groups of the power sector transformation initiative. There is general consensus among Rhode Island stakeholders that such a portal would provide benefits and advance the objectives of integrating additional clean energy generation in a cost-effective and timely manner. DER providers have stated that information such as hosting capacity analysis facilitates the siting of new resources by identifying areas where DERs can be integrated without the need for costly system upgrades and extended interconnection timelines. Similarly, identifying areas of the grid that may become constrained in the future will help DER providers develop potential non-wires alternatives or deploy DERs that can defer distribution system upgrades if appropriately designed. This information could also be used to direct strategic electrification facilities, such as electric vehicle charging stations, to lightly loaded areas. The Company considers the system data portal to be a foundational investment for advancing Rhode Island's clean energy policies.

The content of the system data portal is expected to grow and evolve over time as new tools, data, and analysis are developed. Initially, public and other readily available data and reports will be hosted in a common location for easy web access. In concert with the creation of the portal, the Company is proposing to begin developing detailed assessments of hosting capacity and capacity constraints. The results of these assessments will be posted on the portal in the form of interactive heat maps. While striving for transparency, all data and information that are to be posted on the system data portal will be presented in a fashion that does not present physical security or cybersecurity concerns and that protects the privacy of customer information. Stakeholder engagement is essential to ensure that the system data portal is effective and the Company will continue to work with stakeholders to consider future enhancements.

### Project Cost Estimates

Experience with developing the New York System Data Portal indicates that the labor to develop and maintain the information posted on the portal is the major cost component. The most demanding tasks involve creating hosting capacity analysis and capacity constraint heat maps. Estimates of the resources required to perform these assessments are based on similar work in

progress at National Grid’s New York affiliate. As this is incremental work beyond traditional distribution system planning, the Company plans to hire additional engineers and analysts to manage the portal. The anticipated additional resources include two distribution planning engineers and one analyst and represent \$690,000 of the estimated increment in annual O&M costs. Software and data hosting costs for the initial functionalities of the portal are approximately \$10,000 annually. To begin work on the portal as soon as possible, \$80,000 has been proposed in the SRP 2018 Report. The system data portal proposal within the SRP 2018 Report reflects an initial one-year effort and only limited mapping functionality.

The estimated cash flow requirement for implementing the system data portal is presented in Table 3-1. The costs are primarily for FTEs that will be fully utilized completing RI analysis and therefore cannot be shared with other jurisdictions. The Company proposes to recover these costs through the PST Provision presented in Chapter 10.

**Table 3-1: System Data Portal Cash Flow Estimate**

System Data Portal Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ -	\$ -	\$ -	\$ -
O&M	\$ 0.08	\$ 0.70	\$ 0.70	\$ 0.70	\$ -
<b>Total</b>	\$ 0.08	\$ 0.70	\$ 0.70	\$ 0.70	\$ -

### 3.2 Advanced Metering Functionality

Advanced metering functionality (AMF) can provide customers with enhanced understanding, choice, and control over their electricity consumption. This functionality also provides a wealth of information to support the more efficient operation of the distribution system. The modern grid functionalities that will be advanced through the Company’s AMF program include customer portals, customer choice decision support analytics, customer energy information and analytics and smart meters / advanced meters. A detailed discussion of the Company’s AMF program and the associated business case is provided in Chapter 4.

### 3.3 Feeder Monitoring Sensors

Without remote interval monitoring, loading information at substations and feeders is only captured during routine maintenance and inspection cycles, or if personnel are specifically dispatched to capture data necessary for grid operations. The dynamic impacts of DER on distribution system performance require a more granular understanding of situational awareness to assure service is maintained within acceptable service quality standards. In addition, without a granular level of monitoring at the feeder level, operators and distribution system planners have no choice but to make conservative assumptions with respect to the coincidence of load and DER generation. This can lead to restricted hosting capacity assessments and less optimal operational actions.

In recent years, sensing technology has advanced significantly. There are now several options for “clamp-on” wireless primary distribution feeder monitors for overhead circuits. The Company is considering feeder monitors that use advanced technology and avoid separate communications wiring, power supply wiring, or voltage reference cabling. These feeder monitors clamp into the

primary conductors (individually) and wirelessly communicate to a control box located on a nearby pole. The sensors the Company plans to use will monitor voltage, power, and harmonic content and will be integrated with the SCADA system for immediate use in system operations. The recorded data will be stored for future distribution system planning, interconnection studies, and hosting capacity assessments.

Project Cost Estimates

The Company has been deploying remote interval monitoring and control for new substations and feeders for several years. However, its existing distribution system still has 133 feeders (35%) without interval power measurements or the ability to monitor performance remotely. Therefore, the Company proposes to install feeder monitoring sensors on approximately 26 feeders per year over the next five years at a cost of approximately \$17,500 per feeder. The Company expects to begin this program in FY20 with an average capital expenditure (CAPEX) of \$455,000 each year. The Company’s grid monitoring objective is to have interval data at the feeder level available for all its circuits by 2024.

The estimated cash flow requirement to implement this plan for installing feeder monitoring sensors is presented in Table 3-2. Note that this is a physical infrastructure cost and cannot be shared with other jurisdictions, so cost synergies cannot be realized by coordinating across the operating companies. The Company proposes to recover these costs through the PST Provision presented in Chapter 10.

**Table 3-2: Cash Flow Estimate for Feeder Monitoring Sensors Project**

<b>Feeder Monitoring Sensors Cash Flow, \$M</b>	<b>FY19</b>	<b>FY20</b>	<b>FY21</b>	<b>FY22</b>	<b>FY23</b>
CAPEX	\$ -	\$ 0.46	\$ 0.46	\$ 0.46	\$ 0.46
O&M	\$ -	\$ -	\$ 0.01	\$ 0.01	\$ -
<b>Total</b>	\$ -	\$ 0.46	\$ 0.46	\$ 0.47	\$ 0.46

**3.4 Control Center Enhancements**

The core mission of the Company’s Control Center’s has been to ensure electric system reliability and safety through monitoring, operational actions, and outage response. Increasingly, distribution grid operators are playing a role in optimizing the distribution system in a more dynamic fashion, including proactive monitoring of intelligent electric devices, balancing multiple sources of load or generation, and dynamically assessing outages and restoration options to minimize customer interruption impacts. As the penetration of DERs continues to increase, DERs can be leveraged to play a more active role in managing the distribution system. However, this requires enhanced operational situational awareness to maintain reliability and safety on the distribution system. As operating the system becomes for complex, more sophisticated central management systems are needed to monitor and coordinate remote distribution automation servers/devices, communicate to the edge of the distribution grid, and collect data from grid edge devices.

The management of a more dynamic distribution system will significantly change the Company’s role as operator, as depicted in the table below.

**Table 3-3: The Changing Role of the Distribution Control Center**

<b>Today – Keep the Lights On</b>	<b>Tomorrow – Optimize the Platform</b>
Paper schematic maps and manual cross-reference to GIS as needed	As-operated network model in easy-to-use geographic and schematic electronic interface
SCADA communicating to substations with no or limited quantity feeder devices	Extensive SCADA “outside the substation” for communicating with numerous feeder devices
Very limited visibility into feeder electrical state, including DER	Monitoring, state estimation, and load flow provide improved visibility, including DER
Single real power source to manage	Multiple real power sources to manage
Manually-created switch orders	Switch orders generated automatically or with assistance from ADMS
Outage prediction most often based on customer interruption calls	Outage prediction enhanced with AMF and SCADA devices
Limited historic electrical data that require significant effort to bring value	Historic data on electrical state and system configuration easily accessed by planners, engineering and design, and operations
Minimal short-term load forecasting for use in planned switching	More extensive short-term load and DER forecasting in distribution operations
Limited advanced applications to assist in maximizing performance	ADMS applications improve volt/var control, reliability, and equipment utilization
Deliver power	Enable customer electric power choices and markets

### 3.4.1 *Distribution Supervisory Control and Data Acquisition (DSCADA)*

The primary role of the DSCADA system is to collect data from intelligent electronic devices on the distribution network for use in distribution management system (DMS) simulations and optimization applications. The DSCADA system also transmits commands, settings, and other operational functions to intelligent electronic devices in the field. The DMS provides engineering-focused applications that can either assist in the operations of the distribution network, or automatically monitor and control devices on the distribution network. The Company does not currently operate a DMS.

The Company currently maintains a SCADA system that supports both transmission and distribution (T&D) monitoring and control points and an energy management system that provides network applications primarily for transmission system operations. Substation and line

data are acquired from the T&D substation remote terminal units<sup>7</sup> (RTUs) and distribution pole-top reclosers. In addition to status, the system also provides monitoring, control, and alarming for system limits pertaining to voltage, real, and reactive power, as well as other system parameters.

The rate at which new monitoring and control points are being added to the SCADA system is growing by more than 7% per year due to the increasing number of distribution points being created for distribution automation and the interconnection of large DER facilities. As the SCADA system approaches its capacity, the speed and performance of the system degrades. Also, combining transmission and distribution data in a common system creates data security challenges with respect to bulk transmission requirements and increases expectations for access to distribution system data.

To address these challenges, the Company and its affiliates have developed a roadmap for delivering the control center technology capabilities that will be needed in the future. The roadmap is depicted in Figure 3-3. Major changes include:

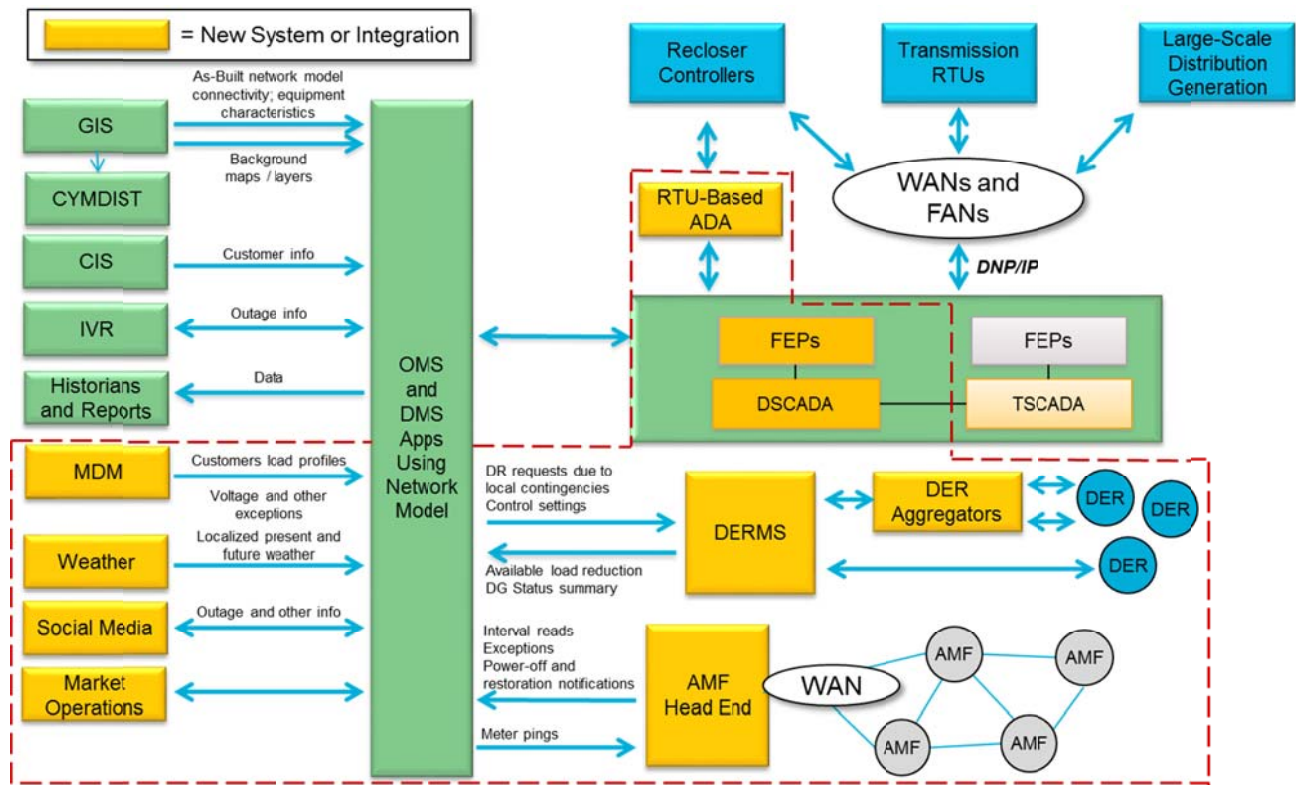
- Deployment of a new DSCADA system, created in part by separating the existing shared SCADA system into distinct transmission SCADA (TSCADA) and DSCADA systems.
- Deployment of Advanced Distribution Management System (ADMS) applications utilizing an “as-operated” distribution network model that reflects the current configuration of the distribution system.
- Retirement of legacy serial RTUs, and introduction of a third-party communication platform for distribution line recloser and SCADA exchange.

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<sup>7</sup> Substation RTUs provide data from remote devices over fiber and phone lines to a control center for use in the SCADA system.



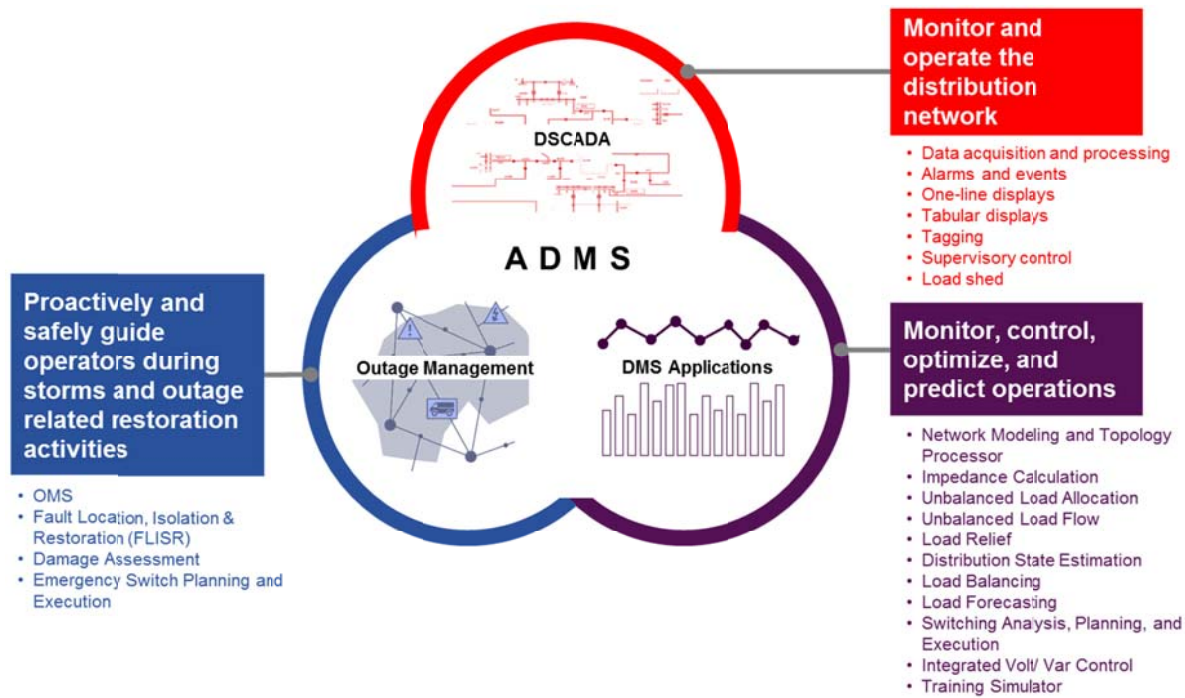
**Figure 3-3: National Grid’s Proposed Distribution Operations Platform**



### 3.4.2 Advanced Distribution Management System (ADMS)

ADMS is an integrated distribution control center platform. The ADMS integrates the functionalities of the OMS, DSCADA, and DMS applications as shown in Figure 3-4. ADMS enables distribution operators to manage the modern distribution grid by providing improved visibility and control, operational flexibility, system efficiency, and automated outage response. DMS applications and DSCADA, when well-integrated with the OMS, enable operators to monitor, control, and predict operations; operate the distribution network in a more proactive fashion; and safely guide the operator’s management of an increasingly complex distribution system. Specifically, an ADMS can use power flow functions considering equipment ratings, distributed generation output cycles based on fuel type, distributed energy storage charge and discharge capabilities, and existing load cycles in real time, just-in-time, or day-ahead fashion to configure the system and deploy resources as efficiently as possible. Without an ADMS, such analysis must be done using a set of static models with worst-case assumptions.

**Figure 3-4: Overview of ADMS Functionality**



National Grid and its affiliates operate distribution systems in multiple jurisdictions and the control center roadmap is intended to be applicable across all service territories. As such, these systems would be deployed by the National Grid USA Service Company, Inc. (the Service Company), with costs allocated to the operating companies that utilize the assets and services. The Company operates a common distribution control center for its Rhode Island and Massachusetts operations, so a coordinated deployment with Massachusetts is the only feasible and cost effective deployment option. Table 3-4 identifies the potential benefits of ADMS deployment.

**Table 3-4: ADMS Benefits and Quantification Methodology<sup>8</sup>**

Benefit	Quantification Methodology
Improves fault location efficiency	Reduction in field crew hours and vehicle miles traveled from more accurate fault location
Improves FLISR "self-healing" network	Avoided reliability investment cost to achieve a reduction in CMI, and assumed reduction in CMI from FLISR from peer utilities
Permits more efficient complex emergency switching	Reduction in control center operator time spent on complex switching operations
Enables VVO and CVR	Reduction in customer energy consumption at retail rate from decreased voltage at customer premise, feeder peak load reduction resulting in avoided generation capacity costs
Improves safety via equipment interrupting capability vs. available fault current	Avoided employee, contractor and public injuries and fatalities resulting in reduction of associated cost
Decreases asset maintenance costs	Elimination of annual capacitor bank inspections
Automates switching analysis	Reduction in employee time spent developing, testing, and executing orders
Increases planning efficiency	Reduction in time spent on data acquisition for distribution planners

The Company’s plan is to deploy DSCADA and ADMS over a four-year horizon. In the first year, a detailed requirements definition study will be completed, followed by a three-year development and deployment schedule.

Project Cost Estimates

The DSCADA and ADMS enhancements proposed in this plan are the same in Rhode Island as they are in the Company’s affiliate jurisdictions. The Company operates a common distribution control center for its Rhode Island and Massachusetts operations, so a coordinated deployment with Massachusetts is the only feasible and cost effective deployment option. Therefore, the Company is presenting only the multi-jurisdiction deployment scenario for this project. In the multi- jurisdiction scenario, assets and systems would be deployed by the Service Company and rental expenses would be allocated to the appropriate operating companies that benefit from these assets and systems once they are placed in service.

*Multi-Jurisdiction Deployment*

Estimated cash flow requirements for the Rhode Island portion of the DSCADA and ADMS implementation plan in the multi-jurisdictional scenario are presented in Table 3-5 below. In this scenario, DSCADA and ADMS deployment supports multiple operating companies and significant cost synergies can be realized because investments can be coordinated across the operating companies. As a shared system, the project would be deployed through the Service Company and placed in service in FY22, at which time an annual rental expense would be allocated to Narragansett Electric Company. The Company proposes to recover these costs through the PST Provision presented in Chapter 10.

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<sup>8</sup> Utility results demonstrate that the line loss reduction benefit from distribution automation is minimal. Other difficult-to-quantify benefits include increased awareness of protection coordination issues, increased awareness of electrical state and device status, improved steady state / transient voltage awareness, and increased training effectiveness.

**Table 3-5: DSCADA & ADMS Cash Flow Estimate – Multi-Jurisdiction Scenario**

DSCADA & ADMS Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 2.52	\$ 3.42	\$ 1.80	\$ -
O&M	\$ 0.44	\$ -	\$ 0.09	\$ 0.14	\$ -
<b>Total</b>	\$ 0.44	\$ 2.52	\$ 3.51	\$ 1.93	\$ -

As part of DSCADA deployment, a remote terminal unit (RTU) separation effort will be completed to segregate distribution data from transmission data. This is necessary to avoid North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) restrictions placed on the distribution data and control system.<sup>9</sup> The estimated costs of this effort are presented in Table 3.6 below. Note that costs for RTU separation cannot be shared with other jurisdictions, so cost synergies cannot be realized by coordinating across the operating companies.

**Table 3-6: RTU Separation Cash Flow Estimate**

RTU Separation Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 0.57	\$ 0.95	\$ 0.19	\$ -
O&M	\$ -	\$ 0.06	\$ 0.06	\$ 0.06	\$ -
<b>Total</b>	\$ -	\$ 0.63	\$ 1.01	\$ 0.25	\$ -

The Company proposes to recover these costs through the PST Provision presented in Chapter 10.

### 3.4.3 Geographic Information System (GIS) Data Enhancement

Modern grid operations require increasing granularity, accuracy, and timeliness of data to achieve the benefits associated with advanced systems functionality. GIS is the foundation on which many of these systems are built. The Company utilizes GIS as its authoritative source for distribution asset information and network configuration. GIS information is used several ways, including for physical infrastructure project design and, through export processes, to support outage management assessments, load flow, and other analysis models. While the system and data maintained by the Company has been fit for purpose to date, the introduction of new use cases, such as for ADMS applications and hosting capacity analysis, requires change. Industry experience deploying ADMS and similar systems has shown that investment in information enhancement is needed to enable the efficient use of these advanced applications.

The Company’s New York affiliate conducted an ADMS pilot on 15 circuits. The pilot showed that enhanced GIS information is necessary for successful network modelling. Lessons learned from this effort have informed the Company’s development of this proposal.

<sup>9</sup> NERC CIP protocols require that any system that connects to transmission assets meet the same compliance standards. Without separate distribution RTUs, NERC CIP protocols require the RTU and communication infrastructure be defined as a critical cyber asset for FERC compliance considerations. Any person using the data or modifying the system would require confidentiality agreements, special permissions, and training.

A project team composed of Company and contractor resources will be convened for Rhode Island. Personnel with skills in engineering, operations, data management, and information systems (IS) will work collectively to analyze data on the Company's entire distribution system consisting of over 470 distribution circuits encompassing more than 6,445 circuit miles. This team will adopt a multifaceted approach that makes use of analytical models and techniques, Company and commercial data sources, and, as required, field observation and monitoring. By leveraging these techniques, the team will develop new GIS capabilities and expand and improve the data necessary to maintain network models for advanced applications.

The project is expected to take three years to complete and will be aligned with milestones for ADMS and other grid modernization projects. Additional quality control processes will be implemented to enhance data accuracy.

Project deliverables will include the following:

**System Enhancements:**

- Configure and program GIS to accommodate new asset types and equipment, including adding expanded equipment attributes and characteristics;
- Configure and program GIS to facilitate capture of greater data and modelling granularity for underground distribution networks;
- Configure and program GIS to facilitate more granularity for low-voltage secondary distribution networks;
- Develop substation modelling capability to support operations and planning processes;
- Develop additional tools and improve existing toolsets used to manage data quality and processes in GIS.

**Data Enhancements:**

- Analyze and enhance existing data, including network connectivity, configuration, and attribute-level values;
- Identify and populate additional attributes and new asset types, including network connectivity, configuration, and attribute-level values;
- Ensure complete population of DER interconnections in GIS and populate customer equipment attributes;
- Analyze, enhance, and populate additional assets to further extend underground distribution network and secondary distribution models and functionality;
- Populate enhanced substation model aligned with use in operational and planning processes.

**Process Review & Improvement:**

- Review procedures and standards associated with the asset data life cycle;
- Identify and implement changes to enhance processes, quality control, and reductions in cycle times;

- Develop and implement data quality metrics and controls to facilitate continuous improvement.

Without these enhancements a significant increase in labor will be required to create and maintain the various network models used for distribution system planning and operational models utilized in ADMS. A timely refresh of data for the ADMS models without the automation of data flows would be inefficient.

Benefits

Implementing the GIS data enhancement project will enable network models to be developed for distribution system planning. It will also ensure that new initiatives, such as hosting capacity analysis and ADMS, can be automated and refreshed more frequently to provide more timely and accurate system assessments. This project is a critical enabler of the ADMS functionalities discussed previously and needs to be well coordinated. The project consists of IS upgrades to the corporate GIS and its costs will be allocated appropriately among benefiting operating companies. Enhancements specific to the Company will be charged directly as incurred. National Grid proposes to begin implementing information system upgrades in FY19 and then begin data enhancements specific to Rhode Island in FY21. The Company proposes to present the upcoming year’s project plan as part of its annual PST Plan.

Project Cost Estimates

While National Grid’s affiliates in both Massachusetts and New York have proposed similar grid modernization projects, these plans have not yet been approved by the applicable regulatory agencies. For illustrative purposes the Company is presenting two scenarios of deployment: a Rhode Island only deployment scenario and a multi-jurisdiction deployment scenario.

*Rhode Island Only Deployment*

Estimated costs for the Rhode Island only GIS data enhancement (IS) implementation plan are presented in Table 3-7.

**Table 3-7: GIS Data Enhancement Cash Flow Estimate for IS Resources - Rhode Island Only Scenario**

GIS Data Enhancement (IS) Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ -	\$ -	\$ -	\$ -
O&M	\$ 3.05	\$ -	\$ -	\$ -	\$ -
<b>Total</b>	\$ 3.05	\$ -	\$ -	\$ -	\$ -

*Multi-Jurisdiction Deployment*

Estimated cash flow requirements for Rhode Island’s portion of the New York-plus-Rhode Island GIS data enhancement (IS) implementation plan are presented in Table 3-8. The IS work relating to GIS supports multiple operating companies and significant cost synergies can be realized if it is coordinated across the operating companies.

**Table 3-8: GIS Data Enhancement Cash Flow Estimate for IS Resources - Multi-Jurisdiction Scenario**

GIS Data Enhancement (IS) Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ -	\$ -	\$ -	\$ -
O&M	\$ 0.43	\$ -	\$ -	\$ -	\$ -
<b>Total</b>	\$ 0.43	\$ -	\$ -	\$ -	\$ -

Regardless of a Rhode Island only or multi-jurisdiction scenario, staff from National Grid’s Asset Data and Analytics team, would be required to lead the data enhancement elements of this project. These costs are shown in Table 3-9.

**Table 3-9: GIS Data Enhancement Cash Flow Estimate for Non-IS Resources**

GIS Data Enhancement (Non-IS) Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ -	\$ -	\$ -	\$ -
O&M	\$ -	\$ -	\$ 1.03	\$ 1.03	\$ 1.03
<b>Total</b>	\$ -	\$ -	\$ 1.03	\$ 1.03	\$ 1.03

### 3.5 Operational Data Management

National Grid utilizes a large number of information systems. However, these systems are currently not as integrated as necessary to support the level of connectivity espoused in the Power Sector Transformation principles. Technologies are required that can (1) exchange information between all generating and consuming energy resources, (2) perform system management using programmable controls, (3) integrate data from ubiquitous sensors and computer-based analytics, and (4) interface with increasingly intelligent devices within the home to help system operators manage peaks. The underlying foundation that supports all these capabilities is network connectivity.

The integration of DER into real-time grid operations will require significant enhancements in telecommunications and information management systems to coordinate the interaction of large volumes of interdependent devices within a complex system that must continuously remain balanced and stable. As part of this plan, the Company is proposing to develop the platform to enable an enterprise service bus architecture, a data lake, and advanced analytics capabilities to support the AMF and grid modernization elements discussed previously in this chapter. These enhancements are explained below.

**3.5.1 Enterprise Service Bus (ESB)**

ESB is the enterprise middleware integration platform that is required to securely move data between systems, automate and manage business processes, transfer files between entities, and enable real-time and batch integration. Many of the Company’s information systems do not move data in real time, which inherently limits their capabilities. Integrating DER requires: greater reporting; predictive analytics; insights into, and management of, the distributed network; and the management of a large volume, variety, and velocity of data. In the current architecture environment, data are available through the development of batch interfaces, for use in other applications, and are not available for real-time use. The development of specific interfaces for applications is resource intensive. To address these challenges and to enable the Company to deliver services in a more effective manner, the Company is moving toward a service-based IS architecture to support applications that require real-time data from disparate sources.

Project Cost Estimates

While National Grid’s affiliates in both Massachusetts and New York have proposed similar grid modernization projects, these plans have not yet been approved by the applicable regulatory agencies. Therefore the Company is presenting two scenarios of deployment: a Rhode Island only deployment scenario and a multi-jurisdiction deployment scenario.

*Rhode Island Only Deployment*

Estimated cash flow requirements for implementing the enterprise service bus plan in Rhode Island only are presented in Table 3-10.

**Table 3-10: Enterprise Service Bus Cash Flow Estimate – Rhode Island Only Scenario**

Enterprise Service Bus Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 5.50	\$ 8.92	\$ 1.49	\$ -
O&M	\$ -	\$ 0.80	\$ 1.95	\$ 2.05	\$ -
<b>Total</b>	\$ -	\$ 6.30	\$ 10.87	\$ 3.54	\$ -

*Multi-Jurisdiction Deployment*

Estimated cash flow requirements for Rhode Island’s portion of a coordinated enterprise service bus implementation plan for New York plus Rhode Island are presented in Table 3-11. The plan supports multiple operating companies and significant cost synergies can be realized if implementation costs are leveraged amongst the operating companies.

**Table 3-11: Enterprise Service Bus Cash Flow Estimate – Multi-Jurisdiction Scenario**

Enterprise Service Bus Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 2.06	\$ 3.77	\$ 0.37	\$ -
O&M	\$ -	\$ 0.27	\$ 0.62	\$ 0.78	\$ -
<b>Total</b>	\$ -	\$ 2.34	\$ 4.39	\$ 1.15	\$ -



### 3.5.2 *Data Management and Analytics*

Systems are needed to store, share, and analyze the large volumes of operational data associated with a modern grid. The Company is proposing investment in three areas, internally referred to as PI Historian (a system for collecting large volumes of data), data lake (a system for storing and retrieving large volumes of data) and advanced analytics.

PI Historian records hundreds of thousands of pieces of raw operational data generated via SCADA systems, with the majority of data being recorded every few seconds. Given the large number of intelligent electronic devices being monitored and controlled in a modernized grid, the historian's capacity and capabilities need to be expanded.

PI Historian will link with a data lake where select data sets will be maintained for use by other applications. Utilizing a data lake rather than developing multiple data links directly with PI Historian will ensure that the proper data are made available for analytics and that these data are properly controlled. In addition to SCADA data, numerous other data sets will be maintained in the data lake to facilitate advanced analytics.

The advanced analytics required to efficiently manage a modern grid require processing massive quantities of data from countless data sources. The Company's compute and storage strategy is based on a hybrid sourcing vision. Currently, the Service Company contracts with an external service provider for computation and data storage, and utilizes various cloud providers for agility and cost efficiency, where appropriate.

Benefits of cloud computing include:

- Reduced time to provide needed computing resources through administered governance;
- Quicker delivery of applications and business capabilities;
- Ability to dynamically scale/flex computing resources to meet business demand; and
- Ability to provide infrastructure at competitive costs.

#### Project Cost Estimates

While National Grid's affiliates in both Massachusetts and New York have proposed similar grid modernization projects, these plans have not yet been approved by the applicable regulatory agencies. Therefore the Company is presenting two scenarios of deployment: a Rhode Island only deployment scenario and a multi-jurisdiction deployment scenario.

#### *Rhode Island Only Deployment*

Estimated cash flow requirements to implement data lakes, PI Historian, and advanced analytics implementation plan for Rhode Island only are presented in Tables 3-12, 3-13, and 3-14.

**Table 3-12: Data Lakes Cash Flow Estimate – Rhode Island Only Scenario**

Data Lake Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 1.39	\$ -	\$ -	\$ -
O&M	\$ -	\$ 0.84	\$ 1.21	\$ 1.64	\$ 1.73
<b>Total</b>	\$ -	\$ 2.24	\$ 1.21	\$ 1.64	\$ 1.73

**Table 3-13: PI Historian Cash Flow Estimate – Rhode Island Only Scenario**

PI Historian Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 0.45	\$ -	\$ -	\$ -
O&M	\$ -	\$ 0.05	\$ 2.05	\$ 2.05	\$ 0.05
<b>Total</b>	\$ -	\$ 0.50	\$ 2.05	\$ 2.05	\$ 0.05

**Table 3-14: Advanced Analytics Cash Flow Estimate – Rhode Island Only Scenario**

Advanced Analytics Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 4.73	\$ 5.42	\$ 3.31	\$ 0.62
O&M	\$ -	\$ 0.11	\$ 1.35	\$ 1.59	\$ 1.95
<b>Total</b>	\$ -	\$ 4.84	\$ 6.77	\$ 4.90	\$ 2.57

*Multi-Jurisdiction Deployment*

Estimated cash flow requirements for Rhode Island’s portion of a data lakes, PI Historian, and advanced analytics implementation plan for New York plus Rhode Island are presented in Tables 3-15 3-16 and 3-17. Data lakes, PI Historian, and advanced analytics support multiple operating companies and significant cost synergies can be realized if these investments are coordinated across the operating companies.

**Table 3-15: Data Lake Cash Flow Estimate – Multi-Jurisdiction Scenario**

Data Lake Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 0.35	\$ -	\$ -	\$ -
O&M	\$ -	\$ 0.37	\$ 0.60	\$ 0.84	\$ 0.93
<b>Total</b>	\$ -	\$ 0.72	\$ 0.60	\$ 0.84	\$ 0.93

**Table 3-16: PI Historian Cash Flow Estimate – Multi-Jurisdiction Scenario**

PI Historian Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 0.11	\$ -	\$ -	\$ -
O&M	\$ -	\$ 0.01	\$ 0.52	\$ 0.52	\$ 0.01
<b>Total</b>	\$ -	\$ 0.13	\$ 0.52	\$ 0.52	\$ 0.01

**Table 3-17: Advanced Analytics Cash Flow Estimate – Multi-Jurisdiction Scenario**

Advanced Analytics Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 3.15	\$ 1.47	\$ 0.94	\$ 0.62
O&M	\$ -	\$ 0.11	\$ 0.46	\$ 0.52	\$ 0.61
<b>Total</b>	\$ -	\$ 3.26	\$ 1.93	\$ 1.46	\$ 1.24

### 3.6 Telecommunications

Communication between devices in the field and Company systems is essential to the overall success of the modern grid. There are several main drivers for the Company’s telecommunications network plan:

- Provide a reliable, cost-effective, two-way communications capability to end devices including meters, grid automation controls, field sensors, substations, field force, and customer home area network (HAN) devices;
- Ensure the network meets all technical requirements for the devices and systems deployed, including availability, latency, bandwidth, security, and other factors;
- Provide operations groups with the capability to manage, maintain, and troubleshoot the communications network; and
- Enable new grid technologies as they become available.

National Grid currently utilizes a number of different communications technologies for the collection of meter and T&D system data. In addition, the Company gathers substation information through a variety of means. The existing communication networks that support these functions are suitable for grid data requirements at the current time. However, these networks must be upgraded and expanded to support the integrated grid envisioned in power sector transformation.

The Company anticipates using its existing private network infrastructure—both private fiber and multiprotocol label switching (MPLS) wide area network (WAN)—to support power sector transformation objectives. Currently the Company has networks in place to support corporate functions, substations RTU/SCADA, off-site data center connectivity, and Company facility interconnections.

To handle a significant increase in the amount of data traversing these networks, the Company anticipates increasing bandwidth at a number of facilities. The Company also anticipates a significant increase in metering data as a result of its proposed AMF rollout, an increase in the number and type of distribution monitoring and control devices, and increases in substation data. This will require enhancements at the Company’s control center locations, data centers, and possibly other large facilities. The Company plans to design and implement bandwidth and security upgrades over a multi-year horizon.

As discussed during numerous power sector transformation meetings on the subject of connectivity, telecommunications options are evolving rapidly. National Grid currently relies on a wide array of telecommunications technologies to support its operations and is actively evaluating alternatives for asset management in this area. As it contemplates its long term

options, the Company will consider the various telecommunications models discussed within the Power Sector Transformation initiative.

Project Cost Estimates

While National Grid’s affiliates in both Massachusetts and New York have proposed similar grid modernization projects, these plans have not yet been approved by the applicable regulatory agencies. Therefore the Company is presenting two scenarios of deployment: a Rhode Island only deployment scenario and a multi-jurisdiction deployment scenario.

*Rhode Island Only Deployment*

Estimated cash flow requirements to implement the telecommunications plan for Rhode Island only are presented in Table 3-18.

**Table 3-18: Telecommunications Cash Flow Estimate – Rhode Island Only Scenario**

Telecommunications Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 0.30	\$ 0.15	\$ 0.15	\$ -
O&M	\$ -	\$ -	\$ 1.95	\$ 2.93	\$ 3.90
<b>Total</b>	\$ -	\$ 0.30	\$ 2.10	\$ 3.08	\$ 3.90

*Multi-Jurisdiction Deployment*

Estimated cash flow requirements for Rhode Island’s portion of a telecommunications implementation plan for New York and Rhode Island are presented in Table 3-19. Telecommunications supports multiple operating companies and significant cost synergies can be realized if these investments are coordinated across the operating companies.

**Table 3-19: Telecommunications Cash Flow Estimate – Multi-Jurisdiction Scenario**

Telecommunications Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 0.12	\$ 0.06	\$ 0.06	\$ -
O&M	\$ -	\$ -	\$ 0.66	\$ 0.98	\$ 1.31
<b>Total</b>	\$ -	\$ 0.12	\$ 0.72	\$ 1.04	\$ 1.31

**3.7 Cybersecurity**

Cybersecurity and privacy provisions are important considerations for any power sector transformation initiative because of the imperative to maintain a reliable and secure electricity and gas infrastructure and provide the protection needed to assure the confidentiality and integrity of the digital overlay. Mere compliance with cybersecurity standards will not assure security. Cybersecurity threats to critical infrastructure emanate from a wide spectrum of potential perpetrators and the cyber threat to the electric grid is real. The question at hand is when, not if, organizations will experience attempts to infiltrate critical U.S. systems and infrastructure. The threat will only grow as the industry upgrades its systems and adopts more advanced and automated technologies, and as the inevitable convergence of information and operational technologies continues.

A reliable and secure grid is necessary to safely enable both the customer-facing and grid-facing aspects of modernizing the grid, including automated demand response, providing customers with myriad options for managing their energy costs through technology-enabled programs, limiting outages with a self-healing, resilient energy network, integrating DERs, and other strategically important functions.

The Company proposes a risk-based cybersecurity framework that encompasses people, processes, and technologies and that recognizes that the electric grid is changing from a relatively closed system, to a complex, highly interconnected environment. The framework will:

- Put forward a set of policies and standards to ensure the Company is working toward a common set of security objectives;
- Provide architecturally secure cybersecurity and privacy services for an efficient, easy-to-use and agile way to deliver the capabilities required to manage cyber risks;
- Look to build and enhance capability by reusing existing security capabilities where possible and, where capability is absent, by investing;
- Deliver the necessary capability to protect and ensure the resiliency of critical Company systems and infrastructure; and
- Address privacy throughout the lifecycle for sensitive customer and system data, as well as information sharing practices.

As part of the framework, the Company will implement cybersecurity and privacy provisions in the form of multiple security services to support each functional area. These security services will serve as the cornerstone for any cybersecurity or privacy-related component of the overall solution. A program to provide regular privacy training and ongoing awareness of communications and activities to all workers and third parties who have access to customer information within the distributed system platform will be included.

The implementation plan calls for a phased roll out of security services, based on business priorities and appetite for cyber risk. A formal review will occur periodically to ensure that proposed cybersecurity and privacy services evolve along with ever-changing cyber threats. These threats will be monitored continuously to ensure that Company systems, customers, and information remain protected and secured.

### Project Cost Estimates

While National Grid's affiliates in both Massachusetts and New York have proposed similar grid modernization projects, these plans have not yet been approved by the applicable regulatory agencies. Therefore the Company is presenting two scenarios of deployment: a Rhode Island only deployment scenario and a multi-jurisdiction deployment scenario.

#### *Rhode Island Only Deployment*

Estimated cash flow requirements to implement the cybersecurity plan for Rhode Island only are presented in Table 3.20.

**Table 3-20: Cybersecurity Cash Flow Estimate – Rhode Island Only Scenario**

Cybersecurity Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 13.84	\$ 6.73	\$ 4.43	\$ 12.33
O&M	\$ 0.00	\$ 8.37	\$ 4.22	\$ 3.37	\$ 3.65
<b>Total</b>	\$ 0.00	\$ 22.22	\$ 10.96	\$ 7.79	\$ 15.98

*Multi-Jurisdiction Deployment*

Estimated cash flow requirements for Rhode Island’s portion of a cybersecurity implementation plan for New York and Rhode Island are presented in Table 3.21. Cybersecurity supports multiple operating companies and significant cost synergies can be realized if these investments are coordinated across the operating companies.

**Table 3-21: Cybersecurity Cash Flow Estimate – Multi-Jurisdiction Scenario**

Cybersecurity Cash Flow, \$M	FY19	FY20	FY21	FY22	FY23
CAPEX	\$ -	\$ 3.96	\$ 1.93	\$ 1.28	\$ 3.24
O&M	\$ 0.00	\$ 2.42	\$ 1.24	\$ 0.96	\$ 1.42
<b>Total</b>	\$ 0.00	\$ 6.38	\$ 3.16	\$ 2.24	\$ 4.66

**3.8 Advancing Power Sector Transformation Goals and State Policies**

The foundational and enabling grid modernization investments proposed in this plan will directly support numerous power sector transformation objectives with respect to distribution system planning and grid connectivity and advanced metering. The Company shares the state’s vision for a power sector transformed by increased DER penetration and the integration of clean energy technologies. These changes will result in a more complex distribution system that must be managed in a much more dynamic fashion. The grid sensing and distribution management systems proposed in this plan are intended to ensure that the more complex system of the future can be operated more efficiently and as safely and reliably as it has in the past.

Table 3-22 explains how individual elements of grid modernization advance, detract from, or are neutral toward goals that the PUC has adopted as a guide for reviewing any proposal filed with the PUC.

**Table 3-22: High level summary of alignment between grid modernization and Docket 4600 goals**

<b>Goals For “New” Electric System</b>	<b>Advances?/Detracts From?/Is Neutral To?</b>
<p>Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels).</p>	<p><u>Advances:</u> The Company’s grid modernization plans are foundational enablers necessary to achieve these goals. The monitoring, control, communications, and data management elements of grid modernization are necessary to effectively manage emerging multi-directional power flows in a reliable, safe, clean, and affordable manner. In addition, proposed cybersecurity elements will enable the integration of new, grid-connected devices and remote control capabilities in a reliable and secure fashion.</p>
<p>Strengthen the Rhode Island economy, support economic competitiveness, and retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures.</p>	<p><u>Advances:</u> The investments herein include new tools, processes, and analytical capabilities that will drive a more efficient grid and ensure the affordability of clean electric power. An example of a new product being developed in Rhode Island includes Utilidata’s VVO/CVR technology, which has been shown to reduce consumption and peak demand in a cost-effective manner. In addition, the system data portal and other grid modernization elements will help more Rhode Island customers become both producers and consumers of energy by enabling them to invest in their own DER technologies in areas that are most cost-effective for these resources.</p>
<p>Address the challenge of climate change and other forms of pollution.</p>	<p><u>Advances:</u> The proposed feeder monitoring system, ADMS, and system data portal will enable higher penetration of clean DERs into the grid, which will reduce Rhode Island’s reliance on central, carbon-based generation technologies. In addition, the modern grid will be more efficient as a result of better monitoring and control of grid-side devices and as customers become more active in managing energy usage.</p>
<p>Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides</p>	<p><u>Advances:</u> The system data portal and new information such as hosting capacity analysis will help more Rhode Island customers and local DER developers become both producers and consumers of energy by enabling them to invest in their own DER technologies in areas where these technologies are most cost effective.</p>

recognizable net benefits.	
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society.	<u>Advances</u> : The monitoring, communications, and data management elements of grid modernization are necessary to assess the locational and temporal value DER may provide to the electric system.
Appropriately charge customers for the cost they impose on the grid.	<u>Advances</u> : The monitoring, communications, data management, and cybersecurity elements of grid modernization will enable new pricing and allocation mechanisms to attribute costs and benefits more equitably.
Appropriately compensate the distribution utility for the services it provides.	Neutral
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	<u>Advances</u> : The system data portal will provide transparency concerning system needs and opportunities for interested stakeholders, thereby fostering a more collaborative approach to distribution system planning and operations.

### 3.9 Conceptual Cost Estimate for Near-Term Roadmap

While National Grid’s affiliates in both Massachusetts and New York have proposed similar grid modernization projects, these plans have not yet been approved by the applicable regulatory agencies. Therefore the Company is presenting two scenarios of deployment: a Rhode Island only deployment scenario and a multi-jurisdiction deployment scenario. The estimated cash flow requirements for implementing the Plan in Rhode Island only are presented in Table 3-23; the requirements for Rhode Island’s portion of implementing a multi-jurisdictional Plan are presented in Table 3-24. Significant cost synergies can be realized if these investments are coordinated across the operating companies. It should be noted that the Company is presenting only the multi-jurisdiction deployment scenario for the DSCADA and ADMS project, so the multi-jurisdiction scenario costs are used in both tables below.<sup>10</sup>

<sup>10</sup> The Company operates a common distribution control center for its Rhode Island and Massachusetts operations, so a coordinated deployment with Massachusetts is the only feasible and cost effective deployment option.



**Table 3-23: Power Sector Transformation Cash Flow Estimate – Rhode Island Only Deployment Scenario**

RI Only Scenario	Project	Op Co.	Capex (\$m) - Cash Flow					O&M (\$m) - Cash Flow					Total (\$m) - Cash Flow							
			FY19	FY20	FY21	FY22	FY23	5-Yr Sum	FY19	FY20	FY21	FY22	FY23	5-Yr Sum	FY19	FY20	FY21	FY22	FY23	5-Yr Sum
	System Data Portal	SvcCo	0.000	0.000	0.000	0.000	0.000	0.00	0.08	0.70	0.70	0.70	0.00	2.2	0.08	0.70	0.70	0.70	0.00	2.2
	Feeder Monitoring Sensors	NECO	0.000	0.455	0.455	0.455	0.455	1.8	0.00	0.01	0.01	0.01	0.00	0.0	0.00	0.46	0.46	0.47	0.46	1.8
	Control Center Enhancements																			
	DSCADA & ADMS		0.000	2.524	3.425	1.797	0.000	7.7	0.44	0.00	0.09	0.14	0.00	0.7	0.44	2.52	3.51	1.93	0.00	8.4
	RTU Separation	NECO	0.000	0.570	0.950	0.190	0.000	1.7	0.00	0.06	0.06	0.06	0.00	0.2	0.00	0.63	1.01	0.25	0.00	1.9
	GIS Data Enhancement (IS)	SvcCo	0.000	0.000	0.000	0.000	0.000	0.0	3.05	0.00	0.00	0.00	0.00	3.0	3.05	0.00	0.00	0.00	0.00	3.0
	GIS Data Enhancement (BR)	SvcCo	0.000	0.000	0.000	0.000	0.000	0.0	0.00	0.00	1.03	1.03	1.03	3.1	0.00	0.00	1.03	1.03	1.03	3.1
	Operational Data Management																			
	Enterprise Service Bus	SvcCo	0.000	5.501	8.919	1.492	0.000	15.9	0.00	0.80	1.95	2.05	0.00	4.8	0.00	6.30	10.87	3.54	0.00	20.7
	Data Lake	SvcCo	0.000	1.394	0.000	0.000	0.000	1.4	0.00	0.84	1.21	1.64	1.73	5.4	0.00	2.24	1.21	1.64	1.73	6.8
	PI Historian	SvcCo	0.000	0.451	0.000	0.000	0.000	0.5	0.00	0.05	2.05	2.05	2.05	6.2	0.00	0.50	2.05	2.05	2.05	6.7
	Advanced Analytics	SvcCo	0.000	4.727	5.419	3.309	0.622	14.1	0.00	0.11	1.35	1.59	1.95	5.0	0.00	4.84	6.77	4.90	2.57	19.1
	Telecommunications	SvcCo	0.000	0.304	0.152	0.152	0.000	0.6	0.00	0.00	1.95	2.93	3.90	8.8	0.00	0.30	2.10	3.08	3.90	9.4
	Cybersecurity	SvcCo	0.000	13.844	6.734	4.427	12.330	37.3	0.00	8.37	4.22	3.37	3.65	19.6	0.00	22.22	10.96	7.79	15.98	57.0
<b>TOTAL</b>			-	<b>29.8</b>	<b>26.1</b>	<b>11.8</b>	<b>13.4</b>	<b>81.1</b>	<b>3.6</b>	<b>10.9</b>	<b>14.6</b>	<b>15.6</b>	<b>14.3</b>	<b>59.0</b>	<b>3.6</b>	<b>40.7</b>	<b>40.7</b>	<b>27.4</b>	<b>27.7</b>	<b>140.0</b>

**Table 3-24: Power Sector Transformation Cash Flow Estimate – Multi-Jurisdiction Deployment Scenario**

Multiple Jurisdiction Scenario	Project	Op Co.	Capex (\$m) - Cash Flow					O&M (\$m) - Cash Flow					Total (\$m) - Cash Flow							
			FY19	FY20	FY21	FY22	FY23	5-Yr Sum	FY19	FY20	FY21	FY22	FY23	5-Yr Sum	FY19	FY20	FY21	FY22	FY23	5-Yr Sum
	System Data Portal	NECO	0.000	0.000	0.000	0.000	0.000	0.0	0.08	0.70	0.70	0.70	0.00	2.2	0.08	0.70	0.70	0.70	0.00	2.2
	Feeder Monitoring Sensors	NECO	0.000	0.455	0.455	0.455	0.455	1.8	0.00	0.00	0.01	0.01	0.00	0.0	0.00	0.46	0.46	0.47	0.46	1.8
	Control Center Enhancements																			
	DSCADA & ADMS	SvcCo	0.000	2.524	3.425	1.797	0.000	7.7	0.44	0.00	0.09	0.14	0.00	0.7	0.44	2.52	3.51	1.93	0.00	8.4
	RTU Separation	NECO	0.000	0.570	0.950	0.190	0.000	1.7	0.00	0.06	0.06	0.06	0.00	0.2	0.00	0.63	1.01	0.25	0.00	1.9
	GIS Data Enhancement (IS)	SvcCo	0.000	0.000	0.000	0.000	0.000	0.0	0.43	0.00	0.00	0.00	0.00	0.4	0.43	0.00	0.00	0.00	0.00	0.4
	GIS Data Enhancement (BR)	NECO	0.000	0.000	0.000	0.000	0.000	0.0	0.00	0.00	1.03	1.03	1.03	3.1	0.00	0.00	1.03	1.03	1.03	3.1
	Operational Data Management																			
	Enterprise Service Bus	SvcCo	0.000	2.063	3.770	0.375	0.000	6.2	0.00	0.27	0.62	0.78	0.00	1.7	0.00	2.34	4.39	1.15	0.00	7.9
	Data Lake	SvcCo	0.000	0.350	0.000	0.000	0.000	0.4	0.00	0.37	0.60	0.84	0.93	2.7	0.00	0.72	0.60	0.84	0.93	3.1
	PI Historian	SvcCo	0.000	0.113	0.000	0.000	0.000	0.1	0.00	0.01	0.52	0.52	0.61	1.1	0.00	0.13	0.52	0.52	0.61	1.2
	Advanced Analytics	SvcCo	0.000	3.148	1.470	0.940	0.622	6.2	0.00	0.11	0.46	0.52	0.81	1.7	0.00	3.26	1.93	1.46	1.24	7.9
	Telecommunications	SvcCo	0.000	0.120	0.060	0.060	0.000	0.2	0.00	0.00	0.66	0.98	1.31	3.0	0.00	0.12	0.72	1.04	1.31	3.2
	Cybersecurity	SvcCo	0.000	3.958	1.926	1.275	3.243	10.4	0.00	2.42	1.24	0.96	1.42	6.0	0.00	6.38	3.16	2.24	4.66	16.4
<b>TOTAL</b>			-	<b>13.3</b>	<b>12.1</b>	<b>5.1</b>	<b>4.3</b>	<b>34.8</b>	<b>0.9</b>	<b>3.9</b>	<b>6.0</b>	<b>6.5</b>	<b>5.3</b>	<b>22.7</b>	<b>0.9</b>	<b>17.2</b>	<b>18.0</b>	<b>11.6</b>	<b>9.6</b>	<b>57.5</b>

### **3.10 Conclusion**

The grid modernization proposals presented in this chapter are critical enablers of DER integration in a safe and reliable fashion and provide a foundation for the continued evolution of the modern grid. This implementation Plan aligns with the recommendations of National Grid affiliates in Massachusetts and New York; an implementation effort in Rhode Island that is well coordinated with implementation efforts in these jurisdictions may result in significant cost efficiencies.

Developing a modern grid will be an on-going journey. This Plan presents meaningful initial steps to transition the planning and operation of the distribution grid so that it is more proactive, dynamic, and efficient. While the Company proposes a portfolio approach to modernizing the grid and supporting systems in the coming years, the expectation is that needs and opportunities will continue to evolve, requiring additional functionalities and capabilities. New functionalities associated with probabilistic planning, numerous optimization applications, and the management of future market-based products in services may become necessary eventually but are not warranted at this time given current levels of data availability and DER penetration.



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## CHAPTER 4: ADVANCED METER FUNCTIONALITY

### 1. OVERVIEW

Today's customers expect more from their utility. Research shows that customers not only expect the utility to provide affordable, reliable, and safe energy, but increasingly expect access to actionable information, greater choice and control over their energy use, and delivery of energy services in a simple and convenient way. The Narragansett Electric Company d/b/a National Grid (the Company) can deliver on these expectations by providing customers with insights into their consumption patterns, offering more pricing options, and facilitating the integration of smarter devices and distributed energy resources, all while maintaining affordable, safe and reliable energy service. This functionality is now possible thanks to recent advances<sup>1</sup> in intelligent metering solutions. The Company believes that advanced metering, when properly deployed, is foundational to its ability to meet evolving customer expectations. With this in mind the business case described in this chapter refers not to advanced metering *infrastructure*, which would imply a focus on the technology, but instead presents a vision for advanced metering *functionality* (AMF) that the Company is committed to delivering for customers in Rhode Island.

The Company proposes to deploy AMF for the benefit of its 790,721<sup>2</sup> residential and commercial customers in Rhode Island. Its AMF deployment program consists of four key elements:

- An integrated system of smart electric meters and natural gas encoded radio transmitters (ERTs)
- A communications network
- An IT platform to collect, monitor, manage, and process raw data into intelligent information, and to engage customers and third parties
- Project management and ongoing business operations

Advanced metering technology will deliver new functionalities and offer significant benefits for customers, for the Company in its role as grid operator, and for society. New functionalities on the customer side include:

- **Enhanced energy management capability** that allows customers to take control of their energy usage through energy efficiency, conservation, and demand response programs, along with access to smart home devices;
- **Enablement of third-party programs and offerings** that will drive innovation and provide additional value to customers, while encouraging new industry participants to enter the market with new customer offerings;
- **Customer service enhancements** focused on Income Eligible customers, including notifications about changes to consumption patterns mid-month that give customers an opportunity to take action before the end of the billing cycle;

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<sup>1</sup> Processing capabilities at the edge of the grid have improved significantly with technology advancement.

<sup>2</sup> Includes gas and electric accounts.

- **Easier move in/out process** because the Company has the ability to start and stop electric service remotely; and
- **Savings on electric vehicle charging costs** by virtue of time-varying pricing that incentivize customers to displace vehicle charging to off-peak times.

In addition to enabling new customer-side functionality, AMF also delivers benefits on the grid side. Such benefits include:

- **Volt-var optimization (VVO)** by meters acting as end-of-line sensors to improve voltage levels across the feeders, above and beyond the existing reductions that VVO technology delivers without AMF;
- **Avoided O&M costs** by reducing the need for vans and labor to read existing meters, manual meter investigations, and connects and disconnects
- **Storm outage management system improvements** using increased visibility into where outages occur to support restoration efforts and, in concert with grid modernization efforts, to enable timely notifications to customers about the status of their outage; and,
- **Revenue benefits**, including reduced thefts of service, reduced write-offs, and improved measurement accuracy.

Broader benefits of AMF include:

- **Societal benefits**, including a reduction in greenhouse gas emissions and economic development through job growth;
- **Enabling distributed energy resources (DERs)** by providing more visibility into where DERs can offer the most value to the grid;
- **Enabling future coordination opportunities** with water utilities, street light infrastructure, gas remote service shutoff valves, and residential methane detectors; and
- **Enabling innovative rate design options** that cannot be delivered by the existing metering infrastructure but when implemented will reward customers for optimizing their energy use. (The Company considers time varying rates as a critical component of a successful deployment; new rates will be proposed in the future to align with the deployment of the physical metering infrastructure).

The AMF program aligns closely with the state's goals for a modern grid as articulated in Docket 4600. Specifically, AMF empowers customers to reduce their energy consumption, creates economic development opportunities, and improves the reliability and efficiency of electric and gas delivery. Additionally, in designing the program the Company has reflected on the PST Phase One Report. Consistent with the recommendations included in that report, the Company's proposal includes:

- Exploring the opportunity to partner with other parties that could share in the cost and benefit from the access to a state-wide communications system. Such partnerships, if found to be workable, can optimize the deployment of telecoms networks across the state;
- Exploring the use of open integration standards and protocols and outsourcing key system components where it makes sense to minimize the risk of premature obsolescence and ensure maximum technology agility in the future. A good example of this is the utilization of

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Software as a Service (SaaS) platforms for elements like customer engagement or meter data management systems (MDMS);

- Enabling Green Button Connect My Data functionality that will act as the platform to provide authorized third-parties access to energy use data on a near-real time basis;
- Leveraging experience and lessons learned from the Company's Smart Energy Solutions pilot in Massachusetts and Clifton Park demonstration program in New York to achieve a more aggressive deployment schedule and deliver the benefits to all customers, including Income Eligible customers, as quickly as possible.

As described in Chapter Two of this Plan, the Company has applied its Rhode Island benefit-cost methodology to provide a quantitative evaluation of AMF deployment in Rhode Island. Two scenarios were evaluated. The first considers a Rhode Island only implementation program, while the second considers a joint Rhode Island and New York Niagara Mohawk<sup>3</sup> implementation strategy to show potential synergies and cost savings to Rhode Island customers should AMF deployment in New York be approved by the state's Public Service Commission.

For each of the implementation scenarios, four pricing sensitivities were evaluated based on the range of time-variant pricing benefits that might be achieved depending on whether customers opt in versus opt out, and whether they achieve high versus low energy savings.<sup>4</sup> **The results of the BCA tests show that full deployment of AMF can achieve net positive benefit-to-cost ratios in both scenarios.** In a Rhode Island only scenario where Rhode Island customers incur 100% of the communications, back office, and implementation costs, savings from time varying rates have to be on the higher end of the spectrum to achieve a net-positive outcome.

Consistent with Docket 4600 guidance, the Company agrees that not all of the benefits delivered by these types of programs can be quantified. As such, the Company also identifies non-quantifiable benefits that should be considered as part of a comprehensive decision framework.

To strike a balance between delivering customer benefits and managing customer bill impacts, the Company proposes a four-year plan to design, procure, and deploy AMF. As described in Chapter Two the scale of investment required to deliver power sector transformation and the associated pace of technology change warrant a staged approach to project development and approval. The proposed new PST Provision for AMF, grid modernization, and other power sector transformation investments will provide increased visibility into the evolving business case for AMF and enable Commission review and approval of costs on an annual basis. In this filing, the Company is seeking approval for FY19 costs of \$2 million, to undertake the next phase of design, including further exploration of partnerships, stakeholder input, and other innovative program elements, and to undertake a procurement exercise. The outcome of the design and procurement phase will determine the costs for year two of the program (to be included in the FY20 PST Plan) and beyond.

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<sup>3</sup> The Company chose to do a joint analysis with the AMF proposal in Niagara Mohawk because of potential alignment on timelines for decision and proposed deployment. The Niagara Mohawk AMI proposal is currently being considered as part of Niagara Mohawk's April 28, 2017 rate case filing (Case Numbers 17-E-0238 and 17-G-0239).

<sup>4</sup> These scenarios were developed using lessons from multiple sources, including from National Grid's Smart Energy Solutions smart grid pilot in Worcester MA. More details can be found in Section B.3.3 in Appendix 1.

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## 2. INTRODUCTION

The evolving needs of customers and the state's clean energy policy objectives are at the heart of the transforming energy landscape. Today's customers expect a more proactive, digital, and personalized relationship with their utility and Rhode Island clean energy policy objectives are in support of more information, convenience, control, and choice. The Company is actively pursuing the foundational technical infrastructure and business capabilities necessary to deliver in this changing customer landscape.

In this Plan, the Company sets out the need for a more modern, dynamic, and flexible electric and gas system, founded on affordability, reliability, and safety, and offering new forms of customer information, convenience, control, and choice. The Plan describes how advanced metering functionality provides the enabling foundational features to meet evolving customer needs and proposes to deploy AMF technology in an effort to provide a modern grid experience to the 790,721 residential and commercial electric and gas customers in Rhode Island.

In setting out its AMF proposal, the Company provides information in three places:

- This chapter (Chapter Four) summarizes the Company's AMF proposal, discusses how AMF enables the modern grid experience and advances state goals, describes how the program will be implemented, and summarizes results from the BCA;
- Appendix 4.1 provides significantly more detail on the technologies the Company is proposing to deploy and on the costs and benefits included in the BCA; and
- Appendix 4.2 provides the Company's Rhode Island AMF BCA Methodology.

### 2.1 Summary of the Company's AMF proposal

As it currently exists, the Company's infrastructure is limited in its ability to meet the evolving and diverse needs of customers. This is particularly true of the Company's metering infrastructure, which serves as the interface between the customer and the Company. In Rhode Island, most meters use automatic meter reading (AMR) technology. Deployed in the early 2000s, this technology sends a radio signal to a fleet of service vans as they drive by to collect monthly reads. This technology contains core features that the Company relies on for identifying customer load, billing customers appropriately based on their electricity consumption, and managing their connection to the Company's infrastructure. However, as customer expectations change, the Company will need a modern infrastructure solution to provide more granular and timely information along with improved convenience, choice, and control. AMF can deliver these features.

The AMF program consists of four key elements described below and illustrated in Figure 4-1.<sup>5</sup>

1. An integrated system of smart electric meters and natural gas ERTs that capture customer usage data and other characteristics at defined intervals;

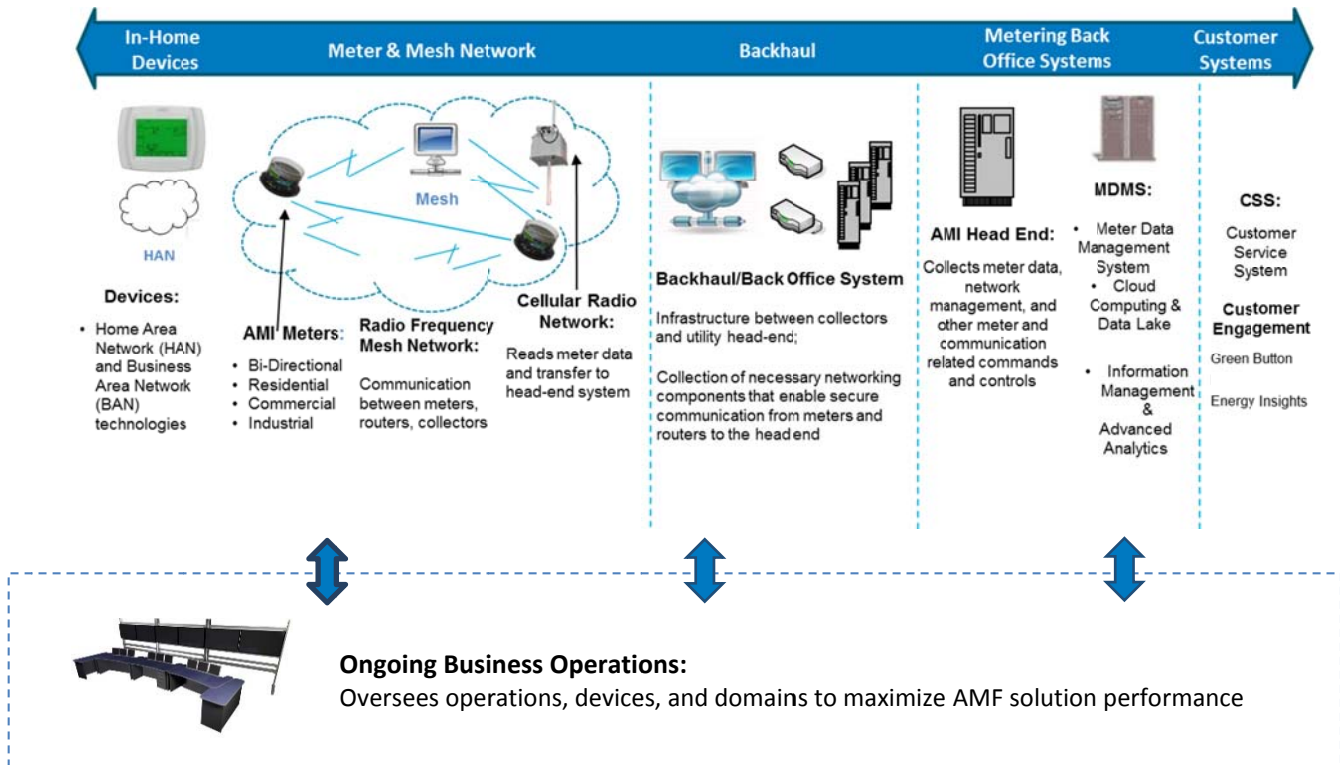
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<sup>5</sup> More details about the components that make up the AMF program and their costs can be found in Appendix Three.



2. A communications network for acquiring meter and field device data and enabling distribution automation (DA);
3. An IT platform for data collection, monitoring, and control of the communication system; an expanded cybersecurity system; a meter data management system (MDMS) to process meter data; an analytics platform to convert raw data into intelligent information for use in decision making by customers and the Company; customer engagement solutions; and
4. Project management and ongoing business operations.

**Figure 4-1: AMF Technology Elements**



## 2.2 Implementation Timeline

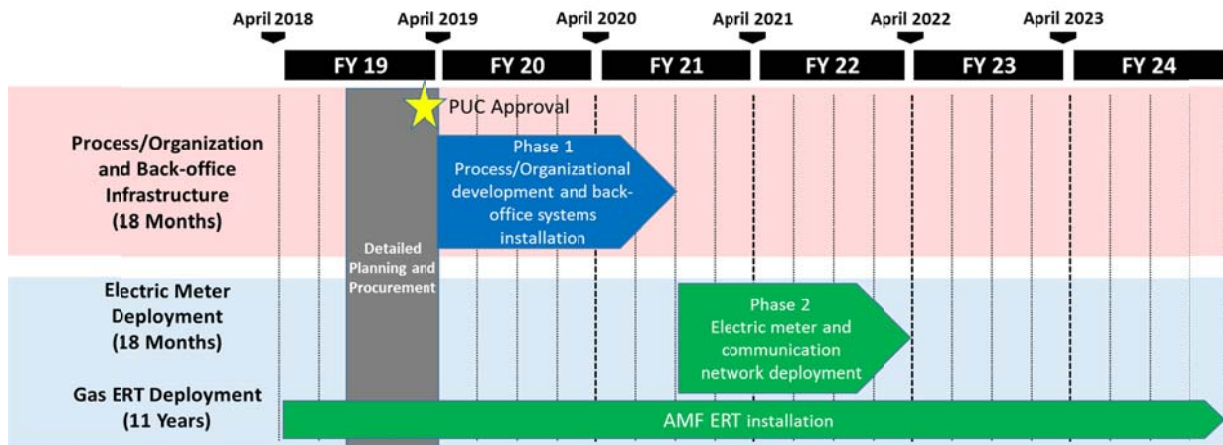
The Company proposed implementation timeline for AMF is illustrated in Figure 4-2. The timeline includes a period for detailed planning and procurement, followed by 18 months of process/organization development and back-office system installation, concluding with 18 months of meter deployment.

During the planning and procurement period, the Company will work with the Division and other interested parties to refine and update its annual AMF plans and conduct a formal design and procurement process to select software, equipment, and support vendors for the program. If the Company undertakes this phase of work in 2018, it is anticipated that the fully costed deployment proposals would be filed with the PUC in January 2019 for approval from April 1 2019.

Following approval of the deployment plan, the Company proposes a three-year timeline for AMF program implementation. Over the eighteen-month period from April 2019 through September 2020, the Company will undertake detailed process design, organizational development, and back-office systems installation. This will involve building and testing end-to-end solutions, developing procedures and training materials, organizing implementation, including training field and office personnel, developing communication materials, and initiating the customer engagement plan.

In October 2020, the Company will commence an 18-month deployment of AMF electric meters and the mesh communication network. The Company estimates that approximately 33% of electric meters will be installed in FY2021, followed by 67% in FY2022. AMF gas ERTs will be installed independent of AMF electric meters, based on the AMR ERT life-cycle replacement program which is estimated to occur over a period of 11 years.

**Figure 4-2: AMF Program Deployment Schedule**



**2.3 Deployment of Time-Varying Rates Program**

AMF technology will allow National Grid to collect utility customers’ energy usage in greater detail than previous technologies will allow<sup>6</sup>. This time-stamped data is the foundation by which new pricing programs can be implemented. Through the provision of more granular, time-variant energy 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 plans to deploy Time Varying Rates (TVR), on an opt-out basis, to customers in conjunction with the AMF program. The Company expects that the rate may consist of two supply pricing components:

**Time of Use** – supply prices would 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,

<sup>6</sup> Section 4.5 provides an overview of why AMR technology is insufficient to deliver the Company’s TVR program

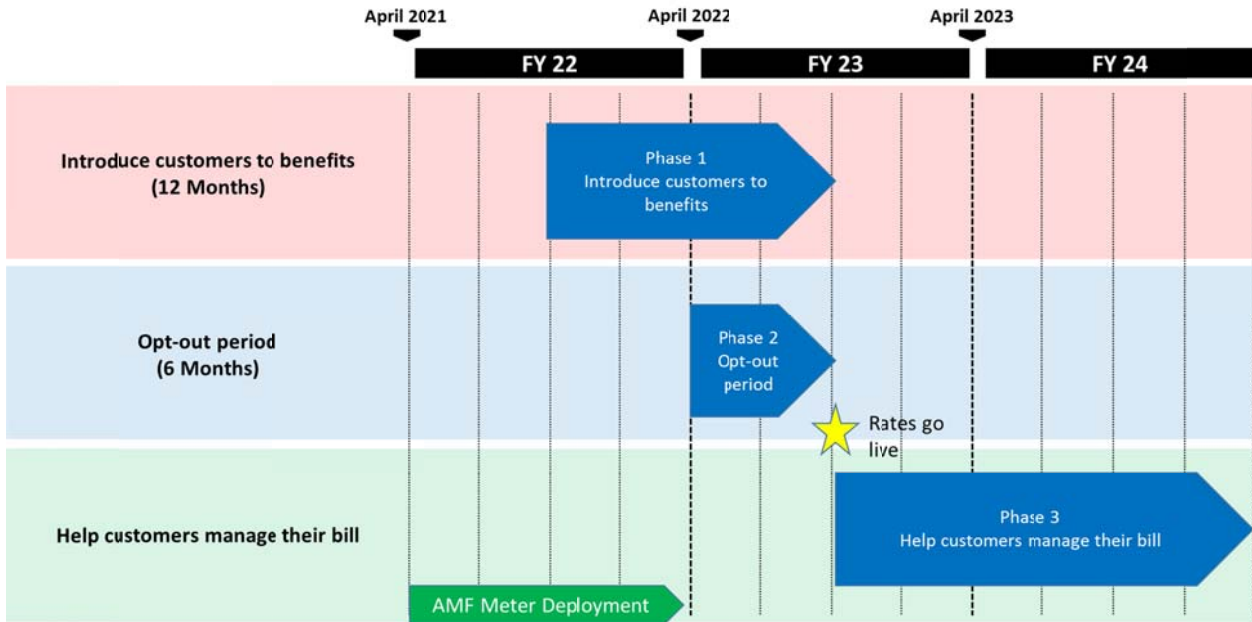
customers save by reducing consumption during higher cost peak periods and/or shifting use from peak to off-peak periods.

**Critical Peak Pricing (CPP)** – supply prices would 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 would be 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.

Based on learnings from the Smart Energy Solutions pilot in Worcester, MA, the Company understands the importance of gradual and ongoing customer outreach and education to introduce new concepts and technologies. The capabilities enabled by AMF will result in fundamental changes in customer access to energy information and their ability to control and manage energy usage. For TVR to be effective, customers must receive sufficient information to interpret and act on the new data and master the new capabilities that will be available to them. The Company proposes a three-phase rollout for the TVR program with a targeted start date of October 2021. This plan is intended to balance the need for customers to have ample time to gain understanding of their energy usage information, the structure of TVR, and their opportunities for achieving savings with the goal of ensuring that the benefits of more efficient rate design are delivered to Rhode Island customers in a timely way. Additionally, it will allow time for testing of the back office and billing processes before the rates go live.

1. Introduce customers to rate structure and benefits (Targeted October 2021 – March 2022): Through the customer engagement plan, the company will introduce the TVR rate structure and present the benefits of transitioning to these rates.
2. Opt out period (Targeted January 2022 – June 2022): The Company will give customers the opportunity to automatically transition to the TVR option or opt-out of this transition and remain on the basic rate. The transition to TVR rates will occur after this period with a targeted go-live date of July 2022.
3. Help customers manage their bills: After the transition to TVR, the Company will continue to work with customers to educate them about their bills and assist them in accessing and using the tools available to understand and control their energy use.

**Figure 4-3: Targeted Time Varying Pricing program deployment schedule**



The Company recognizes the critical nature of a successful rollout of TVR for customers in Rhode Island and considers this to be a major component of its AMF deployment that continues well beyond the installation of advanced meters. As such the Company proposes to work with stakeholders to optimize the design and deployment of these new rate options.

**2.4 Project Costs**

For purposes of this business case and the associated benefit-cost analysis, the Company has leveraged work completed to support AMF filings by its other operating companies, including cost estimates supplied by vendors, to estimate costs for AMF deployment. While National Grid’s affiliates in Massachusetts and New York have proposed similar AMF programs, these plans have not yet been approved by the applicable regulatory agencies. To illustrate the potential synergies of deploying in more than one jurisdiction at the same time, the Company has evaluated two potential deployment scenarios: deployment in Rhode Island only, and deployment in Rhode Island and National Grid’s upstate New York business, Niagara Mohawk. The Company chose Niagara Mohawk for this analysis because the timeline for decision and proposed deployment aligns with the proposed AMF program for Rhode Island. In the event that both programs are approved, the Company will be able to coordinate its deployment efforts across both territories.

Table 4-1 summarizes the estimated costs of the Rhode Island only scenario. Table 4-2 summarizes the estimated costs of the multi-jurisdiction scenario. Appendix 4.1 provides detailed explanations for these estimates.

**Table 4-1 Estimated Costs for the Rhode Island Only Scenario (\$ million)**

<b>Rhode Island Only Deployment</b>	<b>Deployment Period Capital Cost</b>	<b>20 year NPV (FY20\$)</b>
Meter Equipment and Installation	\$98.47	\$83.58
Communication Equipment and Installation	\$4.46	\$7.58
IT Platform and Ongoing IT	\$88.73	\$137.79
Project Management and Ongoing Business Operations	\$5.70	\$30.80
<b>Total</b>		<b>\$259.75</b>

**Table 4-2 Estimated Costs for the Multi-Jurisdiction Scenario (\$ million)**

<b>Multi-jurisdiction Deployment</b>	<b>Deployment Period Capital Cost</b>	<b>20 year NPV (FY20\$)</b>
Meter Equipment and Installation	\$97.92	\$82.68
Communication Equipment and Installation	\$4.12	\$7.06
IT Platform and Ongoing IT	\$53.15	\$72.78
Project Management and Ongoing Business Operations	\$4.58	\$29.09
<b>Total</b>		<b>\$191.61</b>

While these costs are presented to inform PUC evaluation of the Plan, the detailed planning and procurement phase will allow for further refinement of cost estimates for the entire AMF program and help confirm the costs to be included in the FY20 PST Plan, which will be submitted to the PUC for approval in 2019.

### **3. AMF ENABLES THE MODERN GRID EXPERIENCE**

#### **3.1 Diverse and Evolving Customer Expectations**

Consumers are enjoying new and higher levels of service and convenience thanks to the application of advanced technology and big data across industries. Understanding how customers’ diverse and evolving needs manifest in their utility experience is key to developing a more modern grid that creates sustainable value. While reliability and affordability remain the foundation of the Company’s services for its customers, the Company has found through its research that it must respond to an expanding range of customer needs for visibility, control, choice, and convenience in their energy experience. According to an extensive study of customer expectations, including a survey of customers across all of National Grid USA’s service territories, the modern grid experience should address several customer needs.

**Reliability:** Fundamentally, utility customers have an expectation that their power will not go out.<sup>7</sup> Customer response to recent weather events in National Grid service territory and across the country indicates that the demand for a more reliable and resilient grid continues to be paramount.

**Affordability:** When given the right tools, customers will take a more active role to minimize bill costs. For example, customers have shown a willingness to temporarily adjust their energy use in return for bill credits, as indicated by customer research,<sup>8</sup> smart grid pilots completed in other jurisdictions,<sup>9</sup> and by the more than 1,200 residential customers who are already enrolled in the Company's demand response program in Rhode Island.

**Visibility:** Beyond safe, affordable, and reliable power, the Company's customers want personalized, insight-based information on their usage.<sup>10</sup> They also expect this information to be easily accessible. More visible usage and cost information enables better energy management and helps achieve cost savings.<sup>11</sup>

**Control:** Customers want better control over how and when they use power in their homes and businesses.<sup>12</sup> A majority of both residential and commercial customers express interest in devices that can help them manage their energy use, such as "connected" thermostats that can be controlled remotely and that can learn a customer's habits and preferences based upon usage patterns.<sup>13</sup>

**Choice:** Greater level of choice empowers customers—from energy management to clean energy solutions to pricing.<sup>14</sup> Customers also want the ability to choose what communication they receive, when they receive it, and through which channels, in order to personalize their experience.

**Convenience:** The Company recognizes that a key aspect of customer convenience is delivering information and solutions to customers through their most preferred channels. In today's connected world, this indicates an increasing focus on web-based and mobile solutions, allowing customers to manage and optimize energy usage via an "anytime, anywhere" experience.

As customers are presented with more options, the Company will need to deliver solutions in ways that are simple for customers to understand and easy for them to adopt. While consumers express an interest in greater levels of choice, behavioral science research also suggests that overloading consumers with too many choices can result in decision inertia and less satisfaction

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<sup>7</sup> Ninety-five percent of consumers surveyed in a national study indicated that there should be "no" or "rare" outages with the exception of storms. See Bates White Economic Consulting, *Willingness to Avoid Outages: Reliability Demand Survey*, June 2012.

<sup>8</sup> National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.

<sup>9</sup> In the Smart Energy Solutions Pilot conducted in Worcester, Massachusetts, participants responded to peak events to achieve bill savings. See National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.

<sup>10</sup> OPower, *Five Universal Truths About Energy Consumers*, 2013.

<sup>11</sup> National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.

<sup>12</sup> National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.

<sup>13</sup> National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.

<sup>14</sup> National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.

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with an eventual choice.<sup>15</sup> Defaults can also help facilitate better customer decision making as opt-out settings increase participation levels.<sup>16,17</sup>

Automation provides further decision optimization by simplifying or reducing repeatable actions, such as auto-bill pay and "set and forget" features. An industry study on "the new energy consumer" showed that 60% of those surveyed would be interested in technology that could completely automate the management of their electricity use.<sup>18</sup> This type of automation will not be possible without smart meters and a platform that can communicate with smart devices.

### **3.2 Features of the Modern Customer Experience Enabled by AMF**

Recognizing evolving trends in customer expectations National Grid must consider how it delivers a better experience, now and in the future. AMF enables the modern customer experience by collecting consumption data in frequent intervals and allowing customers, the Company, and third parties to access these data in near real time. This has the potential to provide significant benefits to the customer, to the grid operator, and to society. A detailed look at the proposed components and benefits of the AMF program is available in Appendix 4.1.

#### *3.2.1 Customer Benefits*

***More actionable information:*** 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. As a part of the proposal, National Grid will build an energy management portal that will act as a hub for residential, commercial, and industrial customers to view their energy usage, including interval data from smart meters. This will allow customers to take action to adjust their consumption patterns before the bill arrives. Customers will also receive actionable information through other channels such as text messages.

***More pricing options:*** Smarter infrastructure coupled with an enhanced customer platform will enable the Company to offer, in the future, time-varying rates (TVR) in Rhode Island, providing customers with the opportunity to lower their electricity bills by shifting their energy usage to cheaper periods. This has the additional benefit of reducing system demand and energy costs by displacing peak period consumption for activities like electric vehicle charging. AMF will

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<sup>15</sup> Sheena S. and Mark R. Lepper, *When Choice is Demotivating: Can One Desire Too Much of a Good Thing?* Journal of Personality and Social Psychology, 2000, Vol. 79, No. 6, pp. 995-1006.

<sup>16</sup> Richard H. Thaler, *Unless You Are Spock, Irrelevant Things Matter in Economic Behavior*, The New York Times (online), May 8, 2015.

<sup>17</sup> Opt-out default options significantly increase participation, as seen in National Grid's Smart Energy Solutions Pilot in Worcester, Massachusetts, where 95% of participating customers stayed on the default critical peak pricing rate plan and did not opt out. See Navigant, *National Grid Smart Energy Solutions Pilot Final Evaluation Report*, May 2017.

<sup>18</sup> Accenture, *The New Energy Consumer Architecting for the Future*, 2014.

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provide more flexibility in delivering multiple rate options than current AMR meters and will avoid the costs of modifying and upgrading the existing AMR infrastructure to enable TVR<sup>19</sup>.

***Enablement of smart home devices:*** AMF will allow customers to manage their energy consumption through the use of smart devices such as thermostats, water heaters, and other appliances that can be integrated with AMF. Through a home area network, home energy management systems will be able to send and receive secure communications from the Company or third-party market entities. With a customer’s authorization, the system can automatically adjust energy consumption in response to pricing signals and calls for curtailment.

***Access to third party services:*** Company-enabled solutions can be third-party friendly, allowing the private sector to add value above and beyond the scope of what the Company can provide. Collaboration between the Company and other partners can enable a more robust and personalized “energy journey,” with bundled solutions that would not have been possible otherwise. This access will be enabled through the Green Button Connect My Data functionality and will require customer authorization.

***Enhanced customer alerting and personalization tools:*** Customer access to timely, granular information about household energy consumption patterns is an important driver and enabler of behavioral changes and customer actions. These actions can lead to reduced consumption, increased energy affordability, and reduced bill volatility. National Grid Contact Center agents can use this data to propose company programs and offers, enabling more accurate, personalized, appropriate, and actionable offers to customers, and ultimately drive greater program uptake and improved program outcomes.

***Easier move in/out process:*** AMF provides the ability to connect and disconnect electric service remotely and in near real time, reducing the need for manual connects and disconnects. This can improve the experience for customers when starting and stopping service.

### 3.2.2 Operational Benefits

***Volt-var optimization:*** AMF meters can act as end-of-line sensors that provide real-time information to centralized control systems to adjust grid operational characteristics.

***Avoided meter investigation costs:*** AMF meters will reduce in-person visits by diagnosing meter related problems automatically and on demand and by allowing the Company to troubleshoot such problems remotely.

***AMR meter reading:*** AMF meters will send data to the Company through a communications system, reducing the need for AMR meter readers, associated vehicles, and meter reading equipment maintenance.

***Reduction in damage claims:*** AMF will allow for remote interactions that will keep metering service representatives off the road and away from customers’ premises. With fewer opportunities for accidents and damage, damage claims will be reduced.

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<sup>19</sup> More details on our review of the capabilities of AMR meters to deliver time-varying rates are available in Section 3.5



***Storm outage management system improvements:*** AMF will increase visibility during major and minor storms by making it possible to contact meters remotely and determine outage status. Not only does this inform the Company's efforts to restore outages, but increased visibility, in concert with grid modernization efforts, can enable timely notifications to customers about the status of outages.

***Avoided capital and maintenance costs of old systems:*** Existing systems and technology that are in use today will be phased out, avoiding expected maintenance costs.

***Revenue benefits:*** AMF will reduce socialized costs from theft of service, write-offs due to unpaid bills, and the measurement accuracy of existing electro-mechanical meters.

### *3.2.3 Societal and Other Benefits*

***Reduction in greenhouse emissions:*** By helping customers reduce energy consumption and by improving operational efficiencies, AMF may lower emissions.

***Economic development:*** An investment in new infrastructure may result in new jobs and create economic value for the state. Additionally, AMF may result in cost savings, efficiency improvements, and reliability and resiliency gains. By redirecting spending in other sectors of the Rhode Island economy, these investments may generate additional economic benefits.

***More distributed energy resources (DER):*** Rapidly falling costs for solar and energy storage technologies allow customers to generate clean, low-cost energy on site. The Company must continue to enable quick and easy interconnection of these technologies using the best available information about the Company's electric system. AMF can offer more visibility into where DERs can offer the most value to the grid.

***Coordination with other infrastructure:*** The intelligent meters and network infrastructure proposed through the AMF program may have the potential to enhance other infrastructure projects. Examples of this might include sharing networking infrastructure with water utilities, enabling improved controls and sensors for street lighting, and deploying remote gas shutoff valves and methane detectors to customers.

**4. HIGH LEVEL SUMMARY OF ALIGNMENT BETWEEN AMF AND DOCKET 4600 GOALS**

In addition to enabling a modern customer experience, Table 4-3 outlines how the AMF program may advance the state’s Docket 4600 Goals.

**Table 4-3: High-Level Summary of Alignment between AMF and Docket 4600 Goals**

<b>Goals for “New” Electric System</b>	<b>Advances? / Detracts from? / Neutral to?</b>
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances – Gives customers additional tools to reduce their energy consumption and helps the utility improve its operational efficiency. Improves the visibility of DERs on the grid and offer insight into where DERs can provide the most value.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances – Positively impacts GDP and tax revenue, while also creating jobs, generating labor income, and helping build a workforce with the skills and experience required to support Rhode Island’s future as a clean energy economy.
Address the challenge of climate change and other forms of pollution	Advances – Gives customers additional tools to optimize their energy consumption and helps the utility improve operational efficiency.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Advances – Enables time-varying rates and demand response programs, providing the customers the ability to gain value from their energy use and giving them an incentive to invest in devices that will facilitate this control.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Advances – Provides time and location specific information required for DER integration and valuation.
Appropriately charge customers for the cost they impose on the grid	Advances – Provides time and location specific information required for valuation.
Appropriately compensate the distribution utility for the services it provides	Advances – Provides time and location specific information required for valuation.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Advances – Enables new time-varying rate options for customers.

In addition to the stated goals of Docket 4600, the Division has also identified key characteristics that it would like to see in a proposed infrastructure solution. In the PST Phase One Report, the Division identified an interest in infrastructure solutions that eliminate unnecessary investment costs, avoid premature obsolescence, enable authorized third-party access to meter data, and ensure that the investment benefits all customers. This section outlines how the Company plans to address each of these interests.

#### 4.1 Shared Infrastructure Solution

A robust telecommunications system is a foundational component for both AMF infrastructure and the Company's broader grid modernization efforts. The Company sees an opportunity in exploring partnerships with other parties that could share in the cost and benefit from the access to a statewide communications system. Examples of these potential partners include:

- **Local utilities** such as water utilities looking to use the network for their own meter communications;
- **Local agencies** interested in extending or augmenting their E911 system;
- **Municipalities** interested in advancing solutions such as intelligent lighting, warning systems, traffic monitors and environmental sensors;
- **Telecoms providers** trying to reach customers in outlying areas of the state;
- **State agencies or other entities with a mobile workforce** looking to extend or augment their land mobile radio connectivity, particularly in areas of the state where coverage is fragmented or unreliable.

To determine whether a shared network is a feasible option, the Company must first identify other parties that could benefit from the network. The Company will start this search during the design phase of the implementation plan. If the Company finds willing partners, it may then explore ways to structure a potential partnership.

While sharing a network with one or more partners may offer cost-saving opportunities, there are other regulatory, operational, and reputational considerations that should inform the decision of whether to move forward with a partnership. Cybersecurity risks in particular would have to be addressed to ensure the confidentiality of sensitive customer information.

#### 4.2 Upgradability of Infrastructure

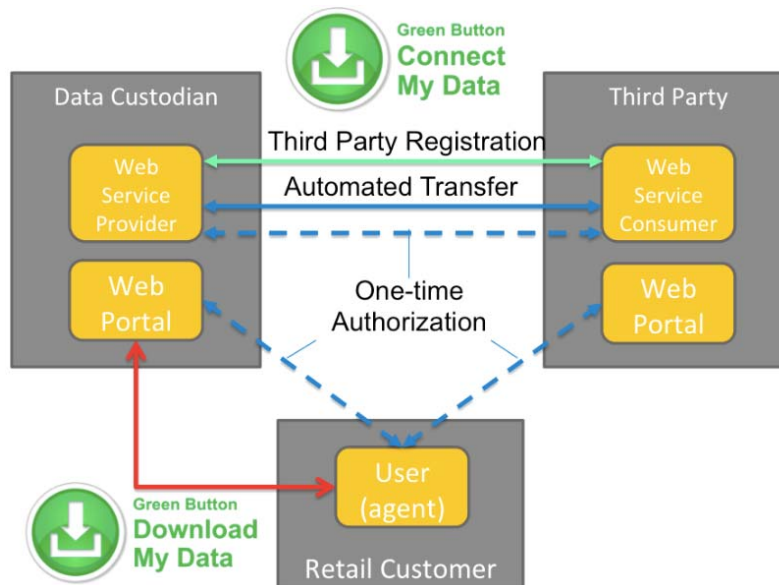
The implementation of AMF functionality introduces an increased risk of technology obsolescence. To mitigate this risk, National Grid will leverage open integration standards and protocols coupled with outsourcing of key system components to ensure maximum technology agility in the future. Vendor-hosted back-office systems coupled with third-party communication networks will provide the ability to cost-effectively adapt to new technological advances in the AMF industry. Furthermore, the metering technology will be adaptable to firmware upgrades and integration with home area network devices.

### 4.3 Third-Party Access

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 4-3. Upon authorization, energy usage data can be transferred as required. Making these data accessible to third parties is critical to animating the market and driving innovation.

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



### 4.4 Accessibility for Income Eligible Customers

While the cost of energy service impacts all National Grid customers, this cost is a larger burden for Rhode Island's Income Eligible customers. A 2016 study from the American Council for an Energy-Efficient Economy (ACEEE) found that customers across the 48 largest metro areas in the US with a household income of \$25,000 or less spend 7.2% of their income on energy utility bills.<sup>20</sup> Compared to the average household, which spends 3.5% of household income on energy utility bills, these Income Eligible households are disproportionately burdened. This contrast is even starker in Providence, where the same study found that customers in the Income Eligible bracket spend, on average, 9.4% of their income on utility bills.

<sup>20</sup> ACEEE, *Lifting the Energy Burden in America's Largest Cities*, 2016.

Based on past experience, there is evidence that Income Eligible customers are interested in, and benefit from, the cost-saving programs delivered by a smarter grid. For example, in the Smart Energy Solutions (SES) Pilot completed in Worcester, Massachusetts, 93% of participating low-income residential customers remained on the default time-varying rate (time of use with critical peak pricing) and did not opt out.<sup>21</sup> Evaluation of the SES Pilot found that:

- Income Eligible customers achieved savings similar to other customers in two of the three customer groups examined in the Pilot. Of the three technology/price groups examined, Income Eligible customers in two of the groups had savings that were not statistically different from the larger group.<sup>22</sup>
- Income Eligible customers reported having the ability to shift their energy use, according to the pre-Pilot and end-of-Pilot surveys that the Company conducted. While not measured explicitly, the Company expects that low-income customers benefited from having access to time-varying rate plans. This is because these customers are less likely to have air conditioning, which means that their load profiles are flatter than those of the average customer, resulting in comparatively lower energy usage during peak times.<sup>23</sup>

#### **4.5 Alternative Metering Options for Delivering Time-Varying Rates**

In an effort to deliver a modern customer experience while minimize costs, the Company has reviewed the option to deliver time-varying rates through the existing AMR meters. Through this review, the Company has found that, while delivering a basic time-varying rate option is technically feasible with AMR infrastructure, there are significant operational challenges and necessary capital upgrades that when compared to investment in AMF may make this option less beneficial to customers overall. Furthermore, relying on AMR meters limits the flexibility to make future changes or enhancements to the rate options offered to customers.

As they are currently set up, the Company's existing AMR meters cannot support time-varying pricing. In particular, the single radio, or encoder receiver transmitter (ERT) that is used to transmit data to the Company does not have the sufficient capacity to deliver the data needed for a time-varying rate program. Typically, the single ERT meters simply 'bubble up' the register reading to capture total usage. In this way, a vehicle driving by once per month equipped to read the ERT can take monthly meter readings and send this information along to a billing engine for monthly billing.

To make time-varying rates feasible with AMR, the existing meters would have to be upgraded to a triple ERT meter. A triple ERT meter, or a meter with three radios, is traditionally used to

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<sup>21</sup> The participation rate in time of use/critical peak pricing among non-low-income residential participants at 96% was in a similar range of that of low income participants

<sup>22</sup> These two groups were "Level 1 CPP Active" and "Level 1 CPP Passive". "Level 1 CPP Active" are customers who were on the Critical Peak Pricing Plan in the SES Pilot (which has on-peak and off-peak rates all of the time, and higher critical peak prices during peak events), or who had visited the Energy Management Portal for the SES Pilot and were on the default technology package for the SES Pilot. "Level 1 CPP Passive" customers were those on the time of use/critical peak pricing plan who had not visited the Energy Management Portal.

<sup>23</sup> The Brattle Group, *Low Income Customers and Time Varying Pricing: Issues, Concerns, and Opportunities*, 2015.

capture the register read for total usage, and peak demand, by collecting peak kW, peak kVA, or peak kVAR. The meter is read in the same way by a vehicle equipped to capture this data which is then sent for billing. In lieu of capturing total energy use and peak demands, three ERTs can be programmed to capture consumption over a set window. For example, one ERT would still be used to capture the register read, one could be used to capture all electricity consumed weekday peak periods, and the last one could be used to capture use on weekday off-peak periods. By using the data from all three ERTs, the Company could then calculate the use not captured in these periods.

There are a number of considerations that should be taken into account when evaluating the use of triple ERT meters as an enabler for time varying rates:

- A comparison of the costs and benefits of a triple ERT approach may provide lower net benefits to customers than the proposed AMF deployment;
- Modifying the time-varying pricing setup is challenging. If the intervals need to be modified, then the meter would need to be removed from the field and re-programmed, and then re-installed, severely limiting the ability to modify time-varying pricing windows without significant expense;
- Flexibility is limited for program expansion: The three ERT setup requires programming the meter to capture whatever intervals of time are desired, but is limited to three intervals.

A triple ERT meter is limited to a simple time of use structure, and would have none of the other attributes of an AMF system, such as remote outage notification, over the air programming to modify the parameters in the meter, and precise interval metering that can then be used with an infinite number of time of use rate structures as needed.

## **5. LESSONS FROM MASSACHUSETTS SUPPORT THE BUSINESS CASE IN RHODE ISLAND**

### **5.1 Lessons from our Smart Energy Solutions Pilot in Massachusetts**

The business case for an AMF program in Rhode Island is built upon knowledge gained through previous and ongoing AMF pilots across National Grid's jurisdictions. Pilots, conducted in Worcester, Massachusetts and Clifton Park, New York, have tested, and continue to test, a number of AMF elements. In particular, lessons learned from the Company's Massachusetts Smart Energy Solutions Pilot have enabled a more aggressive deployment schedule to be proposed, with higher certainty around expected benefits and less uncertainty around technology.

Below are several concrete examples that were tested in the Company's Smart Energy Solutions pilot in Worcester. These examples align with Rhode Island's goals and objectives, and are reflected in the proposal:

- Customer response to new time varying rates
- Benefits and effects of in-home technology, including an energy management portal
- Best practices for customer engagement, outreach, and education
- Benefits of information on real-time energy usage for reducing customers' peak energy use through incentives

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This two-year pilot<sup>24</sup> involved around 11,000 participants and provided important insights regarding customer engagement:

- An opt-out program design is a viable strategy that recruited more participants than an opt-in design would have;
- Residential customers enrolled in the default time-varying rate (time of use with critical peak pricing) achieved average per-customer bill savings of \$236 over the two years of the pilot;
- Enrolled customers reduced load by 4% to 31% during times of critical peak demand;
- After two years, the pilot had a 98% customer retention rate—higher than many comparable opt-in programs;
- More than two-thirds (69%) of customers rated their satisfaction with the pilot at least a 5 on a 7-point scale;
- The availability and utilization of a customer-centric energy management portal delivered incremental benefits for customers in terms of better understanding and optimizing their energy usage, including an incremental 10% reduction in load during critical peak periods; and
- Customers want personalized information and simplified communication channels.

Beyond confirming that AMF offers customer benefits, the pilot provided information about how best to deploy AMF technology and market customer-facing programs. These results demonstrate and validate the value this kind of investment produces for customers and for the system overall.

## 5.2 VVO / Advanced Metering pilot for Rhode Island

The Company hopes to expand on what it has learned from its existing pilots, and to enhance the value of VVO technology, through the proposed small-scale deployment of 16,000 AMF meters filed in the Infrastructure, Safety, and Reliability Plan (ISR) earlier this year. This deployment will offer additional insight into conceptual operational benefits that have not yet been tested in any jurisdiction, identify conditions that are unique to Rhode Island that can impact widespread deployment, and help the local workforce better understand AMF technology and its implementation requirements. Several elements of the AMF program will be tested:

- **Volt-VAR Optimization**—The primary focus of this deployment is to integrate interval voltage data from advanced meters into optimization algorithms to improve system efficiency;
- **New Meter and Communications Technology**—This deployment will use the latest generation meter technology, which includes new features such as load disaggregation and locational awareness; and
- **Installation and Integration**—National Grid will have the opportunity to work with Rhode Island to deploy AMF technology on a small scale and incorporate learnings into the full deployment.

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<sup>24</sup> The Smart Energy Solutions pilot in Worcester continues to operate In 2017 via an interim extension granted by the Massachusetts Department of Public Utilities in late 2016.

The initial deployment is proposed to be completed by FY2019. This gives the Company 18 months to integrate lessons learned into the design and operation of the full-scale AMF deployment, which is proposed to start in the second half of FY2021.

Based on projects underway across all its jurisdictions, the Company believes it is well positioned to deliver the value expected from AMF deployment, and therefore no additional demonstrations are necessary before undertaking full-scale deployment.

## **6. AMF PROGRAM IMPLEMENTATION**

### **6.1 Customer Engagement (Education & Outreach)**

#### *6.1.1 Objective and Approach*

The objective of the Company's customer engagement plan is to build customer awareness and interest—both in grid modernization more broadly and in the AMF technologies needed to enable grid modernization. By engaging customers proactively, the Company hopes to eliminate potential adoption barriers, encourage participation, and facilitate the transition to AMF meters.

National Grid's customer-centric customer engagement plan will be based on foundational insights and analytics gained through past efforts:

- The Company's prior experience in AMF deployment through its two Smart Energy Solutions pilots in Worcester.
- Incorporation of research, findings, and best practices from other utility AMF deployments across the country.
- The Company's vast experience and expertise in customer communication, promotion, and implementation of award-winning energy efficiency programs throughout Rhode Island.

National Grid's customer research has found that there is low familiarity with smart meters and grid modernization, but many customers are interested in learning more.<sup>25</sup> As mentioned in earlier sections, AMF and its enabling technologies will deliver on customers' need for information and personalized options that provide greater transparency, convenience, choice, and control. Nonetheless, the Company recognizes that communicating the spectrum of benefits achievable with advanced metering technologies may be challenging, as utilities have been historically perceived as a transactional, low-interest category. For these reasons, robust and proactive customer communications, supported by research and by a strong brand built on a foundation of trust, will be a crucial factor in successfully implementing AMF and in paving the way to other grid modernization initiatives.

The goals of the customer engagement plan are to:

- Educate customers on grid modernization offerings, including time-varying pricing, in advance of the deployment of AMF in their communities to eliminate potential adoption barriers;

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<sup>25</sup> National Grid, *Value Proposition Research: A Study of 3 Energy Solution Areas*, 2017.



- Build interest in and awareness of the elements of the AMF program to drive participation;
- Ensure a smooth transition process for customers; and
- Shift the focus, after an initial period of driving awareness and building interest among customers, to supporting continued customer engagement and satisfaction.

National Grid’s customer engagement strategy will be carefully planned to match the geographic deployment of AMF technologies and its communications lifecycle will be repeated in various territories until meter deployment is completed. The plan will focus on customers’ experiences and needs at different stages of the deployment process by:

- Building awareness and generating interest prior to meter installation;
- Driving participation and providing connection/transition assistance during rollout, while continuing to build interest; and
- Focusing on customer satisfaction while continuing to drive participation once meters are deployed.

The plan will be divided into three phases (pre-implementation, implementation, sustainability) and align with the areas of focus noted above.

#### Phase 1: Pre-Implementation

Engaging customers and stakeholders prior to the launch of a new program is considered general best practice in terms of effective outreach, engagement, and communications. National Grid will use advertising and other communications mechanisms in the months leading up to market activation and meter installations. At this stage, customers have low familiarity with AMF technology. Thus, the goal in this phase is to eliminate adoption barriers by educating customers about the benefits of grid modernization, and about the “what, why, when, and where” of grid modernization initiatives.

Steady marketing during the pre-implementation phase will be designed to build awareness and momentum by increasing the number of customers willing to learn more about grid modernization technologies and company initiatives. National Grid will leverage research, messaging strategy, and market factors to evaluate and adjust the media channel mix as needed to optimize its education and outreach efforts, while staying within the proposed budget.

#### Phase 2: Implementation

As meters are deployed, it will be important to engage customers through education and outreach. At this point, customer engagement activities will begin to move in parallel paths.

The Company will communicate with customers who can now take advantage of AMF on topics such as: enrollment/opt-out process, timing, installation, functionality, benefits and time-varying rates. At the same time the Company will be continuing to drive participation for customers who do not yet enjoy AMF technology.

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### Phase 3: Sustainability

Continued communication will help create and maintain trust and customer satisfaction, which in turn will enable deeper customer engagement. After the effort to drive awareness and build interest among customers, the customer communications strategy will shift to supporting continued customer engagement by addressing any ongoing customer issues while also promoting and sharing success stories about highly-engaged customers.

#### *6.1.2 Supporting Communications and Tactics*

##### Digital Channels

- Email provides a critical channel to share program information and updates, promotions, tips, success stories, and more, whether through stand-alone messages or e-newsletters.
- A dedicated and mobile-capable web page will serve as the external communications AMF landing page, with topics that include benefits, functionality, contact information, downloadable forms, and more.
- Social media platforms are an effective way to reach wide and customized audiences to share personalized content and updates, while collecting and analyzing real-time data. These platforms are also critical for social listening.

##### Mass Media

Radio and newspaper are cost-effective channels for reaching broad audiences within defined rollout markets, and for building frequency and message retention to:

- Increase customer familiarity with AMF, pique interest, and address adoption barriers in the months leading up to the market activation and meter installations.
- Maintain customer engagement and satisfaction after deployment and installation, and as new energy management technologies become available.

##### Collateral

- Bill inserts and customer newsletters featuring AMF information, tips, success stories, and more can be included in customer bills.
- Brochures can be distributed to customers and stakeholders at community events, town hall meetings and presentations, trade shows, etc.
- Direct marketing tools, such as door hangers and postcards, will be leveraged to communicate directly with customers during the transition process.

##### Call center support:

AMF scripts, talking points, and job aids would be available to support customer calls and to ensure call center staff alignment.

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## In-Person

Face-to-face engagement will offer the opportunity to educate customers on the benefits of grid modernization technologies and to answer questions, while also obtaining immediately valuable feedback and data. The Company plans to leverage various venues and activities for face-to-face engagement, including community events and town halls organized in collaboration with town and community leaders, sporting events and sponsorships, and the Rhode Island Energy Innovation Hub, among others. In-person engagement will be a critical tactic for reaching certain customer groups, including elderly and low-income customers.

### *6.1.3 Customer Insights*

Customer insights will remain a constant component of the customer engagement process to measure the effectiveness of the Company's communications efforts and to identify changes in customer perceptions about grid modernization solutions. Periodic surveys will allow National Grid to implement a "listen, test, learn" approach, which includes listening to what customers say their needs are, using that information to test and measure different messages and communication tactics, and using the results to improve approaches along the way. Survey results will be used to understand customer awareness, sentiment, and interests so that messages and communications channels can be adjusted as needed over the course of the meter installation period and time-varying rate offerings.

Messaging studies will be conducted to test customer priorities, language effectiveness, and communications preferences in the early stages of AMF rollout. Post-rollout, it will be important to test and adjust messages as the market matures and awareness builds. Awareness studies will be conducted to track the effectiveness of National Grid's customer engagement efforts with respect to grid modernization and AMF. Satisfaction studies will be fielded after meters have been installed to assess customers' overall satisfaction with the installation process and to ask about any changes customers might have made in their energy use.

## **6.2 Customer Opt-Out of AMF Meters**

Customers will be given sufficient advance notice, via mail, of plans to install AMF meters and of the opportunity—and procedure to be followed—to opt out of the AMF metering program if they wish. Processes and resources will be in place to support customers who are considering or have decided to opt out. Electric customers who opt out of the program will have an AMF meter installed with the communication capability deactivated. Gas customers who opt out will not have the gas ERT installed. Customers who opt out will have their meters read manually on a monthly basis and will be subject to charges per the terms and conditions specified in the Company's opt-out meter reading tariff.

## **6.3 Meter Deployment Planning**

The Company is planning an 18-month electric meter implementation cycle beginning mid-FY2021 and ending FY2022. Actual electric meter deployment may vary from this assumption based on a number of considerations such as deployment area customer density and benefit realization. The Company plans to develop a more detailed deployment plan in FY2019. As part

of National Grid's programmatic approach, the exact nature of meter deployment will need to be designed and planned to include timing of meter purchase, staging, resource scheduling, management oversight, etc.

#### **6.4 Systems Integration Plan**

System integration is key to harnessing the full magnitude of smart meter benefits across National Grid's infrastructure of devices, software, and systems. Only by enabling data exchange between meters and routers, routers and systems, and systems with other systems is it possible to maximize the effectiveness of the overall platform. As such, various costs associated with information technology and systems integration were included in the AMF business case model. A well-structured approach to systems integration will include the following:

- Capability analysis and end-to-end definition of functionality at each step;
- Systems architecture to define data interfaces between systems and components;
- Detailed requirements definition for all systems and interfaces;
- Custom configuration and development of system application programming interfaces (APIs);
- Detailed test case planning and definition; and
- Careful test execution and defect documentation.

AMF platforms 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 affected systems.

In addition to a functional platform, other benefits of strong systems integration include:

- Improved system response time and performance;
- Lower labor costs and increased operational efficiency; and
- Compatibility across system devices and software.

#### **6.5 Process Design**

Engaging stakeholders within the Company to update processes is critical to successful AMF deployment. Many Company employees will be impacted by this deployment, including meter field technicians, meter shop technicians, customer service representatives, control center operators and billing analysts. Each role will be changed to some degree to accommodate the incorporation of this new technology. To aid in a smooth transition for customers and employees, defining how people will use these technologies is just as important as defining what the technologies are capable of doing. A strong process will include several elements.

**Detailed Definition of System Processes and Requirements:** The Company will conduct workshops with subject matter advisors, vendors, end-users, information systems and technology representatives, and other key stakeholders to gather, define, and document business processes for the new systems. These sessions, particularly the ones that address integration, will uncover additional business, functional, non-functional, performance, technical, data, integration, and transitional requirements.

**Process Design and Organizational Impacts:** The Company will create process flow documents to facilitate stakeholder agreement concerning key sequences, activities, and organizational divisions. The Company will refine processes by documenting requirements, inputs/outputs, contemplated customizations, organization/change impacts, key performance indicators, dependencies, business rules, data needs, data flows, reporting considerations, etc.

**Cross-Workstream Integration:** Teams across the business will work together to ensure shared understanding of solutions that are being designed and tested.

## **6.6 Vendor Selection and Management**

The Company's proposed approach to the detailed design phase of its AMF program includes time to engage with vendors to explore innovative AMF solutions. This will be followed by requests for proposals and engagement in competitive and strategic negotiations with vendors to obtain the best prices and design solutions for customers. The Company's governance framework will manage and oversee the vendor selection process while considering various factors, including vendor reputation, current and future delivery costs, prior industry experience, risk mitigation, and reporting protocol.

## **6.7 Back-Office Upgrades and Communication Network Installation**

After detailed design and procurement and prior to meter deployment, National Grid will install/upgrade the appropriate back-office systems to be able to handle incoming interval meter data. Additionally, the Company will develop procedures and training materials and ensure the relevant field and office personnel are appropriately trained.

## **7. Quantitative Benefit-Cost Analysis**

This section discusses the results of the Company's BCA for the proposed AMF program. A detailed look at the benefit and cost assumptions used in the analysis can be found in Appendix 4.1.

### **7.1 Framework for the Benefit-Cost Analysis**

The Company's BCA utilizes the societal cost test (SCT), which accounts for operational benefits to the Company, as well as benefits experienced by customers, reductions in resource requirements (e.g. generation capacity, energy use), and reductions in externalities such as carbon emissions. The SCT does not treat transfers between parties (such as reductions in theft of service, reductions in write-offs, and improved accuracy of electromechanical meters) as benefits or costs. As described in Chapter Two the Company utilized its Rhode Island cost-benefit methodology to quantify the benefits and costs of AMF deployment. Appendix 4.2 sets out that methodology.

Tables 4-4 and 4-5 summarize the categories of benefits and costs included in the societal cost test for this program.

**Table 4-4: Benefits Included in BCA**

<b>Category</b>	<b>Benefit</b>	<b>Societal Cost Test</b>
Avoided O&M Costs	AMR Meter Reading	X
	Meter Investigation	X
	Remote Connect and Disconnect	X
	Reduction in Damage Claims	X
	Storm OMS Benefit	X
	FCS Meter Reading	X
	Interval Meter Reading	X
Avoided AMR Costs	Capital	X
	Operations & Maintenance	X
Customer	Volt-VAR Optimization	X
	Energy Insights/High Usage Alerts	X
	Time Varying Rates	X
	Electric Vehicle Pricing	X
Societal	Reduction in Greenhouse Gas Emissions	X
Revenue	Reduction in Theft of Service	
	Reduction in Write-offs	
	Electromechanical Meter	

**Table 4-5: Costs Included in BCA**

<b>Category</b>	<b>Cost</b>	<b>Societal Cost Test</b>
Meter Equipment and Installation	Electric Meters	X
	Gas ERTs	X
	Meter and ERT Inventory	X
	Support Infrastructure	X
Communication Equipment and Installation	Network Equipment and Install	X
	Backhaul	X

Category	Cost	Societal Cost Test
IT Platform and Ongoing IT Operations	AMF Head-end and Meter Data Management Systems	X
	Customer Service System	X
	Customer Engagement Products and Services	X
	IS Infrastructure	X
	Cyber Security	X
Project Mgmt. and Ongoing Business Operations	Project Management	X
	Equipment and Installation Refresh Cost	X
	Ongoing Business Management	X
	Customer Engagement Cost	X

## 7.2 Discount Rates

The present value of costs and benefits are discounted back to FY2020 (when costs are first incurred) using the National Grid weighted average cost of capital (“WACC”) as the discount rate. The after-tax WACC (7.51%) is used for the SCT since taxes are considered income transfers and are excluded from the societal test.

## 7.3 Summary of Benefits and Costs

Two scenarios were evaluated: one considers AMF implementation in Rhode Island only; the other considers a joint implementation effort that encompasses Rhode Island and the New York Niagara Mohawk service territory.<sup>26</sup> The latter achieves cost synergies in the IT platform and project management areas. In the multi-jurisdiction scenario, assets and systems would be deployed by the service company, and rental expenses would be allocated to the appropriate operating companies that benefit from these assets and systems once they are placed in service.

For each of the implementation scenarios, four pricing sensitivities were evaluated based on the range of time-variant pricing benefits described and included in Appendix 4.1. Results for each of the scenarios are presented in Tables 4-6 and 4-7 below.

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<sup>26</sup> National Grid also developed a business case for an AMF program in Massachusetts, which is currently under review. If this program were to move ahead, additional synergies would further increase the Benefits/Costs ratio.

**Table 4-6: Rhode Island Only Implementation Societal Test Benefits and Costs**

Category	Component	Scenario 1 Opt-in w/ Low Savings	Scenario 2 Opt-in w/ High Savings	Scenario 3 Opt-out w/ Low Savings	Scenario 4 Opt-out w/ High Savings
Costs 20 Yr NPV (\$ Million)	Meter Equipment and Installation	\$83.58	\$83.58	\$83.58	\$83.58
	Communication Equipment and Installation	\$7.58	\$7.58	\$7.58	\$7.58
	IT Platform and Ongoing IT	\$137.79	\$137.79	\$137.79	\$137.79
	Project Management and Ongoing Business Operations	\$30.80	\$30.80	\$30.80	\$30.80
	Total Costs	\$259.75	\$259.75	\$259.75	\$259.75
Benefits 20 Yr NPV (\$ Million)	Avoided O&M Costs	\$52.64	\$52.64	\$52.64	\$52.64
	Avoided AMR Costs	\$66.49	\$66.49	\$66.49	\$66.49
	Customer	\$68.99	\$122.61	\$87.44	\$162.02
	Societal	\$16.40	\$35.01	\$22.65	\$47.50
	Total Benefits	\$204.52	\$276.74	\$229.22	\$328.65
B/C Ratio	Societal Cost Test	0.79	1.07	0.88	1.27

**Table 4-7: Rhode Island and New York Joint Implementation Societal Test Benefits and Costs**

Category	Component	Scenario 1 Opt-in w/ Low Savings	Scenario 2 Opt-in w/ High Savings	Scenario 3 Opt-out w/ Low Savings	Scenario 4 Opt-out w/ High Savings
Costs	Meter Equipment and Installation	\$82.68	\$82.68	\$82.68	\$82.68
	Communication Equipment and Installation	\$7.06	\$7.06	\$7.06	\$7.06
	IT Platform and	\$72.78	\$72.78	\$72.78	\$72.78



<b>Category</b>	<b>Component</b>	<b>Scenario 1 Opt-in w/ Low Savings</b>	<b>Scenario 2 Opt-in w/ High Savings</b>	<b>Scenario 3 Opt-out w/ Low Savings</b>	<b>Scenario 4 Opt-out w/ High Savings</b>
	Ongoing IT				
	Project Management and Ongoing Business Operations	\$29.09	\$29.09	\$29.09	\$29.09
	Total Costs	\$191.60	\$191.60	\$191.60	\$191.60
<b>Benefits</b>	Avoided O&M Costs	\$52.64	\$52.64	\$52.64	\$52.64
	Avoided AMR Costs	\$66.06	\$66.06	\$66.06	\$66.06
	Customer	\$68.99	\$122.61	\$87.44	\$162.02
	Societal	\$16.40	\$35.01	\$22.65	\$47.50
	Total Benefits	\$204.09	\$276.31	\$228.79	\$328.22
<b>B/C Ratio</b>	Societal Cost Test	1.07	1.44	1.19	1.71

These results demonstrate that the Rhode Island-only implementation scenario has a positive BCA ratio for the high savings TVR sensitivity cases, while the Rhode Island and New York joint implementation scenario has a positive BCA ratio across all four TVR sensitivity cases.

The results of the BCA show that full deployment of AMF can achieve a net positive benefit-to-cost ratio in both scenarios, additional qualitative benefits have also been taken into consideration. These qualitative benefits are described in Table 4-8.

**Table 4.8 Qualitative Benefits of AMF Deployment**

Category	Description / Examples
Societal	<p>AMF will provide the infrastructure and capabilities necessary to enable customers to reduce overall peak demand and energy usage, thereby improving grid reliability and resiliency. Improved reliability and resiliency can reduce the risk of blackouts and sustained blackouts during peak energy demand periods and disasters.</p> <p>AMF will provide a necessary component that enables grid modernization and will assist with building the foundation to support fundamental changes in future energy usage for customers, including the integration of distributed energy resources.</p> <p>The AMF program can generate awareness and greater uptake of alternative energy and cost-saving opportunities.</p>
Economic	<p>AMF has the potential to help customers make better-informed energy decisions, promoting reduced energy costs and reduced peak demand. Lowering costs can reduce strain on financially challenged individuals while also provide additional funds for spending in other areas, which could boost economic activity.</p> <p>AMF allows granular electricity and gas consumption data to be available to customers and approved third-party vendors in a timely and efficient manner. Data can provide quicker decision making for both the consumer and third-party vendors.</p> <p>As other grid modernization efforts develop, AMF infrastructure provides data that can support the effort to deploy grid and DER technologies, replacing other potentially capital intensive data collection strategies.</p>
Educational	<p>The AMF program has the potential to raise customer awareness about opportunities to save costs through improved energy efficiency. Data can be used directly—for example, to help customers learn where to adjust their energy usage. Data can also be used indirectly—for example, to gain a broader understanding of how implementing improved energy technologies can save energy and reduce costs.</p> <p>The AMF initiative could be used to develop educational materials on programs that promote increased energy efficiency, grid stability, and resiliency.</p> <p>Metering data can be used to inform utilities and other entities involved in the energy supply chain to make more informed and effective decisions.</p>

Environmental Externalities	<p>Potential to reduce environmental impacts (e.g., greenhouse gas emissions) as a result of energy conservation enabled by advanced metering infrastructure.</p> <p>Potential to increase awareness of environmental issues associated with different energy technology choices.</p> <p>Support state and federal programs aimed at shifting toward greater reliance on clean, renewable technologies and reduced use of older, less efficient energy sources.</p>
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**8. CONCLUSION**

The advanced meter functionality proposed in this chapter is a foundational element of the Company’s effort to meet evolving customer expectations and advance the state’s goals set out both in Docket 4600 and more recently, Power Sector Transformation. Not only will this functionality enable more visibility, choice, control, and convenience for customers, but it will continue to allow for safe, reliable, and affordable delivery of energy services. The results of the BCA test show that, based on quantifiable benefits delivered to customers and the grid, a full deployment of AMF can achieve a net positive benefit to cost ratio in both the Rhode Island only deployment scenario and the Rhode Island and Niagara Mohawk joint deployment scenario. Delivering the quantifiable benefits included in the BCA, along with the non-quantifiable societal, economic, educational, and environmental benefits, is critical to the state’s transformation effort.

To deploy AMF while managing customer bill impacts, the Company has proposed to implement a new annual PST Plan that will enable a staged approach to project development and approval. Approval of the initial \$2 million revenue requirement will enable the company to embark on the next phase of design, including further exploration of partnerships, stakeholder input and a procurement exercise to refine costs. The Company looks forward to working with stakeholders to design and implement an AMF program that advances Rhode Island’s goals and delivers meaningful benefits to customers, the grid, and society.



Schedule PST -1,  
Chapter 5 - Electric Transportation

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**CHAPTER FIVE: INVESTING IN A CLEAN ENERGY FUTURE**  
**ELECTRIC TRANSPORTATION INITIATIVE**

*The Company proposes a portfolio of three programs that support both National Grid's and the State's commitment to investing in a clean energy future: transportation electrification, heat electrification, and storage. This chapter details the Electric Transportation Initiative, and Chapters Six and Seven detail the Company's Electric Heat and Energy Storage Systems Initiatives, respectively.*

**1. INTRODUCTION**

The Company's Electric Transportation Initiative highlights the importance of the role of the utility in transportation electrification, as set forth in the Beneficial Electrification Principles drafted by the PUC staff and included in the PST Phase One Report. A strong utility role may be the key to growing Electric Vehicle (EV) adoption and scaling the market for EV charging hardware and software in line with the State's goals, and the Company is proposing to undertake this important role. This Initiative seeks to address our customers' and stakeholders' growing interest in transportation electrification, while advancing a number of Rhode Island policy goals.

**2. ABOUT THE PROJECT**

National Grid has the expertise, responsibility, and long-term view required to support Rhode Island in providing adequate, efficient, and economical transportation energy advancing the State's long-term energy and climate policy goals. The PST Phase One Report reflects the view of both commenters and Project team (comprised of the PUC, DPUC, and OER) agree that the utility, as manager of the electric grid, will play a key role in transportation electrification. Today, the Company owns and operates 49 charging station locations (102 ports) across Rhode Island, comprising approximately 60% of the 82 public charging station locations established to date in the state.<sup>1</sup>

New goals under the Rhode Island Zero Emission Vehicle (ZEV) Draft Plan call for growing EV adoption more than 40-fold (from approximately 1,000 to 43,000) by 2025, and the Executive Climate Change Coordinating Council (EC4) greenhouse gas emissions reduction scenario targets the electrification of 34% of on-road vehicle miles traveled by 2035 and 76% by 2050.

After many years of development, EVs are approaching a tipping point in cost and performance, positioning them for broad consideration by our customers. Despite the promise of vehicle technologies, however, the market for light-duty and heavy-duty EVs in Rhode Island remains in its infancy, relative to the State's near-term greenhouse gas and ZEV policy targets.

The Company is proposing a three-year, multi-part Electric Transportation Initiative to meaningfully accelerate electrification of transportation in Rhode Island through multiple market development strategies. The Initiative is comprised of six components:

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<sup>1</sup> Data according to the US Department of Energy's Alternative Fueling Station Locator, as of October 24, 2017: <https://www.afdc.energy.gov/locator/stations/>.

**Table 5-1: Electric Vehicle Proposed Initiative Components**

<b>Company’s Proposed Initiative Components</b>
1. Off-Peak Charging Rebate Pilot
2. Charging Station Demonstration Program
3. Discount Pilot for Direct Current Fast Charging Station Accounts
4. Transportation Education and Outreach
5. Company Fleet Expansion
6. Initiative Evaluation

**2.1. Off-Peak Charging Rebate Pilot**

Home charging is the most convenient and affordable source of vehicle charging for most consumers, and meets most drivers’ daily needs. The Company’s residential customers pay about 20 cents per kWh today,<sup>2</sup> obtaining a cost savings relative to gasoline of about 33 percent.<sup>3</sup> Charging an EV at home, however, can impose significant new load on a residential circuit, depending upon the voltage level and charger type.<sup>4</sup> Given the size of this load, the Company sees an opportunity for cost avoidance from encouraging EV charging off-peak, while further increasing EV drivers’ savings opportunity relative to gasoline.

The Company proposes to offer an Off-Peak Charging Rebate as a pilot to evaluate a simple and convenient way to reward customers for charging their EV during off-peak hours, while expanding customers’ awareness of their charging costs and benefits, and obtaining customer charging time and power level data.

The Company seeks to achieve several objectives through the Off-Peak Charging Rebate Pilot:

- Offer EV drivers a simple and convenient way to benefit from charging their EV off-peak, aligning charging with off-peak hours;
- Study customers’ charging patterns (kW and kWh) across a variety of charging locations and levels (Level 1, Level 2, DC), and their responsiveness to time-differentiated price signals to inform eventual development of time-varying rate structures; and
- Evaluate technology and partnership alternatives to monitor and report charging.

Customers will earn a rebate for every kWh charged starting after 9 p.m. and up until 1 p.m. The Company selected these hours to generally align with the highest load hours based on review of seasonal average load shapes for Rhode Island, and to maximize flexibility to EV drivers. The

<sup>2</sup> This estimate includes 9.5 c/kWh Standard Offer Service plus 10 c/kWh Delivery Service, assuming total household usage of 1,000 kWh per month.

<sup>3</sup> Assuming 20 cents per kWh and vehicle efficiency of 3.5 miles per kWh, an EV’s cost per mile is 5.7 cents. Applying this cost per mile to a 30 mpg internal combustion vehicle would equate to \$1.71 per gallon – about 33% below the current Rhode Island average gas price of \$2.59/gallon.

<sup>4</sup> A common 30-amp charger operating at 240 volts incurs 3.6KW of electric demand. On the high end, a charger operating at 80 amps at 240 volts would incur 19.6KW of demand.

off-peak charging value will be 6 cents per kWh in summer months (June through September) and 4 cents per kWh in all other months. These values reflect (1) the difference in load-weighted on-peak and off-peak energy costs, and (2) an additional payment intended to reflect a contribution to forward capacity market cost savings. Based on the Company's analysis, a customer who charges 300 kWh per month could earn \$18 per month in summer months and \$12 per month in all other months. The Company reserves the right to change the value per kWh as necessary during this Pilot to achieve the Pilot goals.

Anyone charging an EV in National Grid's Rhode Island electric distribution service territory is eligible to participate in the rebate program, and participants may sign-up at no charge. Customers will also be able to earn rewards for activating their accounts (*e.g.* installing the Company's monitoring device or otherwise enabling the Company's data acquisition), for completing surveys, and for referring friends to the program. Based on actions taken, customers will obtain e-gift cards with their rewards balance.

This Pilot will serve as a demonstration of program design, rate design, and marketing strategies in anticipation of the subsequent broad implementation of AMF and time-varying rates. The Company expects the Pilot to reach up to 500 participants over three years.

## **2.2. Charging Station Demonstration Program**

Lack of accessible charging stations is a major barrier to consumer consideration of EVs. At the same time, lack of sufficient electrical infrastructure for charging inhibits the pace of electrification by operators of fleets and transit vehicles. The Company's Demonstration Program aims to test new investment and incentive approaches to increase the number of stations available to Rhode Island consumers and bring down the cost of charging infrastructure for fleet and transit operators.

The most common level of charging power available today offers between 10-20 miles of range per hour. This so-called "Level 2" charging operates at 240 volts and is well-suited for locations where drivers park for four hours or more. National Grid operates 49 of the 75 locations in Rhode Island where public Level 2 charging is offered. A higher-speed, more convenient level of charging power for drivers offers up to 200 miles of range per hour. This Direct Current Fast Charging (DC Fast Charging) operates at 480 volts, and is not widely available because of its high installation and operating costs. There are eight locations in Rhode Island where public DC Fast Charging is offered today, none of which National Grid operates.

The Company's Demonstration Program proposes to develop charging infrastructure for light-duty and heavy-duty vehicles, for use by the general public (Consumer Vehicles) and operators of dedicated fleets or transit agencies (Fleet Vehicles). Table 5-2 below explains the Company's Targeted Charging Segments, the level of charging power envisioned at each site, the number of sites targeted, and the potential number of ports per site.



**Table 5-2: Targeted Charging Segments**

<b>Targeted Charging Segments</b>	<b>Level of Charging</b>	<b># of Sites Targeted</b>	<b>Potential Ports per Site</b>
Consumer Vehicles			
Workplaces	Level 2	20	10
Apartment buildings	Level 2	4	6
Income Eligible community sites	Level 2	4	6
Public transit stations	Level 2	2	10
Public fast-charging locations	DC Fast Charging	4	5
Fleet Vehicles			
Government light-duty fleet	Level 2	3	8
Corporate light-duty fleet	Level 2	3	8
Public transit buses	DC Fast Charging	2	5
Rideshare company charging hub	DC Fast Charging	1	5
Other heavy-duty/DC Fast Charging (port, airport)	DC Fast Charging	2	4
Municipal school buses or other institutions	Level 2	3	1

*Approaches to Charging Demonstration for Consumer Vehicle Segments*

To enable a significant increase in customer access to Level 2 charging in Rhode Island, the Company proposes to demonstrate new approaches to charging infrastructure development, in which the Company makes investment in traditional electrical infrastructure as necessary as well as electrical equipment on a Site Host’s property, and enables Site Hosts to either install EV supply equipment, or to host Company-operated EV supply equipment on their premises. Key aspects of this proposal will include the following:

- Identification and development by the Company of prospective charging sites, working with its Account Managers and equipment vendors to recruit Site Hosts to the program;

- Selection by Site Hosts of desired Level 2 EV supply equipment from a qualifying equipment list developed by National Grid, with options to: a) purchase and install the EV supply equipment; or b) elect for the Company to operate it. Under the first option (Make-Ready<sup>5</sup>), Site Hosts purchasing Level 2 EV supply equipment may qualify for a rebate from the Company toward the cost of that EV supply equipment, to defray the installation. Under the second option (Company-operated), the Company would bear all costs for installing, owning and operating the EV supply equipment;
- Execution by the Site Host of a Site Host Agreement detailing the terms of participation and granting the Company an easement for equipment the Company will own on the Site Host's premises;
- Construction and ownership by the Company of a new distribution service and required electrical infrastructure (such as new electrical panel, conduit, and wiring) at the premises for each charging site;
- For Make-Ready sites, the designation by the Site Host as customer of record for the electric service account and a determination of the pricing, if any, charged to drivers. For Company-operated sites, the Company owns and operates the EV supply equipment, serves as the customer of record for the electric account, and envisions charging drivers for station usage, under the Daily Charging Rate described further below;
- For Company-operated sites, payment by the Site Host of a Participation Payment, discussed further below, representing the Site Host's share of costs for the infrastructure; and
- To encourage Site Hosts or other third-parties to own and operate Level 2 EV supply equipment, the Company proposes to limit Company-operated sites to no more than 50% of the targeted number of Level 2 sites developed in each segment (excluding Income Eligible community sites).

The goal of the final segment in the Consumer Vehicles category is to increase customers' ability to access more costly DC Fast Charging infrastructure. The Company proposes to demonstrate the development, ownership, and operation of DC Fast Charging EV supply equipment at four public locations. This part of the demonstration will be similar to the Company-operated site option for Level 2 charging Site Hosts above, except that the Company envisions charging drivers at these stations a Fast Charging Convenience Rate that would be higher than the Daily Charging Rate.

The Company's ownership and operation of DC Fast Charging stations will ensure that these stations are constructed and operated for the benefit of Rhode Island drivers, while allowing for a public assessment of their economics and utilization. Simultaneously, the Company will offer a time-limited electric bill discount to third-party operators of Fast Charging to reduce their operating costs while the EV market develops, as described in *Section 3: Rate Discount Pilot for DC Fast Charging Station Accounts* below.

#### *Approach to Charging Demonstration for Fleet Vehicle Segments*

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<sup>5</sup> Under this option, the Company is responsible for "making the site ready" for charging to be installed, owned, and operated by the Site Host.

For *Fleet Vehicle* charging segments where fleet and transit operators look to add electrified vehicles to their operations, the Company proposes to make the necessary investment in electrical infrastructure and provide additional incentives to enable fleet operators or other third-parties to install and operate EV supply equipment for new electrified vehicles. All Fleet Vehicle charging sites will be Make-Ready sites, with no Company ownership or operation of the EV supply equipment. Key aspects of this portion of the Demonstration Program will include the following:

- Identification and development by the Company of prospective charging sites, working with its Account Managers and equipment vendors to recruit Site Hosts to the program;
- Purchase by Site Hosts of desired EV supply equipment from the qualifying equipment list, with the potential to qualify for a rebate from the Company toward the cost of that EV supply equipment;
- Execution by the Site Host of the Site Host Agreement, granting the Company an easement for equipment the Company will own on Site Host's premises;
- Construction and ownership by the Company of a new distribution service and required premise electrical infrastructure (such as new electrical panel, conduit, and wiring) for each charging site; and
- Ownership and operation by the Site Host of the EV supply equipment, who will serve as customer of record for the electric account supplying the EV supply equipment.

#### *Site Host Cost Sharing*

The Company will require cost sharing from Site Hosts who benefit from the installation of charging equipment. In the case of Make-Ready sites where Site Hosts operate EV supply equipment, Site Hosts will be responsible for a portion of the EV supply equipment cost (after any rebates) as well as the ongoing cost of station operation and maintenance for a minimum of five years. In the case of Company-operated sites, the Company will charge a Site Host Participation Payment. This amount will be programmatically determined, and the Company reserves the right to modify this amount in order to achieve the Demonstration Program's goals.

#### *Charging Rates for Company-Operated Sites*

The Company will charge users (drivers) of stations at its Company-operated sites a regulated per-kWh rate for the electric commodity supply and service via the Company's EV supply equipment. The Company has defined this Charging Rate structure to be set formulaically via a Company tariff that will be filed prior to program launch, for review and approval by the PUC. The Charging Rate will be adjusted semi-annually via compliance filings, with modifications made to reflect changes in underlying rates.

Two types of Charging Rates will be applicable to users at Company-operated sites. The Company's concept for these rates is summarized below, and proposed rates will be submitted in detailed form in a tariff to the PUC. As a demonstration of EV drivers' responsiveness to price signals, the Company's pricing should encourage drivers to avoid charging during peak hours and to utilize the Company's stations at times when energy costs are lower in order to pay less for charging.

- The Daily Charging Rate will charge for Level 2 charging at an affordable rate per kWh suitable for daily charging, while encouraging drivers to avoid Peak Hours.
  - Component 1: Commodity Charge: Calculated semi-annually as the Base Standard Offer Service rate, excluding the Capacity Component
  - Component 2: Delivery Service Rate: Calculated semi-annually as a per-kWh rate comprised of all the separate rates and factors typically referred to as “delivery service”
  - Component 3: Program Recovery Factor: Designed to recover a portion of site installation cost from drivers
  - Component 4 (Peak Hours Only): Capacity Component: Peak Hours Adder based on the estimated capacity cost in Standard Offer Service rates, applied during defined hours per summer season.
  
- The Fast-Charging Convenience Rate will charge for DC Fast Charging for drivers needing a quick charge, while encouraging drivers to avoid Peak Hours.
  - Pricing will be calculated based on a benchmark of pricing-per-kWh at all other publicly-available DC Fast Charging stations in Rhode Island. If pricing per kWh is unavailable at other stations in Rhode Island, the rate would be two times the Daily Charging Rate.
  - Peak Hours Adder will be applied, consistent with Daily Charging Rate above.

Drivers will have the option to pay for their charging via a network services subscription or via credit card. The Company will conduct a Request for Proposal (RFP) for an EV charging network service provider offering payment capability and 24x7 customer support. This network service provider will be able to support multiple EV supply equipment manufacturers.

#### *Impact of Demonstration on Non-Utility Providers of EV Charging and Related Services*

The Company intends for its Electric Transportation Initiative to facilitate, and not inhibit, the development of transportation charging by property owners and third-party EV charging operators in Rhode Island.

The Company’s proposed Make-Ready approaches will simplify and defray the cost for property owners and third-parties to offer EV charging. Site Hosts will be free to choose from any qualifying EV supply equipment vendors and may operate the station the best way they see fit. The Program will expand business opportunities for Level 2 and fleet EV supply equipment suppliers, network service providers, electricians, and other service providers. The Make-Ready approach will complement rather than compete with the efforts of qualifying Level 2 EV supply equipment vendors, service providers, and charging operators, to identify customers for their products and services.

Not every property owner wishes to take on the responsibility of procuring, installing, and operating charging equipment for their property users or the general public. To ensure this does not limit the speed of charging development in Rhode Island, the Company proposes to give site hosts for Level 2 Consumer Vehicle charging an additional option to have the Company own and operate the EV supply equipment, should this provide greater convenience to the site host.

Under this option, similar to the Make-Ready approach, Site Hosts will also be free to select any qualifying EV supply equipment for the Company to own and operate on its premises. To encourage Site Hosts or other third-parties to own and operate EV supply equipment, the Company proposes to limit the Company-operated option to no more than 50% of the targeted number of Level 2 sites developed in each segment (excluding Income Eligible community sites).

The Charging Demonstration Program also includes a limited number of DC Fast Charging Stations sites the Company will own and operate. The Company's provision of this service, alongside the Rate Discount Pilot offered to third-party operators of DC Fast Charging, will likely ensure that this higher-powered charging option is more broadly available to drivers in Rhode Island. In so doing, the Company will increase the visibility of highly-convenient charging options in Rhode Island, increasing the likelihood that Rhode Island drivers will choose an EV for their next purchase or lease. Increased EV adoption in Rhode Island will benefit the non-utility operators of EV charging stations by increasing those operators' likely customer base. The Company proposes to charge a rate to drivers at its DC Fast stations that is based on an average of the per-kWh fees charged by non-utility DC Fast Chargers in operation in Rhode Island, to ensure the pricing at the Company's stations is reflective of the costs incurred by non-utility entities offering this service. The results of the Company-owned DC Fast Charging portion of the Demonstration Program will increase the information available to the PUC and other stakeholders about the economics, utilization, and electric system impacts of this emerging type of charging technology.

### **2.3. Discount Pilot for DC Fast Charging Station Accounts**

The Company proposes to offer a time-limited discount on the electric bills for dedicated DC Fast Charging station electric accounts established during an initial period of EV market growth. This will encourage the development of these stations, which may be prohibitively expensive to operate otherwise during the early phase of EV market growth because of relatively low station utilization levels and demand-based delivery charges. By lowering the operating cost of DC Fast Charging stations, the Company expects to increase the number of these stations operated by third-parties in Rhode Island. An increase in available public charging infrastructure will address consumers' concerns about EV range, and facilitate an increase in EV adoption.

Any new or existing electric service billed on General C&I Rate G-02 or Large Demand Rate G-32 for dedicated DC Fast Charging purposes is eligible for the discount. The monthly bill discount will be based on a per-kW credit set at the same rate as the applicable (Rate G-02 or Rate G-32) distribution demand charge for a three-year period beginning with the start of service. A monthly bill credit would be applied to the bill that will, essentially, equal the amount the customer is billed for the distribution demand charge.

- The Company will provide a discount equal to the distribution demand charge for a period of three years from the start of service. As the end of this period approaches, the Company will evaluate the impact of the program, review station utilization patterns and load data, and determine the appropriateness of any extensions or modifications.

- During the period discussed above, the Company will issue a bill credit equal to 100% of the distribution demand charge.
- The Discount Pilot will be made available on a first-come, first-serve basis. The Company intends to limit the annual value of the discount to \$300,000 per year.
- Discounts provided through the DC Fast Charging Discount Pilot have the potential to continue up to three years beyond the end of the pilot's term, as the discounts begin when service to the DC Fast Charging station begins. A customer's participation could begin in the last month of the three-year term and would receive the discount monthly during the following three years.

The Company will propose the modifications to its G-02 and G-32 rates necessary to implement this Discount Pilot as part of a subsequent tariff advice filing with the PUC.

#### **2.4. Transportation Education and Outreach**

Reaching Rhode Island's ZEV targets requires a transformation of the consumer light-duty vehicle market, with ZEVs growing from less than 1% of annual sales in Rhode Island in 2016 to approximately 15% by 2025. This type of transformation of one of the largest consumer markets in such a short period requires a collective effort of all stakeholders in the EV value chain: car buyers, utilities, automotive manufacturers and dealers, as well as EV supply equipment vendors.

The Company proposes a multi-channel Education and Outreach plan to increase customer awareness and interest in EVs during the three-years of the Electric Transportation Initiative term. The effort will inform residential and commercial customers about vehicle technologies, federal and state incentives, charging options, rates and programs, and will build broad-based awareness of electric transportation.

Although automakers play an important role in promoting new vehicle models to consumers, automakers face conflicting economic incentives, with EV sales (aside from luxury models) providing lower margins compared to other vehicle segments such as sport utility vehicles and trucks. In any case, automaker promotion efforts will need to be amplified and complemented by many others, with costs distributed across the value chain to achieve the broad levels of awareness and familiarity required to drive this significant change in attitudes towards EVs. To help drive this transition to electric-powered transportation, consumers must be educated on the benefits of EVs to create an awareness of and interest in Battery Electric Vehicles and Plug-in Hybrid Electric Vehicle ownership.

As the PST Phase One Report points out, the Company's customer communication channels have universal reach throughout its service territory, more so than any other organization in the state, and the Company communicates with customers on at least a monthly basis through bills, home energy reports, and less regularly through other channels such as email, social media, billboards, print, and radio media. The Company is a national leader in communicating to customers about energy efficient products and services. Therefore, the Company proposes that it leverage these capabilities and develop new Education and Outreach strategies that will educate customers on the benefits of EVs, the decreasing costs to purchase and maintain an EV, advances

made in driving range, continued increases in charging station availability, and newer charging technologies that greatly reduce EV charging time.

This effort may also coincide with a program proposed by National Grid in Massachusetts, and a program proposed by Eversource in Massachusetts, that may allow for regional communication channels to be used with unified messaging for some of the outreach.

## **2.5. Company Fleet Expansion**

The Company proposes to expand its own experience with fleet electrification by increasing the Company's use of electrified heavy-duty trucks during this Initiative. This will serve as a valuable additional proof-point in the early development of the medium- and heavy-duty electrified vehicle market in Rhode Island.

The Company proposes to add 12 new electrified heavy-duty (Class 7-8) trucks to its fleet in Rhode Island. These trucks could be used for electric operations (*e.g.* bucket truck, digger derrick) or gas operations (*e.g.* gas compressor crew truck, dump truck). These heavy-duty trucks will build on the Company's initial testing of plug-in hybrid EV vans as part of its current fleet.

## **2.6. Initiative Evaluation**

The Company's Initiative is structured as a three-year pilot to test multiple market development strategies, including pricing, rate discount, investment, and incentive programs. The proposal allows for the comparison of multiple strategies for achieving a specific goal; for example, testing site host responsiveness to the choice of operating their own charging with Company incentives, or having the Company operate charging at their site.

The Company will evaluate each electric transportation market development strategy and share these learnings with Rhode Island stakeholders and industry participants. Evaluation activities will characterize the program's impacts on current and prospective EV drivers and site hosts, through methods that may include: (1) surveying the Company's residential customers, (2) surveying of residents and employees at Host Sites, (3) interviews of participating and non-participating sites, and (4) analysis of program data.

The evaluation of Company-operated sites will include analysis of the utilization, economics, and load profiles of each site, to independently inform the PUC, OER, and other stakeholders of the costs and benefits of EV charging operations. Evaluation results will be published at the conclusion of the program and will be supplemented by interim annual reporting.

Additionally, the Company will establish an external Electric Transportation Advisory Committee to review progress and provide input to the Initiative. This group will meet quarterly throughout the course of the Initiative. The Company will also produce annual reports describing the implementation of its Initiative and documenting information gained regarding electric transportation market development. The Company will hold public presentations of each report to ensure broad access to the insights.

### **3. ADVANCING GOALS**

#### **3.1. Advancing Power Sector Transformation Goals and State Policies**

As mentioned above, the Rhode Island ZEV Draft Plan calls for growing EV adoption more than 40-fold (from approximately 1,000 to 43,000) by 2025, and the EC4 greenhouse gas emissions reduction scenario targets the electrification of 34% of on-road vehicle miles traveled by 2035 and 76% by 2050. The Company has considered how Rhode Island’s transportation market must transform to meet these policy goals, and has proposed the Electric Transportation Initiative as a means to advance these goals through the demonstration of multiple market development strategies.

Additionally, the Initiative has been designed for consistency with the PUC staff’s Beneficial Electrification Principles that were included in the PST Phase One Report. This section describes how the proposed Initiative proposal fulfills the PUC staff’s guidance on this topic.<sup>6</sup>

First, the proposal incorporates the “Goals and Benefits of Electrification,<sup>7</sup>” which are themselves consistent with Docket 4600’s goals for a new electric distribution system. The proposal increases the availability of reliable, safe, clean, and affordable energy to Rhode Island customers for transportation purposes. The proposal strengthens the Rhode Island economy by supporting the development of the EV and EV charging markets and by incorporating many components that advance a modern grid and novel approaches to rates. The proposal addresses the challenge of climate change and other harmful emissions through its singular focus on lower-emitting all-electric and partially-electric vehicles. The proposed program aligns utility, customer, and policy objectives through a combination of regulatory innovations including rate design, cost recovery, and incentives. The proposed program facilitates customer investment in their facilities, while enabling customer investment in EVs themselves, for the obtainment of recognizable cost savings. The proposal includes features that appropriately compensate customers for beneficial charging, while charging customers for costs they impose on the grid. The Company’s proposal utilizes a cost-benefit test consistent with the Rhode Island Benefit Cost Framework, to evaluate the Societal Cost Test and Rate Impact Measure for the Initiative, described in the BCA section below. Additional qualitative benefits are described in that section.

Second, the Company’s proposal allows for experimentation and adaptation to evolving technologies and markets, by taking a three-year pilot approach and testing multiple market development strategies, including enabling investment, incentives, discounts, and pricing programs. Program goals are clearly articulated in this proposal, and each program design element is clearly tied to program goals.

The proposal also helps to advance many of the goals outlined in Docket 4600.

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<sup>6</sup> [http://www.ripuc.org/utilityinfo/electric/PST\\_BE\\_draft.pdf](http://www.ripuc.org/utilityinfo/electric/PST_BE_draft.pdf)

<sup>7</sup> See *PST Phase One Report*, pages 57-58.



**Table 5-3: High-Level Summary of Alignment between Electric Vehicle Initiative and Docket 4600 Goals**

Goals For “New” Electric System	Advances? / Detracts from? / Neutral to?
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances - Increases charging availability and affordability at a variety of locations, including home charging and non-home charging.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances - Supports the development of the EV and EV charging markets by incorporating many components that advance a modern grid and novel approaches to rates.
Address the challenge of climate change and other forms of pollution	Advances - Enables the adoption of lower-emitting all-electric and partially-electric vehicles.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Advances - Enables customers to purchase and install their own EV supply equipment, or host Company-operated EV supply equipment with a cost-sharing payment. Also enables fleet customer investment in electrified vehicles.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Advances - Pays enrolled EV customers a rebate for charging conducted off-peak.
Appropriately charge customers for the cost they impose on the grid	Advances - Proposed charging rates at Company-operated stations incorporate peak-time pricing to reflect higher costs.
Appropriately compensate the distribution utility for the services it provides	Advances - Supports the implementation of EV-related Performance Incentive Mechanisms described in Chapter Nine.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Advances - Demonstrates multiple market development strategies to enable EV charging development and EV adoption, through rate design, cost recovery, and incentives.

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The Company will report annually on appropriate metrics to demonstrate progress, including:

#### Charging Demonstration

- Number of site host applicants by location type and operator (Make-Ready or Company-operated)
- Number of executed site host agreements
- Number of sites activated
- Percent of sites developed in disadvantaged communities
- Utilization of activated sites, including kWhs, sessions, and unique drivers, as feasible (anonymized)

#### Education and Outreach Plan

- Total activity and spend by category
- Total attendance at EV events/ride-and-drives
- Impact of activity, where data is available (*e.g.* impressions, click-through rates)

#### Off-Peak Charging Rebate Pilot

- Total number of program participants by type of vehicle and charging level
- Total off-peak charging kWh
- Total value of rewards provided
- Estimated kW shifted

#### DC Fast Charging Discount Pilot

- Total number of rate discount applicants by rate class
- Total number of participating sites by rate type
- Charging kWh delivered by site (anonymized)
- Site Peak kW recorded by site (anonymized)

#### Company Fleet Investment

- Total number of vehicles leased
- Total number of EV supply equipment installed
- kWh consumed per vehicle
- Miles driven per vehicle
- Gasoline consumed per vehicle (if Plug-in Hybrid Electric Vehicle)

The Company will also report annual data on Battery Electric Vehicles and Plug-in Hybrid Electric Vehicle adoption by zip code, and estimated greenhouse gases avoided by those vehicles.

Finally, as required by the PUC Staff's Beneficial Electrification Principles, the Company's proposal provides a platform for innovation in the rapidly-evolving technology sectors of EVs

and EV charging. By providing enabling investment and incentives for site hosts and third-parties to establish charging in the Charging Demonstration, alongside Company-operated EV supply equipment, the Company's program allows site hosts and third-parties to select equipment that meets the program's qualifications, rather than specifying particular technologies in all sectors. As a time-limited program, the Initiative will allow for the installation of many types of charging equipment by many different market participants, without prematurely committing to a technology configuration, deployment approach, or market design.

### **3.2. Benefits for our Customers**

Expanded EV infrastructure provides a number of benefits to the Company's customers who drive an EV today or may do so in the future. Driving electric allows customers to save money on fueling and lower regular maintenance costs compared to an internal combustion engine. Additionally, since most EV drivers charge at home, electrification also allows customers with distributed generation to self-supply some of their transportation energy.

Approximately 1,000 Rhode Island residential customers drive EVs today, while one in four National Grid customers is "extremely or very likely" to consider an electric vehicle for their next vehicle.<sup>8,9</sup> In the heavy-duty segments, there is a growing interest among Rhode Island's public agencies in electrification, representing a promising pool of "early adopters." A survey of National Grid's residential and commercial customers indicated that a majority of customers believe "energy utility companies such as National Grid" should be responsible for installing charging and providing charging services.<sup>10</sup>

This Initiative seeks to enable EV conversion by Rhode Island consumers and fleet operators, through several key impacts, including increased accessibility, affordability, and reliability of charging services for customers; lower electric costs for home charging; and increased customer understanding of EV operating costs and benefits.

## **4. PROJECT COSTS**

The total estimated costs over three years are \$7.34 million in capital and \$4.21 million in expense. These costs include capital investment costs, incremental O&M costs, and incremental full-time equivalents.

Grouped by program type, the overall costs of the program are as follows:

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<sup>8</sup> 1,026 EVs were registered in the Company's service territory as of October 1, 2017, according to data from R.L. Polk.

<sup>9</sup> A Study of 3 Energy Solution Areas (National Grid, May 23, 2014), at 53.

<sup>10</sup> A Study of 3 Energy Solution Areas, at 55.

**Table 5-4: Total Costs by Program Type**

	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>3-Year Total</b>
<b>Off-Peak Charging Rebate Pilot</b>	\$178,745	\$244,420	\$332,567	<b>\$755,731</b>
<b>Charging Station Demonstration Program</b>	\$1,377,313	\$2,368,863	\$5,334,831	<b>\$9,081,008</b>
<b>Discount Pilot for Fast Charging</b>	\$103,622	\$170,650	\$264,488	<b>\$538,760</b>
<b>Transportation Education and Outreach</b>	\$113,970	\$164,959	\$220,468	<b>\$499,397</b>
<b>Company Fleet Expansion</b>	\$264,000	\$128,000	\$192,000	\$584,000
<b>Initiative Evaluation</b>	\$30,000	\$30,000	\$30,000	<b>\$90,000</b>
<b>Total</b>	<b>\$2,067,650</b>	<b>\$3,106,891</b>	<b>\$6,374,354</b>	<b>\$11,548,895</b>

Grouped by type of expense, the overall program costs are as follows:

**Table 5-5: Program Costs by Type of Expense**

	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>3-Year Total</b>
<b>O&amp;M Subtotal</b>	\$879,179	\$1,278,391	\$2,047,843	\$4,205,413
<b>Capital Subtotal</b>	\$1,188,470	\$1,828,501	\$4,326,511	<b>\$7,343,482</b>
<b>Total</b>	<b>\$2,067,650</b>	<b>\$3,106,891</b>	<b>\$6,374,354</b>	<b>\$11,548,895</b>

The *Off-Peak Charging Rebate Program* will incur a total of \$755,731 O&M costs, including \$691,981 of Program Management, Data Acquisition, Evaluation, and Marketing; and \$63,750 of Rebate Payments.

The *Charging Demonstration Program* will incur \$9,081,008 of cost, consisting of \$7,143,482 in capital cost and \$1,937,525 of O&M. Direct capital costs include new service costs (labor and materials), customer premise costs (labor and materials), and EV supply equipment cost (primarily materials). Indirect capital costs include capitalized Program Management Office labor to develop and supervise EV charging site construction, as well as project management tool modifications and data analysis and report tools. The Program will incur the following types of O&M cost: EV Supply Equipment Rebate Cost (incentive toward Site Host purchase of EVSE), non-capitalized Program Management Office cost (labor), site contracting costs, site estimation costs, and utility-operated station O&M cost.

The *Rate Discount Pilot for DC Fast Charging Station Accounts* will incur an estimated \$150,000 for implementation costs, including billing system changes, customer communications, and support. The Company has also estimated a potential value of the discount of \$388,760 over three years. The actual value will depend upon discounts provided to participating customers.

*Transportation Education and Outreach* costs will total \$499,397 for the three years. This cost includes internal marketing program management, content development, and production costs. These production costs will depend on marketing channel, but could include digital advertising, billboard or radio advertising, social media, hosted web content, EV ride-and-drive events, and direct mailings, among others.

The *Company Fleet Expansion* cost, which covers the incremental vehicle cost, will total \$584,000, consisting of \$384,000 O&M and \$200,000 in capital. The Company estimates an annual incremental lease cost of \$8,000 based on an “up-fit” cost of \$80,000 per vehicle (Class 7-8 truck) amortized over 10 years. The capital investment, which covers charging stations, incurs a cost in Year 1 of \$200,000. Support and maintenance costs including repairs, maintenance, and spare parts are estimated at the same level as incremental lease costs annually and included in the O&M amount.

The preliminary cost for the *Initiative Evaluation* is \$90,000 based on conducting one formal study each year, at \$30,000 per year, over three years.

Further details on costs are provided in Workpaper 5.1 - Electric Transport Costs/Assumptions.

## **5. BENEFIT COST ANALYSIS**

As described in Chapter Two, the Company conducted a Benefit Cost Analysis evaluating the Societal Cost Test and Rate Impact Measure for the Electric Transportation Initiative. The Company calculated a Societal Cost Test benefit cost ratio of 1.03 and a Rate Impact Measure ratio of 0.13 based on the potential enablement of EV conversion by consumers and fleet operators through the Initiative, as well as peak energy costs avoided as part of the Off-Peak Charging Rebate Pilot.

The Rebate Pilot also serves as an enabler of future time-varying rates (once Advanced Metering Functionality is available) by gathering experience with a program that offers price signals to EV drivers. The Company’s AMF BCA includes an estimate of the potential benefits from shaping

EV charging patterns through time-varying rates on a longer-time scale.<sup>11</sup> This benefit is separate from the analysis shown in the Electric Transportation Initiative BCA described above.

The benefits and costs included in the Societal Cost Test Electric Transportation BCA model are as follows:

**Table 5-6: Societal Cost Test Benefits and Costs**

<b>Electric Vehicles -- Total</b>		
<b>Benefit</b>	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	\$ -
		\$ -
	<b>Total</b>	<b>\$ 15,535,555</b>
<b>Cost</b>	Total Program Administration Costs	\$ 10,420,428
	Incremental Purchase and Maintenance Cost	\$ 4,671,444
		\$ -
	<b>Total</b>	<b>\$ 15,091,871</b>
<b>BCA Ratio</b>		<b>1.03</b>

The benefits and costs included in the Rate Impact Measure Electric Transportation BCA model are as follows:

<sup>11</sup> This benefit is included in the “Customer Benefits: EV Pricing” section of the AMI BCA, and is calculated on a 20-year NPV basis.

**Table 5-7: Rate Impact Measure Benefits and Costs**

<b>Electric Vehicles -- Total</b>		
<b>Benefit</b>	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)
	Wholesale Market Price Effect	\$ (7,138)
	Net Utility Revenue Increase	\$ 4,604,788
	<b>Total</b>	<b>\$ 1,376,632</b>
<b>Cost</b>	Total Program Administration Costs	\$ 10,420,428
	Net Utility Revenue Decrease	\$ 326,937
	<b>Total</b>	<b>\$ 10,747,365</b>
<b>BCA Ratio</b>		<b>0.13</b>

Further details concerning the BCA Model are provided in Appendix 2.1 - Program BCA.

While the Electric Transportation Initiative passes the quantitative BCA test, additional qualitative benefits have also been taken into consideration. These qualitative benefits are explained below.

**Table 5-8: Qualitative Benefits**

Category	Description/Examples
Societal	<p>Reduces reliance on conventional fuel sources, reducing societal exposure to price volatility and national security costs associated with other fuel sources.</p> <p>Advances local and regional knowledge of clean transportation technologies, positioning Rhode Island for further innovation across related industries, including autonomous vehicles which will have benefits for passenger safety and could also lead to a decrease in traffic congestion.</p>
Economic	<p>Creates new and sustained local jobs through construction of charging stations and EV's as well as long-term maintenance of charging stations, EVs, and other associated industries.</p> <p>Increases awareness of job opportunities in emerging and sustainable energy sources, which can generate interest in these jobs and create future local jobs in these areas.</p> <p>Generates increased exposure and benefits of public (<i>i.e.</i>, utility) and private partnerships through the charging site development activities. This approach could help promote future public/private partnerships that support improving infrastructure and creating jobs.</p>
Educational	<p>Raises awareness among both program participants and other Rhode Island residents of the benefits of renewable and emerging energy technologies (economic, social, environmental, etc.).</p> <p>Creates data from charging stations that can be utilized by various entities in most effectively deploying charging stations in the future in other areas.</p>
Environmental Externalities	<p>Supports state and federal programs advancing Zero Emission Vehicles in the consumer sector and fleet/transit sectors.</p> <p>Could result in increased uptake of other customer energy solutions that lower the environmental (<i>e.g.</i> air, ground, and water) impacts.</p>

## 6. CONCLUSION

As the electric grid evolves, it is important to thoughtfully invest in the infrastructure needed to build a clean energy future, including the transportation sector. The Company believes that the time to start this process is now and that the Electric Transportation Initiative will meaningfully advance Rhode Island's ambitious goals.





Schedule PST -1,  
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**CHAPTER SIX: INVESTING IN A CLEAN ENERGY FUTURE**  
**ELECTRIC HEAT INITIATIVE**

**1. INTRODUCTION**

Although building electric and gas use has declined because of successful energy efficiency initiatives, these programs alone will not be enough to meet Rhode Island’s greenhouse gas (GHG) emissions goals. These goals will require an ambitious and coordinated effort to substantially accelerate investment in building efficiency and to support fuel switching to electric heat. The Company is helping to advance this effort with its Electric Heat Initiative.

**2. ABOUT THE PROJECT**

The purpose of the Electric Heat Initiative (referred to herein as the Initiative) is to launch new and innovative electric heat services for customers, while meaningfully accelerating efficient heat electrification in Rhode Island through multiple supporting market development strategies.

The Rhode Island Executive Climate Change Coordinating Council (EC4) issued on December 31, 2016 its “Rhode Island Greenhouse Gas Emissions Reduction Plan” (the EC4 Plan). The 2050 pathway envisioned by the EC4 report implies an annual conversion rate of approximately 13,000 customers per year to heat pumps every year between now and 2050. Adoption rates are currently far lower than this, and furthermore, at current and projected fuel prices, heat pump adoption is not economical for natural gas customers in Rhode Island or elsewhere in New England. The strongest case today, both economically and for GHG emissions reduction, is converting delivered fuel customers to efficient heat pumps. Accordingly, the offerings from National Grid are targeted toward those high-cost, high-emissions customers. For example, the 2018 energy efficiency program plan (EE Program) proposes incentives for approximately 60 fuel-oil customers per year. Yet given the shortfall between that number and the vision laid out in the EC4 Plan, this Initiative dedicates additional resources to accelerate adoption of air- and ground-source heat pumps by the customers with the highest energy costs and largest emissions footprints. In the process, this Initiative helps to animate an active third-party ecosystem in Rhode Island of efficient heat electrification.

The Electric Heat Initiative consists of four components, which together create a robust approach to thermal market development and focus on facilitating customer investments in a clean energy future:

- a. *A Ground-Source Heat Pump Program* to support the goals of converting more Rhode Island buildings to low-carbon heating;
- b. *Equipment incentives to encourage Income Eligible residential customers* to convert from delivered fuels to efficient cold-climate air-source or ground-source heat pumps systems;
- c. *Community-Based Outreach* will launch partnerships with two municipalities per year to collaboratively set community “heat conversion” goals and to educate and conduct outreach in support of meeting these conversion goals; and
- d. *Oil/Propane Dealer Training Programs* to support installation and sales training for up to 20 oil dealers across the three years of the program.

The next section provides additional details on each of these components.

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## 2.1. Ground-Source Heat Pump Program

Under the Ground-Source Heat Pump Program, the Company will establish a partnership to convert one large commercial or institutional building that currently heats with oil to Geothermal Heat Pumps. The target will be a system up to approximately 82 tons of cooling capacity, roughly the size of a commercial building or public school. The Company will invest in and own the ground heat exchanger, and the building owner will invest in and own the remainder of the system.

The program will demonstrate the market transformation value of partial utility ownership to dramatically lower the upfront costs of ground-source heat pump systems, which has been widely acknowledged as the main barrier to widespread adoption. Additionally, by requiring non-utility ownership of the remainder of the system, this project arrangement will help to understand market appetite for hybrid ownership of ground-source heat pump systems. The system will be instrumented and the performance documented over two years in detail, and this data will be used to further develop a permanent program to scale this technology. Finally, the project will be used as a case study teaching tool for the benefit of the industry.

There are multiple types of underground geothermal infrastructure to serve ground-source heat pumps including closed loop vertical systems using bore holes drilled from 250-500 feet deep for small footprints and horizontal piping networks for larger footprints. The design and selection will be determined collaboratively with the customer(s) selected. The customer will be expected to provide the funding for the acquisition and installation of the new above ground heating and air conditioning geothermal equipment.

Ground-source heat pumps are not a new technology but are the most efficient heating and cooling systems available to our customers today. This equipment exchanges heat underground below the frost line where the temperature is moderate year round. The result is exceptionally high efficiency and the use of a renewable resource. For example, a state-of the art geothermal heat pump using new Variable Refrigerant Flow technology can exhibit a Coefficient of Performance for heating of 5.3. This means that for every British thermal unit (BTU) of electricity provided by the grid, nearly 5.3 BTUs of heat are delivered to the conditioned space. In this case the result is a reduction of heating costs of approximately 53% and a reduction in greenhouse gas production for heating of approximately 70% compared to No. 2 Heating Oil in Rhode Island. On a total cost of ownership basis, these systems are clearly economical, yet the higher upfront costs remain a persistent barrier to adoption.

In order to select the ground-source heat pump site, the Company will collaborate with the PUC or its designee to identify a single building or a set of buildings, such as commercial office building or a public school, to provide a ground-source heat pump heating and cooling system. Public buildings have typically been early adopters of environmentally superior technologies in Rhode Island and across the northeast. The Company representatives will:

- a. Reach out to managers of buildings that are currently heated throughout Rhode Island and develop a list of potential facilities based on level of interest;

- b. Evaluate and prioritize potential sites from a technical perspective in terms of their size, benefits to the customers, and the cost to implement;
- c. Develop a preliminary design negotiate with the preferred facilities a cost sharing of the demonstration project;
- d. Manage all aspects of installation and commission the system; and
- e. Monitor and evaluate the performance of the system and report the results to the PUC.

These results will be used to develop data that can directly validate or modify the benefits to the participating customers and to project the energy system benefit for all customers based the projected grid value of the new load shape that results from ground-source heat pump utilization for the electric utility. Both will be incorporated in to the benefit-cost analysis of this Initiative as described in Section 5. That analysis will be further used as the basis for the development of a number of financing and ownership scenarios and utility rate design options that will be used to inform public policy recommendations. The building served by the system will also be used as a teaching tool for the proposed oil dealer training program.

## **2.2. Equipment Incentives**

Equipment incentives are designed to lower the upfront cost barrier for Rhode Island residential customers to convert to efficient cold-climate air-source or ground-source heat pump systems.

This component of the Electric Heat Initiative will be targeted to a mix of market-rate and Income Eligible customers, thus expanding the eligible pool of customers beyond the program that is set forth in the Company's 2018-2020 Energy Efficiency Procurement Plan.<sup>1</sup> In the EE Program, rebates are available only to market-rate customers. In contrast, approximately 50% of the Electric Heat Initiative equipment incentive budget will be set aside for Income Eligible customers. The Company will explore program options to encourage bundling of weatherization with heat pumps to maximize energy and cost savings.

Eligibility will be limited to residential customers within the service territory for whom efficient electric heating has a Societal Cost Test ratio greater than one. At the current time, delivered fuel customers pass that test, while customers heating with natural gas do not. Most of the installations are expected to be delivered for cold-climate air-source heat pump systems, as they have a lower up-front cost for customers. The Northeast Energy Efficiency Partnership specification for cold-climate performance will be used to determine eligibility of cold-climate air-source heat pump systems.

This portion of the Electric Heat Initiative will be delivered in close coordination with the EE program, focusing on coordination in three key areas: appropriate rebate targeting, clear customer communication, and dedicated outcome tracking. Incentive levels will be harmonized across the programs to ensure effective delivery. The Electric Heat Initiative incentive program will enable the Company to target a broader and deeper customer base than the EE Program, and aligns well with the Power Sector Transformation principles.

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<sup>1</sup> *Approved in Docket No. 4684.*

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### 2.3. Community-Based Outreach

The purpose of the Community-Based Outreach program is to increase and leverage local engagement in achieving the goals of the Electric Heat Initiative. The program will launch partnerships with two municipalities per year to collaboratively set community “heat conversions” goals and to conduct outreach in support of achieving the goals.

The Company will reimburse communities up to \$20,000 in outreach expenses in support of meeting mutually-agreed upon targets. These outreach funding levels are based on similar community-based EE campaigns in Massachusetts. Communities will be selected based on their ability to increase market awareness and drive adoption of heat pumps. National Grid will also provide technical assistance to help communities design and implement community outreach programs.

Communities will be empowered to select local HVAC contractors, oil dealers, and other home contractors to serve as installers for the campaign. National Grid program staff (or National Grid’s designated consultant) will work with communities to develop requests for proposals (RFPs), providing guidelines on technology and installer requirements and evaluation criteria (*e.g.* training and certification, pricing, etc.). National Grid staff will also participate in installer selection discussions to provide feedback and support evaluation of responses; however, it is expected that the ultimate selection of installer(s) will be determined by a community selection committee.

In order to promote high-quality installations for a clean energy future, for both this Community Campaign program and for the Incentives program detailed above, National Grid will not limit the number of contractors eligible to participate. Rather, the Company will encourage adoption of common installer eligibility requirements across the Electric Heat Initiative program and the EE Program so as to ensure experienced, high quality contractors participate in delivery of heat pump systems. Suggested minimum qualifications include:

- Highest manufacturer certification(s) for relevant cold-climate air-source heat pump cold-climate air-source heat pumps and/or North American Technician Excellence certification with a specialization in heat pumps and/or International Ground Source Heat Pump Association accreditation for ground-source heat pump contractors;
- Documentation illustrating that they have attended relevant heat pump trainings in the past three years; and
- Documentation illustrating experience installing at least 10 air-source heat pump systems meeting the cold-climate specifications of the Northeast Energy Efficiency Partnership – or at least three ground-source heat pump systems – in the most recent calendar year.

Additional installer requirements may be incorporated before officially launching the program. National Grid believes it is important to afford communities flexibility when making installer selections: communities may include other decision variables when selecting qualified local contractors (*e.g.* communities may want to select contractors who can best local customer service, commit to providing significant in-kind contributions to support outreach, can demonstrate ability to serve a significant increase in local demand). In all cases, National Grid

will provide guidelines and technical assistance to support RFP development and installer selection in order to ensure that high quality, experience installers are selected. A representative from National Grid may also serve on the installer selection committee for each community.

Installers will be asked to provide the most competitive pricing possible for the program, which will in turn provide customers benefits and is in line with state goals. National Grid will provide communities with resources and technical support to work with installers to develop discounted pricing structures (*e.g.* tiered pricing, flat discounted pricing). The opportunities for these structures will depend on the structure of the campaign, size of potential market, number of installers, and technologies selected.

Depending on the volume of installations achieved, significant customer volume discounts and cost reductions in ground-source heat pump installation (*e.g.* resulting from improved coordination of labor in drilling and installation through local clustering of installations) could be achieved that could be passed onto customers through the negotiated pricing structure. The community program is uniquely positioned to demonstrate such pricing reductions.

Outreach will be driven at the grassroots level by communities, with support from National Grid. Outreach will be managed by a designated Campaign Coordinator (a city staff member or local community member), who will engage local community groups to secure volunteer support, convene events, and conduct other relevant outreach activities. This approach supports the State's goals of strengthening the Rhode Island economy.

National Grid (via support from technology manufacturers) will provide a range of template outreach and educational materials that communities can adapt to align with local values and interests. National Grid will also develop an outreach model to help communities identify customers who are most likely to adopt heat pumps. Installers selected to serve the campaigns will also be expected to provide in-kind contributions to support customer outreach.

#### **2.4. Oil/Propane Dealer Training Programs**

Training programs will be established to support the diversification of oil and propane dealers into the heat pump industry, thus contributing to a robust renewable heating and cooling supply chain, and the strengthening of the Rhode Island economy. The Company will offer installation and sales training for up to 20 oil dealers across the three years of Initiative.

The training programs will be conducted on multiple occasions per year by a consultant retained by the company. The training will be publicized in conjunction with relevant stakeholders, including the OER.

Manufacturers have indicated their preliminary interest in providing materials and in-kind technical assistance to support the Initiative, with potential additional in-kind support from heat pump manufacturers and other stakeholders, such as trade groups and building code officials. The training will provide hands on instruction in the design and installation of state-of-the art air-source heat pumps, and will also introduce the technologies and techniques used in the major types of ground-source systems.

**3. ADVANCING GOALS**

**3.1. Advancing Power Sector Transformation Goals and State Policies**

The Company’s proposed investment in an Electric Heat Initiative has been crafted to closely align with various complementary state goals, policies, and legislation, especially Rhode Island Docket 4600 and the Power System Transformation proceeding. Specifically, Docket 4600 guidance directs electric system stakeholders to create an electric system of the future that “address[es] the challenge of climate change and other forms of pollution,” and “facilitate[s] increasing customer investment in their facilities...[including] electrification of heating.” At a high level, the Electric Heat Initiative directly aligns with these and other Docket 4600 goals, as described in Table 6.1. Specific points of alignment are discussed in the next section.

**Table 6.1: High-Level Summary of Alignment between Electric Heat Initiative and Docket 4600 Goals**

<b>Goals For “New” Electric System</b>	<b>Advances?/Detracts from?/Neutral to?</b>
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances - The Electric Heat Initiative advances this goal by providing greater access to clean and affordable electric heat in place of costlier and more polluting delivered fuels.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances - The Electric Heat Initiative advances this goal by invigorating the renewable thermal market, facilitating customer investment in their homes, and supporting the formation of a robust supply chain.
Address the challenge of climate change and other forms of pollution	Advances - This goal is central to the Electric Heat Initiative, as it aims to achieve high-impact emissions reduction opportunities in the residential and small commercial heating sectors.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Advances - This goal is also central to the Electric Heat Initiative, which is structured to leverage utility investment to unlock customer investment in their heating systems.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Advances - The Electric Heat Initiative advances this goal, as the rebate amounts closely align with the social value of GHG emissions reduction attributable to the heating systems.
Appropriately charge customers for the cost	Neutral - The Electric Heat Initiative is neutral on



they impose on the grid	this goal.
Appropriately compensate the distribution utility for the services it provides	Neutral - The Electric Heat Initiative is neutral on this goal.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Advances - The Electric Heat Initiative advances this goal, by re-directing utility incentives toward the GHG reduction goals of the Resilient Rhode Island Act of 2014 and the Rhode Island GHG Emissions Reduction Plan of 2016.

Furthermore, the Electric Heat Initiative directly responds to Rhode Island’s 2015 State Energy Plan, the 2016 SIRI Vision Document, the 2016 EC4 Plan, the 2017 Rhode Island Thermal Market Development Strategy, and the 2017 Power Sector Transformation stakeholder process.

The 2015 State Energy Plan recommended that the State take concrete steps to “mature the renewable thermal market.” This Initiative aims to directly support this recommendation by establishing a coordinated set of market development activities.

Subsequently, the 2016 SIRI Vision Document recommended “to fully incorporate EE, strategic electrification, and active load management into the next Three-Year EE Plan (Mid 2017).” Accordingly, the Company proposed a strategic heat electrification offering into its 2018-2020 Energy Efficiency and System Reliability Procurement Plan recently approved by the PUC in Docket No. 4684. This Initiative is proposed in addition to, and in coordination with, the EE Program for two reasons: (i) to ensure dedicated outreach to Income Eligible customers, and (ii) to accelerate maturation of the renewable thermal market by marshaling multiple sources of funding.

In December 2016, with GHG emissions reductions in mind, the Rhode Island EC4 Plan argued the need for rapid thermal market transformation. Undertaken in accordance with the provisions of Rhode Island General Laws §42-6.2-2(2), the EC4 Plan includes strategies, programs, and actions to meet the targets for GHG emissions reductions as established in the Resilient Rhode Island Act. The EC4 Plan carried out scenario modeling to illuminate pathways for the State to meet its GHG emissions reduction targets. The resulting scenarios suggested that unprecedented levels of heat pump adoption would be required to achieve the state’s 2050 targets: 81% of residential and 67% of commercial heating load. The EC4 Plan describes the emissions mitigation value of heat pumps as:

*High-efficient electric cold climate heating systems (i.e., air source heat pumps (ductless mini-split or central systems) or ground-source heat pumps) offer GHG reductions in the thermal sector by displacing emissions from fossil fuel heating systems (i.e., natural gas furnaces and oil boilers). Electric heat pump systems produce a GHG reduction benefit due to the inherent efficiency of the heating technology as well as the relatively cleaner emissions profile of New England’s power grid supply compared to that of natural gas or*

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*oil heating systems. This GHG reduction benefit increases over time as the electricity supply shifts toward a more decarbonized resource mix.<sup>2</sup>*

The January 2017 “Rhode Island Thermal Market Development Strategy,” commissioned by the Rhode Island Office of Energy Resources, included three policy recommendations:

- a. Provide funding for EM&V and/or multifamily and commercial demonstration projects for Renewable Thermal technologies;
- b. Expand access to low-cost financing for Renewable Thermal technologies; and
- c. Encourage Renewable Thermal marketing through utility programs.<sup>3</sup>

The Company’s 2018 EE Proposal invests in an evaluation, measurement & verification framework linked to incentives. Complementing this investment, the Electric Heat Initiative invests in utility marketing, utility financing, and other market development programs. For example, the Electric Heat Initiative invests in a utility-financed commercial demonstration of ground-source heat pump technology. Ground-source heat pump adoption has been very slow primarily to high initial costs, principally for the underground assets. According to the US Department of Energy “[t]he primary ground-source heat pump market failure is the expectation that building owners finance the infrastructure, or outside-the-building portion of the system, such as the ground heat exchanger.”<sup>4</sup>

Finally, in its November 8, 2017 PST Phase One Report, the rationale for supporting investment in Beneficial Electrification is provided:

*Beneficial electrification is possible due to significant increases in the efficiency of end-use equipment (e.g., heat pumps and batteries), technological advances in other sectors (e.g., electric vehicles), and declining electric sector emission rates. The opportunity exists to reduce electric sector emissions and electric system costs while lowering individual Rhode Islanders’ energy burden. Electrification is also an emerging business opportunity for utilities to allow entities, in some cases including the utility itself, to develop new and innovative services for customers.<sup>5</sup>*

The Electric Heat Initiative directly responds to all of these policy proposals, expands the role for third parties, and provides a platform for technology innovation that allows for adaptive experimentation and bolsters a competitive third-party ecosystem of heat electrification with the intent to achieve market scale.

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<sup>2</sup> Rhode Island Executive Climate Change Coordinating Council (EC4) Greenhouse Gas Emissions Reduction Plan (2016). <http://climatechange.ri.gov/documents/ec4-ghg-emissions-reduction-plan-final-draft-2016-12-29-clean.pdf>

<sup>3</sup> Rhode Island Renewable Thermal Market Development Strategy (2017). <http://www.synapse-energy.com/sites/default/files/RI-Renewable-Thermal-15-119.pdf>

<sup>4</sup> Geothermal (Ground-Source) Heat Pumps: Market Status, Barriers to Adoption, and Actions to Overcome Barriers (2008). Oak Ridge National Laboratory. [https://www1.eere.energy.gov/geothermal/pdfs/ornl\\_ghp\\_study.pdf](https://www1.eere.energy.gov/geothermal/pdfs/ornl_ghp_study.pdf)

<sup>5</sup> RI Power Sector Transformation Phase One Report (2017). [http://www.ripuc.org/utilityinfo/electric/PST%20Report\\_Nov\\_8.pdf](http://www.ripuc.org/utilityinfo/electric/PST%20Report_Nov_8.pdf)

To ensure these goals are being met, the Company proposes to set specific metrics by which to demonstrate progress and enable mid-course corrections. These are discussed further in the Performance Incentive Mechanisms Chapter Nine.

### 3.2. Benefits for our Customers

In addition to lowering energy system emissions, this Initiative also lowers electric system costs and individual Rhode Islanders’ energy burden, through the development of new and innovative electric heat services for customers. Specifically, the Initiative articulates program goals of targeting services to customers with the highest heating energy costs and highest emissions footprints, and of lowering electric system costs through peak reduction and through building off-peak load.

Regarding private benefits, an individual residential customer is expected to save approximately \$500 dollars per year in heating costs. The large ground-source heat pump customer is expected to save approximately \$9,000 dollars per year in heating costs, not including potential cooling savings. In both cases, specific savings will depend upon the size and efficiency of the existing system and of the new heat pump system. Lifetime savings are expected to total \$7,500 for a typical residential system, and \$225,000 dollars for the large ground-source heat pump system, respectively.

Additionally, in order to ensure the Company is aligned with Rhode Island stakeholders and electric heat industry groups, the Company has participated in the Power Sector Transformation working group sessions on electrification, and has engaged with key stakeholder groups such as the Renewable Thermal Alliance and the Northeast Energy Efficiency Project.

### 4. PROJECT COSTS

The total estimated costs over three years are \$0.50 million capital and \$1.41 million expense. The total program will cost approximately \$1.91 million dollars over the course of the three years. These costs include capital investment costs, incremental O&M costs, and incremental full-time equivalents.

Grouped by program type, the overall costs of the program are as follows:

**Table 6.2: Costs by Program**

	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>3-year Total</b>
<b>GSHP Program</b>	\$0	\$595,000	\$0	<b>\$595,000</b>
<b>Equipment Incentives</b>	\$252,140	\$280,890	\$309,640	<b>\$842,670</b>
<b>Community-Based Marketing</b>	\$95,500	\$95,500	\$95,500	<b>\$286,500</b>
<b>Oil dealer training and support</b>	\$61,000	\$61,000	\$61,000	<b>\$183,000</b>
<b>Total</b>	<b>\$408,640</b>	<b>\$1,032,390</b>	<b>\$466,140</b>	<b>\$1,907,170</b>

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Under the *Ground-Source Heat Pump Program*, the Company proposes to include \$500,000 of direct expense in the Capital requirements in Year 2. These capital expenses will be recovered via rates based on an asset life of 50 years. Program administration will cost \$45,000 in Year 2, and consultant support will cost \$50,000 in Year 2, for a total cost of \$595,000.

The Company proposes \$95,000 for project management and evaluation. This amount will be used to fund the entirety of the underground heat exchanger/s. The customer will be expected to provide the funding for the acquisition and installation of the above ground geothermal equipment.

Geothermal systems provide heating and cooling and are typically quoted in terms of their cooling capacity in Refrigeration Tons, equivalent to 12,000 BTU of cooling. One Refrigeration Ton of cooling typically serves 350 square feet of occupied commercial space. Typical all-in costs range from \$7,000-\$10,500/ton depending on many localized factors. In a recent project in New York, an RFP was issued by the Company for the demonstration project including a shared loop geothermal system rated at 30 tons of cooling. The final cost was \$308,270.00 of which the underground heat exchanger and lateral piping costs are \$182,270.70.<sup>6</sup> This equates to \$6,075 per ton of underground heat exchanger. Accordingly, the proposed project will invest \$500,000 and is expected to provide up to 82 tons of cooling and 760 MBtuh of heating to an occupied space of 28,800 square feet. The customer will be asked to invest approximately \$3,900 per ton or \$320,000 in geothermal equipment which, depending on on-site conditions, is comparable to the costs of investing in conventional combined heating and cooling system replacements. If the system provides heating for 1,000 full load hours each heating season, the savings could be \$9,000 annually not including savings in cooling. Such a system would also avoid the emissions of 53 tons of GHG emissions annually.

For the *Equipment Incentives program*, the incremental costs and funding requirements totals \$708,750 dollars across the three years. The annual incentive pool for customer equipment is \$207,500, \$236,250, and \$265,000 in the respective program years. Program delivery, including outreach and program administration, totals \$133,920 over the three years, or \$44,640 per year. In total this program element will cost \$842,670.

The incentive size will depend on the installed system. Partial cold-climate air-source heat pump systems are common, and are commonly employed to displace (rather than fully replace) fossil fuel combustion. Such partial replacement is allowed under this program. It is expected that customers will install a variety of cold-climate air-source heat pump system sizes, ranging from five to one ton, resulting in an average cold-climate air-source heat pump tonnage of three tons per home, resulting in approximately 80% displacement of fuel oil and significant energy burden reduction with lowest upfront cost.

Most of the systems that are likely to be supported through the Equipment Incentives program will be through the cold-climate air-source heat pump systems. Market research indicates a typical all-in cost of \$3,200 per ton of cold-climate air-source heat pump cooling capacity and \$8,000 per ton of ground-source heat pump cooling capacity. For reference, to meet all heating

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<sup>6</sup> Contractor pricing of \$172,500 plus thermal conductivity test and environmental review.

demands, a typical residential home (1,800 square feet) would require approximately five tons of cold-climate air-source heat pump capacity and four tons of ground-source heat pump capacity.

Partial ground-source heat pump conversion is rarely economic, as the upfront ground-loop costs are substantially similar for a three or a five ton system, yielding few benefits of small systems. A typical ground-source heat pump system is expected to be a whole-home system of four tons.

For market-rate customers, incentive levels will be approximately 20% of the all-in cost of heating capacity. Incentives levels will be harmonized with the EE Program, and both will be adjusted periodically to reflect prevailing market prices for heat pump technology and installation costs. For Income Eligible customers, incentive levels will be 100% of the all-in cost of heating capacity.

Total incentives per customer system will be capped at five tons for cold-climate air-source heat pump and four tons for ground-source heat pump. While incentives may vary over the life of the program, the average total market rate incentive will be approximately \$1,920 per cold-climate air-source heat pump system (assuming an average of three tons per adopting customer) and \$3,000 per ground-source heat pump system (assuming an average of four tons per adopting customer). At this level, the funding for incentives will allow approximately 220 customer conversions over the course of three years. It is expected that incentives will be delivered to HVAC contractors so as to maximize uptake and minimize paperwork.

*Community-Based Outreach support and incentives* total \$180,000, or \$60,000 per year. Program delivery will cost \$61,500 over the three years, or \$20,500 per year, and consulting support will cost \$45,000, or \$15,000 per year. In total this program component will cost \$286,500.

*Oil/Propane Dealer Training Program* will cost \$183,000 total over the course of three years. Of this total amount, \$75,000 (\$25,000 per year) will be to retain sales and installation training consultant support, and \$108,000 (\$36,000 per year) will be for program design and delivery.

Further details on costs are provided in Workpaper 6.1 - Electric Heat Costs/Assumptions.

## **5. BENEFIT COST ANALYSIS**

As described in Chapter Two, the Company conducted a Benefit Cost Analysis evaluating the Societal Cost Test and Rate Impact Measure for the Electric Heat Initiative. The Company calculated a Societal Cost Test benefit cost ratio of 1.12 and a Rate Impact Measure cost test ratio of 2.42 and brings approximately \$0.4M of net benefits over the three-year program.

The benefits and costs included in the Societal Cost Test Electric Heat BCA model are as follows:

**Table 6-4: Societal Cost Test Benefits and Costs**

Electric Heat - BCA Ratio		
<b>Benefits</b>	Forward Commitment: Capacity Value	\$ 277,788
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)	\$ (1,121,845)
	Avoided Renewable Energy Credit (REC) Cost	\$ (99,926)
	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	\$ -
		<b>\$ 3,745,721</b>
<b>Costs</b>	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	\$ 1,073,830
	Program Participant / Prosumer Benefits / Costs	\$ 2,275,503
		<b>\$ 3,349,332</b>
<b>BCA Ratio</b>		<b>1.12</b>

The benefits and costs included in the Rate Impact Measure Electric Heat BCA model are as follows:

**Table 6:5: Rate Impact Measure Benefits and Costs**

Electric Heat - BCA Ratio		
<b>Benefits</b>	Forward Commitment: Capacity Value	\$ 277,788
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)	\$ (1,121,845)
	Avoided Renewable Energy Credit (REC) Cost	\$ (99,926)
	Wholesale Market Price Impacts	\$ (5,073)
	Change in Utility Revenue	\$ 3,552,155
	<b>\$ 2,603,098</b>	
<b>Costs</b>	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	\$ 1,073,830
	<b>\$ 1,073,830</b>	
	<b>BCA Ratio</b>	<b>2.42</b>

Further details concerning the BCA Model are provided in Appendix 2.1 - Program BCA.

While the Electric Heat Initiative passes the quantitative BCA test, additional qualitative benefits have also been taken into consideration. These qualitative benefits are explained below.

**Table 6-6: Qualitative Benefits of the Electric Heat Initiative**

Category	Description/Examples
Societal	<p>Potential to lower monthly heating and cooling bills, leading to fewer interruptions in service. This can lead to significantly improved quality of life and overall sense of personal security, particularly for Income Eligible participants with less stable financial situations or access to utilities.</p> <p>Implementing this program will create significant interaction between the community and the Company (often seen as an extension of the state), and providing positive improvements in the quality of life in these encounters can foster substantial goodwill between the community and state.</p> <p>Incorporating this program can generate awareness of alternative energy opportunities to save costs, which can lead to participants increasing use of other alternative energy solutions with lower costs. This program will also demonstrate how reductions in energy demand and peak load relate to reduced chances for blackouts and corresponding impacts.</p>
Economic	<p>Potential to provide new local job opportunities through the construction activities and on-going site maintenance.</p> <p>Generate increased exposure and benefits of public (<i>i.e.</i>, utility) and private partnerships through large-scale ground-source heat pump program, promoting future public/private partnerships that support improving infrastructure and creating jobs.</p> <p>Participating in, and acknowledgement of, these programs increases awareness of job opportunities in emerging and sustainable energy sources, which can generate interest in these jobs and create future local jobs in these areas.</p> <p>Observing the benefits from making alternative energy selections to save costs can encourage participants to seek out other opportunities to save costs, improving financial stability and encouraging spending in other areas to boost local economies.</p> <p>Reduce the likelihood that an Income Eligible individual falls into arrears, reducing risk of difficulties to the individual and utility through managing the arrears process. Also, can promote more stable income for Income Eligible individuals through lower expenses.</p>



Educational	<p>Raises awareness in both the program participants and other tangential citizens to the benefits of renewable and emerging energy technologies (economic, social, environmental, etc.). This could lead increased technology and emerging ways of communities interacting with utilities to manage their future energy needs (e.g., apps, platforms, etc.).</p> <p>Increase understanding of opportunities and methodologies to save cost with this initiative can result in overall rise in level of awareness of ways to save cost across other aspects of day to day life planning.</p> <p>Initiative could be used to develop educational materials on energy efficiency programs that allow increased energy efficiency, grid stability, and resiliency.</p>
Environmental Externalities	<p>Increase awareness of environmental issues associated with choices from selecting different energy technologies and how choosing different technologies can reduce environmental impacts.</p> <p>Result in uptake of increased levels of citizen energy solutions that lowers the environmental (e.g., air, ground, and water) impacts from older, less energy efficient, and higher risk energy sources.</p> <p>Support the state and federal programs in shifting toward more renewable technologies with less environmental impacts as compared to older, less energy efficient energy technologies.</p>

Finally, the Company also expects important economic development benefits to accrue by supporting the growth of a labor-intensive sector with a direct positive impact on the building trades. However, these benefits are not included in the final BCA to ensure accounting consistency across the Power Sector Transformation Initiatives.

## 6. CONCLUSION

Rhode Island already has clean electricity, and it will continue to become cleaner over coming years. Pairing this clean electricity with heat pump technology is a win-win for customers and the environment. Today, this synergy is vastly underutilized. Each year, thousands of Rhode Island heating systems are replaced, but the vast majority of customers replacing their oil or propane systems are unfamiliar with the cleaner and less expensive option of electric heat pumps. Additionally, they have no rebate incentives to switch, so they stay with delivered fuels. This trend is a significant lost opportunity to save customers money and reduce heating emissions. As the electric grid evolves toward even cleaner supply, it is important to thoughtfully invest in a broad portfolio of programs that accelerate customer adoption of heat pump technology. National Grid believes that the time to start this process is now.



Schedule PST -1,  
Chapter 7 - Energy Storage

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**CHAPTER SEVEN: INVESTING IN A CLEAN ENERGY FUTURE  
ENERGY STORAGE SYSTEM INITIATIVE**

**1. INTRODUCTION**

Although electricity use has decreased due to successful energy efficiency initiatives, demand reductions alone have not been enough to meet Rhode Island's resiliency and greenhouse gas emissions goals. A large and coordinated effort to expand investment in efficiency and clean energy sources is required and timely to enable Rhode Island to achieve its environmental and economic ambitions. Energy storage is critical for achieving a clean energy future as it provides the ability to optimize system performance over time and allows intermittent renewable resources, such as wind and solar, to make a larger contribution to overall generation. The Company intends to play a leadership role by including in the Plan expanded investment in energy storage.

To effectively integrate energy storage, utilities must become involved with this technology early on, developing process improvements and methods to properly and efficiently take advantage of the benefits that storage can provide. It is for this reason that the Company proposes an Energy Storage System Initiative in its clean energy portfolio.

**2. ABOUT THE PROJECT**

To demonstrate energy storage, the Company proposes to install and own approximately two MWh of energy storage at locations that will test benefits to the distribution system, maximize benefits to co-located customers/partners, and enable youth/community educational opportunities. The program will include an innovation component, which, in addition to providing the Company with lesson learned, will facilitate the development of additional projects and improve the Company's ability to accommodate this technology on the distribution system.

National Grid already owns or is in the process of installing approximately 15 MWh of energy storage in Massachusetts. Experience gained constructing these facilities will be applied in Rhode Island, allowing the Company to construct new storage systems in a more efficient manner.

The Company's preference is to work with a community partner to host physical energy storage systems and opportunistically integrate these systems into their existing Science Technology Engineering and Math (commonly referred to as STEM) educational curriculum. Integrating energy storage projects with community/youth educational outreach efforts will help to highlight the benefits of this technology and increase community awareness while also providing direct benefits to partner organizations in the form of energy and cost savings.

In exchange for allowing National Grid to leverage the installation for on-going Research and Development (R&D), the partner would receive demand reductions from the systems use. Potential partners include Save the Bay, Roger Williams Park Zoo, Providence Children's Museum, and a state school campus. The Company has not yet finalized the locations and partners, but a suitable partner must be willing to work with National Grid on siting requirements. Absent an appropriate partner, energy storage systems could be paired with the Company's proposed solar locations to minimize interconnection costs.

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The Company has identified several objectives for its Energy Storage System program.

The first objective is to maximize quantifiable benefits by:

- Reducing system capacity through daily peak shifts;
- Reducing system dynamic wear-out effects from co-located intermittent generation;
- Understanding the role of energy storage in renewables integration; and
- Identifying potential reliability benefits related to ramping/smoothing of renewable generation, voltage/VAR support, and reductions in sustained and momentary outages.

The second objective is to advance internal research and development through a better understanding of:

- The commercial energy storage market;
- The capabilities of grid interactive inverters;
- Interconnection processes and challenges;
- Optimized use cases for energy storage system control and integration;
- The utilization of energy storage to enable additional distributed generation hosting capacity;
- Potential collaboration with Company volt/VAR optimization and conservation voltage reduction system expansions; and
- O&M expectations for energy storage systems.

The third objective is to promote energy awareness through educational outreach to community and youth organizations, including:

- Creating an accessible portal for learning about energy storage;
- Designing educational interfaces at each project site; and
- Quantifying public engagement in the program.

A proposal to expand energy storage in Rhode Island is timely for several reasons:

- It advances state objectives identified through the Power Sector Transformation Initiative, and provides direct benefits to customers;
- Early utility engagement with this technology, before a commercial market develops, is important in identifying process improvements and methods needed to properly and efficiently take advantage of the benefits that energy storage can provide, especially in light of the technology's potential impact on fundamental operating principles of the electric system;
- Projects of this scope provide lesson learned about key aspects of the siting, permitting, construction, interconnection, and operation of energy storage systems. This "learning by doing" will benefit the Company with future projects of this type; and
- Current interest in renewable energy and energy storage can be avenues to attract Rhode Island youth to STEM fields and energy research.

Connecting energy storage systems to the Company's distribution system may require upgrades to the host partner's service, potentially behind the customer's meter. Such interconnections will

be implemented in accordance with the Company's standards. The Company will follow all standard interconnection requirements with the exception of allowances needed to accommodate system testing. The Company may test advanced system functionalities and enhancements that are currently outside the scope of the interconnection process.

If this plan is approved, the Company will formulate a strategy for engaging with potential partners and developers, define site requirements, begin writing an RFP, and develop a list of potential bidders. The Company's plan is to issue an RFP and conduct meetings with potential bidders within 12 months of project approval. In addition, the Company plans to procure items with long lead-times for delivery in the first year. The Company expects to construct the energy storage system over a two-year period from the date of program approval.

### **3. ADVANCING GOALS**

#### **3.1. Advancing Power Sector Transformation Goals and State Policies**

The Energy Storage System Initiative strengthens the Company's commitment to the Rhode Island Power Sector Transformation Initiative and aligns with the state's clean energy goals. Energy storage is a key enabling technology for advancing the deployment of clean energy resources, particularly intermittent renewables, and thereby further diversifying and decarbonizing the state's energy supply. In addition, energy storage provides important system benefits in terms of resiliency and local economic development, and therefore has the potential to play an important role in supporting the objectives of the Resilient Rhode Island Act of 2014<sup>1</sup>.

Based on its experience developing approximately 35 MW of Company-owned solar generation facilities and storage in the Commonwealth of Massachusetts, the Company supports a robust and comprehensive RFP process as the best way to acquire energy storage systems. To support the economic goals in Docket 4600, preference during the RFP process will be given to developers who can engineer, procure, and construct systems in Rhode Island, and who have successfully interconnected similar sized systems in the state.

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<sup>1</sup> *R.I. Gen. Laws Ch. 42-62*

**Table 7-1: High-Level Summary of Alignment Between Energy Storage System and Docket 4600 Goals**

Goals For “New” Electric System	Advances? / Detracts from? / Neutral to?
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances – Energy storage has the potential to increase distributed generation and increase reliability.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances – The storage program would provide local economic benefits, both during the construction phase and over the system’s operating lifetime.
Address the challenge of climate change and other forms of pollution	Advances – Energy storage has the potential to increase distributed generation and enable higher penetration of solar, thereby providing more reliable, safe, clean, and affordable energy.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Advances – Company-owned storage provides opportunities to understand how to better integrate storage into the distribution system.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Advances – Energy storage projects can help develop a better understanding of how to compensate distributed resources in the distribution system.
Appropriately charge customers for the cost they impose on the grid	Neutral
Appropriately compensate the distribution utility for the services it provides	Neutral
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Neutral

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### 3.2. Benefits for our Customers

If the energy storage demonstration project is paired with a STEM educational partner, it will provide additional opportunities for integrated community/youth educational outreach, highlighting technology benefits and enhancing energy awareness, while also educating target audiences (*e.g.*, school-aged children) about efficient and cost-effective energy use. The Company also expects to develop complementary educational materials about how energy storage fits into the broader energy ecosystem. Absent a STEM educational partner, the Company may consider cost-sharing opportunities with private entities. As the system would provide demand benefits to the host facility, the Company would also leverage these benefits to enlist the partner organization in efforts to better understand the interconnection and operation of energy storage capabilities in the distribution system.

Tapping into an existing educational partnership is an effective way to provide additional unquantified value. This model has been successful in other regions. For example, the Central Maine Power/Avangrid partnership with Gulf of Maine Research Institute exposed every middle school student in Maine to an ‘energy’ session during their annual visit while their “Powerhouse” program was operating.

To share lessons learned for the benefit of energy storage providers and developers, the utility industry, stakeholders, and customers, the Company plans to present findings from its energy storage project at industry conferences, targeting at least two major conferences annually.

### 4. PROJECT COSTS

The average total development capital cost of the proposed Energy Storage System Initiative over the course of three years totals \$2.3 million. The costs by year are shown in Table 7-2. Of this total, the estimated capital cost in the first year is \$0.9 million and \$1.3 million in the second year. The Company used information from the RFP issued for its Massachusetts solar and storage program, which includes storage facilities, to develop these cost estimates. The cost estimate reflects concept-level assumptions about system size. If needed to remain within budget, the Company could reduce the number of systems or the size of the systems deployed through the program.

The Company will require that selected developers provide a quote for the first five years of O&M services that includes a five-year workmanship or labor guarantee on the entire developed system and a ten-year warranty on inverters and batteries. This will encourage developers to provide a complete bid, including development and maintenance.

The Company estimates that annual O&M costs will total \$70,250, which is the level of expenditure necessary to ensure that systems operate safely and properly and generate at their maximum capacity over their projected design life. Site maintenance costs include annual system O&M; site upkeep; project management of maintenance, oversight, reporting and analysis; property taxes; any property rental or lease payments; and other costs associated with site upkeep. Company oversight and reporting of system performance will include oversight of annual O&M and any reporting to state and local agencies, along with any costs for research and testing on site.



**Table 7-2: Energy Storage System Program Costs by Year**

	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>3 - Year Total</b>
<b>O&amp;M total</b>	\$5,000	\$24,000	\$41,250	<b>\$70,250</b>
<b>Capital</b>	\$894,375	\$1,341,563	\$0	<b>\$2,235,938</b>
<b>Total</b>	<b>\$899,375</b>	<b>\$1,365,563</b>	<b>\$41,250</b>	<b>\$2,306,188</b>

Further details on costs are provided in Workpaper 7.1 - Energy Storage Costs/Assumptions.

**5. BENEFIT COST ANALYSIS**

As described in Chapter Two, the Company conducted a Benefit Cost Analysis to evaluate the Societal Cost Test and Ratepayer Impact Measure for the energy storage program. The Company calculated a Societal Cost Test benefit cost ratio of 0.45 and a Ratepayer Impact Measure cost test ratio of 0.49.

The benefits and costs included in the Societal Cost Test benefit cost analysis model are as follows:

**Table 7-3: Societal Cost Test Benefits and Costs**

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

The benefits and costs included in the Ratepayer Impact Measure benefit cost analysis model are as follows:

**Table 7-4: Ratepayer Impact Measure Benefits and Costs:**

Energy Storage - BCA Ratio		
<b>Benefits</b>	Forward Commitment: Capacity Value	\$ 889,173
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)	\$ 139,264
	Avoided Renewable Energy Credit (REC) Cost	\$ (2,859)
	Wholesale Market Price Impacts	\$ (136)
		<b>\$ 1,025,442</b>
<b>Costs</b>	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	\$ 2,260,660
	Frequency Regulation	\$ (163,044)
		<b>\$ 2,097,616</b>
<b>BCA Ratio</b>		<b>0.49</b>

Further details concerning the BCA model are provided in Appendix 2.1 - Program BCA.

While the proposed Energy Storage System Initiative does not pass the benefit cost test, the program still provides value to customers and the distribution system, while advancing goals adopted through state legislation. Energy storage is anticipated to be a significant market in the near future, and all customers will benefit if the Company can maximize its understanding of operations and processes for accommodating energy storage before the technology achieves wider commercial deployment. Therefore the Company includes this Energy Storage System program in the Plan. This approach is consistent with the findings of the Docket 4600 Final Working Group Report. Table 7-5 provides a qualitative description of the potential benefits of the Energy Storage System Initiative.

**Table 7-5: Qualitative Benefits of the Energy Storage System Initiative**

Category	Description / Examples
Societal	<p>Participation in the Energy Storage System Initiative can further improve a customer’s personal comfort level and give them the ability to make informed decisions regarding their energy usage. For many income eligible populations, this will represent a significant interaction with the Company (often seen as a tangible representation of public and government service), which in turn can generate substantial goodwill for the state.</p> <p>This program can further improve personal, community and youth awareness. It provides educational benefits that bring along with it increased energy awareness and the ability to make informed decisions regarding energy usage. For many of these populations this will represent a significant interaction with the utility (often seen as a tangible representation of public and government service) that can in turn generate substantial goodwill toward the state.</p>
Economic	<p>The results of the Company’s high-level economic development assessment indicated that the Energy Storage System Initiative has the potential to provide new and recurring local job opportunities through activities such as site maintenance.</p> <p>Increased awareness of employment opportunities in new and upcoming areas such as storage and battery technology can provide additional optionality and avenues for employment that many citizens may not have considered prior to implementing these initiatives.</p> <p>Greater visibility into how energy is generated and used and impacts a customer’s "bottom line".</p> <p>The program has the potential to provide some level of state and local tax revenue.</p>
Educational	<p>Opportunity to educate general public as well as specific target demographics (e.g., school-aged children) on how they can improve usage of energy by deploying discrete storage solutions and creating complementary educational materials around how this solution fits into the broader energy ecosystem.</p> <p>Exposes Rhode Island customers to new and emerging technologies that will likely have significant impacts across a variety of dimensions (economic, social, environmental, etc.) and that may affect them in very specific and tangible ways. This could entail new and more efficient ways of interacting with the Company (such as mobile apps that showcase storage capacities) and how they choose to purchase and manage their own energy in the future.</p> <p>This could be further expanded to include educational materials that help</p>

	<p>customers understand how to participate in related initiatives, such as energy efficiency, which further contribute to deployment and improved performance of clean energy solutions.</p>
<p>Environmental Externalities</p>	<p>Awareness of broad environmental issues such as the tangible energy and environmental impacts resulting from older, less efficient energy solutions (<i>e.g.</i>, particulate emissions).</p> <p>Importance of the shift to cleaner options to support sustainability initiatives at the state, local, and federal levels and ensure that progress is continued against goals set forth in critical pieces of policy and legislation.</p> <p>Increased sensitivity to how individual behaviors related to energy usage and personal choice impact the local environment – this is greatly enhanced by pairing with complementary educational and informational initiatives that highlight specifically how the technologies work. In this case it would be useful to demonstrate how energy storage provides the ability to take advantage of the spread between inexpensive, off-peak charging rates and expensive, on-peak charging rates.</p>

**6. CONCLUSION**

As the electric grid evolves, it is important to thoughtfully invest in the infrastructure needed to build a clean energy future. The proposed Energy Storage System Initiative is a critical component of its broader Power Sector Transformation initiative for Rhode Island.



Schedule PST -1,  
Chapter 8 - Income Eligible

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## CHAPTER EIGHT: ENABLING OUR INCOME ELIGIBLE CUSTOMERS

### 1. INTRODUCTION

National Grid has a long history of supporting Income Eligible customers in Rhode Island by providing tools to help these customers manage both the affordability of their overall energy costs, as well as monthly volatility in their utility bills. Rapid change in the energy and technology landscape creates new challenges for these customers, but also puts National Grid in a unique position to provide value to Income Eligible customers through the use of renewable technologies such as solar.

### 2. ABOUT THE PROJECTS

National Grid proposes two initiatives as part of the Plan to better support our Income Eligible customers: (1) the Solar demonstration Program for Income Eligible customers (referred to herein as the Solar Program) and (2) an Income Eligible Customer Rewards Program. These independent initiatives are proposed in addition to the support programs the Company already provides to Income Eligible customers, and in addition to other proposed investments in the Company's base distribution rate case, as discussed in the pre-filed direct testimony of Company Witness John F. Isberg. The reasons why these additional proposals are included under the Company's Plan are explained further below.

### 3. SOLAR PROGRAM

The proposed Solar Program consists of a utility-owned solar photovoltaic demonstration program for installations up to 3.75 MW. The Company will use these solar sites for community education and renewable energy generation. Several of the Company-owned sites being evaluated for this program are located near affordable housing developments.

The Solar Program will allow for safe, reliable, and affordable delivery of energy services to Rhode Island customers over the long term. The Program is aligned with Docket 4600 Guidance Document and the supporting details are provided in Section 4.1 below. Moreover, a project of this scope will allow the Company to learn from the siting, permitting, construction, interconnection, and operation of these systems. This knowledge and experience, in turn, will benefit customers and solar developers, as renewable projects progress forward in the future, and spur new market growth. In addition, the program can leverage current public interest in renewable energy and energy storage to attract Rhode Island youth into science, technology, engineering, and math (commonly referred to as STEM) and energy research fields.

#### 3.1. Site Locations

Possible site locations for these installations may include available property owned by the Company or a subsidiary of National Grid. If the Company selects a property owned by a National Grid subsidiary, it may lease the property from the subsidiary. If suitable location(s) are not found at Company-owned properties, the Company may consider leasing property from a third party. The Company will also consider co-locating the solar sites with the Energy Storage System, presented in Chapter Seven. Locating the proposed Energy Storage System as part of a

solar project could help reduce project costs and could provide additional opportunities to demonstrate the advantages of co-locating energy storage with intermittent renewables, such as smoothing out sudden changes in solar irradiance or shifting generation peaks.

The Company plans to use the installation sites for 25 years in order to fully realize the value of the Solar Program assets, and will pay property taxes in cities and towns where the systems will be installed, thus benefiting Rhode Island communities.

### **3.2. Generating Value for Income Eligible Customers**

The Company proposes to use revenues from the solar sites to lower energy bills for Income Eligible customers who may reside at nonprofit, affordable housing locations. Proceeds will be transferred to the Company's Income Eligible targeted programs, which seek to reduce energy use within this customer group. For example, rather than providing a one-time reduction of a customer's bill, the Company may provide energy saving measures, above those provided through current energy efficiency programs.

The Company intends to maximize the value of outputs, including environmental attributes such as renewable energy certificates, as well as energy and capacity from the proposed solar generation facilities. The Company plans to register the solar generators and the energy component of their output with the Independent System Operator-New England (ISO-NE).

Electricity generated by these solar generators will be sold into ISO-NE's energy markets. The energy output component will be unit-contingent, meaning that ISO-NE will pay for only the energy that is produced by each generating unit. The Company will receive payments from the ISO for this generation at the nodal real time locational marginal price. Energy output from these solar generating units will not be incorporated into the Standard Offer Service. The Company proposes to maintain the flexibility to qualify and commit these solar generation units in the ISO-NE's Forward Capacity Market in the future, in keeping with the stated intent to maximize the value of the units' output.

For each megawatt hour of energy produced by these solar generation facilities, one renewable energy certificate will be issued by the New England Power Pool Generator Information System and then deposited into the Company's Generator Information System sub-account on a quarterly basis. The Company proposes to use these renewable energy certificates to help satisfy its renewable portfolio standard requirement in a given compliance year, and monetize the value of the renewable energy certificates for the benefit of the program. Alternatively, the renewable energy certificates may be monetized by selling them in the open market. In that case, the Company would monetize any renewable energy certificates by entering into bilateral transactions with creditworthy counterparties by issuing requests for proposal or by using brokers to solicit suitable buyers.

The Company recognizes that there are efficiencies in self-supplying renewable energy certificates to meet its renewable portfolio standard obligations. This avoids the need to engage in transactions to purchase renewable energy certificates from other sources for renewable portfolio standard compliance purposes, and to engage in transactions to sell the renewable energy certificates generated by the solar units. Reducing the number of renewable energy



certificates that have to be purchased and sold will reduce administrative as well as transaction costs, which may include broker fees. The Company does not anticipate that transaction costs would be significant; nonetheless, reducing costs on both sides of the transaction (*i.e.*, renewable energy certificates purchases for Standard Offer Service customers and renewable energy certificates sales for distribution customers) would be more efficient and increase overall value to all customers.

Proceeds from energy sales to ISO-NE, sales of renewable energy certificates, and potential proceeds from forward capacity markets will be directly captured and documented by the Company. The Company will use these proceeds to directly fund energy saving projects that reduce electric bills for customers at nonprofit, affordable-housing projects, consistent with the Renewable Energy Standard set forth in R.I. Gen. Laws § 39-26-6(g). In the event that not all proceeds can be directed to energy savings projects, remaining proceeds may be used to reduce system costs or operating expenses. The Company will utilize existing energy efficiency program channels and mechanisms to solicit customer participation in energy savings projects that reduce electricity bills for customers at the nonprofit, affordable-housing projects.

### **3.3. Solar Procurement Process**

National Grid has experience with solar ownership in Massachusetts, where the Company has either constructed or is in the process of constructing approximately 35MW of Company-owned solar generation. Given this experience, the Company will issue a request for proposal to solicit bids from developers to install systems in selected locations. The Company will seek proposals from bidders who have previously completed the installation of at least one project with a similar design capacity to the proposed project within the Company's service territory, and will give preference to these developers. Additionally, the Company will ask bidders to provide a design sample of a system equal to or larger than 100 kW.

The request for proposals will offer guidance on types of acceptable bids while also encouraging developers to propose innovative approaches to project implementation. At a minimum, developers will be responsible for providing detailed plans for engineering, installing, and commissioning the systems, whether on third-party-owned property or on Company-owned property.

Systems will be constructed over a three-year period from the date of program approval.

## **4. ADVANCING GOALS: SOLAR PROGRAM**

### **4.1. Advancing Power Sector Transformation Goals and State Policies**

The Solar Program will advance state goals while also increasing the Company's knowledge of solar technologies and their impact on the electricity system, generating clean power within the state of Rhode Island, and providing targeted investment in the income eligible community.

Rhode Island Governor Raimondo has established a goal to increase clean energy in Rhode Island to approximately 1,000 MW by 2020, and this program is intended to support that. Additionally, this program aligns with the energy security, cost-effectiveness, and sustainability goals of ENERGY 2035.

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The Company's Solar Program is designed to meet the specific requirements of R.I. Gen. Laws § 39-26-6(g), which authorizes utility ownership of up to 15 MW of renewable generation demonstration projects, provided that a portion of demonstration projects specifically benefit customers of nonprofit affordable housing projects.

The Solar Program also helps to achieve numerous climate-related goals set out in state legislation and other policies or programs:

- Rhode Island Greenhouse Gas Emissions Reduction Plan<sup>1</sup>, which requires a plan to achieve 80% reduction in greenhouse gas emissions by 2050;
- City of Providence Executive Order that commits Providence to becoming “carbon neutral” by 2050;
- Energy 2035 Rhode Island<sup>2</sup>, which is intended to set Rhode Island on track to meet the energy security, cost, and sustainability vision and generate positive energy, economic, and environmental benefits for the state;
- Renewable Energy Standard, R.I. Gen. Laws § 39-26-6, which requires the State's retail electricity providers to supply 38.5% of their retail electricity sales from renewable resources by 2035; and
- Regional Greenhouse Gas Initiative (RGGI), which is a market-based program to reduce greenhouse gas emissions from electric power generating units across nine northeastern states.

Although the Company is authorized to own up to 15 MW of solar generating capacity under R.I. Gen. Laws § 39-26-6(g), the Company is only looking to invest in up to 3.75 MW of solar facilities, for purposes of maximizing benefits to Income Eligible customers. The Company may propose additional projects in the future.

The Solar Program aligns with Docket 4600 Goals, as described in Table 8-1 below.

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<sup>1</sup> <http://climatechange.ri.gov/documents/ec4-ghg-emissions-reduction-plan-final-draft-2016-12-29-clean.pdf>

<sup>2</sup> <http://www.planning.ri.gov/documents/LU/energy/energy15.pdf>

**Table 8-1: High-Level Summary of Alignment Between Solar Program and Docket 4600 Goals**

Goals for “New” Electric System	Advances? / Detracts from? / Neutral to?
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances – solar generators to provide reliable, safe, clean, and affordable energy.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances – solar development provides local economic benefits both during the construction phase and over the life of the system.
Address the challenge of climate change and other forms of pollution	Advances – solar energy has no greenhouse gas or other pollutant emissions.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Advances – Company-owned solar provides opportunities to understand how to better integrate distributed generation into the distribution system.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Neutral
Appropriately charge customers for the cost they impose on the grid	Neutral
Appropriately compensate the distribution utility for the services it provides	Neutral
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Neutral

Lastly, the program includes an innovation component aimed at increasing the Company’s understanding of opportunities to facilitate growth for additional projects and improve its accommodation of distributed generation technologies on the distribution system.

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#### **4.2. BENEFITS FOR OUR CUSTOMERS - SOLAR PROGRAM**

This program, which will include two sites built in the vicinity of nonprofit affordable housing, will demonstrate how a Company-owned solar system can directly benefit Income Eligible customers. The program is designed to provide several types of benefits:

- Investing revenues from the solar sites into energy-saving programs for Income Eligible programs to help lower these customers' electric bills;
- Reducing the electric bills of Income Eligible customers to reduce the burden of funding Income Eligible energy discounts for all Rhode Island customers;
- Lowering energy costs to provide local economic development benefits;
- Providing a model for helping Income Eligible customers derive direct benefits from the deployment of renewable energy;
- Promoting awareness of environmental issues, such as pollution impacts from older, less efficient energy technologies (*e.g.*, particulate emissions);
- Facilitating community education by locating solar sites in accessible locations;
- Learning more about Income Eligible customers' engagement with renewable energy through the Rewards Program;
- Reducing reduce service interruptions for Income Eligible customers (particularly for Income Eligible participants with less stable financial situations or access to utilities) through the Reward Program; and
- Potentially creating new and recurring local job opportunities.

In her March 2, 2017 letter to the PUC, Division, and OER, Governor Raimondo stated that, to advance a cleaner, more affordable, and reliable energy system, Rhode Island must ensure that its energy system continues to evolve in a manner that will benefit all Rhode Island residents and fosters job growth and innovation. Given current public interest in renewable energy technologies, the Company's solar projects offer an innovative outreach opportunity to attract Rhode Island youth into STEM and energy research.

#### **5. PROJECT COSTS – SOLAR PROGRAM**

The aggregate total development (capital) cost estimate for the Solar Program is approximately \$9 million. Estimated capital costs by year are shown in Table 8-2. These costs are necessary to ensure that the systems operate safely and properly and generate at their maximum capacity over their projected design life. Site maintenance costs include annual site maintenance; project management of maintenance, oversight, reporting, and analysis; property taxes; any lease payments; and other costs associated with site upkeep.

The Company will require that selected developers provide a quote for the first five years of O&M services. This will encourage developers to provide a complete bid that includes development and maintenance. Also during the first five years, the Company expects the developer to be responsible for site maintenance of the solar generating sites. For subsequent years, the Company may select one or more O&M service providers. However, the Company will oversee the solar generating systems and will be responsible for maintaining the performance of these systems over their expected operating life.

The Company’s estimate of O&M costs assumes that annual system and site maintenance services will be provided by third-parties. Additional costs will be incurred by service providers, along with Company oversight, management, analysis, and reporting on facility performance, and for any directly site-related incremental work.

While the Company will leverage its experience and personnel from other initiatives, it will require additional costs to manage these projects. These program costs are built into the O&M estimate. The Company does expect that all the O&M costs will rise over time with inflation at an estimated rate of 2.5% per year.

The Company does not expect to use any proceeds from the Solar Program to offset O&M costs. Rather, the Company will seek to recover O&M costs associated with the Solar Program through an annual reconciliation filing. The annual reconciliation filing will detail revenue and expenses associated with the program, as well as energy savings achieved by its solar installations at nonprofit, affordable-housing complexes.

**Table 8-2: Solar Program Costs by Year**

	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>3-Year Total</b>
<b>O&amp;M total</b>	\$8,750	\$38,875	\$108,125	<b>\$155,750</b>
<b>Capital</b>	\$1,337,500	\$2,550,000	\$5,175,000	<b>\$9,062,500</b>
<b>Total</b>	<b>\$1,346,250</b>	<b>\$2,588,875</b>	<b>\$5,283,125</b>	<b>\$9,218,250</b>

A point about development costs versus ownership costs is worth noting: Development costs are the costs the Company expects to pay developers once construction of these turn-key systems is complete. Ownership costs include development costs, project management costs, commissioning costs, and capital overhead allocations.

Further details on costs are provided in Workpaper 8.1 - Solar Costs/Assumptions. Note that the Total Ownership costs in the supporting workpaper vary from the BCA Model, where rounding was applied. Column J and Column K display the differences. The BCA Model and supporting Revenue Requirements align.

**6. BENEFIT COST ANALYSIS**

As described in Chapter Two, the Company conducted a benefit-cost analysis to evaluate Societal Cost Test and Rate Impact Measure for the Solar Program. The Company calculated a Societal Cost Test benefit-cost ratio of 0.85 and a Rate Impact Measure benefit-cost ratio of 0.63.

Benefits and costs included in the Societal Cost Test analysis for the Solar Program are summarized in Table 8-3.

**Table 8-3: Societal Cost Test Benefits and Costs**

Solar - BCA Ratio		
<b>Benefits</b>	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	\$ -
		\$ -
		<b>\$ 6,044,680</b>
<b>Costs</b>	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	\$ 7,093,687
		\$ -
		<b>\$ 7,093,687</b>
	<b>BCA Ratio</b>	<b>0.85</b>

The benefits and costs included in the Rate Impact Measure for the Solar Program BCA model are as follows:

**Table 8-4: Rate Impact Measure Benefits and Costs**

Solar - BCA Ratio		
<b>Benefits</b>	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
	Wholesale Market Price Impacts	\$ 7,598
		0 \$ -
		0 \$ -
		0 \$ -
		0 \$ -
		<b>\$ 4,447,170</b>
<b>Costs</b>	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	\$ 7,093,687
		0 \$ -
		<b>\$ 7,093,687</b>
	<b>BCA Ratio</b>	<b>0.63</b>

Further details concerning the BCA Model are provided in Appendix 2.1 - Program BCA.

Although the results of the Benefit-Cost Analysis suggest that costs will slightly exceed benefits, the Company strongly believes that this program provides value, both to customers and to the distribution system, while also advancing required state legislation. Additionally, as the Company’s first experience with ownership of this type of asset in Rhode Island, the program could generate “learning-by-doing” benefits that would associated with utility ownership that could provide for cost reductions in the future. Finally, this program provides benefits that align with goals articulated in the Docket 4600 Final Working Group Report, as noted in Chapter Two. These qualitative benefits are explained below.

**Table 8-5: Qualitative Benefits**

Category	Description- /Examples
Societal	<p>Participation in the Solar Program can further improve a customer’s personal comfort level and give them the ability to make informed decisions regarding their energy usage. For many income eligible populations, this will represent a significant interaction with the Company (often seen as a tangible representation of public and government service), which in turn can generate substantial goodwill for the State.</p> <p>Fewer interruptions in service, particularly for Income Eligible participants with less stable financial situations or access to the Company, can significantly improve quality of life and overall sense of personal security.</p> <p>In addition, solar technology itself has emerged as a symbol for new, innovative energy solution that delivers local infrastructure improvements and employment benefits.</p>
Economic	<p>The results of the Company’s high-level economic development assessment indicated that the Solar Program has the potential to provide new and recurring local job opportunities through activities such as site maintenance.</p> <p>Increased awareness of employment opportunities in emerging energy technology areas such as solar technology can provide additional career options and new avenues for employment that many Rhode Island citizens may not have considered prior to implementing these initiatives.</p> <p>Greater public understanding of energy sources and impacts, and of their relevance for customers' "bottom line".</p> <p>Greater understanding can also reduce the likelihood that an Income Eligible customer falls into arrears or has other difficulties managing their utility account. This in turn will reduce negative interactions with the Company, creating fewer interactions that may come at additional risk or expense (e.g., utility disconnect calls, account management via call center customer support</p>

	staff).
Educational	<p>Exposes Rhode Island customers to new and emerging technologies that could eventually impact them in specific and tangible ways. This could be through the use of new and more efficient technologies for interacting with the Company (such as mobile apps that showcase current generation of electricity from solar sources), and greater control over customers’ own energy purchase and management in the future.</p> <p>The Solar Project can be expanded to include educational materials for helping citizens understand how to participate in related initiatives, such as energy efficiency, which further contribute to deployment and improved performance of clean energy solutions.</p>
Environmental Externalities	<p>Awareness of broad environmental issues such as the tangible energy and environmental impacts resulting from older, less efficient energy solutions (<i>e.g.</i>, particulate emissions).</p> <p>Enhanced awareness of the importance of shifting to cleaner energy technologies as a way to support sustainability initiatives at the state, local, and federal levels and to ensure continued progress toward state-wide goals.</p> <p>Increased sensitivity as to how individual energy behavior affects the local environment, particularly if the project is paired with complementary educational and informational initiatives that highlight specifically how solar technologies work. Additionally, the Company could demonstrate how solar generation coincides favorably with peak load, thereby helping to ensure that customers have the energy they need and reduce the likelihood outages when energy demand is greatest.</p>

**7. ABOUT THE INCOME ELIGIBLE CUSTOMER REWARDS PROGRAM**

The Income Eligible Customer Rewards Program will be designed to achieve two goals, both in support of increasing the rate at which Income Eligible customers make timely bill payments and to reduce the incidence of arrears, collection, and service termination situations. Incremental opportunities exist to provide additional benefits to Income Eligible customers in the form of utility managed “reward” accounts. These accounts will:

- Provide a mechanism for the Company to convey direct financial benefits to customers who exhibit behaviors or take actions that the Company wishes to incentivize, either because they increase the likelihood that customers will stay current on their bills or because they directly reduce the cost of serving these customers; and
- Provide vulnerable customers with a “bank” from which they can draw to pay their utility bill during months when that might otherwise be challenging, recognizing that many Income



Eligible customers lack access to savings that would traditionally provide a cushion against unanticipated increases in expenses and/or reductions in income.

**8. ADVANCING GOALS- INCOME ELIGIBLE REWARDS PROGRAM**

**8.1. Advancing Power Sector Transformation Goals and State Policies**

The Company’s proposed Income Eligible Customer Rewards Program will help Rhode Island achieve goals set forth in Docket 4600.

The Docket 4600 Working Group members embraced eight goals and the Company’s Income Eligible Rewards Program meets the goal of providing reliable, safe, clean, and affordable energy to Rhode Island customers over the long term.

Docket 4600 places emphasis on low income/customer protections and opportunities by specifically recommending temporary additional discounts or other mechanisms as needed for low income consumers related to rate increases driven by programs, infrastructure changes, or uneven access to new programs or resources (*i.e.*, where the benefit of the new programs or resources will not accrue to low-income consumers), or as required by principles of equity or burden. The Company’s Income Eligible Program meets this recommendation.

**Table 8-6: High-Level Summary of Alignment between Income Eligible Customer Rewards Program and Docket 4600 Goals**

<b>Goals for “New” Electric System</b>	<b>Advances? / Detracts from? / Neutral to?</b>
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances- The Rewards Program advances this goal by creating a mechanism to incentivize actions and behaviors among income eligible customers that support progress toward a clean energy system.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Neutral
Address the challenge of climate change and other forms of pollution	Advances - The Rewards Program supports the Company’s efforts to address climate change and other forms of pollution by encouraging customers to participate in energy-saving behaviors and programs.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles	Neutral

and heating) where that investment provides recognizable net benefits	
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Neutral
Appropriately charge customers for the cost they impose on the grid	Advances - The Rewards Program supports the Company’s efforts to appropriately charge customers for the costs they impose on the grid by providing a mechanism to share directly with Income Eligible customers the benefits of customer actions and behaviors that reduce the costs of serving customers in this segment.
Appropriately compensate the distribution utility for the services it provides	Neutral
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Advances- The Rewards Program supports this goal by providing a direct mechanism for aligning incentives for Income Eligible customers with customer behaviors and actions that further these objectives.

## 8.2. Benefits for our Customers

The Company anticipates that this program will benefit Income Eligible customers, as well as the broader Rhode Island utility customer base.

The benefits for Income Eligible customers include:

- By providing incremental financial rewards for desired behaviors, the program can nudge customers into taking actions that are ultimately to their long-term benefit. For example, customers could earn rewards for maintaining a track record of on-time bill payment, participating in budget billing or other programs designed to reduce monthly volatility in customer bills, taking behavioral or other direct energy efficiency measures to reduce energy consumption (and costs), and promoting participation by other Income Eligible customers;
- In contrast to the threat of service termination, the Rewards Program will provide a positive mechanism for promoting desired customer behaviors. It also enables the Company to share the benefits of actions that reduce system costs directly with the customers who take those actions;
- By encouraging Income Eligible customers to adopt and utilize technologies (such as home energy monitoring tools, connected home/smart thermostat technologies, high efficiency HVAC solutions, etc.) that can support reduced energy consumption and increased energy

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affordability, the Company can use reward accounts to promote customer engagement around these emerging technologies among a customer segment where that engagement might otherwise lag; and

- By definition, the Company's Income Eligible customers are more vulnerable to external financial shocks. Unanticipated expenses or income volatility can reduce these customers' ability to stay current on their utility bills, even where they have taken action to manage their energy expenses. Reward accounts can provide a financial buffer for customers who are otherwise less likely to have savings they can draw upon in these situations.

By putting Income Eligible Customers in a better position to stay current on their utility bills, the Reward Program can also be expected to produce a broader set of positive outcomes to the benefit of all National Grid customers in Rhode Island.

- By directly incentivizing on-time bill payment among the cohort of customers currently most likely to fall into arrears, Reward Accounts can reduce collection expenses, service termination costs, and bad debt write-downs associated with current bill payment performance among Income Eligible customers;
- By providing direct incentives for managing consumption (whether in aggregate, or, in conjunction with advanced metering, during specified periods of high demand), reward accounts can enhance participation by Income Eligible customers in energy efficiency and other demand-side management programs with system-wide benefits; and
- By conveying financial benefits through rewards accounts that are linked to customer utility accounts, the Company can ensure that these funds stay in the utility system and are utilized by Income Eligible customers to stay current on their utility bills.

## **9. PROJECT COSTS - INCOME ELIGIBLE REWARDS PROGRAM**

Total costs for the Income Eligible Reward Program are yet to be determined, and will be a function of the specific reward account triggers, mechanisms and levels that will need to be established as part of an internal program development effort in conjunction with broader external stakeholder engagement. To this end, the Company has retained an external consultancy firm, Utility Boost, to support development of a business case and design of the Reward Program. Working with Utility Boost, the Company is completing a Benefit-Cost Analysis that aligns program costs with anticipated benefits in the form of reduced arrearages and bad-debt write downs, reduced collection and service termination expense, and reduced Contact Center burdens. The BCA, expected to be complete in early 2018, will inform the appropriate scope and scale of the reward program. The Company anticipates collaborating with the Division to finalize program design. Subject to development of an appropriately robust business case, the Company will seek to introduce costs into this filing for a pilot scale deployment in FY19 and would anticipate proposing a larger scale deployment as part of its FY20 Power Sector Transformation Plan if the PUC approves the Plan.

Generally, cost components can be expected to fall into three categories:

- Program development costs, including internal and external training and communications necessary to educate customers and staff about reward accounts, and changes to internal processes as needed to enable customers to utilize reward balances.
- Technology investments to track the disbursement and utilization of customer reward benefits, including the presentation of balances and transactions to customers and reconciliation with Company billing and accounting systems.
- Funds needed to maintain the pool of monetary incentives that are ultimately conveyed to Income Eligible customers who take desired actions.

## **10. CONCLUSION**

Census data and other customer demographic information suggest that National Grid serves as many as 100,000 Income Eligible households in the state of Rhode Island. When these customers struggle to pay their utility bills, the impacts are felt throughout our service territory in the form of increased costs for all customers. Moreover, our Income Eligible customers are the least well positioned to take advantage of the many emerging technologies that will enable enhanced customer control over their energy consumption and contribute to a more sustainable and reliable modern electrical infrastructure.

National Grid is committed to ensuring that all of our customers benefit from these developments. Thus, the Company sees the development of Solar demonstration Program for Income Eligible customers and an Income Eligible Customer Rewards Program, as proposed in this chapter, as a foundational component of its broader Power Sector Transformation initiative.



Schedule PST -1,  
Chapter 9 - Performance

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**CHAPTER NINE: DRIVING OUTCOMES THAT CUSTOMERS VALUE: THE ROLE FOR  
PERFORMANCE INCENTIVES IN THIS TRANSFORMATION**

**1. PERFORMANCE-BASED REGULATION IS ESSENTIAL TO POWER SECTOR TRANSFORMATION**

While the fundamental objective of the electric utility to provide safe, reliable, and affordable electricity service has remained relatively constant over the past several decades, new objectives around sustainability, system efficiency, resiliency, grid modernization, distributed energy resource integration, and customer engagement have gained prominence with regulators and customers. And increasingly, these new objectives are transforming expectations for electric distribution utilities. In Rhode Island, these objectives are fundamental to the energy policy goals (discussed in Chapter Two) that have been articulated through Docket 4600 and the Power Sector Transformation Initiative.<sup>1</sup>

Integration of these objectives into the utility business environment requires electric distribution utilities to perform new functions that are materially different from the functions that support their core business, and will require innovation with regard to technology adoption and deployment, business and management practices, and the customer relationship. However, the current regulatory framework creates a disincentive for utilities to take on the risk associated with innovation in support of new goals for the electric system. Although today's regulatory framework supports cost-recovery and earnings on investment deemed prudent by regulators, it is not sufficient to drive innovative utility performance in delivering these new objectives. To best encourage utilities to innovate and to align their financial interests with broader policy goals and customer outcomes that expand beyond core performance obligations, new compensation mechanisms are needed.

A shift toward performance-based regulation is foundational to the power sector transformation envisioned by the state. This chapter proposes first steps in what is likely to be a longer process of evolution that uncovers new opportunities to incent both overall efficiencies and system cost reductions, while also driving exceptional utility performance in areas of importance. By rewarding utilities based on performance, regulation can better mirror the outcomes of competitive markets, where firms earn higher returns if they innovate and provide products and services that create more value for customers.

Through Docket 4600 and Power Sector Transformation the Division, the Company, and numerous stakeholders spoke to the value of incentives in advancing state policy objectives. All

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<sup>1</sup> Outside of Rhode Island, similar objectives have provided the foundation for initiatives such as Massachusetts Grid Modernization and New York REV. For example, the four objectives of Massachusetts Grid Modernization are: (1) reducing the effects of outages; (2) optimizing demand, including reducing system and customer costs; (3) integrating distributed resources; and (4) improving workforce and asset management. See, Order in D.P.U. 12-76-B, June 12, 2014, at 10-13. The NY REV objectives are: (1) customer knowledge and tools that support effective management of their total energy bill; (2) market animation and leverage of ratepayer contributions; (3) system wide efficiency; (4) fuel and resource diversity; (5) system reliability and resiliency; and (6) reduction of carbon emissions. See Case 14-M-010, Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues, at 1-2 (August 22, 2014).

of these parties recognize that new incentives may be necessary to encourage innovation and investments that might not otherwise occur under traditional cost-of-service regulation. In adopting the specific recommendation from Docket 4600 to “Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives,” the Rhode Island PUC has recognized their value as well.

The Company firmly believes that carefully designed performance incentives can help advance Rhode Island’s energy policy goals and provide broad new benefits to customers. Specifically, the Company believes that incentives are most likely to be appropriate and effective where:

- (1) there is a demonstrated market failure or a unique strategic role that can be served by the utility;
- (2) there is an opportunity to produce significant benefits to customers and/or promote Rhode Island’s energy policy goals; and
- (3) the distribution company plays a distinct and clear role in bringing about the desired outcome.

Utility performance incentives are not new to the state of Rhode Island. The PUC has previously approved Company tariffs that allow for the collection of performance incentives associated with the procurement of long-term renewable electricity contracts for retail customers, both from wholesale power providers and, separately, from eligible distributed-generation projects (the latter under the Renewable Energy Growth Program).

With respect to energy efficiency, the PUC has approved shareholder incentives for the Company’s energy efficiency programs dating back to 1990.

In addition, under its Service Quality Plan<sup>2</sup>, the Company is subject to performance standards in the areas of reliability and customer service with associated metrics, targets, and penalties, with the potential to earn offsets that can be applied against future penalties. These service quality metrics are used to evaluate the Company’s performance in meeting its core obligations to customers.

The Company expects that the incentives in this proposal will most closely resemble the existing incentives for energy efficiency, in that they are reward-only and designed to provide increasing rewards with higher levels of performance (with exceptions where incentives relate to milestones). The incentives in the Company’s Plan support the delivery of new benefits and savings to customers and in many cases reflect new areas of accountability for the Company that expand beyond its core obligations. In the near term, reward-only incentives are desirable in order to establish performance-based incentives as a beneficial mechanism for both the utility and customers.

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<sup>2</sup> The Company’s Service Quality Plan is described in Attachment 1 to the Company’s Agreement to Modify Performance Benchmarks (Agreement) filed with the Rhode Island Public Utilities Commission (PUC) on March 14, 2007, and approved by the PUC in Docket 3628.



The Company is proposing two types of new performance incentives. The first type includes new incentives related to capital efficiency for electric distribution investments, including (1) an incentive for capital savings on complex capital projects included in the Company's Infrastructure, Safety, and Reliability (ISR) Plan; and (2) an incentive for improvements in the efficient delivery of overhead distribution line projects. The Company also discusses its plans to propose similar incentives for its gas distribution business.

The second type of incentive the Company is proposing is a portfolio of performance incentive mechanisms that reward performance in delivering key programs and objectives aligned with state policy goals. The Company views the performance incentive mechanisms included in this proposal as a first step in a broader evolution of the regulatory framework that will unfold as the power sector transforms, bringing new opportunities to customers. Successful implementation of these incentives is likely to foster further innovation in the Rhode Island power sector, by providing both the Company and regulators with the confidence to identify and propose new areas for incentives that might drive further efficiencies or customer benefits. The Company recognizes that it may make sense over time to modify this portfolio of performance incentive mechanisms through additions of new incentives or through other modifications as the Company develops experience in measuring and delivering these objectives, deploys new technologies, and as state regulatory and policy priorities evolve.

Combined, these proposed incentives work to advance the three goals for a new regulatory framework articulated in the PST Phase One Report:

- Control the long-term costs of the electric system;
- Give customers more energy choices and information; and
- Build a flexible grid to integrate more clean energy generation.

## **2. PROPOSED CAPITAL EFFICIENCY INCENTIVES**

The Company's ability to identify efficiencies in the delivery of capital investments has the potential to generate meaningful savings for customers over time. However, the current regulatory framework does not reward the utility for identifying and delivering such efficiencies. An important element of performance-based regulation is the movement toward a regulatory framework that provides a more equal incentive for the delivery of operating and capital cost savings. To that end, the Company is proposing two new incentives related to the efficient delivery of capital. The first proposal targets complex capital projects and provides incentives for the Company to find ways to deliver agreed-upon outputs at a lower-than-forecast cost. The second proposal is designed to encourage increased productivity in the delivery of overhead distribution-line projects, providing incentives for the Company to innovate to more efficiently deliver roughly \$45m 'routine' capex per year. In addition to the two proposed incentives, the Company describes its intent to develop and propose incentives for capital cost efficiencies for its gas business. While this falls outside of the scope of the Power Sector Transformation Initiative, it is included in this chapter to reflect the Company's ambition to incorporate performance incentives across both its electric and gas businesses.

### **2.1. Complex Capital Projects Capital Cost Incentive**

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This incentive would reward the company for delivering a portfolio of complex capital projects that close in a given fiscal year at a cost below an accepted baseline capital cost estimate.

*Summary of incentive structure and scope*

Under this proposal, the award for a given year will be calculated based on a comparison of the actual capital costs at closure over the lifetime of the set of projects closing in a given fiscal year, to a baseline estimate of cost – based on final sanction costs – for the same set of projects. The comparison of actual to baseline capital costs will be done on a portfolio basis, rather than project by project, such that any capital spend in excess of sanctioned amounts for a given closed project will count against savings for the full portfolio of projects closed in that fiscal year.

The Company proposes that when a portfolio of projects is delivered for a capital cost that is less than the baseline cost, the Company retains 50% of the savings. The Company proposes to cap the value of savings that might be retained by the Company in a given year at \$2.5 million.

The Company proposes that this new incentive mechanism would start in FY 2020, and would apply to all complex capital projects closing in FY 2020 and beyond. Based on the size of projects that closed in FYs 2015, 2016, and 2017, this incentive is expected to apply to portfolios reflecting approximately \$5 million to \$15 million in capital expenditures annually, though this range may change over time.

*Determining project eligibility and baseline capital costs*

For projects that have already been included in a previous ISR and are scheduled to close during FY 2020, or FY 2021, the Company proposes a rolling process to have the Commission review and confirm those projects as eligible for the incentive, and to formally note their final sanction capital costs as the baseline. Looking ahead, for new complex projects added to the ISR, the Company proposes to indicate eligible projects and propose final sanction capital costs as the baseline for evaluating performance within its ISR Plan.

*Reporting and incentive payment*

For each portfolio of closed projects, the Company will report to the PUC, as part of its annual PST Reconciliation Filing, as well as its ISR Reconciliation Filing, its actual capital expenditures relative to the total capital cost estimate, with a calculation of the value of the incentive payment the Company has earned. The Company proposes that any positive incentives earned in a given fiscal year would be collected through the PST Provision in the following fiscal year.

## **2.2. Construction Costs per Mile Productivity Incentive**

The Company is also proposing an incentive for productivity improvements in the delivery of overhead distribution line projects. The metric underlying this incentive would be a composite per-mile construction costs metric that the Company is currently working to develop and

benchmark. The projects that would be captured by this metric represent the overhead distribution line budget of the Company’s approved spend under the ISR.

Under this incentive, the Company would be rewarded with a positive revenue adjustment for achieving target reductions in construction costs per mile as defined by the metric. The awarded incentive would increase in proportion to performance, and would be capped with a maximum annual value. Any positive incentives earned in a given fiscal year would be collected through the PST Provision in the following fiscal year.

The Company proposes to develop a baseline and targets for this metric for consideration in the Electric ISR filing to take effect in FY 2020.

### **2.3. Intent to Propose Gas Capital Efficiency Incentives:**

The Company is considering proposing incentives for its gas distribution business. The Company expects to propose specific metrics and targets for such an incentive for consideration as part of its FY 2020 ISR filing.

### **3. NATIONAL GRID’S PERFORMANCE INCENTIVE MECHANISMS PROPOSAL**

The Company has developed its performance incentive mechanisms proposal to support the policy priorities identified by stakeholders through Docket 4600 and emphasized during the Power Sector Transformation Initiative. The Company proposes to develop performance incentive mechanisms in the following three categories: (1) System Efficiency, (2) Distributed Energy Resources, and (3) Network Support Services. These three categories align with the recommended categories for performance incentive mechanisms in the PST Phase One Report. The report describes each category as follows: (1) System Efficiency incentives are intended “to achieve savings for ratepayers from the utility controlling long-term utility costs”<sup>3</sup>; (2) Distributed Energy Resources “includes targeted incentives for a range of distributed energy resources that require utility action to implement”<sup>4</sup>; and (3) Network Support Services “includes actions that the utility will need to accomplish to demonstrate capabilities essential for the future utility.”<sup>5</sup> The Company believes that incentives in these three categories, described in more detail below, will advance the objectives identified in both the Power Sector Transformation Initiative and Docket 4600, and provide new benefits and opportunities to customers.

(1) System Efficiency – Incentives around system efficiency are intended to drive the Company to deliver both near and long-term savings to customers by encouraging more efficient use of the system. Reductions in system coincident peak demand, for example, can reduce forward capacity market costs to customers below what they otherwise might have been, and can also reduce transmission expenses. Further, integration of new load in a manner that does not increase peak demand can avoid or minimize the infrastructure investments needed to support this additional load, and create downward pressure on rates by spreading the fixed costs of the system over more load.

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<sup>3</sup> PST Phase One Report, page 24.

<sup>4</sup> *Ibid.*

<sup>5</sup> *Ibid.*

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- (2) Distributed Energy Resources—Incentives to encourage the Company’s active efforts to integrate distributed energy resources support the state’s goals of encouraging customer engagement and investment, promoting emissions reductions, and supporting economic development within the state. The new performance incentive mechanisms in this category were developed to be complementary to existing incentives for distributed energy resources, such as energy efficiency and distributed generation contracts.
- (3) Network Support Services – Incentives in this category reward the Company for actions that support the development of a more digitized and decentralized system. These activities lay the groundwork for the longer term transformation of the power sector.

Within each of these three categories, the Company is proposing a set of performance incentive mechanisms intended to encourage successful delivery of new programs and broader Company activities aligned with Rhode Island state goals.

Each performance incentive is composed of (1) a metric to capture Company results in the specific area of interest; (2) targets that indicate performance goals or milestones for each metric; and (3) a financial incentive associated with the achievement of each target. Where a range of targets is included, the Company proposes to earn incremental rewards along the line between targets and earnings levels. The individual metrics and the Company’s approach to setting targets are described in more detail below; specific targets and proposed earnings levels are summarized in Table 9-1, which provides a high-level overview of the performance incentive mechanisms in each category and the proposed maximum earnings opportunities for each. The maximum earnings level is denominated in basis points;<sup>6</sup> however, the Company proposes that the incentives not be implemented as an adjustment to ROE, but rather as a payment calculated based on equivalent basis point value determined by the size of the rate base in the given year. The Company has followed the following principles in development of this proposal.

- Establish incentives that reward the Company for successful delivery of activities, programs, investments, and outcomes that are foundational to power sector transformation. In some cases, these incentives are designed to reward the Company for successful delivery of innovative new programs and investments as proposed, in recognition that these activities fall outside of its traditional core obligations and provide new opportunities for customers and benefits to the system. Targets and milestones have been set to reflect this objective. Incentives are justified in these cases to drive outstanding Company performance in these new areas, and to ensure that – given their relevance to state policy goals and importance to laying a successful foundation for power sector transformation – they remain priorities for Company leadership. In other cases, the incentives are designed to reward the Company for achieving particular performance outcomes that provide benefits or savings to customers. In these cases, the minimum target required for earning an incentive represents a clear step beyond what the Company currently achieves.
- Align, to the extent possible, with the proposed performance incentive mechanisms in the PST Phase One Report. In following this principle, the Company has developed performance incentive mechanisms that are directly in support of the Rhode Island state

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<sup>6</sup> Specifically, a basis point refers to 1 basis point of electric distribution common equity grossed up for taxes. For the rate year ending August, 2019, the Company has estimated the value of a basis point to be \$59,493.

energy goals articulated in Docket 4600 as well as the goals articulated in the Power Sector Transformation Initiative. Where the Company has omitted metrics included for performance incentives that were included in the PST Phase One Report, a rationale for this omission is provided.

- Assign values to individual performance incentive mechanisms based on a combination of (1) relevance to developing a foundation for transforming the power sector in the near term, and (2) the associated benefits or savings to customers due the activity encouraged by the incentive. The Company has supported the proposed values for individual incentives using analyses of benefits and costs where possible. Where quantification is not possible, the Company has provided a qualitative description of the most significant benefits and costs.

**Table 9-1: Overview of Proposed Performance Incentive Mechanisms and Maximum Earnings Opportunity in Basis Points**

Category and Supporting Metrics	2019	2020	2021
<b>System Efficiency</b>	<b>23.5</b>	<b>23.5</b>	<b>23.5</b>
Monthly Transmission Peak Demand Reduction	3	3	3
Forward Capacity Market Peak Demand Reduction	18	18	18
EV Off-Peak Charging Rebate Participation	2.5	2.5	2.5
<b>Distributed Energy Resources</b>	<b>29.5</b>	<b>29.5</b>	<b>29.5</b>
DG-Friendly Substation Transformers	10	10	10
DR -- Connected Solutions Participation	5	5	5
DR -- C&I Participation	5	5	5
Electric Heat Initiative	2	2	2
Electric Vehicles	3.5	3.5	3.5
Behind-the-Meter Storage	2	2	2
Utility-Owned Storage	2	2	2
<b>Network Support Services</b>	<b>22</b>	<b>22</b>	<b>22</b>
VVO Pilot Impacts	2	2	2
AMF Customer Engagement and Deployment	2	2	2
Interconnection -- Time to ISA	6	6	6
Interconnection -- Avg days to system modification	6	6	6
Interconnection -- Estimated vs actual costs	6	6	6
<b>Total</b>	<b>75</b>	<b>75</b>	<b>75</b>

### 3.1. System Efficiency Performance Incentive Mechanisms

The Company proposes three System Efficiency metrics: Monthly Transmission Peak Demand Reduction, Forward Capacity Market Peak Demand Reduction, and EV Off-Peak Rebate Participation. The Company expects that there will be value in additional System Efficiency performance incentive mechanisms in the near to medium term, particularly upon deployment of AMF. For example, the Company believes that time-varying rate participation, which was

included as a performance incentive mechanism in the PST Phase One Report, will be a valuable metric when such rates are more broadly enabled by AMF.

### **Monthly Transmission Peak Demand Reduction and Forward Capacity Market Peak**

**Demand Reduction:** The Company's peak demand reduction metrics are intended to provide savings to customers in two ways: reductions in monthly transmission billings from New England Power to Nantucket Electric and through reductions in forward capacity market costs. The Monthly Transmission Peak Demand Reduction metric will measure the annual sum of reductions in the monthly peaks on a year-over-year basis, based on the overall Company loads used in calculating monthly ISO-NE Regional Network Service (RNS) billings (loads will be weather-normalized for the purposes of applying this metric).<sup>7</sup> The Forward Capacity Market Peak Demand Reduction metric will measure reductions in the weather-normalized annual peak load on a year-over-year basis, using the same data. To control for weather variations, the Company proposes to normalize the peak for the average weather for the past 10 annual peak days.

The Company also proposes that the weather-normalized load reported for both metrics be adjusted, as warranted, to account for the addition of any large new electric loads on the system in a given year. These adjustments would be based on actual new peak demands seen at the new large load sites that are coincident with monthly or annual peak load.

The Company expects a number of programs and resources, including energy efficiency, energy storage, distributed generation, grid modernization efforts such as the deployment of volt-var optimization (VVO), and demand response to contribute to meeting these peak demand reduction targets.

To establish the annual peak target, the Company used its internal peak forecast, including forecast peak impacts from energy efficiency,<sup>8</sup> solar PV, and VVO, as well as the programs proposed in this Plan. With this information, the Company developed minimum, mid- point, and maximum targets. All three target points were set to represent incremental effort beyond what is expected under the Company's energy efficiency program plans. For the annual peak targets, the Company expects that payment of the incentive would require demonstration of savings beyond what is achieved through energy efficiency programs. Monthly transmission peak targets were set to encompass and expand upon the annual peak savings, with the size of the expansion increasing from year to year. The Company set initial targets for the sum of monthly peak reductions in recognition that it will have to develop an appropriate program to manage monthly peak loads to directly provide customer savings reductions in billed transmission costs relative to what would occur absent the program. Workpaper 9.1 – Peak Demand Reduction Targets includes supporting material for the development of these targets.

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<sup>7</sup> See the Company's February 16, 2017 Electric Retail Rate Filing, specifically the discussion presented in Tiffany Forsyth's testimony and Schedule TMF-2, page 1 of 2. Available at: [http://www.ripuc.org/eventsactions/docket/4691-NGrid-2017-RetailRate\(2-16-17\).pdf](http://www.ripuc.org/eventsactions/docket/4691-NGrid-2017-RetailRate(2-16-17).pdf)

<sup>8</sup> Energy efficiency targets incorporated in the forecast include targets for combined heat and power.

**Table 9-2: Monthly Transmission Peak Demand Reduction Targets and Basis Points**

Annual sum of monthly peak MW reductions				
	2019	2020	2021	Basis Points
Minimum	28	23	26	1
Target	36	34	36	1.75
Maximum	47	44	46	2.5

**Table 9-3: Forward Capacity Market Peak Demand Reduction Targets and Basis Points**

Annual peak demand reduction (MW)				
	2019	2020	2021	Basis Points
Minimum	22	18	19	6
Target	29	26	26	12
Maximum	38	31	31	18

**EV Off-Peak Charging Rebate Participation:** The EV Residential Off-Peak Charging Rebate participation metric will measure the number of customers participating in the Company’s proposed rebate program for off-peak EV charging relative to the Company’s target and budgeted participation levels. This program supports the state’s system efficiency goals by encouraging current and future EV drivers to shift EV charging loads to off-peak hours. The program will also offer an important opportunity to demonstrate Rhode Island customers’ response to, and potential savings from, time-variant price signals. Customers will benefit from increased familiarity with such price signals in advance of broader deployment of time-varying rates.

The Company set its participation target for the off-peak charging rebate program to reflect the target participation levels that support the Company’s proposed program budget. Thus, the incentive will reward the Company for timely and successful marketing and delivery of this new customer offering. The minimum target allows the Company to start to earn an incentive when it approaches 80% of the target participation level for the year; the maximum allows earnings to increase for participation up to 120% of the participation target should the Company find implementation efficiencies that enable enrollment beyond funded target levels.

**Table 9-4: EV Off-Peak Rebate Participation Targets and Basis Points**

<b>Number of participants</b>				
	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Basis Points</b>
Minimum	80	188	400	2
Target	100	250	500	2.5
Maximum	120	300	600	3

**3.2. Distributed Energy Resources Performance Incentive Mechanisms**

The Company’s seven proposed Distributed Energy Resources metrics are intended to directly support the achievement of multiple Rhode Island regulatory goals articulated in the Docket 4600 stakeholder report and adopted by the PUC, particularly:

- Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels).
- Address the challenge of climate change and other forms of pollution.
- Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits.
- Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures.

The Company has proposed specific performance incentive mechanisms intended to complement the existing incentives the Company has in place in support of energy efficiency, the Renewable Energy Growth Program, and renewable energy contracts. Metrics for these new performance incentive mechanisms include: (1) DG-Friendly Substations; (2) Demand Response- Connected Solutions Participation; (3) Demand Response- C&I Participation; (4) Electric Heat Initiative; (5) Electric Vehicles; (6) Behind-the-Meter Storage; and (7) Company-Owned Storage. The demand response participation metrics will reward the Company for successfully increasing demand response program participation, which will support system-coincident peak reductions that can provide generation and transmission capacity savings, while also promoting customer engagement. The DG-friendly substation transformers metric, as well as the EV, heat, and storage metrics will advance the State’s goal of promoting clean, distributed energy resources and increasing customer engagement and investment.

**DG-Friendly Substation Transformer:** this metric will indicate the number of substation transformers that have ground fault detection (3V0) installed and are capable of readily accommodating distributed generation, thereby allowing for the installation of distributed generation capacity up to the thermal rating of a particular substation transformer. The targets for this incentive reflect ambitious goals for the 3V0 program the Company included in its recent ISR filing. These targets will enhance the system’s ability to accommodate higher penetration



levels of distributed generation and accelerate the interconnection of distributed resources that might otherwise be delayed under a less proactive approach to these upgrades.

**Table 9-5: DG-Friendly Substation Transformers Targets and Basis Points**

<b>Cumulative 3V0 installations over 2019-2021</b>				
	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Basis Points</b>
Minimum	1	2	3	1
Target	3	6	12	6
Maximum	5	10	15	10

**Demand Response- Connected Solutions Participation:** This metric for this incentive will be number of residential customers participating in the Company’s Connected Solutions program. The Company will develop targets for this metric under the Company’s Energy Efficiency 1-Year Plan for 2019. This metric is intended to reward the Company for effective and efficient customer engagement, and is not intended to be duplicative of existing incentives. Basis points are intended to be illustrative of the potential size of the incentive.

**Table 9-6: Connected Solutions Customer Participation Targets and Basis Points**

<b>Number of Participants</b>				
	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Basis Points</b>
Minimum	Targets to be developed in 1-			1
Target	Year EE Plan			3
Maximum				5

**Demand Response- C&I Participation:** The metric for this incentive will be number of contracted MWs in the Company’s C&I demand response programs. Similar to the Company’s proposed Connected Solutions participation metric, the development of targets for this metric will be developed as part of the Energy Efficiency 1-Year Plan for 2019. This metric is intended to reward the Company for effective and efficient customer engagement, and is not intended to be duplicative of existing incentives. Basis points are intended to be illustrative of the potential size of the incentive.

**Table 9-7: C&I Customer Participation Targets and Basis Points**

<b>Enrolled MW</b>				
	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Basis Points</b>
Minimum	Targets to be developed in 1-			1
Target	Year EE Plan			3
Maximum				5

**Electric Heat Initiative:** This metric for this incentive is the annual CO<sub>2</sub> reductions attributable to the ground source heat pump and equipment incentives being offered under the Electric Heat Initiative. Targets for these metrics were developed to represent the Company’s effective delivery of program objectives, in particular, achieving effective targeting of highly-emitting customers, maximizing participation on a fixed incentive budget, and encouraging proper system design and utilization. Workpaper 9.2 – Electric Heat Initiative Targets includes supporting material for the development of this target.

**Table 9-8: Electric Heat Initiative Targets and Basis Points**

<b>Metric tons CO2 avoided per year</b>				
	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Basis Points</b>
Minimum	119	178	156	0.67
Target	149	223	195	0.83
Maximum	179	268	234	2

**Electric Vehicles:**

This metric is intended to capture the impact of the Company’s EV program on EV adoption in the Rhode Island relative to predicted market trends. The metric will measure incremental increase – above predicted levels – of personal EVs in the state on an annual basis. The targets were set to represent an improvement in Rhode Island upon the forecast trend for EV sales in New England as projected by the Energy Information Administration’s Annual Energy Outlook 2017. Proposed targets and basis points are summarized in the table below and reflect a 20%, 40%, and 80% improvement over the EIA’s projected EV sales growth for New England (corresponding to the minimum, target, and maximum levels, respectively). Workpaper 9.3 – Electric Vehicles Targets includes supporting material for the development of this target.

**Table 9-9: Electric Vehicles Targets and Basis Points**

<b>Annual incremental registered EVs (above forecast)</b>				
	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Basis Points</b>
Minimum	130	176	239	1
Target	259	352	477	2
Maximum	519	703	954	3.5

**Behind-the-Meter Storage:** The Company is proposing to include an incentive for behind-the-meter storage in response to the recommendations PST Phase One Report. Although the Company does not have a program in place to encourage behind-the-meter storage, the Company is committed to working with interested customers to evaluate opportunities for storage. The proposed metric for these efforts is the incremental MW of installed behind-the-meter storage each year.

**Table 9-10: Behind-the-meter Storage Targets and Basis Points**

<b>Incremental installed MW</b>				
	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Basis Points</b>
Minimum	1	1	1	0.33
Target	3	3	3	1
Maximum	6	6	6	2

**Company-Owned Storage:** The proposed metric for this incentive is will the number of MW of Company-owned storage used to support peak reduction or provide other system benefits. This metric would include the Company’s storage proposal described in Chapter Seven. In addition, the Company expects to continually evaluate the business case for storage, and has set targets and associated basis points to encourage this ongoing evaluation.

**Table 9-11: Company-Owned Storage Targets and Basis Points**

<b>Incremental installed MW</b>				
	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Basis Points</b>
Minimum	1	1	1	0.33
Target	3	3	3	1
Maximum	6	6	6	2

### 3.3. Network Support Services Performance Incentive Mechanisms

The Company’s proposed Network Support Services performance incentive mechanisms are composed of the following five metrics: (1) AMF Customer Engagement; (2) VVO Pilot Delivery; (3) Interconnection Support- Time to ISA; (4) Interconnection Support- Average days to System Modification; (5) Interconnection Support- Estimate versus Actual Costs. At this

time, the Company is not including proposed performance incentive mechanisms for access to customer information, and income eligible customers, both of which were included in the PST Phase One Report recommendations. The Company believes that there is value in an incentive related to access to customer information, but that it would be best developed as AMF deployment advances. Similarly, with respect to income eligible customers, the Company suggests that development of a performance incentive should follow implementation of the Company’s proposals affecting income eligible customers. Finally, while the Company has not proposed a broad customer engagement performance incentive mechanism as described in the PST Phase One Report, it has developed performance incentive mechanisms to support customer engagement in specific contexts, such as the EV off-peak charging rebate, demand response programs, and, as discussed in this section, AMF deployment.

**AMF Customer Engagement and Deployment:** This metric focuses on the Company’s progress and success in conducting customer outreach and education in support of AMF deployment, as well as the Company’s success in achieving early deployment targets. Successfully educating customers about the benefits that AMF will be critical to achieving their engagement and, ultimately, to encouraging participation in programs that will enable the achievement of benefits from AMF. Achieving early deployment targets is critical to enabling the rapid delivery of customer and system benefits from AMF. These incentives would reward the Company for successfully driving internal resources to achieve an ambitious delivery timeline. Proposed milestones and basis points are summarized in the table below, followed by additional explanation of the customer engagement milestones.

**Table 9-12: AMF Customer Engagement and Deployment Milestones and Basis Points**

Year	Milestones	Basis Points
2019	Deliver customer engagement plan	2
2020	Conduct and report on customer awareness survey	1
2020	Commence mass scale meter deployment	1
2021	Achieve 30% deployment and customer portal access	2

A short explanation of the customer engagement milestones follows:

- Deliver customer engagement plan. The Company would submit a plan that reflects customer insights from internal customer research, knowledge gained from Company experience with pilot projects, and industry best practices. The Company expects that specific requirements for earning an incentive for this milestone will be further developed through this proceeding.
- Conduct and report on customer awareness survey. The Company intends to conduct both pre- and post-deployment surveys to establish a baseline of customer awareness and to inform outreach efforts, and to measure the impact of customer engagement programs.

**VVO Pilot Delivery:** This metric will reward the Company for successful delivery of the VVO Pilot proposed through the ISR. Under this pilot, the Company will evaluate AMF’s contribution

to power sector transformation objectives, and has proposed an initial small-scale deployment of 16,000 meters. The immediate focus of this project is the integration of interval voltage data from AMF meters into the optimization algorithms of the volt-var optimization/conservation voltage reduction (VVO/CVR) to improve system efficiency. The VVO Pilot Delivery metric will measure 1) the timely delivery of the project; and 2) delivery of the expected system impacts of the project, specifically, a minimum additional 1% reduction in energy consumption and peak demand on top of what is expected from primary VVO/CVR optimization. This performance incentive mechanism will reward the Company for a successful project that lends itself to an improved understanding of the system optimization benefits from AMF, and help lay the foundation for broader successful deployment of AMF.

**Table 9-13: VVO Pilot Delivery Milestones and Basis Points**

Year	Milestones	Basis Points
2019	Project in service	2
2020	Achievement of enhanced VVO/CVR impacts	2
2021	Achievement of enhanced VVO/CVR impacts	2

**Interconnection Support – Time to ISA:** This metric will capture the Company’s average performance over all processes against the required timeframes specified in the Interconnection Tariff for submitting an executable Interconnection Service Agreement (ISA). The Company would receive a performance incentive based on the degree to which it outperforms the requirements in the Interconnection Tariff. Specifically, the metric will be calculated as the percent difference between:

- (1) the aggregate number of business days allowed by the Interconnection Tariff to provide an executable ISA over all processes; and
- (2) the average time measured in business days necessary for the Company to provide a customer with an executable ISA, commencing from the date a completed application is received, over all processes.

**Table 9-14: Time to ISA Targets and Basis Points**

Percent below required timeframe				
	2019	2020	2021	Basis Points
Minimum	5%	5%	5%	2
Target	10%	10%	10%	4
Maximum	15%	15%	15%	6

**The Interconnection Support – Average Days to System Modification:** This metric will capture the Company’s average performance over all processes against the required timeframes in the Interconnection Tariff for completion of system modifications identified by the Company in the ISA. The Company would receive a performance incentive based on the degree to which

it outperforms requirements in either the Interconnection Tariff or an average of actual days versus expected in all executed ISA. Specifically, the metric will be calculated as the percent difference between:

- (1) the total aggregate number of business days allowed by the Interconnection Tariff to complete system modifications, over all processes; and
- (2) the average time measured in business days necessary for the Company to complete system modifications, commencing from the date of execution of the ISA, over all processes.

**Table 9-15: Average Days to System Modification Targets and Basis Points**

Percent below required timeframe				
	2019	2020	2021	Basis Points
Minimum	5%	5%	5%	2
Target	10%	10%	10%	4
Maximum	15%	15%	15%	6

**Interconnection Support – Estimate versus Actual Cost:** This metric will focus on the accuracy of the cost estimates provided to interconnecting customers. Specifically, the metric would be calculated as the overall percent difference between the sum of costs estimated by the Company for interconnection and the sum of the actual costs paid by interconnecting customers.

**Table 9-16: Estimate versus Actual Cost Targets and Basis Points**

+/-% difference				
	2019	2020	2021	Basis Points
Minimum	10%	10%	10%	0
Target	6%	6%	6%	4
Maximum	4%	4%	4%	6

#### 4. IMPACT ON POLICY GOALS AND BENEFITS TO CUSTOMERS

In light of the recent the PUC’s Docket 4600 Guidance, the Company has reviewed its performance-based regulation proposal in terms of its impacts on each of the goals identified in the Docket 4600 Stakeholder Report and adopted by the PUC.

**Table 9-17: Overview of Proposal Impacts on State Energy Policy Goals**

<b>GOALS FOR “NEW” ELECTRIC SYSTEM</b>	<b>Advances?/Detracts From/Is Neutral Toward?</b>
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances – Supports utility delivery of capital cost, and capacity and transmission cost savings.\
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances – Supports utility delivery of capacity and transmission cost savings; encourages distributed energy resource development; promotes customer engagement and supports timely AMF deployment.
Address the challenge of climate change and other forms of pollution	Advances – Reductions in energy use during peak periods will reduce carbon emissions; increasing and expediting distributed energy resource integration will deliver larger and earlier CO <sub>2</sub> reductions.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Advances – Enables efficient interconnection of distributed energy resources, encourages electrification of vehicles and heat; rewards company investment in and support of energy storage.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Neutral – Does not address compensation of distributed energy resources.
Appropriately charge customers for the cost they impose on the grid	Advances – Rewards the Company for achieving participation targets in EV off-peak rebate; rewards timely deployment of AMF, which will support development of rates that are more aligned with cost-causation.
Appropriately compensate the distribution utility for the services it provides	Advances – Rewards timely deployment of AMF, which will support development of rates more aligned with cost-causation and support appropriate utility compensation.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design,	Advances – Proposed incentives reward the Company for activities that are geared toward meeting state policy goals and that generate

cost recovery, and incentive	opportunities and savings for customers.
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While the Company has not conducted a quantitative benefit-cost analysis (BCA) of the full performance incentive mechanism portfolio, it has quantified benefits and costs where possible and provided a qualitative explanation of key benefits in cases where quantification is not possible. A summary of the relevant analysis for each performance incentive mechanism category follows. Supporting analysis is included in Workpaper 9.4 – Incentives Benefits.

**4.1. System Efficiency**

The system efficiency metrics provide two major benefits to customers. Annual peak reductions will – after three years – contribute to avoided generation capacity costs by reducing the amount of capacity that must be secured through the ISO-NE Forward Capacity Auction (FCA). Reductions in monthly peaks reduce the transmission costs billed to the Company relative to what they otherwise would have been. These benefits are discussed in more detail below.

The Company has not quantified the costs of achieving the proposed peak demand reduction targets. Peak demand reductions will be supported by the Company’s energy efficiency programs, though, as noted above, earning an incentive will require additional incremental annual peak demand reductions. Peak demand reductions will also be supported by growth in distributed generation, and at a smaller scale, by projects such as VVO/CVR (include in the FY 2019 ISR) and other projects described in this document – all of which are intended to serve multiple objectives. In addition, achievement of peak demand reduction targets will likely require new Company efforts to foster renewable energy integration, storage, and demand response. Not all of these programs have been defined by the Company at this point.

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

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<sup>9</sup> An exception to this might be called demand response events, however, the Company expects to be able to grow demand response enrolled and participating capacity as programs ramp up, such that it can be expected that the same reductions are achieved (and expanded) from year to year.



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

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

For the Monthly Transmission Peak Demand Reduction metric, an estimate of potential customer savings can be developed using current transmission rates. The Company has estimated customer savings from the targets using the current RNS rate of \$110.35 kW-yr.<sup>10</sup> Table 9-19 displays the present value of estimated customer savings over 2019-2021 based on current rates. Under the Company’s proposed incentive, customers would retain approximately two-thirds to three quarters of the savings in this example. Note that the savings estimates in this example are likely to be conservative, as they ignore the cumulative effect of year over year savings.

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

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

With respect to the EV off-peak charging rebate, the limited size of the proposed program prevents it from demonstrating positive quantified net benefits as a stand-alone program in the Company’s BCA. However, the Company believes that the proposed size of the incentive is justified due the value placed on the transition to time-varying rates in Docket 4600, and the value that this program will provide in understanding customer response to time-differentiated price signals. The program is also important to the state’s goals for beneficial electrification as it will both improve the economics of EV ownership and help ensure that additions of new load from participating EV owners are concentrated during off-peak hours.

<sup>10</sup> See the Company’s February 16, 2017 Electric Retail Rate Filing, specifically the discussion presented in Tiffany Forsyth’s testimony and Schedule TMF-2, page 1 of 2. Available at: [http://www.ripuc.org/eventsactions/docket/4691-NGrid-2017-RetailRate\(2-16-17\).pdf](http://www.ripuc.org/eventsactions/docket/4691-NGrid-2017-RetailRate(2-16-17).pdf)

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## 4.2. Distributed Energy Resources

As discussed earlier in this chapter, the Distributed Energy Resources performance incentive mechanisms are intended accelerate system improvements that support greater deployment of distributed generation resources, increased penetration of distributed energy resources, and customer investment in their energy infrastructure. The activities underlying these performance incentive mechanisms will lead to quantifiable benefits based on a number of outcomes, including:

- Reductions in CO<sub>2</sub> and criteria pollutant emissions;
- Avoided energy and capacity costs;
- Avoided renewable energy credit (REC) costs; and
- In the case of EVs and heat electrification, avoided costs of non-electric fuels.

Further, the activities supported by these incentives directly support of a number of Docket 4600 and Power Sector Transformation Initiative objectives. They will drive increasing customer investment in their facilities, where that investment provides recognizable net benefits. These activities will also promote economic development and help to strengthen the Rhode Island economy, and directly support the state's CO<sub>2</sub> emissions reduction goals.

The Company has proposed the largest incentive around the DG-Friendly Substation metric. The Company's proactive installation of 3V0 has the potential to expedite interconnection of large quantities of distributed generation, thereby expediting the achievement of the benefits described above. However, the Company has not quantified the net benefits to customers from these efforts, due to the assumptions that would have to be made about the timing of distributed generation installations absent these investments, the number and size of installations accelerated, and the specific technology being installed.

The potential earnings under the Electric Vehicles and Electric Heat Initiative performance incentive mechanisms in comparison with the net benefits from these initiatives are presented in Table 9-20. The maximum earnings opportunity for the Electric Vehicles performance incentive mechanisms has been set based on the NPV of the quantified net benefits associated with the portion of the program geared toward customer vehicle conversion, such that over 60% of net benefits remain with customers. While the quantified net benefits of the Electric Heat Initiative suggest that customers would retain only about 25% of the net benefits, the Company believes that the proposed maximum incentive equal to two basis points annually is warranted given that the Electric Heat Initiative provides important economic development benefits that have not been quantified in the BCA. In particular, the program will support the growth in the state of a labor-intensive sector with a direct positive impact on the building trades.

**Table 9-20: Comparison of Potential Incentive Value and Quantified Net Benefits for the Electric Transportation Initiative and Electric Heat Initiative**

	<b>Program Net Benefits (NPV)</b>	<b>Incentive Value 2019-2021 (NPV)</b>	<b>Share of Quantified Net Benefits to Customer</b>
Electric Vehicles	\$1,414,836	\$517,399	0.63
Electric Heat Initiative	\$396,389	\$295,657	0.25

### 4.3. Network Support Services

The activities supported by the Company’s proposed Network Support Services performance incentive mechanisms are, as discussed above, foundational to broader power sector transformation. While it is difficult to quantify the benefits of the metrics in this category, these incentives will serve to support the Company’s timely delivery of operational and customer benefits from AMF while also rewarding enhanced interconnection practices that provide cost savings to developers and accelerate the achievement of CO<sub>2</sub> emissions reductions, peak demand reductions, energy savings, local economic development, and other benefits associated with distributed energy resources.

The VVO Pilot Delivery metric will deliver additional energy and peak demand reductions due to further optimization of VVO/CVR. In doing so, it will demonstrate the potential system efficiencies that can be obtained through the combination of AMF and VVO/CVR.

While it is difficult to quantify the benefits of the AMF Customer Engagement and Deployment metrics, these incentives are provided in recognition of the foundational role that AMF will play in the transformation of the power sector. These incentives will encourage the Company to achieve the benefits of AMF, discussed in great detail in Chapter 4, as expeditiously as possible through effective customer engagement and ambitious deployment schedules.

Similarly, the benefits from achieving the interconnection targets are difficult to quantify, but timely and efficient interconnection of distributed generation is foundational to providing the benefits from distributed generation, including:

- Reductions in CO<sub>2</sub> and criteria pollutant emissions;
- Avoided energy and capacity costs; and
- Avoided REC costs.

The value that the Company has assigned to the interconnection metrics reflects the Company’s view of the importance of efficient interconnection processes, both because of their broader implications for Rhode Island’s distribution system, and their foundational role in achieving the state’s energy and economic development goals.

## **5. EVALUATION AND REPORTING**

As part of its annual PST Reconciliation Filing (discussed in Chapter Ten), the Company will report on prior calendar year performance relative to each target and the calculations for the incentives earned. Incentives will be recovered on a per-kWh basis from all customers through the PST Provision.

The Company notes that many of the proposed performance incentive mechanisms and associated targets are directly related to products and services proposed in this Plan. To the extent the Commission does not approve or otherwise curtails those initiatives, the portfolio of performance incentives mechanisms may require modification in order to serve as a meaningful and appropriate set of incentives for the Company. In the future, the Company may wish to propose modifications to performance incentive mechanisms as new information emerges that might impact the appropriateness of metrics or targets in place.



Schedule PST - 1

Chapter 10 – Funding the Transformation

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## CHAPTER 10: FUNDING THE TRANSFORMATION

### 1. INTRODUCTION

The success of the Plan will be dependent upon sufficient revenue to recover the Company's incremental costs to construct, own, operate, and maintain its proposed PST investments. Success will also depend upon the Company's ability to fund the management, marketing, and evaluation of its PST Initiatives, as well as system enhancements needed to implement the initiatives. To that end, in Appendices 10.10 and 10.11 (for electric and gas respectively), the Company is submitting a PST Provision that provides for the recovery of forecasted and actual PST-related incremental capital and operation and maintenance ("O&M") costs, subject to full reconciliation, for PST Initiatives approved by the PUC, pursuant to an annual pre-approved budget. In addition, the PST Provision also provides the Company an opportunity to earn performance incentives associated with the PST Initiatives and to recover earned performance incentives through the PST Reconciliation Factors.

As described in more detail herein, the Company will submit by January 1 each year its annual PST Plan and PST Factors for its upcoming PST Plan Year, which coincides with the beginning of Company's fiscal year on April 1, based on the Company's forecasted costs for such initiatives. The Company will seek approval of both its annual PST Plan and PST Factors by April 1, to allow the Company to implement its annual PST Plan coincident with the beginning of its fiscal year.

In addition, by August 1 of each year, the Company proposes to file an annual report with the PUC and Division on the progress of its PST Initiatives, including information on the prior fiscal year's activities. The Company is cognizant that, in implementing its PST Plan in any fiscal year, the circumstances encountered during the year may require reasonable deviations from the original PST Plan. In such cases, the Company would explain in its annual report any significant deviations the Company implemented during the prior PST Plan Year from the annual PST Plan approved by the PUC.

Also by August 1, the Company will submit a PST Reconciliation Filing in which it will reconcile the prior PST Plan Year's revenue requirement based on actual investment and O&M expenses and the revenue billed from the PST Factors in effect during the same PST Year. The Company will seek approval of its PST Reconciliation Factors annually in this filing, to take effect the following October 1.

The FY 2019 level of incremental O&M expense contained in the Company's proposed Plan is \$3.593 million. The Company is not seeking funding for any PST related capital investment in FY19. Each of these categories of spending is addressed below. In addition, a description of the Company's proposed revenue requirements and associated illustrative calculations are outlined herein. Finally, the Company is providing a PST Provision for review and approval.

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## 2. DESCRIPTION OF KEY COMPONENTS OF THE PST PROVISION

The PST Provision provides for the recovery of incremental costs associated with the Company's PST Plan approved by the PUC. To be eligible for recovery, PST Plan costs must: (1) be pre-authorized by the PUC; (2) include only costs of investing in PST Initiatives; (3) be incremental to those costs that the Company currently recovers through any other rate, charge, or factor; and (4) be prudently incurred. The Company's rates for Retail Delivery Service are subject to adjustment to reflect the operation of the PST Provision.

For all PST Initiatives except the expansion of Grid Modernization activities, including AMF, the Company's PST-related costs are proposed to be recovered through two cost recovery factors:

- (1) PST Factors, designed to recover the Company's cumulative actual PST capital investment for years prior a given PST Plan Year, and forecasted PST capital investment for the PST Plan Year, plus forecasted O&M Expense for the PST Plan Year; and
- (2) PST Reconciliation Factors, designed to recover or credit any over or under recovery of the Annual Revenue Requirement on cumulative actual PST capital investment through the end of the prior PST Plan Year plus actual O&M expense for the prior PST Plan Year.

The Company is proposing the PST Factors and PST Reconciliation Factors for Grid Modernization Expansion, including AMF, be based upon the categorization of the nature of the spending in this initiative to better define how the benefits will accrue to customers. The Company is proposing to categorize capital and O&M expense as those that are customer-related (i.e., driven by the number of customers the Company serves) and those that are distribution-related or shared between customer-related and distribution-related (i.e., driven by the overall benefit to the Company's distribution system and the service it provides and common costs such as program and project management). By categorizing the costs of Grid Modernization Expansion, including AMF, in this way, the Company is able to allocate the revenue requirement and O&M expenses to its customer rate classes in a manner consistent with how the same costs are allocated to the rate classes as part of a general rate case as reflected in a cost of service study and, ultimately, and allocated cost of service study. By taking this approach of categorizing the costs in this way to allow for this type of allocation, when these investments and O&M expenses eventually become a part of a distribution cost of service study, the allocation of the overall revenue requirement will be aligned with how these costs were allocated to and recovered from customers through the PST Factors.

The PST Factors are proposed to be applied to all retail delivery service bills. The PST Factors will be adjusted annually, subject to the PUC's review and approval. The operation of these factors is described in more detail below.



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## **2.1 PST Factors**

The PST Factors will recover both capital investment and O&M expense and will be effective during the PST Plan Year, coincident with the PST Plan upon which they are calculated. Each PST Initiative will have its own factor based on forecasted capital investment and O&M expense. For capital cost recovery, the factor for each PST Initiative shall recover the Annual Revenue Requirement on Cumulative Capital Expenditures, including Forecasted Capital Expenditures as approved by the PUC in the Company's annual PST Plan Filings. The factor for each PST Initiative will also recover the Forecasted O&M Expense as approved by the PUC in the Company's annual PST Plan Filings. The Company shall calculate separate revenue requirements and add to it the PST Initiative's forecasted O&M expense, resulting in a factor for each PST Initiative. The Company will aggregate all factors for all PST Initiatives into the PST Factors for billing purposes.

PST capital investment and O&M expense recovery shall include an annual reconciliation of the Annual Revenue Requirement on the sum of Actual Capital Expenditures for all PST Plan Years plus Actual O&M Expense to actual billed revenue generated from the PST Factors for the applicable PST Plan Year. The balance from the reconciliation shall accrue interest monthly at the same rate as that paid on customer deposits. The recovery or crediting of the reconciliation balance, including interest, shall be reflected in PST Reconciliation Factors. The Company shall submit a filing by August 1 of each year (Reconciliation Filing) in which the Company shall propose the PST Reconciliation Factors to become effective for the 12 months beginning October 1. The amounts approved for recovery or crediting through the PST Reconciliation Factors shall be subject to reconciliation with amounts billed through the PST Reconciliation Factors, and shall accrue interest monthly at the same rate as that paid on customer deposits, and any difference, including interest, reflected in future PST Reconciliation Factors. The Company shall prepare separate reconciliations for each PST Initiative based upon the calculation of separate revenue requirements plus O&M expense and actual billed revenue specific to each PST Initiative factor, shall calculate reconciliation factors for each PST Initiative, and aggregate all reconciliation factors for all PST Initiatives into the PST Reconciliation Factor for billing purposes.

## **2.2 PERFORMANCE INCENTIVES**

The PST Provision also includes a Performance Incentive Factor which is designed to recover performance incentives earned by the Company as a result of the Company achieving specific performance metrics pertaining to the efficient delivery of the Company's capital program (Capital Efficiency) and the achievement of objectives in the system efficiency, distributed energy resources, and network support services. Except otherwise noted in Appendix A of the PST Provision, the Company shall measure actual performance against the performance metrics identified during the calendar years shown in the appendix.

**3. DESCRIPTION OF ILLUSTRATIVE REVENUE REQUIREMENT CALCULATION**

Based upon the estimated amounts for the PST Plan, the Company has calculated the revenue requirement resulting from the projected incremental PST capital and O&M expenditures. Please refer to Appendix 10.1. This section contains a description of the revenue requirement models and illustrative revenue requirement calculations. These calculations would form the basis for the PST Factors, described above. The revenue requirement calculations assume costs during FY 2019 for a transitional six month period, effective October 1, 2018, that would be eligible for recovery and included in the first annual Reconciliation Filing which will propose PST Reconciliation Factors to become effective October 1, 2019, and then annual recovery for future fiscal years, effective April 1, 2019. The pre-tax rate of return on rate base would be that rate of return approved by the PUC in the Company’s present general rate case and, going forward, it would change as the PUC may approve changes to the rate of return in future proceedings. Any change in the rate of return would be applicable on a prospective basis effective on the date on which the change is effective.

Appendix 10.1, Pages 1 and 2, provides a summary of the total revenue requirement on all PST initiatives, including recovery of PST O&M expense, for the six months ending March 31, 2019 and further provides an illustrative revenue requirement for the fiscal years (FY) ending March 31, 2020, March 31, 2021, and March 31, 2022. Page 1 presents the summary of revenue requirements including the costs of deploying AMF and Modern Grid programs on a Rhode Island only basis, with the total revenue requirement amount shown on Line 11 and the total revenue requirements for the Company’s electric and gas divisions shown on Lines 7 and 10, respectively (noting that for FY20, FY21 and FY22 the revenue requirements are illustrative). Page 2 presents the same summary revenue requirement view including the cost of deploying AMF and Modern Grid programs in Rhode Island if one of the Company’s affiliates in Massachusetts or New York deploys these programs at the same time. The subsequent pages present the individual revenue requirement calculations supporting each of five PST initiatives, as follows:

<b>Illustrative Revenue Requirements</b>	<b>Appendix Reference</b>
Summary of Revenue Requirements	Appendix 10.1
Grid Mod – Rhode Island only deployment	Appendix 10.2
Grid Mod – multi jurisdiction deployment	Appendix 10.3
AMF – Rhode Island only deployment	Appendix 10.4
AMI – multi jurisdiction deployment	Appendix 10.5
Electric Transportation	Appendix 10.6
Electric Heat	Appendix 10.7
Storage	Appendix 10.8
Solar	Appendix 10.9

For the six months ending March 31, 2019, the Company is proposing to recover O&M expense only. The initial six months of costs are based on the work that can be achieved in that initial period, specific to the context of each individual program. In most instances, the initial costs are ‘start up’ costs for the program (including next level program design and early implementation activities), ahead of PST capital investments and ongoing implementation costs to follow in FY 2020 and beyond. The revenue requirement calculations included in the above noted appendices present the initial six months of costs described above, and for illustrative purposes, a full 12 months of recovery related to PST capital investments and O&M expense, for each FY beginning with the FY ending March 31, 2020. The proposed PST capital investment and O&M expenses for each PST initiative follow the cost information as outlined in the program BCAs and as provided in Appendix 2.1 and Appendix 4.1. The revenue requirement calculations all follow the same general methodology described below.

In general, the total revenue requirement for each PST program consists of (1) O&M expenses associated with each program, and (2) a capital component consisting of the a return of and on any incremental PST investment where applicable. For those PST programs involving a level of capital investment, the capital component of the revenue requirement consists of: (1) a return on the average rate base derived from incremental PST capital investments, including taxes, (2) book depreciation expense incurred on incremental PST capital investments, and (3) incremental property tax expense projected to be assessed on the incremental PST investment.

Each PST revenue requirement (actual for FY19 and illustrative thereafter) begins with a summary revenue requirement page, which details the O&M components of the revenue requirement separately from the PST capital investment components of the revenue requirement (if applicable), as well as the delineation of O&M and capital components between the Company’s electric and gas divisions where the PST investments benefit the customers of both businesses. The summary page is followed by the revenue requirement calculation(s) on the various capital investments of that PST program.

Each capital revenue requirement begins with the determination of depreciable net plant in service that will be included in the rate base for that PST program. Because depreciation expense is affected by plant retirements, any projected plant retirements driven by PST investment have been deducted from plant additions in determining the depreciable plant upon which book depreciation expense is calculated. Retirements, however, do not affect rate base as both “plant in service” and “depreciation reserve” are reduced by the installed value of the plant being retired and therefore have no impact on net plant. Cost of removal if applicable affects rate base but not depreciation expense. Consequently, the cumulative cost of removal is combined with cumulative depreciable capital investment to derive the cumulative net plant, included in PST rate base, upon which the annual PST revenue requirement is calculated.

Book depreciation expense is computed using the applicable depreciation rate, based on the PST investments’ assigned plant unit code(s), and as approved in the Company’s most recent distribution base rate case. In the year of investment, the calculation of book depreciation assumes a half-year convention. In the following years, current year book depreciation is added

to the prior years' book depreciation to arrive at cumulative book depreciation, which is included in the calculation of year-end rate base as a deduction, which is described below.

Year-end rate base includes the cumulative net plant described above adjusted for accumulated depreciation and accumulated deferred tax reserves. The deferred tax amount arising from the PST capital investment equals the difference between book depreciation and tax depreciation on those PST capital investments, times the effective federal tax rate. Each illustrative revenue requirement calculation is accompanied by a calculation of tax depreciation which outlines the tax assumptions used to arrive at total projected annual tax depreciation expense. Generally, the tax depreciation calculation assumes that some portion of PST capital investment will be eligible for immediate federal tax deductions on the Company's corresponding FY federal income tax returns. These accelerated tax deductions may include but are not limited to: bonus depreciation, which is currently set to expire on December 31, 2019 and capital repairs deductions. These accelerated tax deductions have the effect of increasing accumulated deferred taxes, therefore lowering the amount of rate base upon which the revenue requirement is calculated and ultimately lowering the amount that customers will pay under the proposed PST mechanism. Any remaining portion of PST capital investment which does not qualify for accelerated tax depreciation treatment would be depreciated over an estimated tax life, which is determined under the guidance of the Company's tax department and the classification of plant investments on the Company's books (i.e. plant unit code). Total accelerated tax deductions plus cost of removal and any loss on partial retirements recorded for tax purposes comprises total annual tax depreciation carried forward to the revenue requirement calculation. The current year's tax depreciation is then accumulated with prior years' tax depreciation amounts to arrive at the cumulative tax depreciation amount. Cumulative tax depreciation is compared to cumulative book depreciation to determine the cumulative book/tax timer, to which the effective federal tax rate is applied to calculate the accumulated deferred tax reserve.

The deferred tax calculations included in the illustrative revenue requirements include offsets for tax net operating losses (NOL) and tax proration adjustments. NOLs are generated when the Company has tax deductions on its income tax returns that exceed its taxable income. NOLs are recorded as non-cash assets on the Company's balance sheet and represent a benefit that the Company and customers will receive when the Company is able to realize actual cash savings and applies these NOLs against taxable income in the future. If any portion of the Company's NOL is determined to be driven by PST investment, the Company will offset the accumulated deferred income tax liability by that portion of the NOL. Conversely, if the Company is able to utilize any portion of its NOL attributable to PST investment in future years, the Company will increase accumulated deferred income taxes in the fiscal year that NOL is utilized. The deferred tax proration adjustment fulfills requirements set out under IRS Regulation 26 C.F.R. §1.167(1)-1(h)(6). When a regulatory filing is based on a future period, tax normalization rules stipulate that deferred taxes must be prorated to reflect the period of time that the cumulative deferred income tax reserves are in rate base. As the proposed PST mechanism is based on a future period using forecasted PST capital investments, the proration adjustment has been included here as an offset to the deferred tax reserve. Therefore, total net deferred tax reserve includes the summation of the deferred tax reserve net of NOL and proration adjustments.

The year-end PST rate base is comprised of the net PST capital investment less accumulated depreciation and the net deferred income tax reserve. The revenue requirement is calculated on an average rate base. In the year of investment, the calculation of average rate base uses a half-year convention (end of year rate base divided by 2). In the following years, the calculation of average rate base is derived by taking the beginning and year-end rate base divided by 2.

Average rate base is then multiplied by the pre-tax rate of return approved in the Company's most recent rate case. For illustrative purposes, the PST revenue requirements provided in the appendix to Chapter 10 utilize the Company's proposed rate of return in Docket 4770. That rate of return is used to compute the amount of return and taxes included in the PST capital component of revenue requirement. To this, depreciation expense and property tax expense are added to arrive at the total annual capital component of the PST revenue requirement.



Appendix 2.1,  
Program BCA

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC Docket No. 4770  
Appendix 2.1 - Program BCA  
Page 1 of 80



# Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models

Reference Document  
November 2017

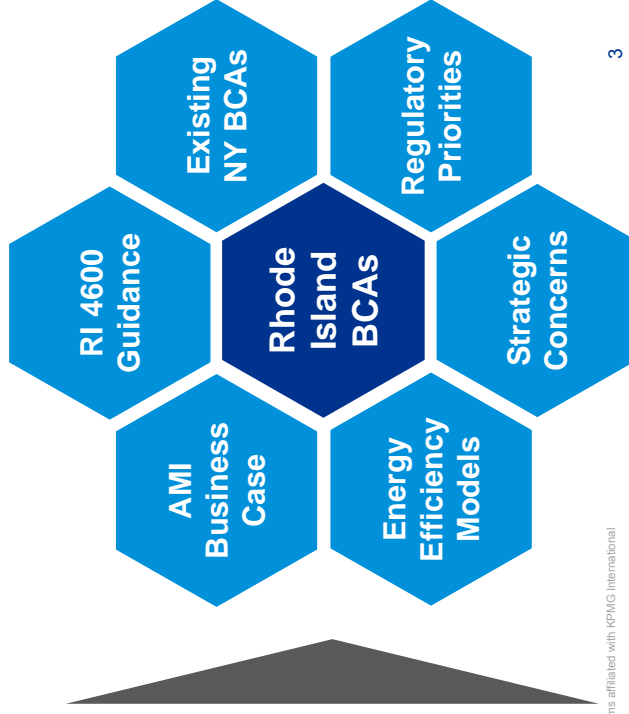


# The joint NG-KPMG approach to developing BCAs involved iterating on both quantitative & qualitative benefits



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# 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



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# 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 Infrastructure	Electric Transmission Capacity Costs/Value	✓	✓	✓	N/A	N/A	N/A	N/A	N/A
Avoided Transmission Losses	Electric Transmission Capacity Costs/Value	✓	✓	✓	N/A	N/A	N/A	N/A	N/A
Avoided Ancillary Services	Forward Commitment: Ancillary Services Value	✓	✓	✓	N/A	N/A	N/A	N/A	N/A
Wholesale Market Price Impacts	Energy Demand Reduction Induced Price Effect (DRDRIPE) + Capacity Demand Reduction Induced Price Effect (DRDRIPE)		✓	✓					
Avoided Distribution Capacity Infrastructure	Distribution Capacity Costs	✓	✓	✓	N/A	N/A	N/A	N/A	N/A
Avoided O&M	Distribution Capacity Costs	✓	✓	✓	N/A	N/A	N/A	N/A	N/A
Avoided Distribution Losses	Distribution Delivery Costs	✓	✓	✓	N/A	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	N/A
Net Avoided Outage Costs	Distribution System and Customer Reliability/Resilience Impacts	✓	✓	✓	N/A	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	✓	✓	✓					
Net Non-Energy Benefits	Non-Electric Avoided Fuel Cost	✓	✓	✓					
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 Electric Transmission Infrastructure costs for Site Specific	✓	✓	✓	N/A	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	N/A
Participant DER Cost	Utility/Third Party Developer Renewable Energy, Efficiency, or Program Participant/Prosumer Benefits/Costs	✓	✓	✓					
Lost Utility Revenue (Cost shift from non-participants to									
Net Non-Energy Costs	Non-Energy Costs/Benefits: Economic Development	✓			Not applied	Not applied	Not applied	Not applied	Not applied

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# The BCAs are collected in a single, consistent tool

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	Rli BCA Summary	BCA summary and comprehensive 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 Category	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		Electric Heat - BCA Ratio			
	SCT	RIM	UCT	RIM		
Benefits	x	x	x	x	\$ 277,788	
	x	x	x	x	\$ (1,121,845)	
	x	x	x	x	\$ (99,926)	
	x	x	x	x	\$ (5,073)	
	x	x	x	x	\$ 527,088	
	x	x	x	x	\$ 222	
	x	x	x	x	\$ 4,162,394	
	x	x	x	x	\$ -	
	x	x	x	x	\$ 3,562,165	
	x	x	x	x	\$ 7,292,803	
	Costs	x	x	x	x	\$ 1,073,830
		x	x	x	x	\$ 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



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# Specific investments also have complete breakdowns

EH - BCA Summary	
<b>Societal Cost Test</b>	
RI Electric Heat BCA	
<b>Electric Heat - BCA Ratio</b>	
Forward Commitment Capacity Value	\$ 277,788
Energy Supply & Transmission Operating Value of Energy Provided	\$ (1,121,845)
Avoided Renewable Energy Credit (REC) Cost	\$ (99,326)
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	\$ -
Utility / Third Party Developer Renewable Energy Efficiency or Program Participant / Prosumer Benefits / Costs	\$ 3,745,721
<b>Benefits</b>	<b>\$ 1,073,830</b>
<b>Cost</b>	<b>\$ 2,275,503</b>
<b>BCA Ratio</b>	<b>1.12</b>
<b>RIM Cost Test</b>	
RI Electric Heat BCA	
<b>Electric Heat - BCA Ratio</b>	
Forward Commitment Capacity Value	\$ 277,788
Energy Supply & Transmission Operating Value of Energy Provided	\$ (1,121,845)
Avoided Renewable Energy Credit (REC) Cost	\$ (99,326)
Wholesale Market Price Impacts	\$ (5,073)
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	\$ -
Utility / Third Party Developer Renewable Energy Efficiency or Program Participant / Prosumer Benefits / Costs	\$ 3,552,155
<b>Benefits</b>	<b>\$ 2,603,098</b>
<b>Cost</b>	<b>\$ 1,073,830</b>
<b>BCA Ratio</b>	<b>2.42</b>

Comprehensive Benefits & Costs	
<b>Electric Heat - BCA Ratio</b>	
Forward Commitment Capacity Value	\$ 277,788
Energy Supply & Transmission Operating Value of Energy Provided	\$ (1,121,845)
Avoided Renewable Energy Credit (REC) Cost	\$ (99,326)
Wholesale Market Price Impacts	\$ (5,073)
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	\$ -
Change in Utility Revenue	\$ 3,552,155
Utility / Third Party Developer Renewable Energy Efficiency or Program Participant / Prosumer Benefits / Costs	\$ 7,292,803
<b>Benefits</b>	<b>\$ 1,073,830</b>
<b>Cost</b>	<b>\$ 2,275,503</b>
<b>BCA Ratio</b>	<b>3,349,332</b>

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

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

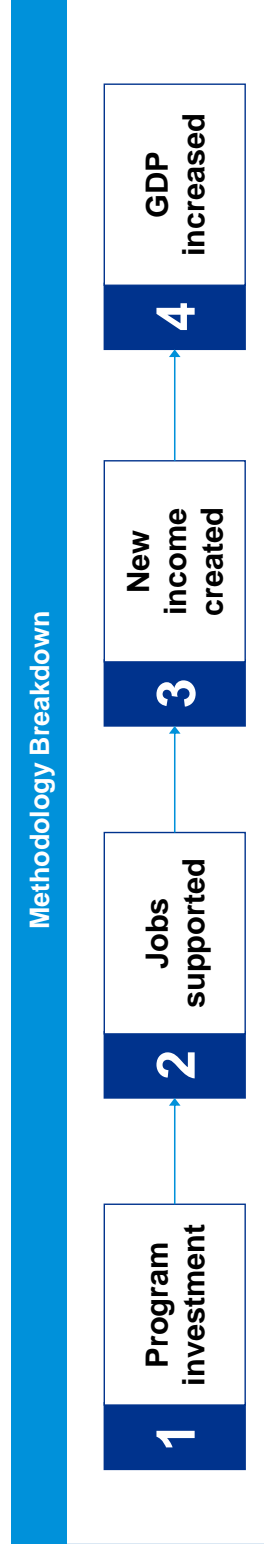
Some examples of globally-defined variables are AESC pricing, emissions assumptions, unit conversions, time assumptions, residential heat pricing, etc.



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

## Review of Economic Development Method

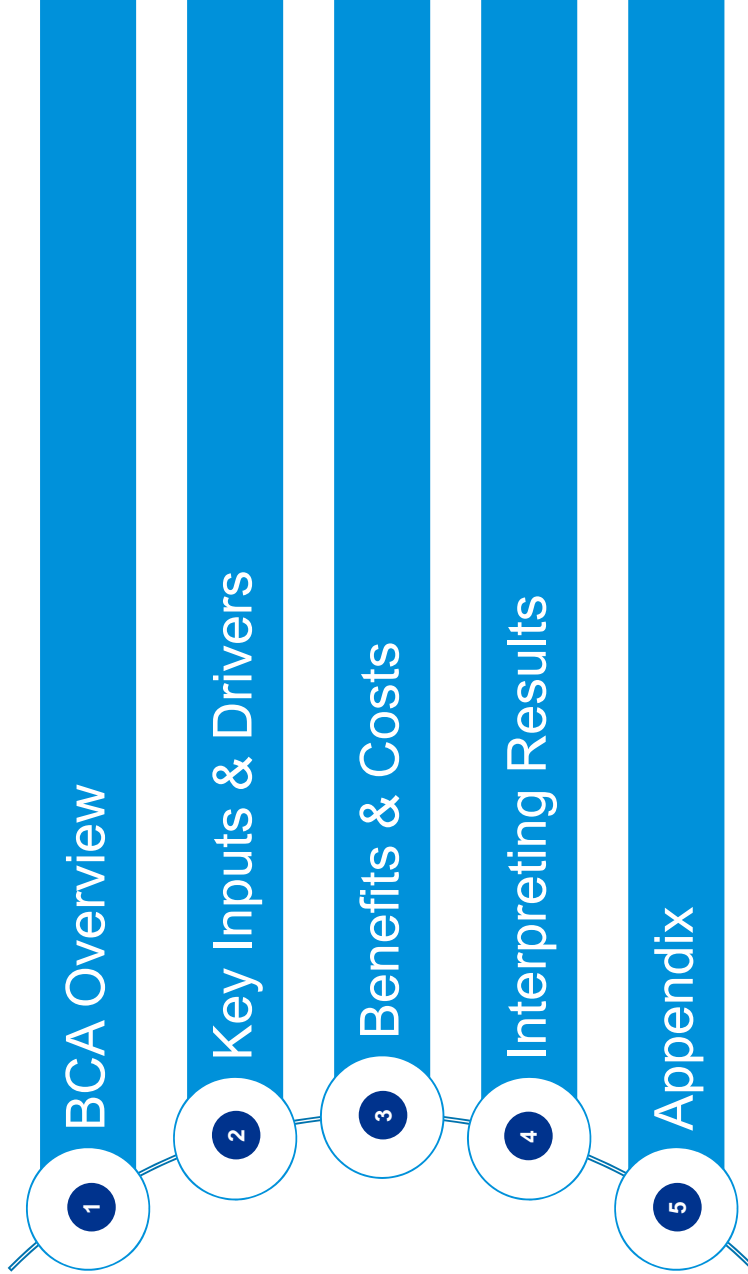
- Valued the increased GDP in Rhode Island attributable to each of the program investments
- Used the REMI input-output analysis model to measure the increased economic activity created by the program
  - Developed a GDP number resulting from increased incomes and spending
  - Further categorized benefit 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



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# Table of Contents – Individual Programs



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THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a NATIONAL GRID  
RIPUC Docket No. 4770  
Appendix 2.1 - Program BCA  
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# Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models *Transportation*

Reference Document  
November 2017

# 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

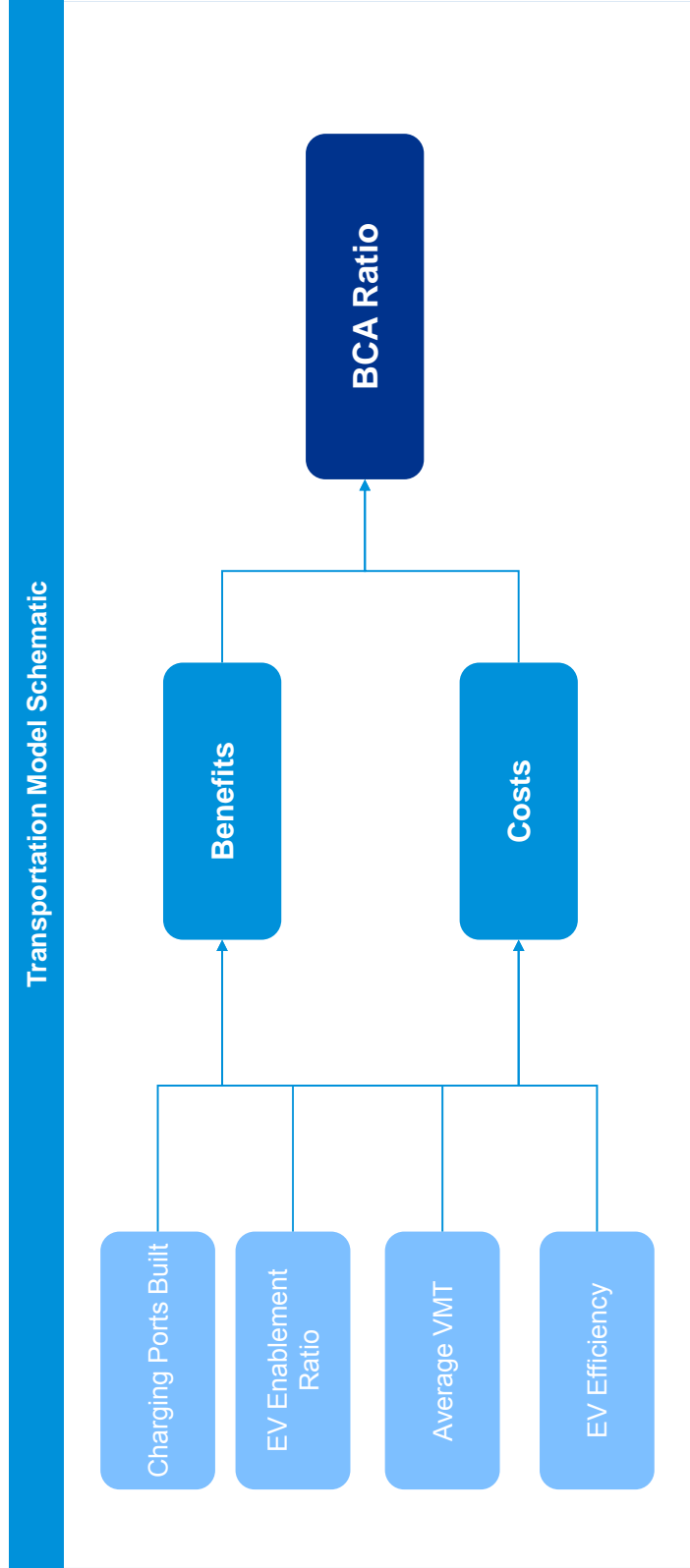
## Modeling Overview

- 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



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# Model Overview



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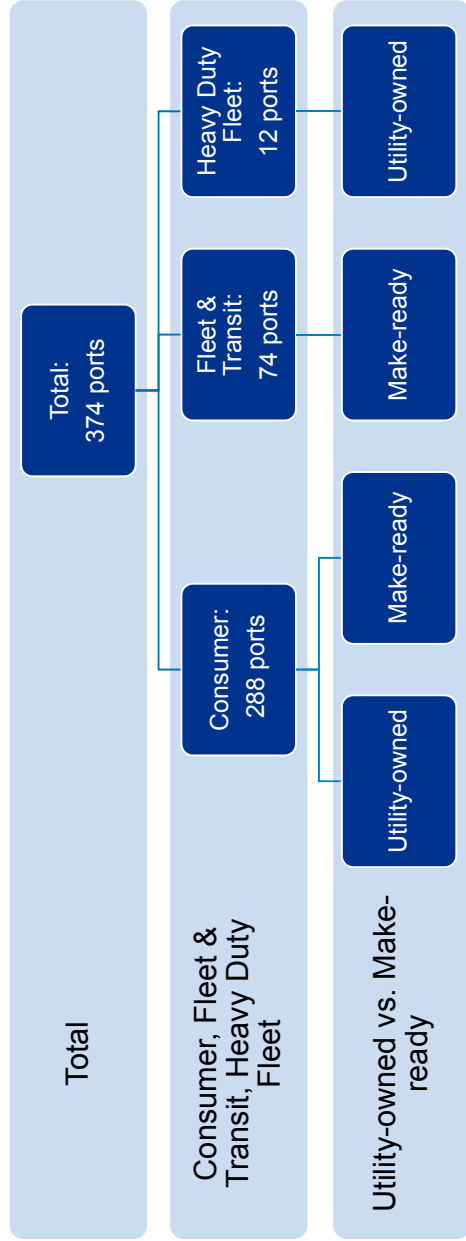
# Key Inputs Table

Key Inputs	Definition	Model Usage	Source(s)
<b>Charging Ports Built</b>	<ul style="list-style-type: none"> <li>Total number of Consumer as well as Fleet &amp; Transit charging ports built (374)</li> </ul>	Used together to approximate the total number of electric vehicles adopted by the program	<ul style="list-style-type: none"> <li>Transportation Initiative - Draft Testimony (Karsten Barde)</li> <li>CALSTART</li> <li>Auto Alliance</li> <li>Alternative Fuels Data Center</li> </ul>
<b>EV Enablement Ratios</b>	<ul style="list-style-type: none"> <li>Approximation of the number of electric vehicles adopted to the construction of each port</li> <li>There are different ratios depending on the type of vehicle</li> </ul>		
<b>Average VMT</b>	<ul style="list-style-type: none"> <li>Average number of miles traveled annually per vehicle</li> <li>Differs depending on vehicle type</li> </ul>	Used with total vehicles enabled to project the total electricity usage increase and avoided fuel cost attributable to the program	<ul style="list-style-type: none"> <li>RITA</li> <li>RI DOT</li> <li>Transportation Initiative - Draft Testimony (Karsten Barde)</li> </ul>
<b>Vehicle Efficiency</b>	<ul style="list-style-type: none"> <li>For EV's: Average number of miles traveled per kWh of electricity</li> <li>For internal combustion engine (ICE) vehicles: Average number of miles traveled per gallon of fuel</li> </ul>		
<b>BEV</b>	<ul style="list-style-type: none"> <li>Battery Electric Vehicle – Make up about 30% of the consumer EV market</li> <li>Cover 95% of miles on battery power</li> </ul>	Use these specifications to help determine total electricity usage from charging. These values are also used in fuel displacement cost	<ul style="list-style-type: none"> <li>NY Model Assumptions</li> <li>Transportation Initiative - Draft Testimony (Karsten Barde)</li> </ul>
<b>PHEV</b>	<ul style="list-style-type: none"> <li>Plug in Hybrid Electric Vehicle – Make up about 70% of the consumer EV market</li> <li>Cover 85% of miles on battery power</li> </ul>		
<b>BEB</b>	<ul style="list-style-type: none"> <li>Battery Electric Bus – Assumed to be 100% of the heavy duty vehicles adopted</li> <li>Cover 95% of miles on battery power</li> </ul>		
<b>HD Fleet PHEV</b>	<ul style="list-style-type: none"> <li>Heavy Duty Plug in Hybrid Electric Vehicle – 12 vehicles to be adopted by National Grid</li> <li>Cover 50% of miles on battery power</li> </ul>		

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# Key Input #1 – Charging Ports Built

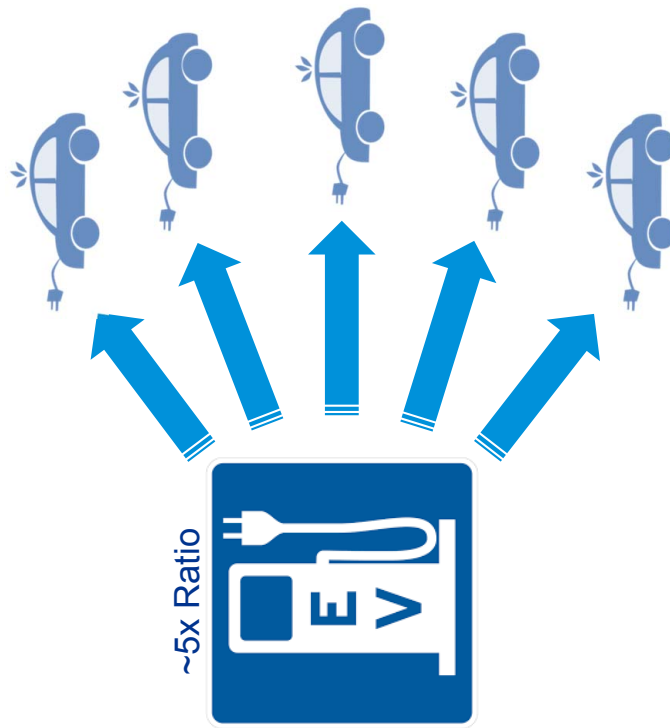


- National Grid will be administrating the construction of 374 total charging ports
- Of those, 288 ports will be consumer facing and 78 ports will be for fleet and transit vehicles
- On the consumer side, ~50% will be utility-owned and operated



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# Key Input #2 – EV Enablement Ratios



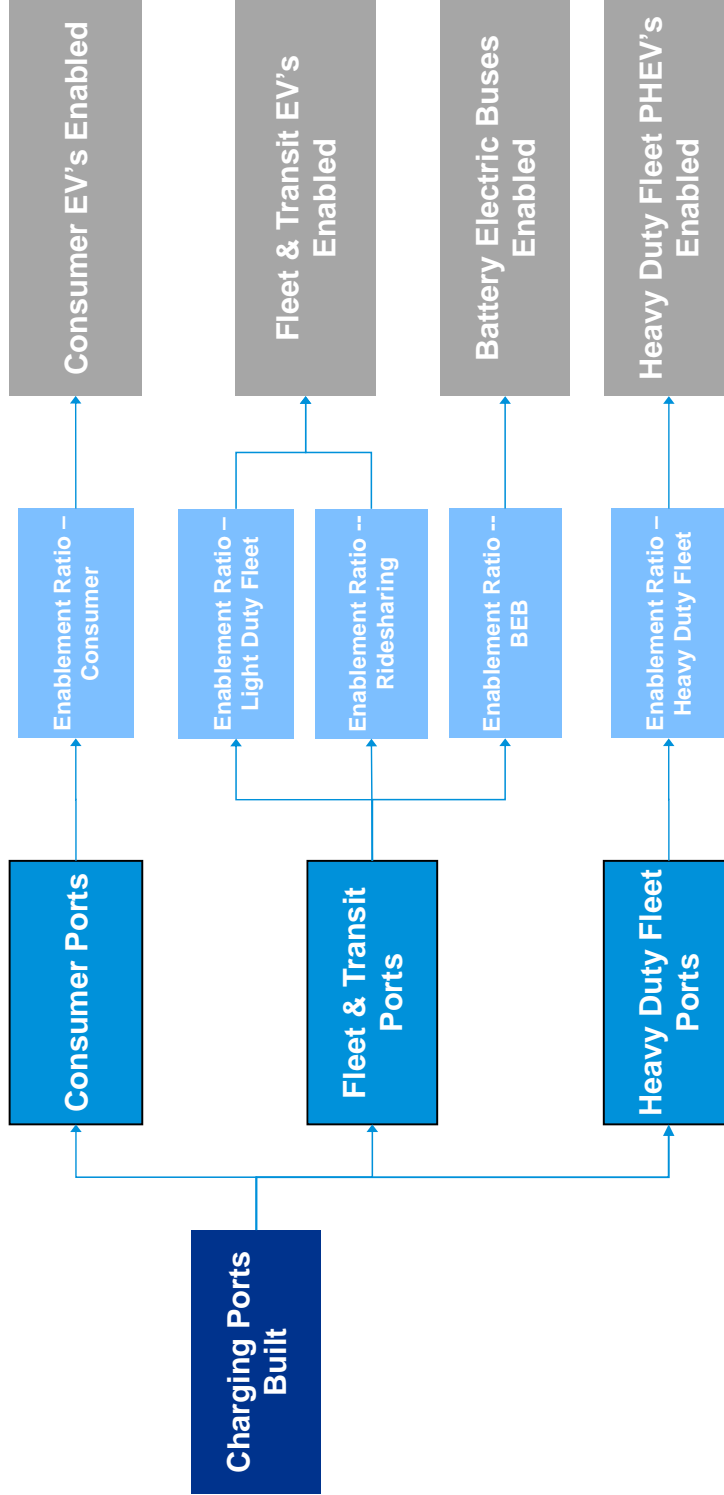
- Projected # of electric vehicles that will be adopted due to the construction of each port
- Calculated by benchmarking the average # of vehicles per port in other states
- This assumption is still significantly lower than the current national average
- Ratio assumptions
  - Consumer: 5.25 vehicles/port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

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# Electric Vehicles Enabled

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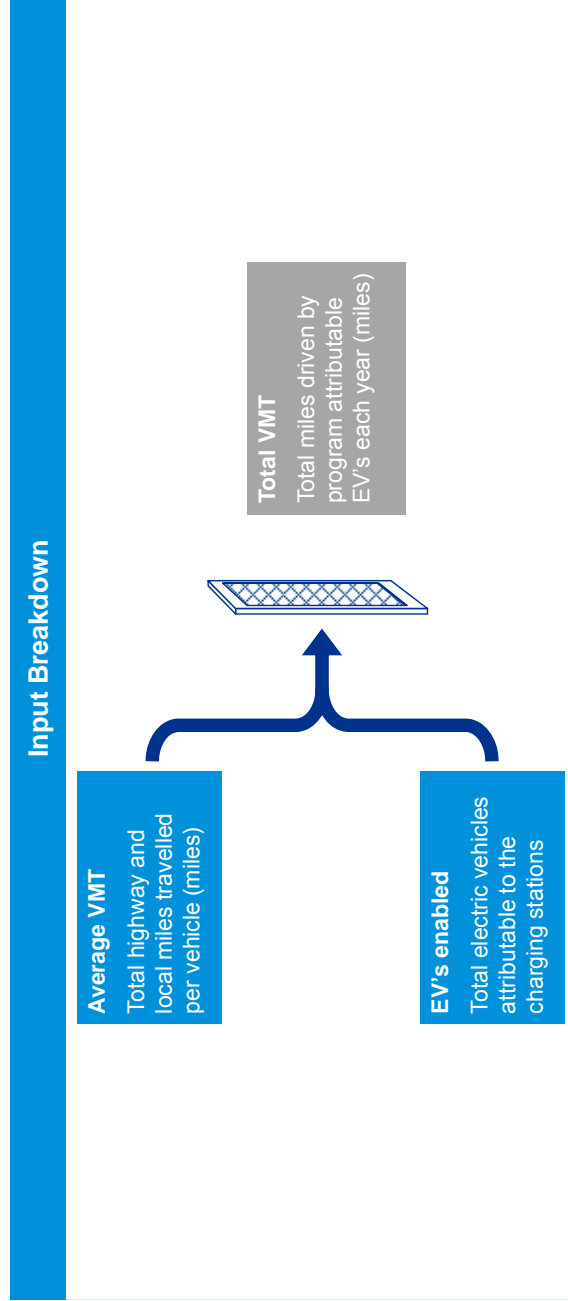


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# Key Input #3 – Average VMT

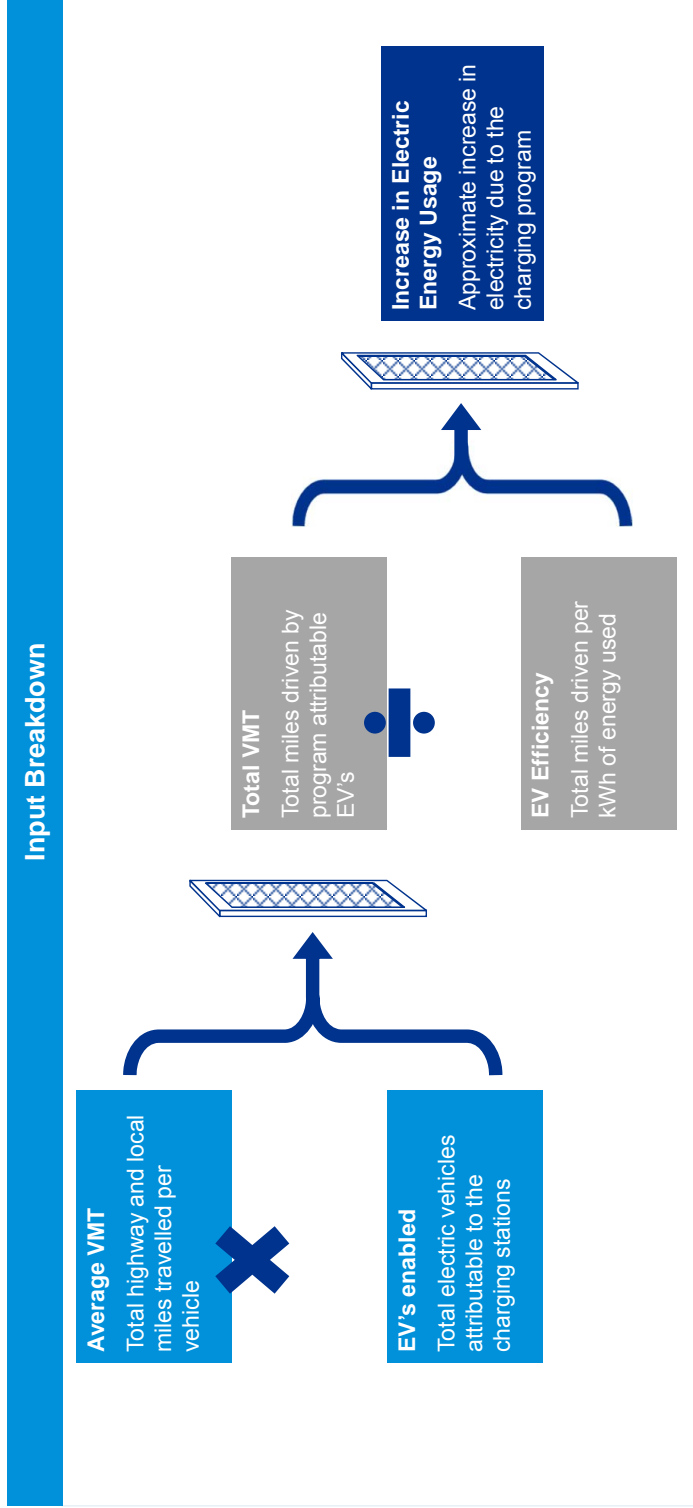


- Average annual miles driven per vehicle in Rhode Island
- Calculated by leveraging highway and local driving data
- Average VMT differs depending on vehicle function (i.e. consumer vs. ridesharing)



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# Key Input #4 – EV Efficiency

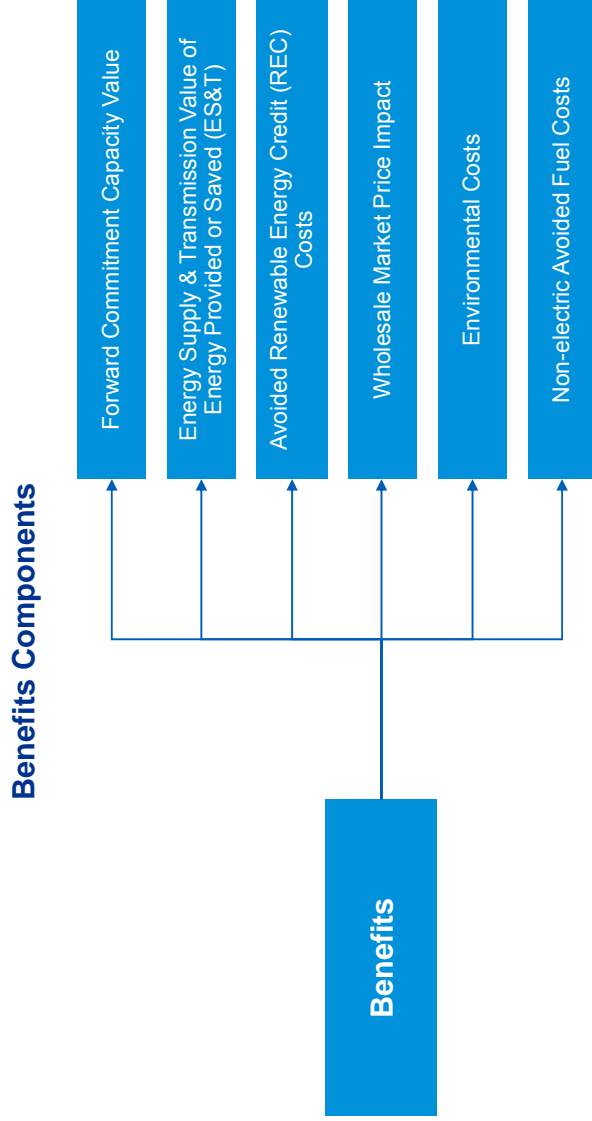


Dividing Total VMT by average Electric Vehicle Efficiency yields an estimate of the total increase in electric energy usage

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# Benefits – Overview

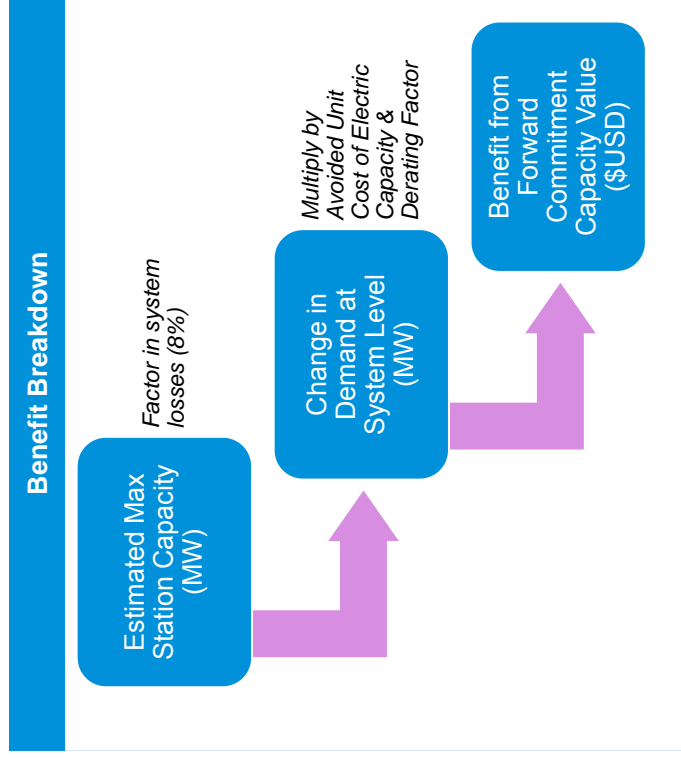


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# Benefits – Forward Commitment Capacity Value

## Forward Commitment Capacity Value

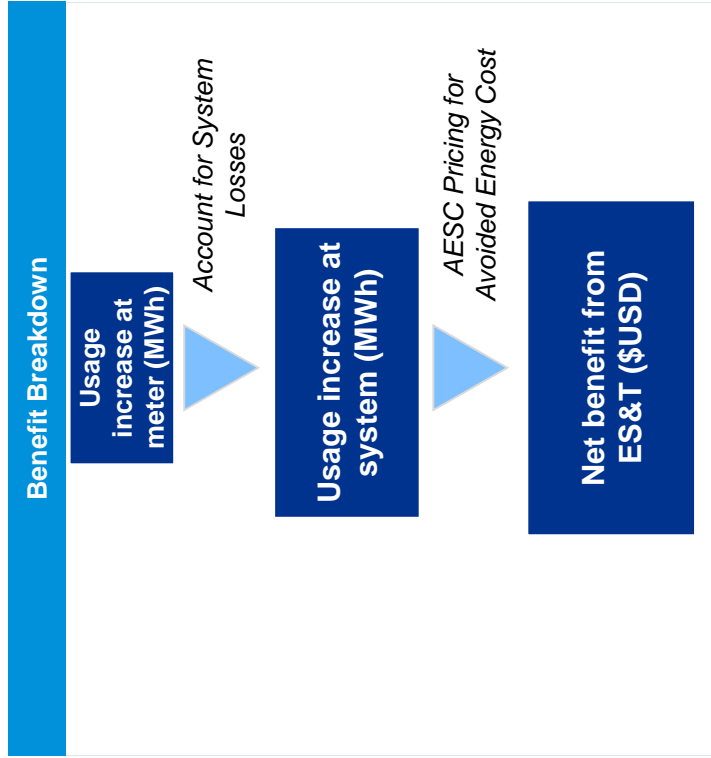
- ❑ Values the increase or decrease in the total energy demand attributable to the program
- ❑ Numbers are delayed by four years because bidding into the forward capacity market takes place 4 years in advance in Rhode Island
- ❑ In the case of EV charging stations, the program will lead to an increase 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



# 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

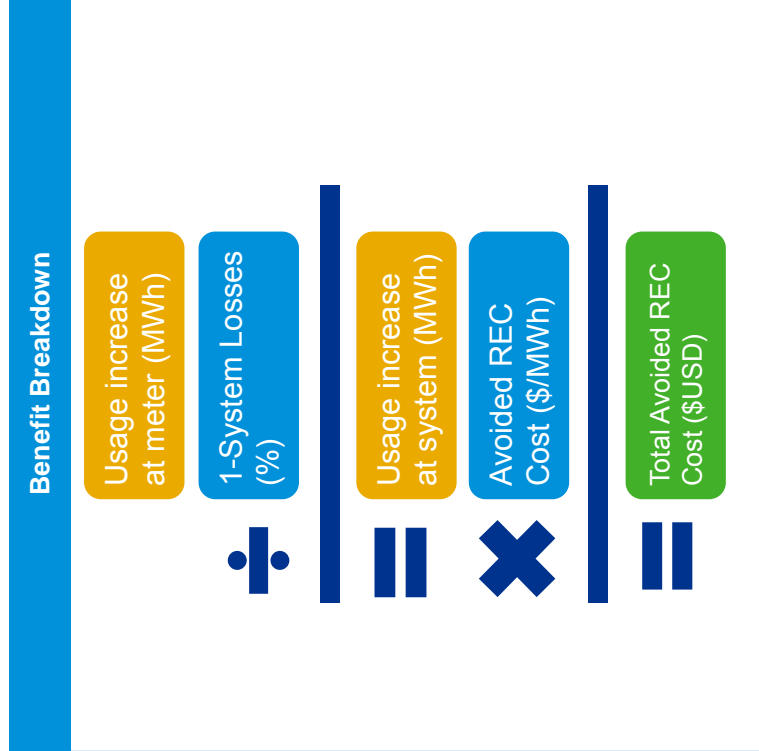


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# Benefits – Avoided REC Costs

## 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

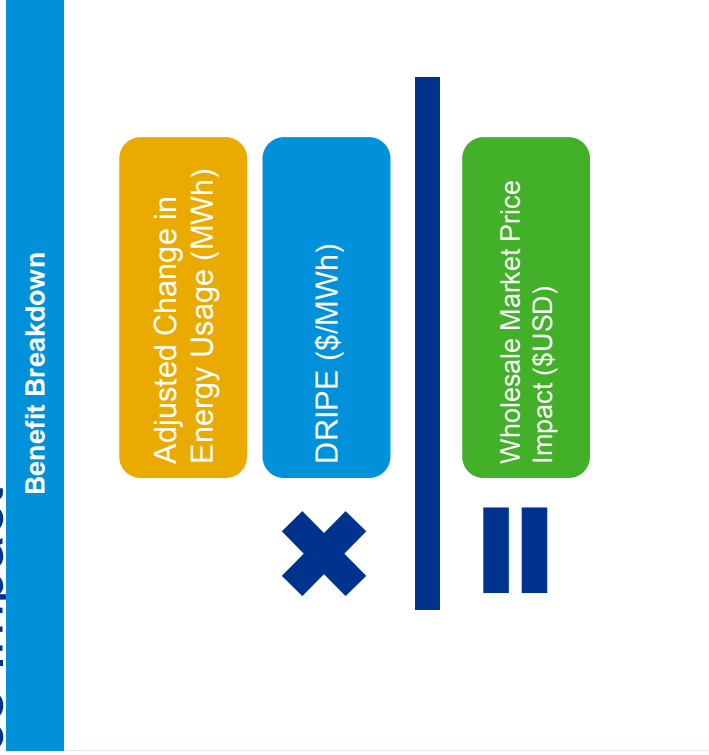


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# Benefits – Wholesale Market Price Impact

## 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



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# 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<sub>2</sub> (\$/short ton)
- Calculate the total electricity usage for EVs
- Multiply it by the non-embedded cost of CO<sub>2</sub> (\$/MWh)
- Net the two values to arrive at the final

## Criteria Air Pollutant and Other Environmental Costs

- Attributes value to the avoided emissions of SO<sub>2</sub>, NOX, and PM<sub>2.5</sub>
- 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



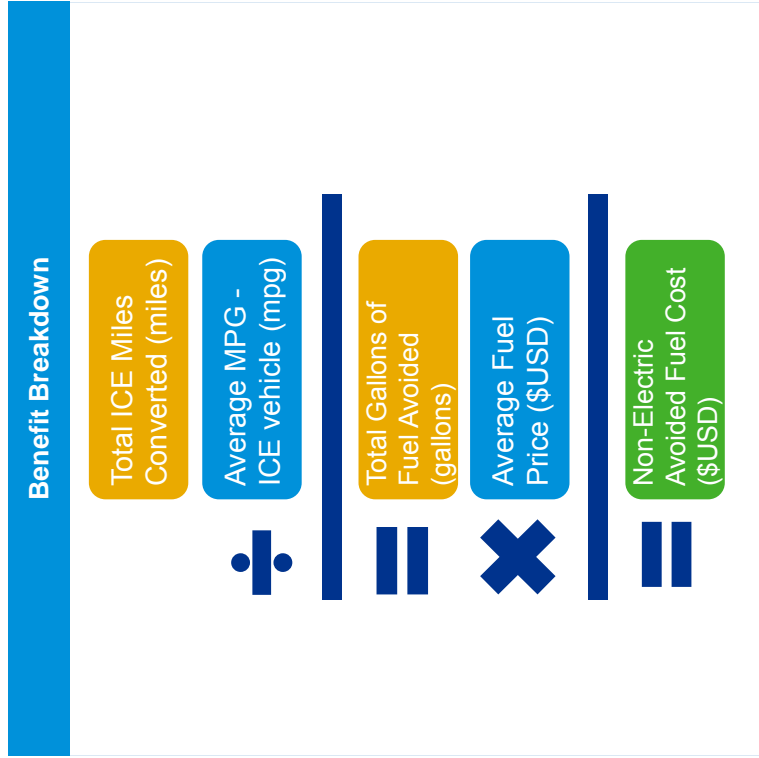
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# Benefits – Non-Electric Avoided Fuel Costs

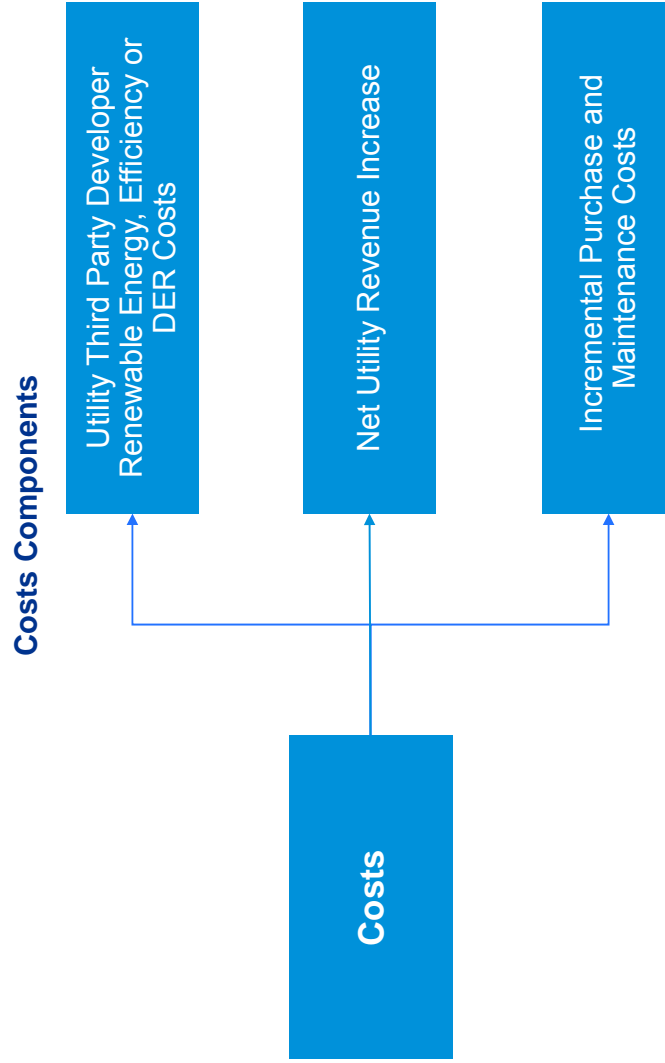
## Non-Electric Avoided Fuel Costs

- 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



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# Costs – Overview



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# 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



# Results – Transportation

Electric Vehicles -- Total	
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	\$ -
<b>Total</b>	<b>\$ 15,535,555</b>
Total Program Administration Costs	\$ 10,420,428
Incremental Purchase and Maintenance Cost	\$ 4,671,444
<b>Total</b>	<b>\$ 15,091,871</b>
<b>BCA Ratio</b>	
	<b>1.03</b>

**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



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# Rhode Island 2017 Power Sector Transformation Project Benefit Cost Analysis Models *Electric Heat*

Reference Document

November 2017

# 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

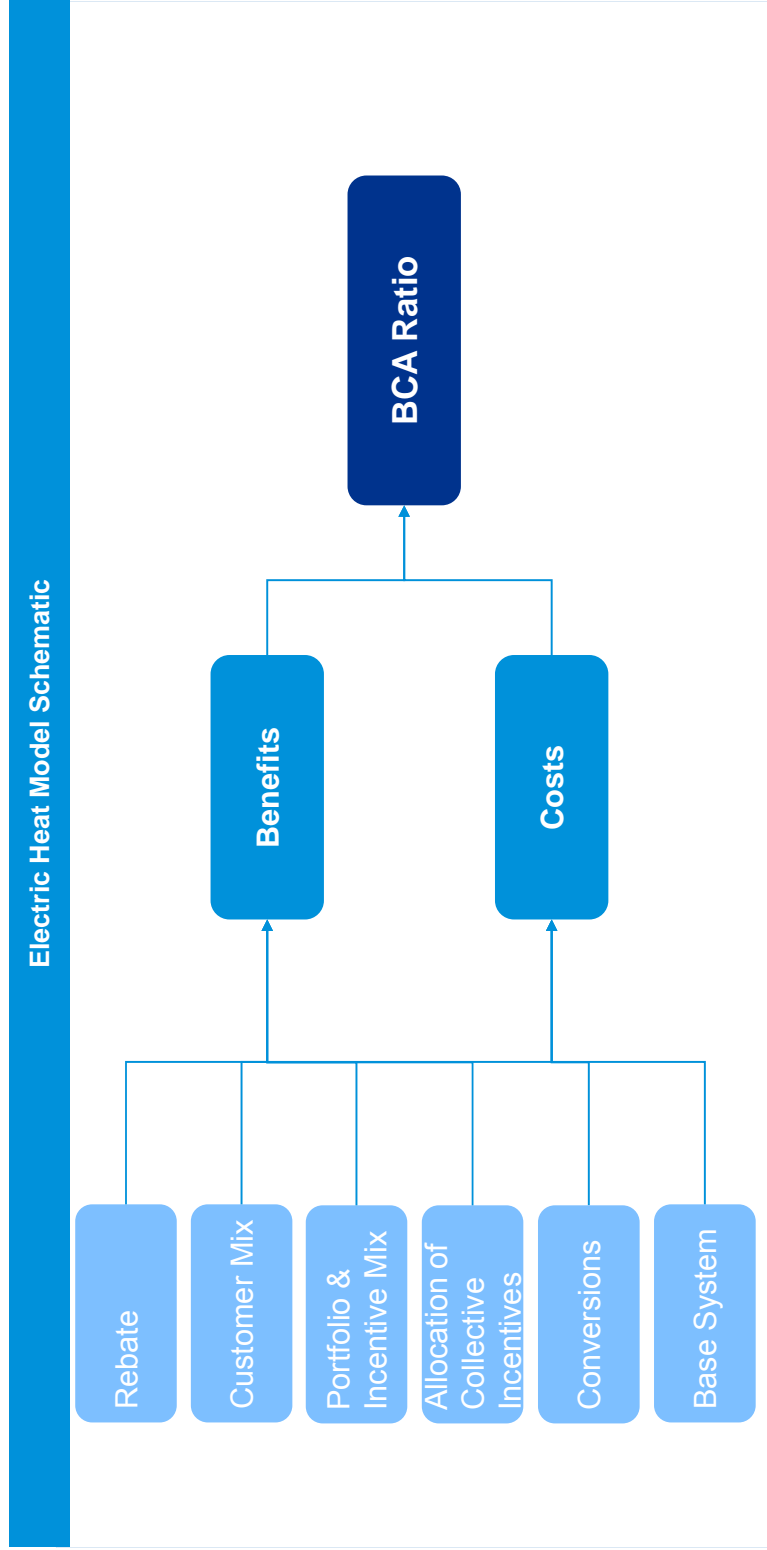
- Assumptions are made concerning the rebate budget, the portfolio and incentive mix, the customer mix, and the allocation of collective incentives to estimate the number of system conversions for each configuration type
- A base heating and cooling system is then selected to develop a "current state"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



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# Model Overview



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# Key Inputs Table

Key Inputs	Definition	Model Usage	Source(s)
<b>Rebate</b>	<ul style="list-style-type: none"> <li>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</li> <li>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</li> </ul>	<i>Involved in determining the total number of conversions</i>	Mackay Miller and RI testimony
<b>Portfolio and Incentive Mix</b>	<ul style="list-style-type: none"> <li>The percentage share of the rebate that goes to low income participants versus market participants</li> <li>The larger share that goes to market participants, the higher the SCT ratio because they are receiving a much lower rebate %</li> </ul>		
<b>Conversions</b>	<ul style="list-style-type: none"> <li>The total number of systems converted into electric heat systems</li> <li>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</li> </ul>	<i>A key driver of every benefit category</i>	Calculated based on information from Mackay Miller and RI testimony
<b>Allocation of Collective Incentives</b>	<ul style="list-style-type: none"> <li>Determines the share of total incentives that is allocated towards each system type</li> </ul>	<i>Determines which system configurations will see the most conversions</i>	Mackay Miller and RI testimony
<b>Customer Mix</b>	<ul style="list-style-type: none"> <li>The target level of customers that will be low income versus market participants</li> <li>The higher percentage that are market participants, the higher the SCT ratio because more conversions will occur</li> </ul>	<i>Contributes to the total number of conversions</i>	Mackay Miller and RI testimony
<b>Base System</b>	<ul style="list-style-type: none"> <li>Defines the system that will be converted to electric heat</li> <li>Provides the model with a baseline for comparison</li> <li>Options for Base Heat include Fuel Oil, Propane, Natural Gas, and Electricity</li> <li>Options for Base Cooling include No AC, Window AC, and Central AC</li> </ul>	<i>Impacts the magnitudes of nearly every benefits category</i>	Mackay Miller and RI testimony



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# Control Panel Breakdown

**Control Panel - select heating portfolio scenario in table below**

**Switch key:**  
 Select from Drop-down  
 Populate Area

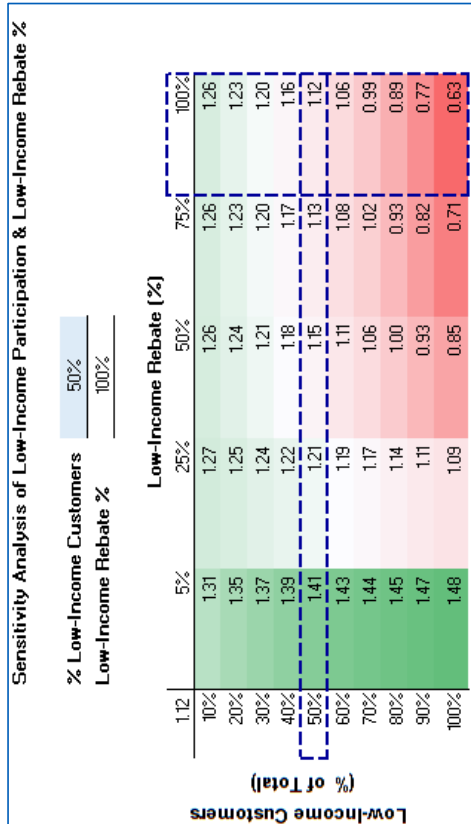
**Control Panel Description**

- 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

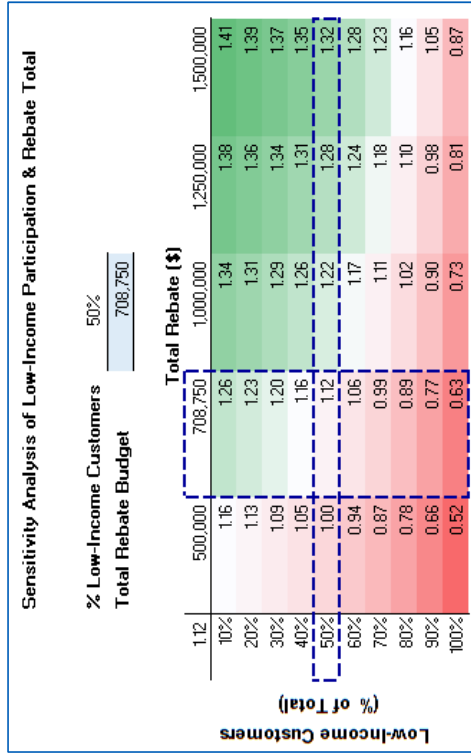


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# Key Inputs #1-2 – Customer Mix & Rebate Budget



**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.

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

Portfolio & Incentive Mix Customer	% of Total
Low-Income	50%
Market	50%
<b>Total</b>	<b>100%</b>

**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%
<b>Total</b>	<b>100%</b>	<b>100%</b>
<b>Check (Sum equal to 100%)</b>	<b>Y</b>	<b>Y</b>

**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	3,361.00	3,361.00	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	3,361.00	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.



# Key Inputs #5,6 – Base System & Conversions

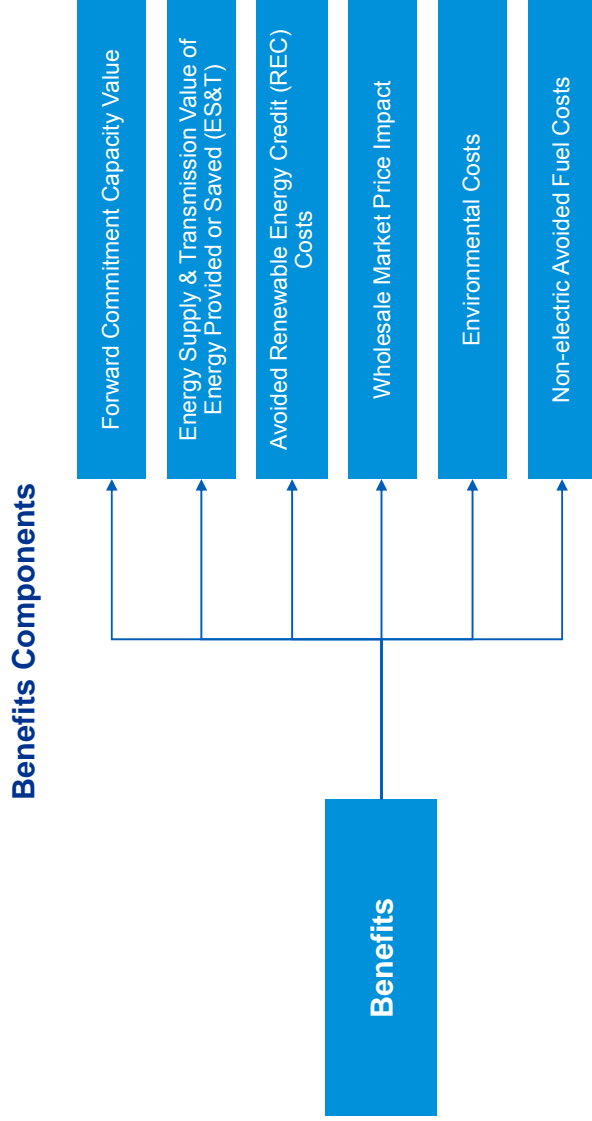
System Technology Selections Technology Type	Base Heating	Base Cooling	New System Type	Incentive Allocated (yr)	Progression Schedule (number of conversions)				Total Converted
					2018	2019	2020	2021	
Type A	Fuel Oil	No AC	ASHP 3 ton	Yes	33.00	45.00	50.00	50.00	134.00
Type B	Fuel Oil	No AC	GSHP Horizontal Loop 4 ton	Yes	18.00	20.00	24.00	24.00	62.00
Type C	Fuel Oil	No AC	GSHP Vertical Loop 82 ton	NA	-	1.00	-	-	1.00
Type D	Fuel Oil	No AC	ASHP 5 ton	No	-	-	-	-	-
<b>Total</b>					<b>57.00</b>	<b>66.00</b>	<b>74.00</b>	<b>74.00</b>	<b>197.00</b>

**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



# Benefits – Overview



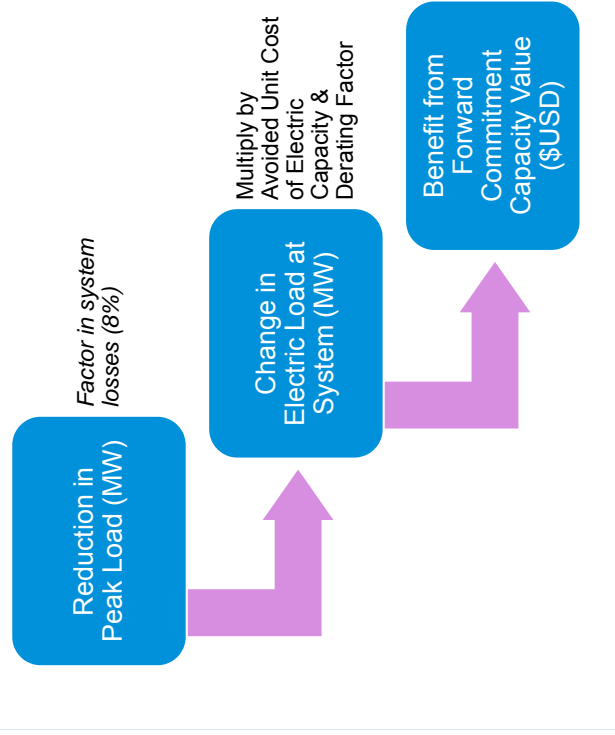
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# Benefits – Forward Commitment Capacity Value

## 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

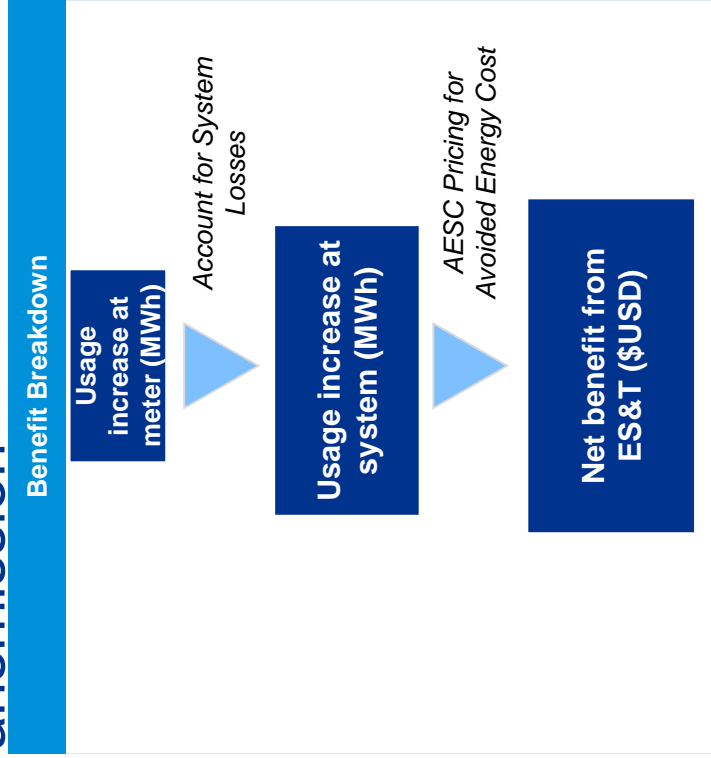
## Benefit Breakdown



# Benefits – Energy Supply and Transmission

## Energy Supply & Transmission

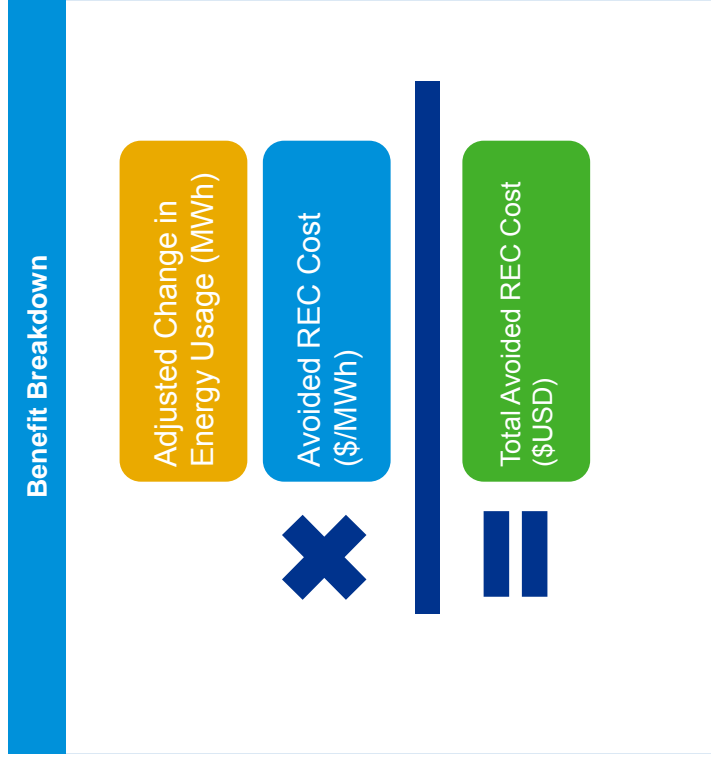
- ❑ Values the total avoided cost of generating and distributing energy
- ❑ The electric heat program will lead to a greater level of total electricity usage
- ❑ In turn, there is an increase in the cost to generate and transmit this energy



# 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

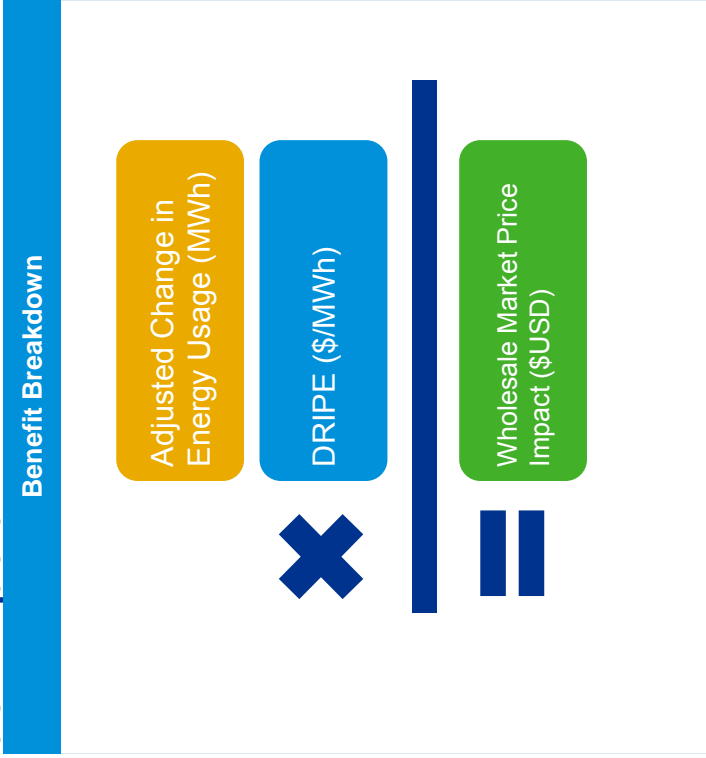




# Benefits – Wholesale Market Price Impact

## 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



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# 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



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# Benefits – Non-Electric Avoided Fuel Costs

## Non-Electric Avoided Fuel Costs

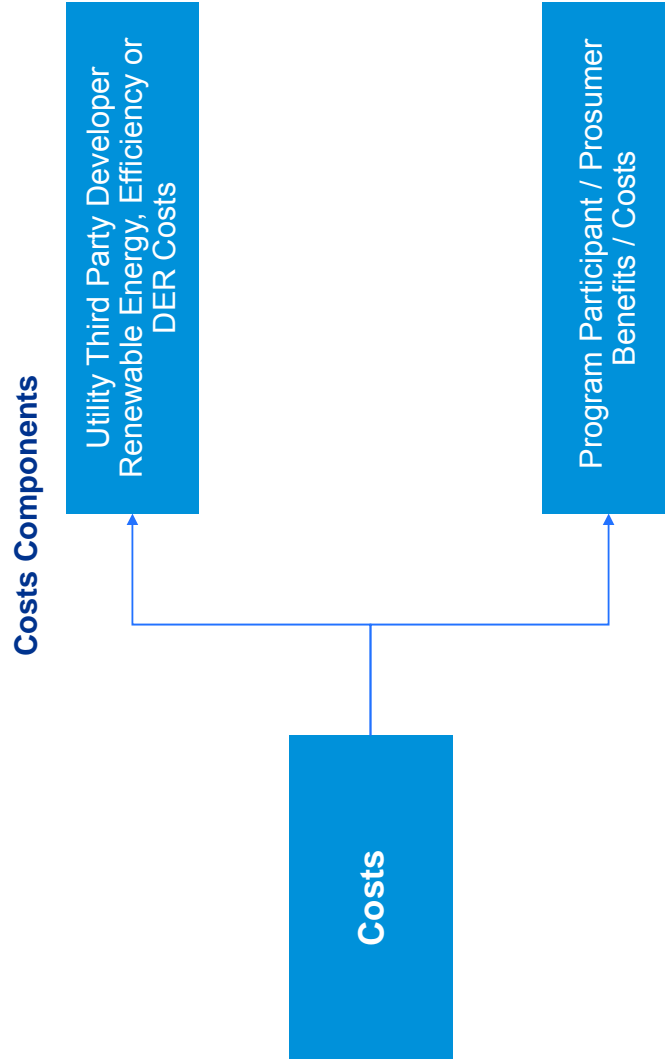
- ❑ Values the fuel not consumed due to the adoption of the electric heating system
- ❑ Multiplies the reduction in consumption by the average price of consumption (\$/MMBTU)
- ❑ This category captures the majority of the benefits of the electric heating system conversions



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# Costs – Overview

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# 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







# 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

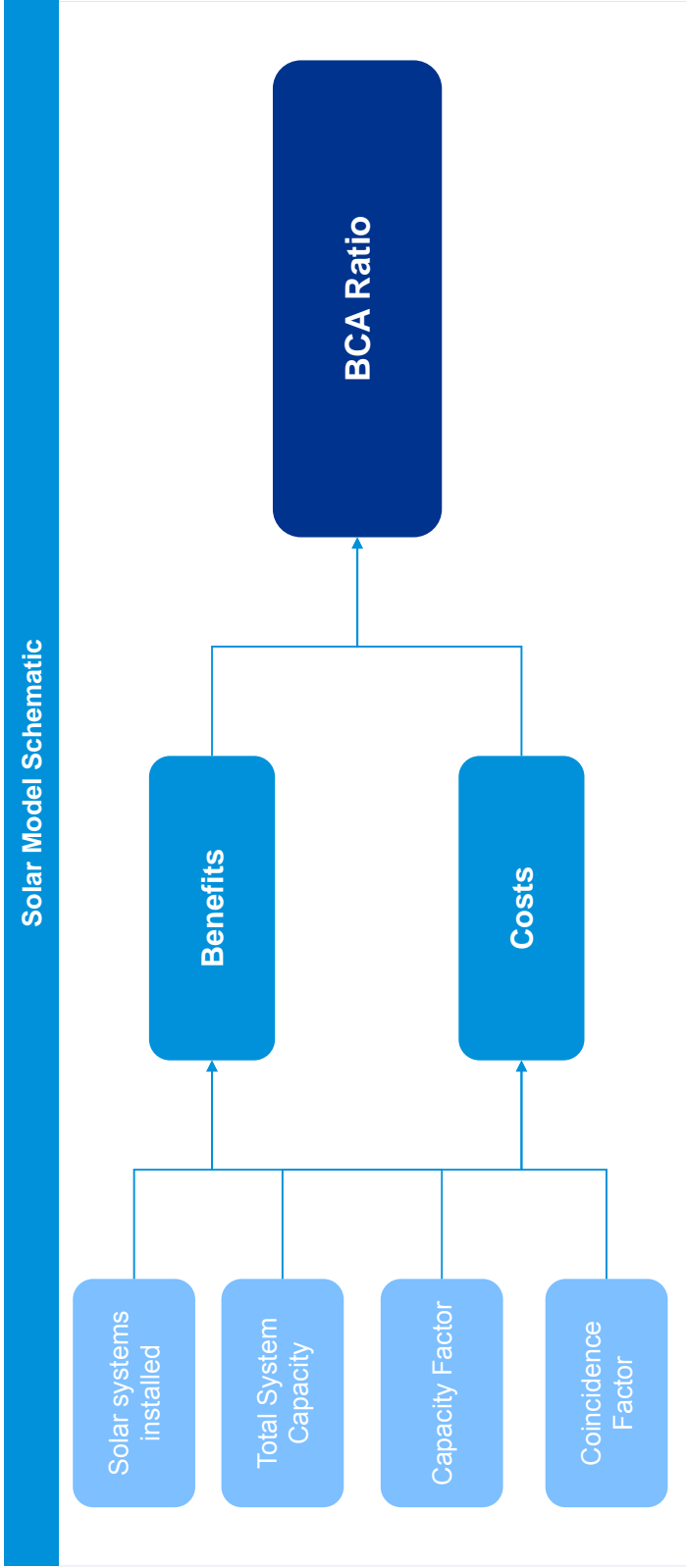
- Total System Capacity and Capacity Factor are used to estimate the total annual energy output from solar generation and derive an Adjusted Peak Load
- These numbers are then used with AESC prices to value the capacity and usage benefits from the solar program



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# Model Overview



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# Key Inputs Table

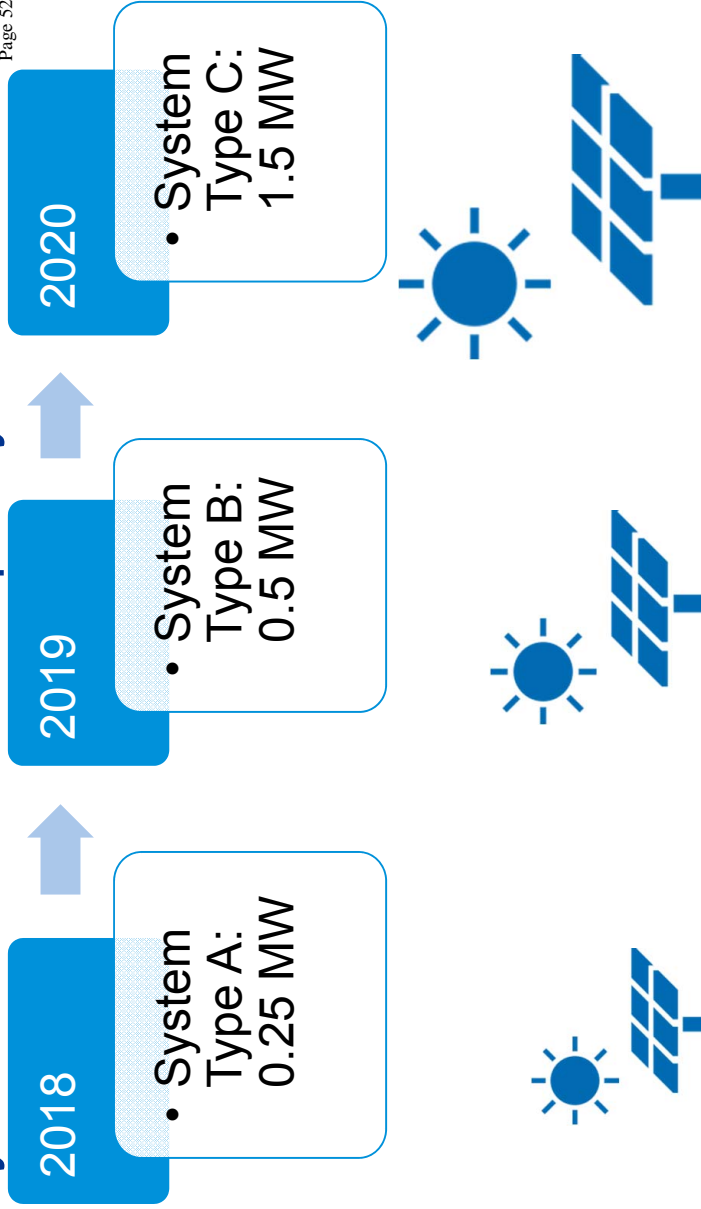
Key Inputs	Definition	Model Usage	Source(s)
<b>Systems Built</b>	<ul style="list-style-type: none"> <li>The total number of systems built by National Grid and their respective years.</li> <li>NG is building one 0.25 MW solar canopy in 2018, one 0.5 MW solar canopy in 2019, and a larger 1.5 MW solar unit in 2020</li> </ul>	Used to determine the peak site capacity and the total solar energy generation in a given year	Calculated based on RI testimony
<b>Total System Capacity</b>	<ul style="list-style-type: none"> <li>The peak capacity of the total solar generation system</li> <li>The sites come on line and start accruing benefits the year after they are built</li> </ul>		
<b>Capacity Factor</b>	<ul style="list-style-type: none"> <li>The ratio of actual power generation over a year divided by installed capacity</li> <li>The capacity factor suggests that, over the course of a year, the system is generating energy at 16.1% of its peak operating capacity</li> <li>Solar has a relatively low capacity factor in comparison to other forms of energy generation</li> </ul>	Used with total system capacity to estimate the average annual output from solar generation	PV Watts
<b>System Coincidence Factor</b>	<ul style="list-style-type: none"> <li>A measure of solar generation capacity during the time of peak energy demand</li> <li>The amount of energy that it generates during this period informs how much it reduces the peak load of the system</li> <li>Estimated to be 28.1%</li> <li>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</li> </ul>	Used to calculate the Benefit from Forward Commitment Capacity Value	Confirmed with project team



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## Key Inputs #1/2 – Systems Installed & Capacity

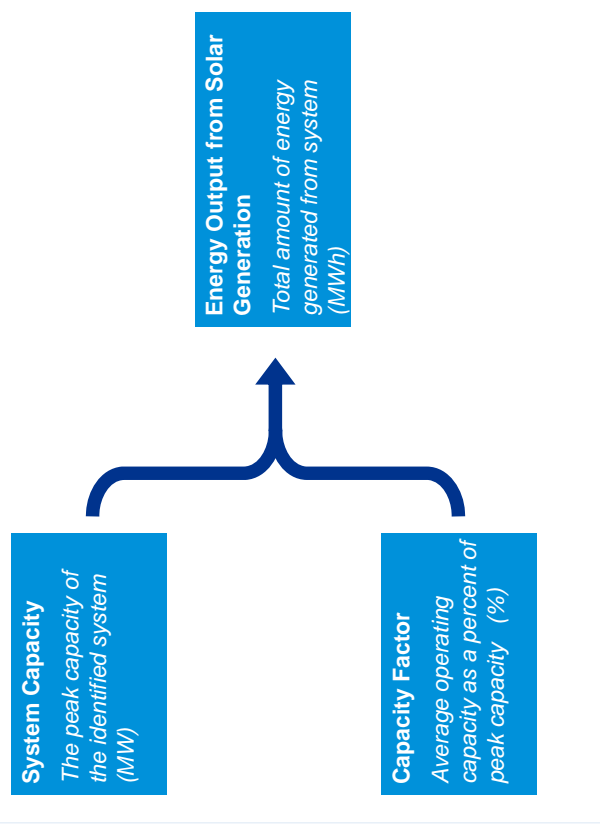
- National Grid will undergo construction of 3 solar sites from 2018 to 2020
- Over this period, the total system capacity will increase from 0.25 MW to 2.25 MW
- These systems all have a useful life of 25 years



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# Key Input #3 – Capacity Factor

## Input Breakdown

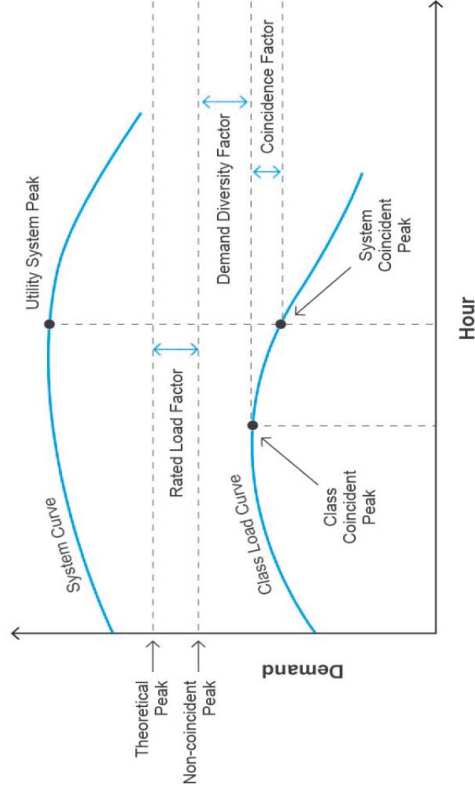


- The capacity factor is a descriptive statistic characterizing the average operating capacity of the systems in question
- This is expressed as a percentage of the peak system capacity
- This is an important metric because it can be used to determine which locations and sites are most suitable for solar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

## 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



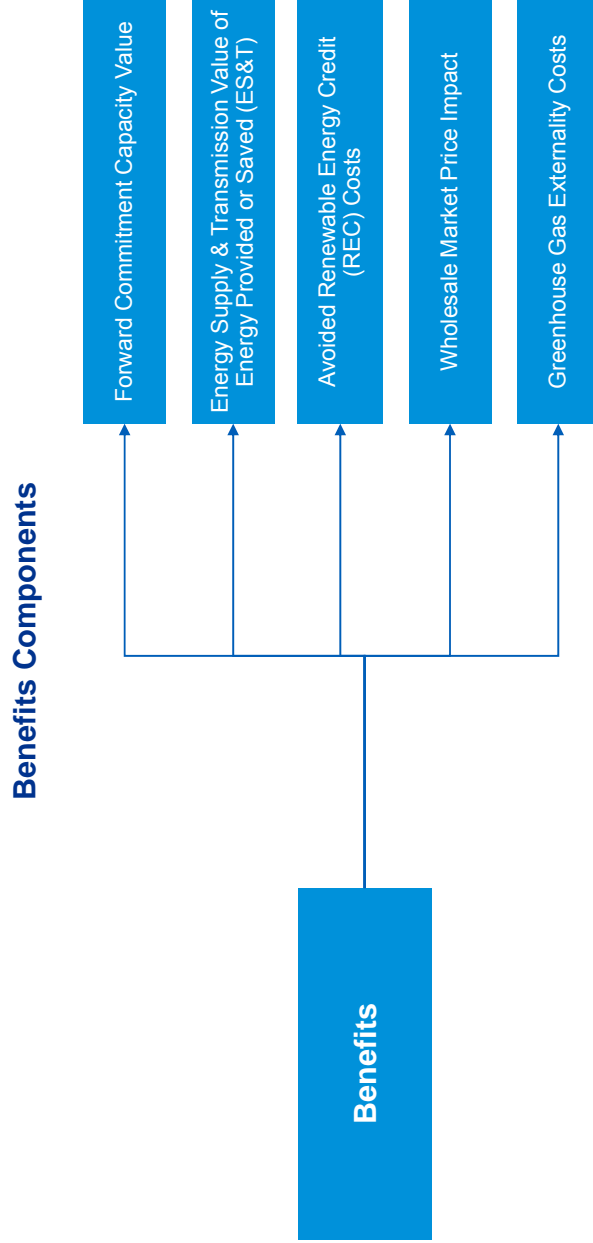
Source: NREL – Peak Demand and Time-Differentiated Energy Savings Cross-Cutting Protocols



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# Benefits Overview

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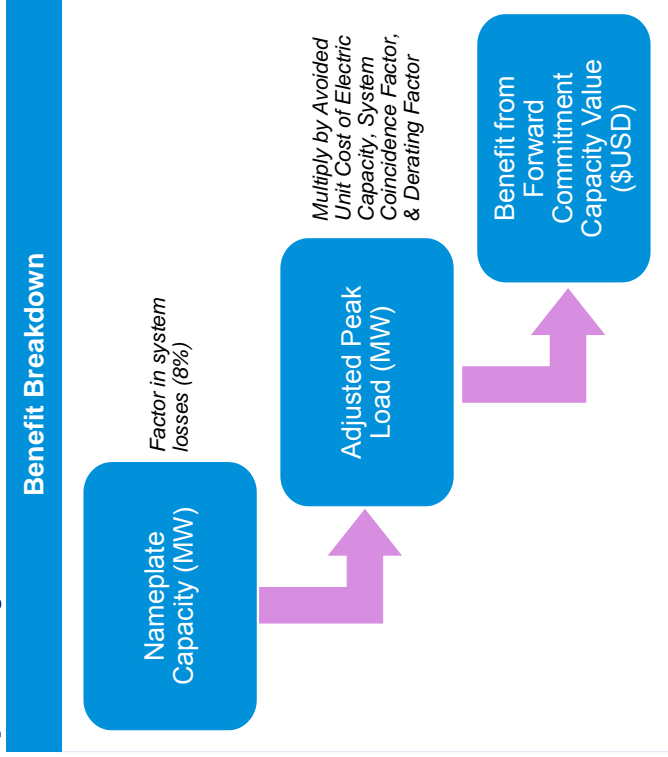


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# Benefit – Forward Commitment Capacity Value

## Forward Commitment Capacity Value

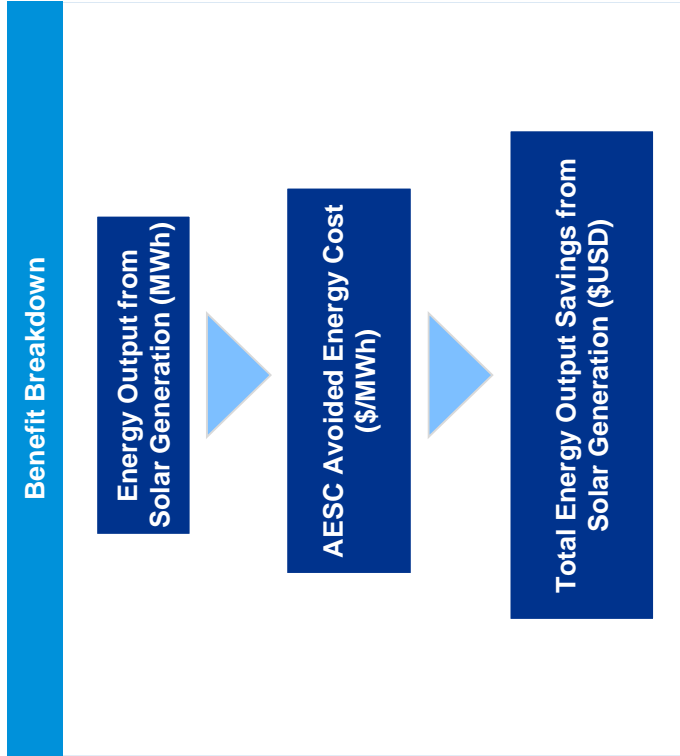
- ❑ Values the increase or decrease in the total energy demand attributable to the program
- ❑ Numbers are delayed by four years because of requirement to bid into the forward capacity market 4 years in advance
- ❑ Increased energy generation from Solar helps to lessen the total load demand on the system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



# Benefit – 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

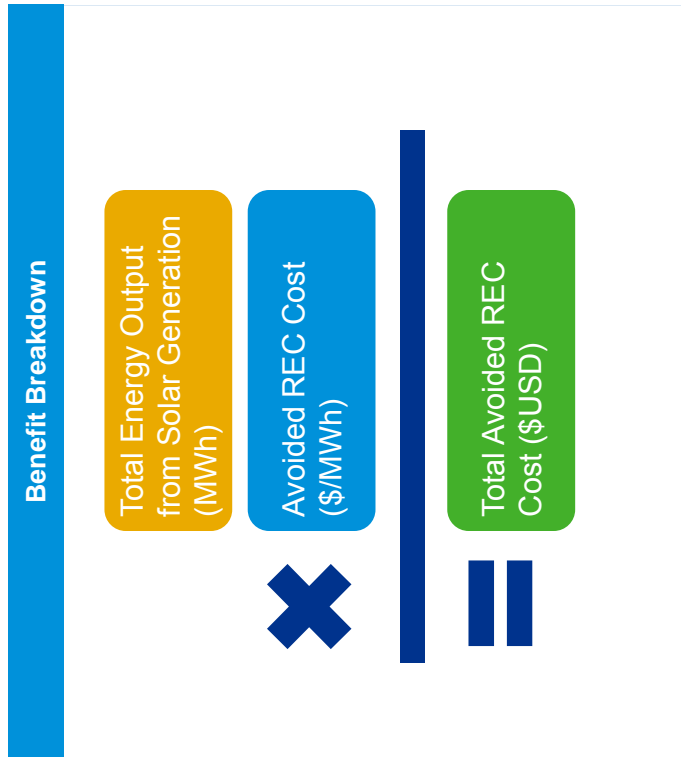




## Benefit – Avoided REC Costs

### 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 – 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



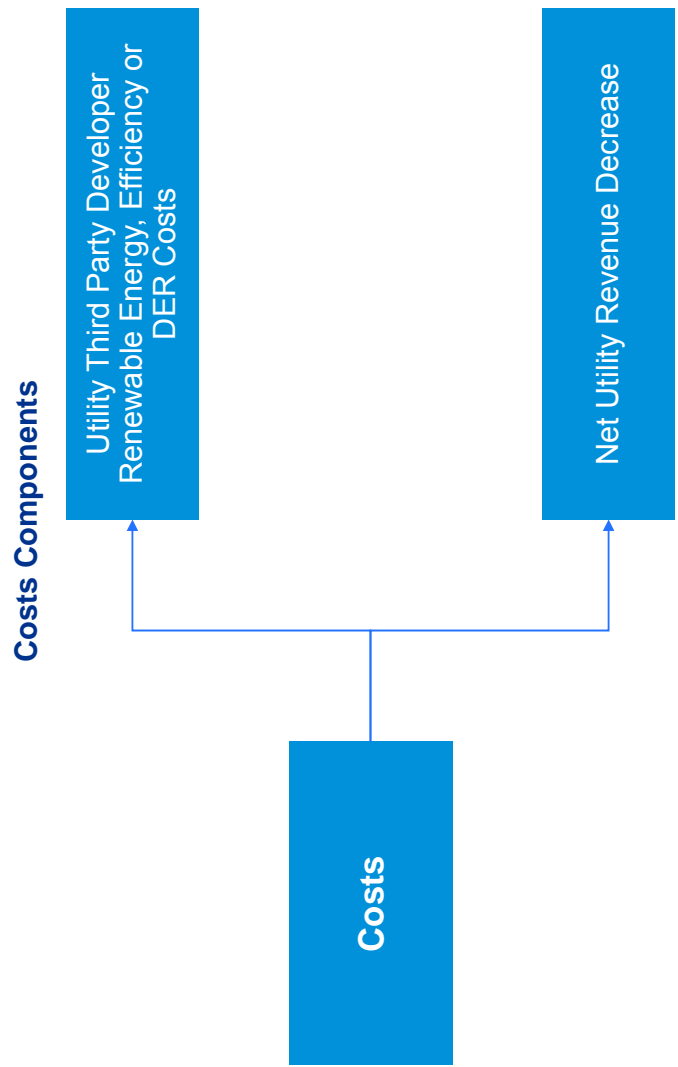
# Benefit – GHG Externality Cost Avoided Greenhouse Gas Externality Costs

- ❑ 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



# Costs Overview

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# Description of Cost Categories

Utility Third Party Developer Renewable Energy, Efficiency or DER Costs
<p><b>Combination of Capex and Opex Sub-total, less any relevant tax incentives</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Capex refers to the direct cost of building the sites</li> <li><input type="checkbox"/> Opex Sub-total includes the ongoing site maintenance costs as well as the inverter leases</li> <li><input type="checkbox"/> Tax incentives refer to the ITC tax incentive as well as the R&amp;D tax incentive</li> </ul>

Net Utility Revenue Decrease
<p><b>Captures National Grid's projected decrease in revenue attributable to the program</b></p> <ul style="list-style-type: none"> <li><input type="checkbox"/> Accounts for the fact that the utility will not be receiving charges from electricity generation</li> <li><input type="checkbox"/> This cost is only included in the RIM test</li> </ul>



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# 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	
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
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

# 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

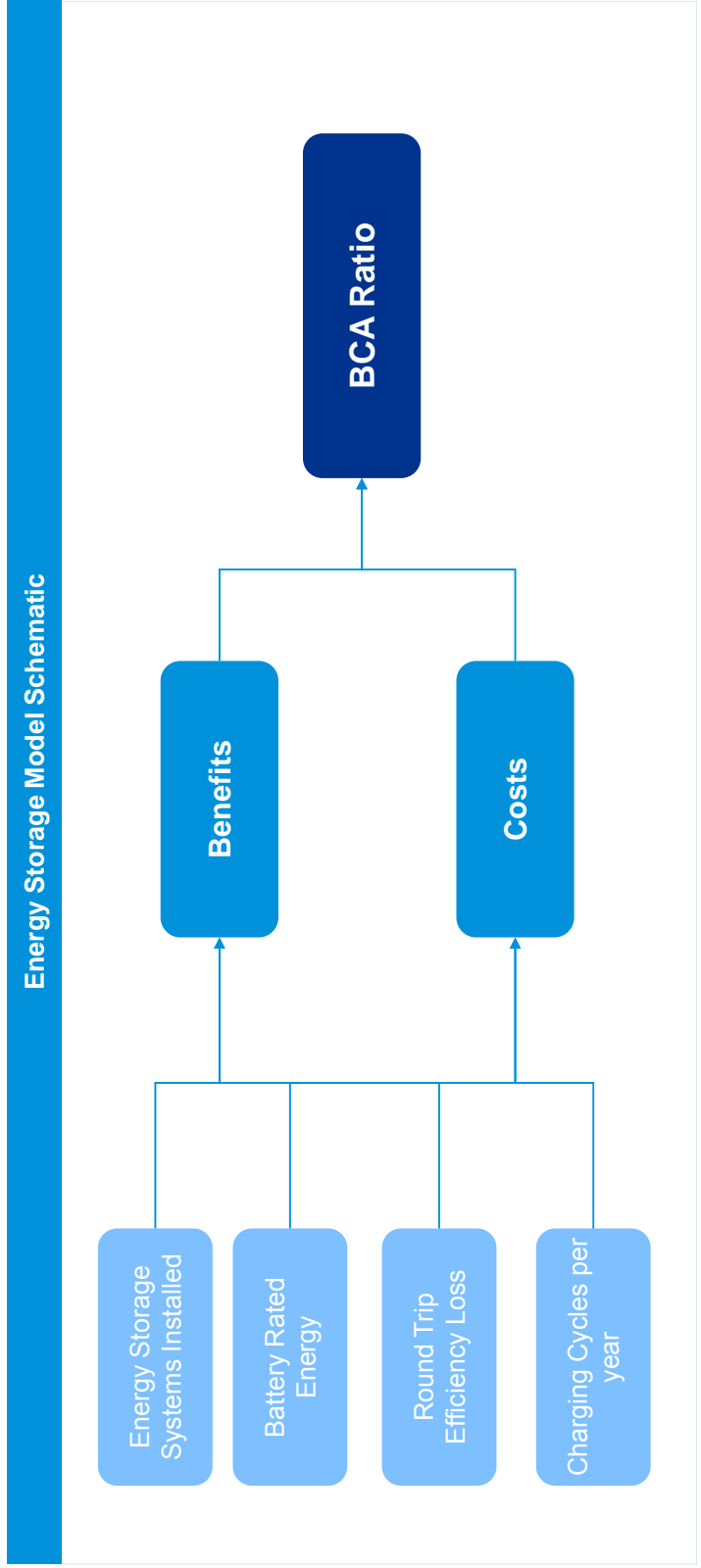
- Given rated energy, the difference is calculated between energy displaced from Off-peak to On-peak over a single full charging cycle
- An assumption is then made regarding number of cycles per year as well as the round trip efficiency loss
- Using these factors, it is possible to forecast the total 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



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# Model Overview



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# Key Inputs

Key Inputs	Definition	Model Usage	Sources
<b>Energy Storage Systems Built</b> <ul style="list-style-type: none"> <li>The total number of systems built by National Grid and their respective years.</li> <li>NG is building one 0.5 MW battery in 2018, and one 0.75 MW battery in 2019</li> </ul>		<p>Used in order to calculate the amount of energy displaced from On-peak to Off-peak as well as the change in energy load</p>	<p>RI testimony - October 3<sup>rd</sup> 2017 -</p>
<b>Battery Rated Energy</b> <ul style="list-style-type: none"> <li>The total amount of energy that the batteries can store</li> <li>The batteries are assumed to come online and start accruing benefits the year after they are built</li> </ul>			
<b>Round Trip Efficiency Loss</b> <ul style="list-style-type: none"> <li>The amount of energy lost when converting from one system to another</li> <li>Assumed round trip efficiency loss was 10%, meaning that through the process of charging and discharging the batteries lose about 10% of usable energy</li> </ul>		<p>Used in order to calculate the total energy usage increase which is used in all usage related benefits</p>	<p>Kenmore Energy Storage Project File</p>
<b>Charging Cycles per Year</b> <ul style="list-style-type: none"> <li>The amount of times a battery charges and discharges annually</li> <li>Assuming 1 discharge per day, 5 days per week</li> </ul>		<p>Used to calculate the total energy displaced and charged annually</p>	<p>Lazard Levelized Cost of Storage 2.0 Study</p>

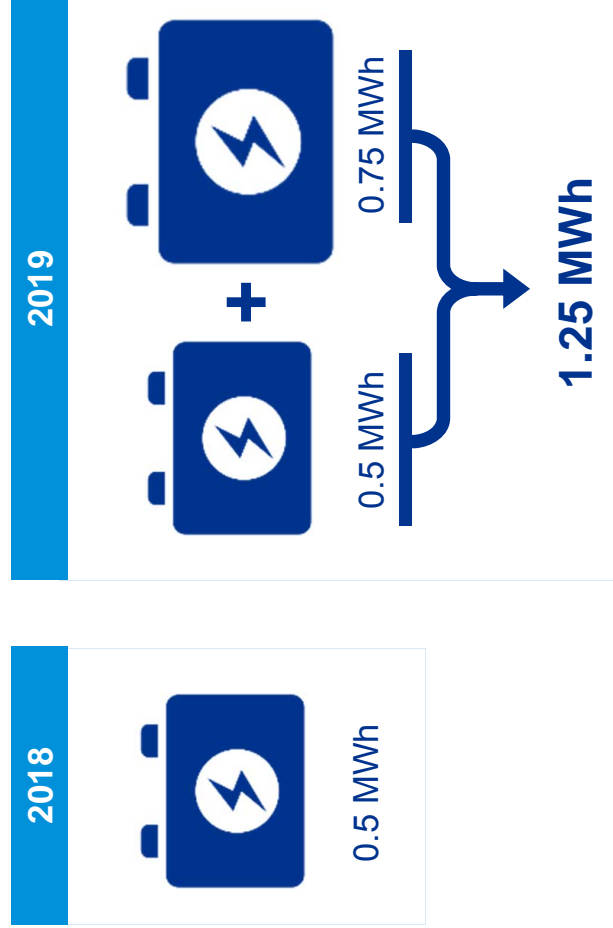


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# Key Input #1-2 – System Builds & Total Energy

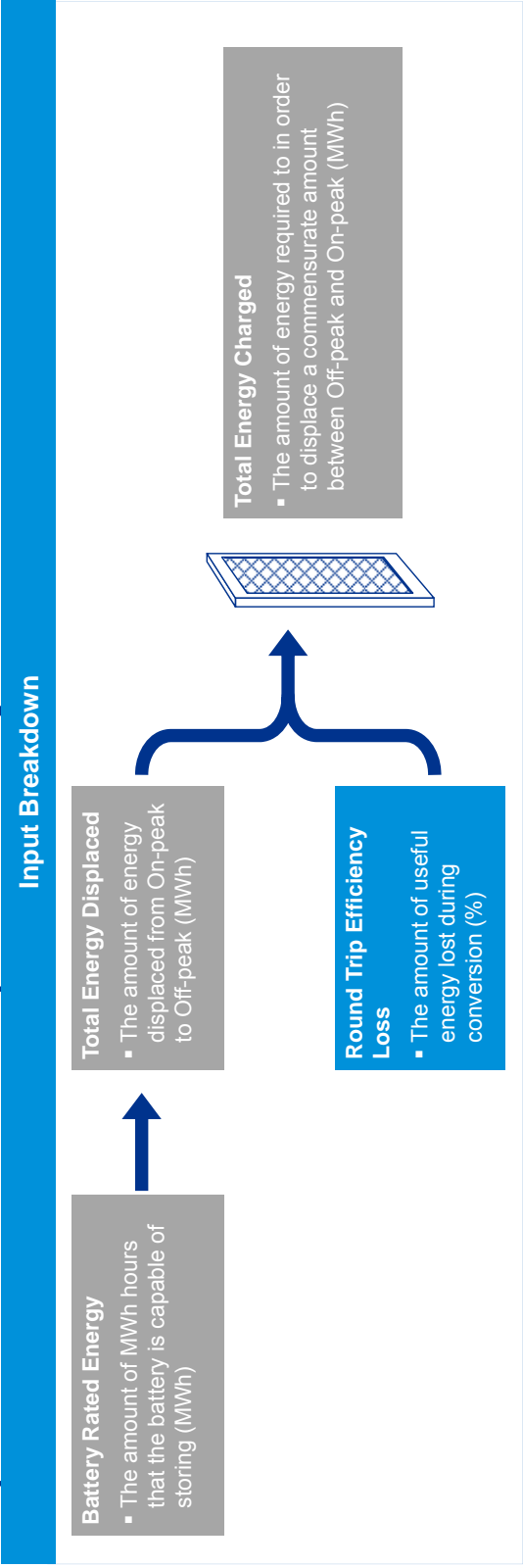
- National Grid proposes the construction of 2 energy storage systems in 2018 and 2019
- Over this period, the total storage of the system increases from 0.5 MWh to 1.25 MWh
- Systems are assumed to have a useful life of 12 years
- Benefits begin accruing in the year following the system build

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# Key Input #3 – Round Trip Efficiency Loss



- ❑ 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

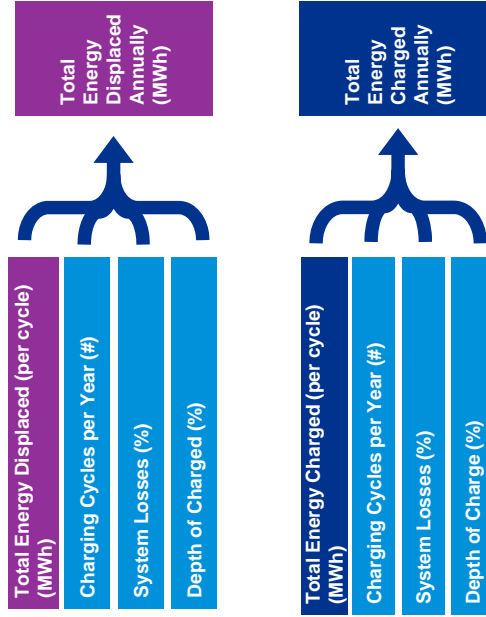


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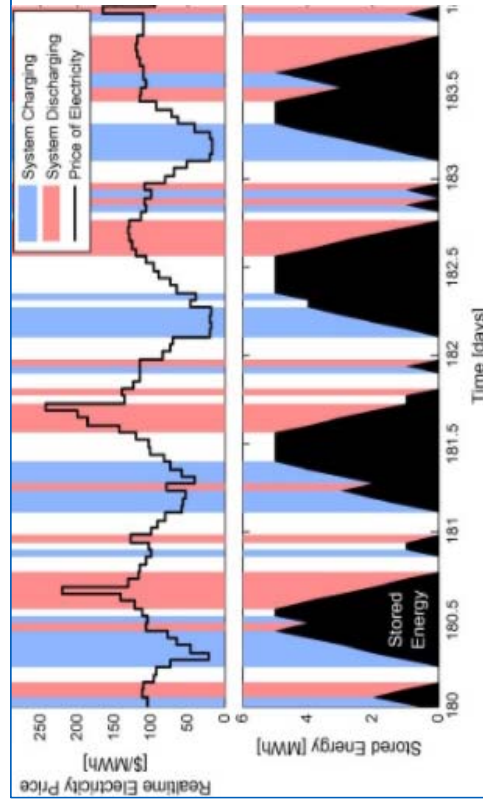
## Key Input #4 – Charging Cycles Per Year

- 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

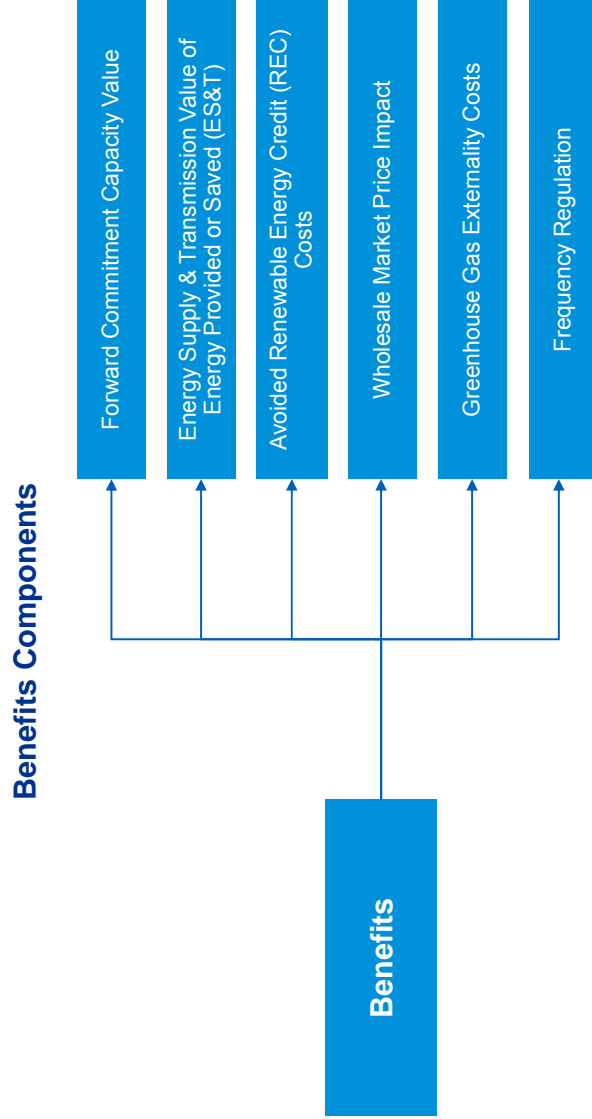


### Sample Battery Dispatch Profile



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# Benefits – Overview

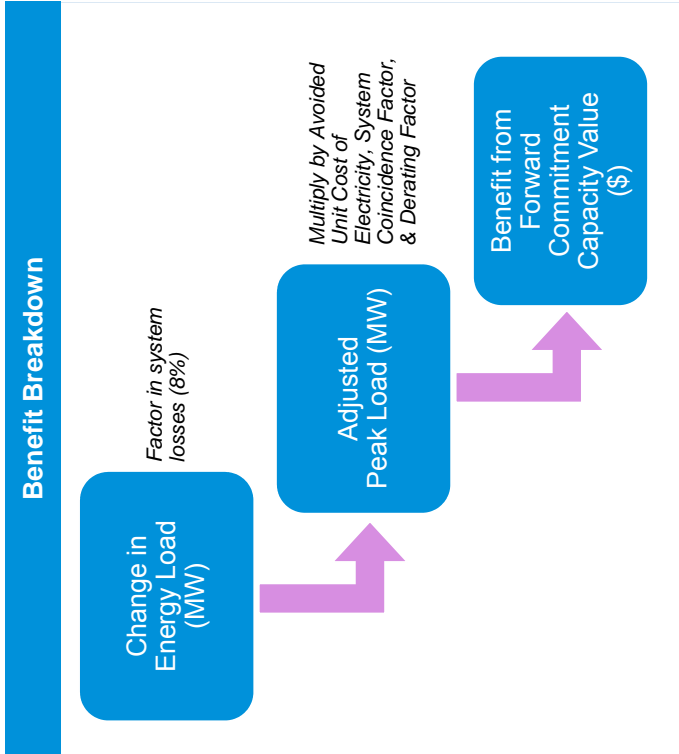


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# Benefits – Forward Commitment Capacity Value

## Forward Commitment Capacity Value

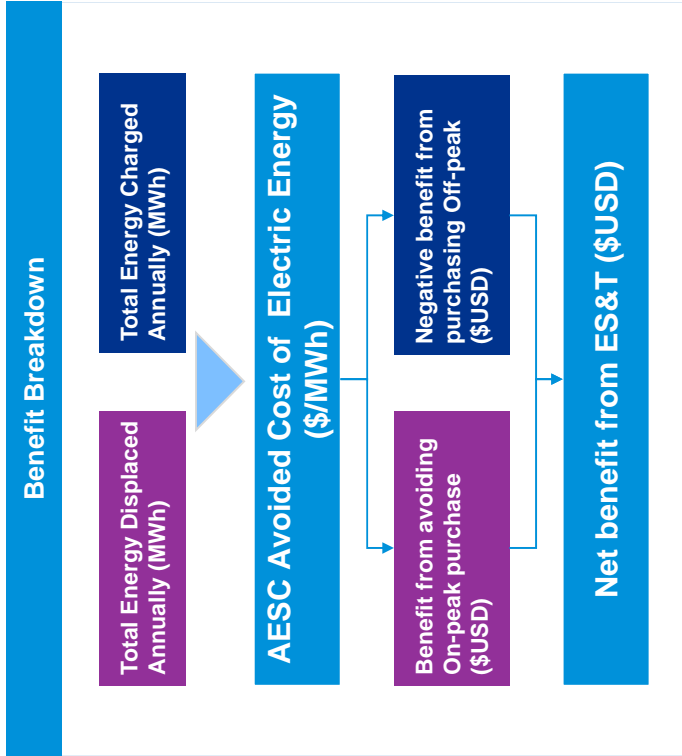
- ❑ Values the increase or decrease in the total energy demand attributable to the program
- ❑ Numbers are lagged by four years because you must bid into the forward capacity market 4 years in advance (in accordance with AESC guidance)
- ❑ The displaced energy from charging Off-peak and discharging On-peak 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





# Benefits – Avoided REC Costs

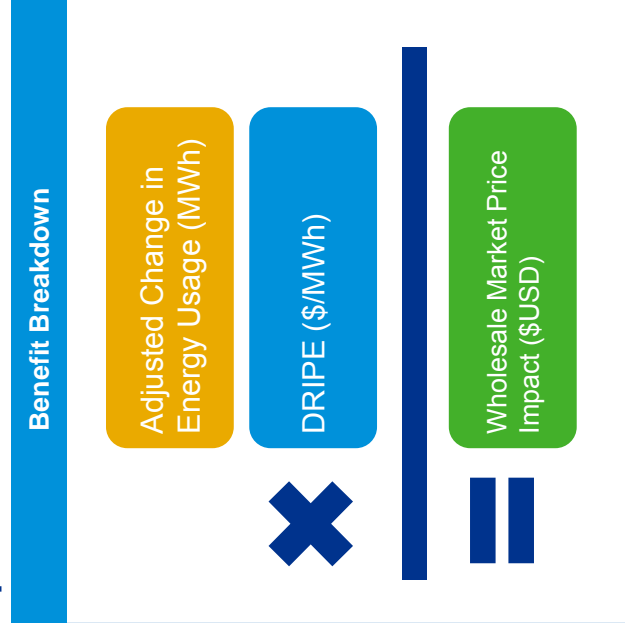
- ❑ For each MWh of power generated from a renewable energy source, National Grid receives 1 REC
- ❑ The Energy Storage program has a negative Avoided REC Cost because they are increasing energy usage and have to purchase RECs to offset usage increase



# Benefits – Wholesale Market Price Impact

## Wholesale Market Price Impact

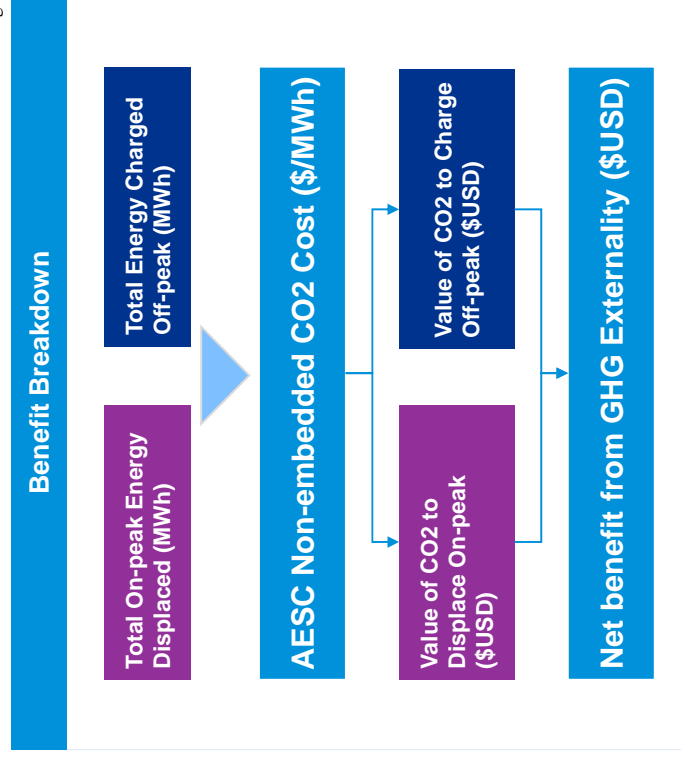
- ❑ Values the price changes in the market that are **directly attributable to the program itself**
- ❑ For example, it captures how an increase in the electricity usage impacts actual market supply and demand, and eventually equilibrium prices
- ❑ Uses the AESC Demand Reduction Induced Price Effect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



## 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

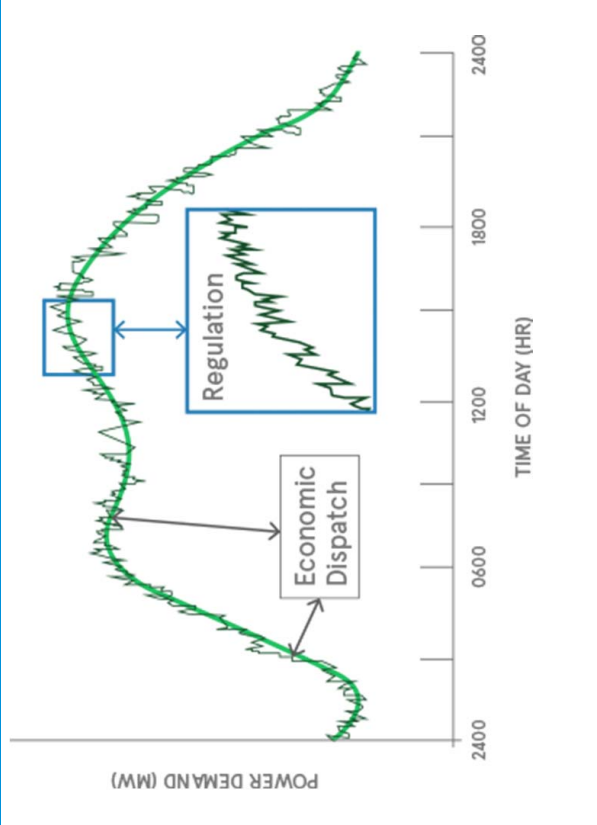


# Benefits – Frequency Regulation

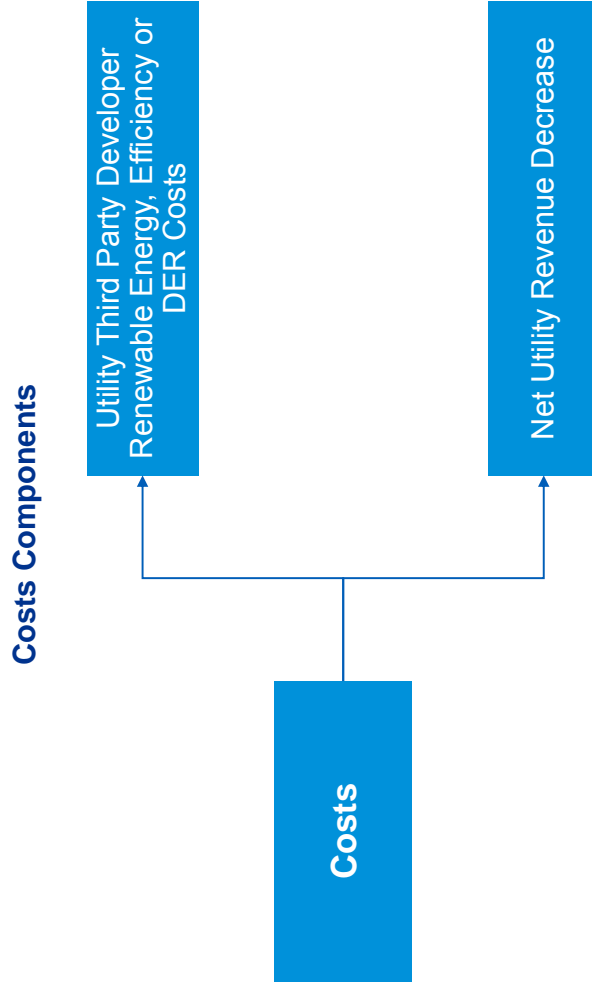
## Frequency Regulation

- ❑ 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



# Costs – Overview



# 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



# Energy Storage – Results

**ES - BCA Summary**  
 Return to Contents → 

**Societal Cost Test**  
**RI Energy Storage BCA**

<b>Energy Storage - BCA Ratio</b>	
<b>Benefits</b>	
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	\$ -
Economic Development	\$ (6,674)
	\$ -
	<b>\$ 1,018,904</b>
<b>Costs</b>	
Utility/ Third Party Developer Renewable Energy, Efficiency, or DER Costs	\$ 2,260,660
	<b>\$ 2,260,660</b>
	<b>0.45</b>

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

Charging during off-peak and displacing avoided 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**

<b>Rhode Island Investment Proposal</b>					
<b>Total Investment Spending and Economic Impacts by Project Planning through Construction Phase (2018-2021)</b>					
<b>Year</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Sum</b>
<b><u>Spending Plan (Labor &amp; Materials)</u></b>					
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
<u>AMI Meters*</u>	<u>\$0.0</u>	<u>\$32.6</u>	<u>\$62.3</u>	<u>\$85.8</u>	<u>\$180.6</u>
Total	\$5.0	\$41.0	\$74.6	\$86.0	\$206.6
<b><u>Impact on RI GDP (\$m)</u></b>					
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
<u>AMI Meters</u>	<u>\$0.0</u>	<u>\$3.8</u>	<u>\$16.2</u>	<u>\$27.7</u>	<u>\$47.6</u>
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**

<b>Rhode Island Economic Impact Summary - All Projects</b>					
	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Sum</b>
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**

<b>Job Impacts - All Projects</b>					
	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Sum</b>
Direct	21	60	163	174	419
Indirect	4	13	36	38	92
<u>Induced</u>	<u>8</u>	<u>24</u>	<u>66</u>	<u>70</u>	<u>169</u>
Total	34	98	265	283	679
<b>Job Impacts - Non AMI</b>					
	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Sum</b>
Direct	21	37	58	1	117
Indirect	4	8	12	0	24
<u>Induced</u>	<u>8</u>	<u>15</u>	<u>24</u>	<u>1</u>	<u>49</u>
Total	34	59	94	3	190
<b>Job Impacts - Electric Heat</b>					
	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Sum</b>
Direct	5	8	6	0	18
Indirect	1	2	1	0	4
<u>Induced</u>	<u>2</u>	<u>3</u>	<u>2</u>	<u>0</u>	<u>7</u>
Total	8	12	9	0	30
<b>Job Impacts - Company Owned Solar</b>					
	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Sum</b>
Direct	5	10	19	1	35
Indirect	1	2	4	0	7
<u>Induced</u>	<u>2</u>	<u>4</u>	<u>8</u>	<u>1</u>	<u>15</u>
Total	8	16	31	2	57
<b>Job Impacts - Company Owned Storage</b>					
	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Sum</b>
Direct	3	5	0	0	9
Indirect	1	1	0	0	2
<u>Induced</u>	<u>1</u>	<u>2</u>	<u>0</u>	<u>0</u>	<u>4</u>
Total	6	8	1	0	15
<b>Job Impacts - Electric Vehicles</b>					
	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Sum</b>
Direct	8	14	33	0	55
Indirect	2	3	7	0	11
<u>Induced</u>	<u>3</u>	<u>6</u>	<u>14</u>	<u>0</u>	<u>22</u>
Total	12	23	53	0	89
<b>Job Impacts - AMI*</b>					
	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Sum</b>
Direct	0	23	105	173	301
Indirect	0	6	24	38	68
<u>Induced</u>	<u>0</u>	<u>9</u>	<u>42</u>	<u>69</u>	<u>120</u>
Total	0	38	171	280	489

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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.