Massachusetts Electric Company
and
Nantucket Electric Company
d/b/a
National Grid

Grid Modernization Plan

Book 1 of 1

August 19, 2015

Submitted to:
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nationalgrid

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Submitted to:
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Hearing Officer:
Jonathan Goldberg

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1. Executive Summary

1.1 The Potential from Grid Modernization

Massachusetts Electric Company and Nantucket Electric Company d/b/a/ National Grid's ("National Grid" or "Company") Grid Modernization Plan ("GMP" or "Plan") provides the opportunity to consider a fundamental change in the energy future for its customers, its electric system and the Commonwealth of Massachusetts. The future of the distribution utility is evolving towards the integration of load and generation at the distribution level, for the benefit of customers receiving deliveries of electricity and customers generating electricity behind or at the meter. New technologies, especially in the areas of communications and coordinated controls, can enable significant changes in how the grid operates, as well as in customers' experiences and empowerment. These technologies, which have only become cost effective and more widely used recently, are driving the opportunity for Grid Modernization advances. National Grid's GMP proposes to leverage these new enabling technologies to move operation of the distribution grid towards greater levels of efficiency and reliability, while enabling a cleaner and more environmentally-friendly electric system. Under this plan, customers would have more information and greater control over their energy usage and cost. The GMP would allow National Grid to facilitate integration of distributed energy resources, minimize outages, provide improved outage communication and response, and operate the electric distribution grid more efficiently using real-time information and controls, all in a cost-effective manner and to the benefit of National Grid's customers.

The Company's GMP begins a discussion regarding the scale, scope and timing of grid modernization investments. The investments presented in the Plan comprise specific advances in operation of the distribution grid and customer opportunities. The main components of the Plan can be considered individually or holistically. This filing proposes four alternative plan scenarios that reflect a range of options and each can be considered in whole or in part. The scenarios allow the Department and stakeholders to understand the value brought to customers in each scenario and the cost to achieve the value each scenario offers. Thus, the Department can evaluate the breadth of offerings and their benefits while considering the pace of, and ultimate cost to achieve, grid modernization.

National Grid's GMP proposes investments in advanced meter technology, communications, distribution control systems, advanced distribution automation, voltage management and associated infrastructure required to support these capabilities. These investments provide the capability to continuously receive, send and process data on system conditions, outages, distributed resources, component health and reliability. Information and automation can transform the capabilities of the electric grid in the future, enabling improved reliability and operational efficiency. This will make opportunities available to the customer for convenience, control and choice in their energy service. Grid operators would have improved diagnostic capabilities for operation and maintenance of the grid. Customers would have detailed real-time information on their own energy use to allow them to respond to time-varying rates by modifying their electricity use and shifting their load to lower-priced hours, or simply to budget their monthly use through the provision of information. When appropriately managed and operated, these technologies and customer opportunities will help improve system utilization, thereby providing the opportunity to reduce potential future costs to provide electric service to all customers.

1.2 Grid Modernization Plan Requirements

On June 12, 2014, the Department issued its grid modernization order, D.P.U. 12-76-B ("Order" or "D.P.U. 12-76-B"). The Order requires the electric distribution companies in Massachusetts to file ten year grid modernization plans with the Department that outline how each company will make measurable progress toward the Department's four grid modernization objectives, which 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[1] ("Objectives"). GMPs must be updated in subsequent base rate cases, and the first grid modernization plan filings must include a five-year short term investment plan ("STIP") which applies to a company's capital investments and which includes an approach to achieving advanced metering functionality ("AMF") within five years of the Department's approval of the GMP, if this is justified by a business case analysis.[2]

As defined by the Department, AMF includes: (1) the collection of customers' interval usage data, in near real time, usable for settlement in the ISO-NE energy and ancillary services markets; (2) automated outage restoration and notification; (3) two-way communication between customers and the electric distribution company; and (4) with a customer's permission, communication with and control of appliances.[3]

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[1] D.P.U. 12-76-B, at 2 (2014).

[2] D.P.U. 12-76-B at 3. If the business case analysis does not justify deploying AMF within five years, a company may include an alternative to achieve AMF in longer than five years, together with a business case that justifies the alternative.

[3] D.P.U. 12-76-B, at 3 n.1.

On November 5, 2014, the Department issued two additional orders which also contain requirements for GMP filings. D.P.U. 12-76-C requires the electric distribution companies to submit a business case in support of the STIP portion of their GMPs. D.P.U. 12-76-C prescribes the required elements of the business case, and directs the utilities to submit completed Business Case Summary Templates as provided by the Department. The Department also issued D.P.U. 14-04-C, which adopts a time varying rates ("TVR") framework for Basic Service which will go into effect following the deployment of AMF, and which directs utilities to prepare their GMPs in a manner consistent with this new Basic Service rate structure.

1.3 Comprehensive Plan Development and Stakeholder Engagement Processes

National Grid engaged in a comprehensive process to formulate its GMP. This process began with National Grid's participation in the Department's working groups to provide input on the objectives for grid modernization. To develop its plan, the Company: drew on learnings from its own Smart Energy Solutions ("SES") Pilot with 15,000 customers in Worcester; formed twenty working groups to research and make recommendations on the different technologies and initiatives which the Company should include in its GMP; issued Requests for Proposal and a Request for Information to obtain cost and market information, in order to inform its selection process; conducted customer knowledge research to learn more about what customers would like to see from grid modernization; engaged in an extensive stakeholder engagement process, including soliciting input from stakeholders and incorporating that input into the GMP; and conducted the Business Case Benefit-Cost analysis for its STIP. All of these efforts have informed the Company's GMP, and are further detailed in Section 11 of this Plan.

1.4 Grid Modernization Plan Scenarios

National Grid considered different scenarios that would make measurable progress towards the Department's four objectives for grid modernization and that would achieve AMF. National Grid examined the different technologies it could deploy, the necessary supporting infrastructure, the interdependencies of these components, the scope and scale of these potential deployments and the costs, benefits and affordability of different options, among other considerations.

As a result of these efforts, National Grid is proposing four different scenarios for its grid modernization plan: 1) a Balanced Plan scenario; 2) an AMI-Focused scenario; 3) a Grid-Focused scenario; and 4) an Opt-In scenario. Each scenario will make progress on the Department's four objectives and will achieve AMF with different focuses resulting in different levels of investment and expense. The following table summarizes the scenarios with the Balanced Plan scenario being the most comprehensive option, and the Opt-In scenario being the least comprehensive option at the lowest total 10 year cost. National Grid recommends that the Department consider the benefits from each plan and the impact to customers in terms of benefits and bill impacts. These scenarios provide the Department the opportunity to consider its short term and long-term objectives regarding which investments to approve in light of the Objectives, costs to customers and benefits to customers from grid modernization.

Table 1: GMP Scenarios

Funding Source	Plan Category	Plan Component	Balanced Plan Scenario	AMI-Focused Scenario	Grid-Focused Scenario	Opt-In Scenario
STIP	Field Deployment	**AMI Meters**	100% Opt-out deployed in 5 Years	100% Opt-out deployed in 5 Years	30% Opt-out deployed in 10 Years, 70% Opt-in (cell)	100% Opt-In (cell) in full territory in 10 years
		CLM	Customer Portal and DRMS, Devices through Energy Efficiency Programs	Customer Portal and DRMS, Devices through Energy Efficiency Programs	Customer Portal and DRMS, Devices through Energy Efficiency Programs	Expansion of Customer Application and Online Portals deployed in SES pilot
		ADA, VVO, Feeder Monitors	ADA / VVO to 30% of customers, feeder monitors	VVO to 10% of customers	ADA / VVO to 30% of customers, feeder monitors	ADA and VVO to 30% of customers, feeder monitors
	Enabling Infrastructure/ Initiatives	**ADMS/DSCADA**	Yes	No	Yes	Yes
		Telecomm	To support AMI, and Grid investments	To support AMI, and Grid investments	To support AMI, and Grid investments – 30% territory	Cell based AMI and Grid investments
		IT/OT investments	Incl. data lake, MDMS, integration services, INOC, applications	Same as Balanced, with a reduction of integration services	Same as Balanced, with a reduction of integration services	Expansion of MDMS and Head-End system deployed in SES pilot
		Cybersecurity and Billing	As necessary	As necessary for reduced scope	As necessary for reduced scope	Expansion of SES pilot
		Workforce, Training and Asset Management	Training and mobility services	Training Only	Training and mobility services	Training Only
		Marketing, Education and Outreach	Yes: Opt-Out Focused	Yes: Opt-Out Focused	Yes: Both Opt-Out and Opt-In	Yes: Opt-in Focused
DER Tariff / Interconnect	DER	DER	Application tools, analytic investment, proactive substation upgrades	Application tools, analytic investment, proactive substation upgrades	Application tools, analytic investment, proactive substation upgrades	Application tools, analytic investment, proactive substation upgrades
Separate RD&D Tracker	RD&D	RD&D	Pilots (ES, microgrids, EV, etc.)	Pilots (ES, microgrids, EV, etc.)	Pilots (ES, microgrids, EV, etc.)	Pilots (ES, microgrids, EV, etc.)
	5 Year STIP Costs		**$830.5M**	**$657.1M**	**$573.1M**	**$225.3M**
	10 Year GMP Costs (Incl. STIP costs)		**$1,315.0M**	**$954.1M**	**$994.0M**	**$521.37M**
	15 Year Benefit-Cost Ratio (not including qualitative benefits)		**0.90**	**1.02**	**0.57**	**0.56**

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The table below presents the present value of monetized benefits by scenario and Plan component.

Table 2: Present Value of Monetized Benefits by Scenario and Plan Component

Plan Category	Plan Component	Monetized Benefit Category	Balanced Plan Scenario	AMI-Focused Scenario	Grid-Focused Scenario	Opt-In Scenario
Field Deployment	AMI Meters	T & D Capital Savings	$17.9M	$17.9M	$5.6M	$.7M
		Distribution O & M Savings	$110.1M	$110.1M	$34.6M	$2.2M
		Theft Reduction	$94.6M	$94.6M	$29.7M	$1.9M
			$222.6M	$222.6M	$69.9M	$4.8M
	CLM	Electricity Cost Savings	$388.5M	$388.5M	$139.4M	$15.8M
	ADA, VVO, Feeder Monitors	System Optimization	$68.4M	$51.3M	$68.4M	$68.4M
		Electricity Cost Savings	$81.6M	$53.3M	$81.6M	$81.6M
		Power Interruptions	$36.M	$0	$36.M	$36.M
			$186.M	$104.5M	$186.M	$186.M
Enabling Infrastructure/ Initiative	ADMS/DSCADA	Power Interruptions	$64.7M	$0	$20.3M	$0
	Telecomm	Distribution O & M Savings	$25.4M	$25.4M	$14.9M	$0
		Power Interruptions	$39.8M	$39.8M	$12.5M	$2.M
			$65.3M	$65.3M	$27.4M	$2.M
	Workforce, Training and Asset Management	Distribution O & M Savings	$9.1M	$0	$0	$0
DER/EV	EV	Distributed Energy Resources	$20.3M	$20.3M	$20.3M	$20.3M
		Grand Total	$956.5M	$801.2M	$463.3M	$228.8M

National Grid is proposing four scenarios which include the following core technologies and investments:

- Automated Metering Infrastructure ("AMI"): The deployment of smart interval smart meters enabled with two way communications allowing customers to participate in Time Varying Rate programs.
- Customer Load Management ("CLM"): Customer facing technologies and programs which integrate Energy Efficiency devices with AMI data and control.

- Volt VAR Optimization and Conservation Voltage Reduction: The layered control and automation necessary to optimize the voltage and power factor of the distribution circuits in real time to reduce system losses and customer consumption.
- Advanced Distribution Automation ("ADA"): The layered control and automation to coordinate protective sectionalizing devices to minimize the impact of outages for customers.
- Feeder Monitors: Interval meters on the distribution grid in areas where the Company currently does not have SCADA monitoring.
- Communications: Field Area Network ("FAN") and Backhaul communications infrastructure to support field device control and monitoring.
- Advanced Distribution Management System ("ADMS") and Distribution Supervisory Control and Data Acquisition System ("DSCADA"): A comprehensive IT/OT platform for system operators to monitor and control distribution circuits remotely and in real time.
- Information and Operational Technologies ("IT/OT"): Computer and communications infrastructure necessary to support the exponential increase in data and control.
- Cybersecurity: Infrastructure and protocols needed to ensure proper digital risk and security with increased levels of data and remote access.
- Training and Asset Management: Investments associated with mobile workforce tools, Geographic Information Systems ("GIS) and the necessary training associated with many of the technologies previously mentioned
- Marketing Outreach and Education: Investments needed to provide customers with the information necessary to understand some of the core technology investments and associated offerings.

These investments directly impact or support one or more of the Objectives as shown in the table below.

Table 3: GMP Investments Impact on Objectives

GMP Investment	Reduce the Effect of Outages	Optimize demand, including reducing system and customer costs	Integrate distributed resources	Improve workforce and asset management
Smart Meters and AMI Backoffice	Directly Impacts	Directly Impacts	Directly Impacts	Directly Impacts
Customer Load Management		Directly Impacts		
Conservation Voltage Reduction / Volt VAR Optimization		Directly Impacts	Supports	Supports
Advanced Distribution Automation	Directly Impacts			Supports
Feeder Monitors	Directly Impacts		Directly Impacts	Directly Impacts
Telecommunications IT/OT	Supports	Supports	Supports	Supports
CyberSecurity	Supports	Supports	Supports	Supports
ADMS / DSCADA	Directly Impacts	Supports	Supports	Supports
Training and Asset Management	Supports	Supports	Supports	Supports
Marketing, Education, and Outreach	Supports	Supports	Supports	Supports

✓ Directly Impacts ✓ Supports

The cost of deployment and the level of benefit achieved can be managed by varying the deployment scope and scale of these investments. The Company has developed four deployment scenarios of varying cost and benefit but each leverages the same or similar technologies as described above.

1.4.1 Balanced Plan Scenario

The Balanced Plan scenario is the Company's most comprehensive proposal which meets the requirements for AMF with a full roll-out of AMI to all customers. In addition, advanced distribution technologies are proposed to manage the operations of the grid, provide faster restoration of service in outage events and manage voltage on selected feeders which will serve to reduce customer's bills, improve efficiency of the operation of the grid and facilitate interconnection of distributed generation. The Balanced Plan will achieve AMF in National Grid's entire Massachusetts service territory in five years. This deployment would include all the necessary enabling infrastructure (telecommunications, information technology, operational technology and cybersecurity) to support the AMI and grid investments. It proposes to provide in-home customer load management devices to customers through existing energy efficiency programs,[4] and for the GMP to fund a customer portal and Demand Response Management System ("DRMS") to enable demand response, which will give customers more real-time information on and control over their energy use, as well as the opportunity to reduce their use and save on costs.

The Balanced Plan scenario also includes an ADMS and DSCADA, which would enable more efficient grid operations and help integrate distributed energy resources. This scenario would deploy ADA, including Fault Location, Isolation and Service Restoration ("FLISR"), which would create a self-healing grid that automatically re-routes power in the event of an outage and thereby minimizes the impact of outages. It would deploy Conservation Voltage Reduction/Volt VAR Optimization ("CVR/VVO"), which would help to optimize voltage and save on energy usage and costs for customers. ADA and CVR/VVO would be deployed to 30% of customers in this plan. The Balanced Plan would also install feeder monitors on currently unmonitored circuits which are not proposed to have CVR/VVO or ADA, in order to provide more real-time information on the grid which will enable more efficient operations and planning.

As part of proposed workforce, training and asset management ("WTAM") improvements, the Company would invest in mobile tools and technology to improve data capture capabilities. This will facilitate greater insight into equipment performance, reduce delays in data availability and enhance data quality, while also training workers on these many new technologies. A comprehensive Marketing, Education and Outreach ("MEO") plan will educate customers on grid modernization and the options and benefits for them. National Grid also is proposing a series of statewide and company-specific infrastructure and performance metrics, which will measure National Grid's progress on implementing its GMP and on the Department's four grid modernization objectives. The estimated monetized benefit-cost ratio over 15 years from this plan is 0.90. Rates to customers would increase by 3.9% over 5 years[5] as investments are put into service, and would stabilize at that level in years 6 through 10.

[4] The Company administers multiple energy efficiency programs through its three year energy efficiency plan, along with the other utilities in Massachusetts, which the Department approved in D.P.U. 12-109.

[5] For a typical residential customer using 600 kWh/month. The increase represents the impact of the STIP and RD&D factors.

The Balanced Plan scenario will reach the largest number of customers and will achieve the greatest total amount of benefits for customers in the shortest reasonable amount of time, as compared to the other three scenarios. It will create numerous quantitative and qualitative benefits, as will the other three scenarios. The Balanced Plan scenario will reduce the effects of outages through ADA for self-healing and the communications capability of meters to identify customers who have lost service which should improve Company response to outages. The Balanced Plan would optimize demand through the use of AMI, TVR, DRMS and CVR/VVO technology. This scenario would assist integration of DG through the use of an ADMS and CVR/VVO technology managing the operations of the grid, particularly voltage and frequency. Finally, workforce and asset management would be improved with greater visibility of grid operations (ADA), improved notification of outage events (AMI), improved system planning, improved and more up to date asset information, extensive workforce training to build and operate the new technology.

1.4.2 AMI-Focused Scenario

The AMI-Focused scenario concentrates on the roll-out of AMF to all customers. This scenario includes meters and all supporting functions for the meters that are proposed in the Balanced Plan scenario. This scenario reduces the amount of advanced distribution equipment in an effort to reduce total overall cost over 10 years. Thus, CVR/VVO would be deployed to 10% of customers over 10 years instead of 30% of customers in the Balanced Plan scenario. The Company would not make investments in ADA/FLISR, feeder monitors, ADMS or DSCADA. These changes result in a reduced scope of IT and OT to support AMI data integration only, and cybersecurity as necessary. Mobility services would also be eliminated from the WTAM proposal. The estimated monetized benefit-cost ratio over 15 years from this plan is 1.02. Rates to customers would increase over 5 years by 3.1%[6] as investments are put into service, and would stabilize at that level in years 6 through 10.

The AMI-Focused scenario would provide AMF for all customers and make available the same CLM solutions as the Balanced Plan scenario. The AMI-Focused scenario has a higher monetized benefit-cost ratio than the Balanced Plan scenario, but because the AMI-Focused scenario has less grid investments, it has less of the qualitative benefits that these investments

[6] For a typical residential customer using 600 kWh/month. The increase represents the impact of the STIP and RD&D factors.

offer, including: improved efficiency of grid operations; improvements in knowledge regarding the capability of the system to integrate load and generation; facilitating promotion of renewable and other types of DG; and creating the best platform for enabling the distribution system and customers to take advantage of the benefits of automation, advances in technology and data analytics, into the future.

1.4.3 Grid Focused Scenario

This scenario proposes all of the distribution grid investments in the Balanced scenario. These include investments in ADA/FLISR and CVR/VVO, which would be deployed to approximately 30% of customers over ten years. The Company would take advantage of the communications infrastructure and associated other IS infrastructure to provide AMI to the customers in the areas receiving the distribution investments. AMI would be available on an opt-in the other 70% of the service territory. There would still be sensors installed on circuits which are not proposed to have CVR/VVO or ADA/FLISR, and telecommunications would be limited to a Field Area Network ("FAN") to support the grid investments and AMI. There would be minimal IT/OT to support AMI data integration only, and there would be cybersecurity as necessary for the reduced scope. The WTAM proposal would include both training and mobility investments. The MEO plan would educate customers on both AMI Opt-Out and the AMI Opt-In option. The estimated benefit-cost ratio over 15 years from this plan is 0.57. Rates to customers would increase over 5 years by 2.6%[7] as investments are put into service, and would stabilize at that level in years 6 through 10.

This plan allows meter roll-out to follow grid investments that would require field communications. This scenario would provide the same comprehensive suite of benefits to customers in the deployment areas as the Balanced scenario but at less cost because the geographical reach of meters and communications would be reduced to the areas selected for grid investments. These benefits also would be available to customers who opt in. The qualitative benefits resulting from the grid investments would be the same as those discussed in the Balanced Plan scenario. Broadening the roll-out of these capabilities across the service territory would be achieved in later years.

[7] For a typical residential customer using 600 kWh/month. The increase represents the impact of the STIP and RD&D factors.

1.4.4 Opt-In Scenario

This scenario would invest in the advanced distribution technologies proposed in the Balanced Plan scenario. AMI would be available to any customer who elects to opt in to the meter. The meters would use cellular communications capability to provide two-way communication, which is a more economic approach for a small roll-out. The Company estimates that approximately 30,000 customers would opt in to AMI.[8] In the areas where the advanced distribution technology is deployed, the communications capability will be identical to the proposal in the Balanced Plan scenario. The Company would expand its CLM, IT/OT investments and cybersecurity platforms from the existing SES Program in Worcester to manage the needs of opt-in customers. There would still be ADA/FLISR and CVR/VVO deployed to 30% of customers, and feeder monitors installed on circuits which are not proposed to have CVR/VVO or ADA/FLISR. Mobility services would not be included as part of the WTAM proposal. The MEO Plan would focus on the opt-in component of AMI and the benefits from the grid modernization being completed in certain areas. The estimated benefit-cost ratio over 15 years from this plan is 0.56. Rates to customers would increase over 5 years by 1.2%[9] as investments are put into service, and would stabilize at that level in years 6 through 10.

This alternative would make progress on the Objectives of the Order. The difference would be that access to AMF would be provided to customers who request the capability, instead of on an opt-out basis. This approach allows the Company to meet the requirements for AMF and the Objectives while also providing a lower cost option for the 10 year plan.

1.4.5 Common Components

There are components of National Grid's grid modernization proposal that are the same across all four plan scenarios. These include the proposals for: (i) DG; (ii) a research, development and deployment/pilot program ("RD&D"); (iii) distribution rate changes; and (iv) cost recovery mechanisms.

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[8] This is in addition to the Company's customers in the SES Pilot who already have AMI meters.

[9] For a typical residential customer using 600 kWh/month. The increase represents the impact of the STIP and RD&D factors.

Distributed Generation

The Company has identified two streams of investment and expense which can be considered to facilitate DG uptake on the system. These streams are (i) applications for interconnection and (ii) investments in common upgrades when certain levels of DG are installed on the grid on a specific substation.

There are a number of potential investments and expenses which could facilitate the processing of the continually increasing number of interconnection applications. The current process consists of application processing, screening, studying and then physical interconnection. National Grid has identified potential pre-application tools for information on the ability of the Company to support more DG capability in an area and any necessary investments to expand the Company's ability to accept additional DG capacity. Investments have been identified that provide new tools that the Company can use to process and screen applications more quickly. Lastly, a set of analytical tools have been identified that could improve understanding of the potential impact on the distribution system with greater amounts of DG on the system. The Company has also identified common upgrades to its distribution system to enable greater capability to accept DG. These investments are upgrades to a subset of substations, and include 3V0 protection schemes and Direct Transfer Trip integration for security of service to customers. The Company has identified 10% of service territory substations which would be eligible for this option. Each substation would be fitted with a 3V0 protection scheme to adequately protect the transmission and distribution ("T&D") system due from impacts of high DG penetration. In addition, a Point-to-Multi-Point ("P2MP") Direct Transfer Trip ("DTT") transmitter would be installed. These upgrades will not eliminate the possibility for further required protection upgrades as more DG is placed in an area, however they would address the most common upgrades due to DG penetration.

These investments are not included in the Company's GMP scenarios because the investments would normally be recovered through the Company's Standards for Interconnection of Distributed Generation tariff, M.D.P.U. No. 1248 ("Interconnection Tariff") for those customers contemplating construction of DG facilities requiring interconnection to the electric system. The Company is not proposing to recover the cost of these investments in this filing, but anticipates submitting a proposal to the Department for their recovery in the future. Until such time as the Company has a recovery mechanism for the costs of these DG Investments, it proposes to recover the costs through its Interconnection Tariff. Any proposal for a change in the Company's Interconnection Tariff would be brought before the Distributed Generation Collaborative.

Research, Development and Deployment

National Grid proposes an expanded RD&D program, as called for by the Order. National Grid's RD&D Program will seek to test the application of promising new technologies and processes that may provide benefits to customers by advancing the Objectives. The RD&D effort anticipates an increase in collaboration among the utilities in the State as well as collaboration through industry and state entities. These collaborations may provide potential third party resources, which would result in lower costs. RD&D will be paid for through a separate tracker, as the Order allows.

Distribution Rate Changes

National Grid is also proposing distribution rate changes which will better align cost recovery with cost causation, including for customers with distributed generation, through a four-tier inclining customer charge for Residential Regular Rate R-1 (Rate R-1) and Residential Low Income Rate R-2 (Rate R-2) and Small Commercial and Industrial (C&I) Rate G-1 (Rate G-1) customers. The Company also is proposing a charge applicable to large stand-alone DG projects facility that will be based upon the size the DG facility. In addition, the Company proposes that DG facilities, unless they are specifically enrolling in net metering, not net the station service usage against the amount of electricity generated by the DG facility. There are two reasons for these proposals. First, pricing of electric service should move closer to cost causation, and this proposal seeks to do that. Second, current pricing is not sustainable as a means to continue funding a safe, reliable distribution grid and bring forward the grid modernization capabilities described in this GMP.

Cost Recovery

In order to proceed with any of the proposed grid modernization, RD&D or DG investments, timely cost recovery is necessary. The Department's Order allows distribution companies to recover their incremental grid modernization AMF costs and other capital costs (if the company is also investing in AMF) for the STIP through a targeted cost recovery mechanism. National Grid is proposing a tracker mechanism that will allow for concurrent recovery of these costs. The Company also is proposing to include incremental grid modernization operations and maintenance ("O&M") and GMP development costs in this tracker, which is a departure from the Department's Order. There are a number of issues with the limitations on cost recovery D.P.U. 12-76-B. First, the Department's provision on STIP recovery delays any cash flow until the year after investments have gone into service, or are recorded in Construction Work in Progress ("CWIP") for spending on AMF. In order to accomplish the investments identified in this filing, which are above and beyond what is reflected in the Company's base distribution rates and in the operation of its capital investment recovery mechanism, the Company would need a funding source of these costs to more efficiently plan and carry out its GMP. Second, O&M costs are incurred on nearly every capital investment project, and the Company would need to fund those expenses out of pocket until the next rate case. Since the expenses are specific to grid modernization, and would not have been incurred but for carrying out its GMP upon Department approval, any delay in filing a rate case would cause the Company to not recover those costs, with shareholders funding what will become an annual, ongoing cost. Third, favoring capital expenses over O&M expenses sends a signal that there is a distortion in incentives, and it is often asserted that this causes utilities to favor capital investments instead of O&M alternatives since the recovery of annual O&M costs is lost until captured in the test year of the next rate case. The Company has not approached its GMP with this intent. Rather, the

Company chose to propose third party services alternatives which will result in it incurring O&M costs when those alternatives are in the best interest of customers.

1.4.6 Progress on the Objectives

National Grid's proposals contain a comprehensive suite of investments and initiatives that will modernize the Company's infrastructure for the 21st century and deliver significant customer benefits, including energy supply savings, reduced outage time, reduced numbers of customers impacted by outages, improved system operations and system planning, and more information and tools to allow greater customer control over their energy use. Each scenario provides the opportunity for the Department to evaluate the benefits and costs. The Balanced Plan scenario is the most comprehensive, but each of the other scenarios also makes measurable progress towards on the Objectives.

The proposed investments and initiatives make progress on the Objectives in the following ways:

(i) They will reduce the effects of outages by providing automated outage and restoration notifications, assisting with locating outage locations and damage, and automatically rerouting power during outages in order to minimize the number of customers impacted and the length of outages. The ADA program is specifically designed to significantly reduce the minutes of customers interrupted by automatically re-routing power in a way that the current system is not capable of, and will be deployed on the most high value feeders. In addition, AMI will provide real time status updates to a new Outage Management System (via an ADMS), which will direct crews to trouble, before the Company receives customer supplied outage notifications.

(ii) They will optimize demand by: creating a more efficient electric system with more real-time monitoring and control, better-managed system voltage and fewer losses; enabling the reduction of peak demand through demand response and customer load management solutions; and creating the opportunity for customer energy savings through TVRs. The CVR/VVO program will intelligently switch reactive power and voltage support devices to reduce losses, improve power factor and reduce demand in a way that the current system is unable to do. This program is designed to provide peak and demand savings to customers, without them having to take any active steps.

(iii) They will help integrate DG by providing more real-time information about the distribution system. The increased operational system awareness from the deployment of feeder monitors, ADA, CVR/VVO and AMI will collectively allow for much more data to be utilized when determining DG impact studies. Additionally, if the Department approves National Grid's separate proposals on DG, these proposals will improve the distribution system's readiness to accept distributed resources and provide customers with more information about use of DG.

(iv) They will improve workforce and asset management by providing more-real time and more detailed asset information, which will help improve operational efficiency, provide advance warning of potential equipment issues that could otherwise result in failures and/or outages, and help with system planning. The information available to the Company as a result of the key GMP investments will be used to more efficiently use the Company's workforce. Further, the investment in mobile tools for the operations workforce will allow the Company to more effectively capture accurate information on assets.

1.4.7 Business Case Analysis Summary

National Grid is presenting four scenarios that invest in AMF and grid automation technologies, to different degrees. The Company's business case is a combined assessment of the expected benefits from the STIP, including a quantitative assessment of value to customers and a qualitative assessment of potential opportunities for customers. The business case presents the goals and drivers for the Company's proposed STIP investments, as well as technology and project descriptions for the included items. The Company developed a comprehensive benefit-cost model that it used to assess the cost-effectiveness of the STIP.

Monetized benefits from the STIP stem from avoided wholesale energy and capacity market costs, improved reliability, avoided or deferred O&M costs, reductions in unaccounted for electricity and enhanced revenue. Benefits evaluated in this STIP also include the avoided costs of replacing current technologies with like technologies for those investments that will reach the end of their useful lives within the benefit-cost analysis time horizon. All monetized benefits have uncertainty regarding the ability to achieve those benefits and this uncertainty can be higher for certain elements of monetized benefits than from others.

The STIP will also create many additional benefits that are difficult to quantify and/or that are qualitative, including: improved crew productivity; increased customer convenience; greater customer satisfaction; better integration of distributed resources; acceleration of future beneficial technology; better optimized system planning; safety improvements; improved compliance; and reductions in greenhouse gas emissions.

National Grid's Business Case analysis for the four scenarios is presented in Section 6 of this Plan. The remainder of the GMP is structured as follows. Section 2 presents the Baseline Capital Plan; Section 3 provides a summary of the Plan grouping along with the benefits, costs and deployment schedules for each of the scenarios. Section 4 and 5 present the proposed field deployment and enabling infrastructure investments. Section 7 contains the Company's DG proposal and Section 8 presents the RD&D proposal and initiatives. Section 9 contains the MEO Plan while Section 10 presents the proposed metrics, both statewide and company-specific.

Section 11 touches on the development of the GMP and Section 12 details the Rates, Cost Recovery and Bill impacts associated with the Company's proposals.

2. Baseline Capital Plan without Grid Modernization-Specific Efforts

In order to understand how grid modernization projects will result in incremental investments above the Company's existing capital plan, a detailed understanding of the typical capital investment plan is required. The Company develops its capital investment plan ("Baseline Plan") to meet its obligation to provide safe and reliable electric service for customers, in a prudent manner and at reasonable costs. The Baseline Plan is a five year plan and includes capital investments that address five primary areas of need:

- Customer Requests/Public Requirements
- Damage/Failure
- System Capacity and Performance
- Asset Condition
- Non-infrastructure

Once the five year capital budget is established, a ten year budgetary forecast is developed by the Company's investment planning group using economic and inflationary predictions where applicable. When the six to ten year budget forecast is developed, there are few to no specific projects identified. The current five year plan budget by category, with the added six to ten year forecast, is shown in Table 4.

Table 4: 5 Year Capital Budget With 6-10 Year Forecast (in thousands)

	Five Year Capital Plan					Forecast				
Spending Rationale	FY16 Budget	FY17 Budget	FY18 Budget	FY19 Budget	FY20 Budget	FY21 Budget	FY22 Budget	FY23 Budget	FY24 Budget	FY25 Budget
Statutory/Regulatory	45,400	47,300	48,600	50,100	51,700	53,500	55,300	57,200	59,100	61,100
Damage/Failure	28,300	28,700	29,200	29,600	30,100	30,300	30,500	30,600	30,800	31,100
Asset Condition	84,700	105,600	116,200	120,700	120,500	122,300	124,100	126,000	127,900	129,800
Non-Infrastructure	1,300	1,000	1,000	1,000	1,000	1,000	1,000	1,100	1,100	1,100
System Capacity & Performance	70,300	57,400	65,000	58,600	56,700	57,400	58,100	59,100	60,100	60,900
Total Budget	230,000	240,000	260,000	260,000	260,000	264,500	269,000	274,000	279,000	284,000

In order to understand whether grid modernization investments would be incremental to the Baseline Plan, further explanation of the System Capacity and Performance and Asset Condition rationales is warranted. The infrastructure development projects within these two categories of the five year Baseline Plan originates from annual reviews and targeted area studies. These reviews and studies are based on system and asset planning guidelines that focus on a variety of system performance topics including thermal (equipment capacity), reliability, voltage performance and incorporation of multi-year asset replacement/removal strategies. The Baseline Plan does not include any provisions for the progression of the Objectives as outlined in the Order. In other words, the system and asset planning guidelines, which are the main planning inputs into the projects within the Baseline Plan, do not currently include provisions for grid modernization. However, there are some specific elements of the Baseline Plan which do already include devices that can be modified with grid modernization-type controls, discussed in the next section.

2.1 Baseline Capital Plan Specifics Related to Grid Modernization

Although the Company Baseline Plan calls for the installation of modern equipment, the Company's proposed GMP is fully incremental in that it will provide the necessary additions to integrate modern equipment into modern systems to further advance the Objectives.

For the purposes of distinguishing the Baseline Plan from the incremental GMP, the devices put into service under the Baseline Plan can be separated into three categories: (i) structural equipment; (ii) energized equipment; and (iii) control equipment. Structural equipment is any device that supports the energized or control equipment, such as poles, crossarms, guy wires, anchors, concrete foundations, metal supports and frames, and brackets. Energized equipment is any device that carries distribution level voltages, such as conductors, cables, bus work, breakers, reclosers, regulators, capacitors, inductors, power transformers, service transformers and fuses. Lastly, control equipment[10] is those devices that sense and take action upon an energized device. Control equipment examples include recloser controls, breaker controls, regulator controls, capacitor controls, relays, meters, sensors and telecommunications equipment. Equipment from all three categories has been installed, replaced, repaired and updated by the Company over decades. The current range of vintages, versions and technology of the existing electric system is wide. With the obligation to provide safe and reliable electric service for customers in a prudent manner and at a reasonable cost, equipment standards are only revised after thorough review of proven technology.

Grid modernization impacts the control category the most, with a secondary impact to the energized equipment category and little effect on the existing structural components in the Baseline Plan. To further review grid modernization impacts to energized and control equipment within the Baseline Plan, an illustrative device-specific analysis is compared to the grid modernization-type features and is shown in Table 5.

[10] Although control equipment is technically energized, it is energized at service level voltages such as 120/240V, not distribution level voltages.

Table 5: Incremental Equipment Impacts of Grid Modernization Features

Grid Modernization Feature	Baseline Plan	Incremental Grid Modernization Plan
Advanced Distribution Automation -Fault Location, Isolation, and Service Restoration	Reclosers are installed along radial feeders to autonomously interrupt fault currents and segment the feeder following a contingency. Reclosers are typically integrated with SCADA to allow Control Center Operators to monitor and control the devices remotely.	Additional reclosers are installed at feeder tie points, telecommunications will be provided between reclosers acting as a team, and appropriate controls and control schemes will be installed to enable optimal segmentation and automated restoration of unaffected segments. Remote monitoring and control also will be provided to manual override of automated control schemes. These devices will also integrate operational performance data to an ADMS/DSCADA system.
Volt/VAR Optimization – Conservation Voltage Reduction	Capacitors and voltage regulators are installed along distribution feeders with autonomous controls to maintain system voltages within allowable ANSI+/- 5% range.	Capacitors and voltage regulators may be installed or upgraded so that they may be integrated into a centralized control scheme to further optimize their operation to reduce system losses and operate the system lower in the allowable ANSI range for energy efficiency purposes. To do so, existing capacitors and line regulators need to be enabled with telecommunications and advanced controllers and control schemes. These devices will also integrate operational performance data to an ADMS/DSCADA system.
Advanced Distribution Management System	Substation breakers and new line reclosers are being integrated into a common T&D SCADA system for remote monitoring and control by control center operators.	To accommodate the large number of new distributed devices, a dedicated DSCADA is required. In addition to DSCADA, an ADMS is proposed to model the distribution system and evaluate system performance based on near real time system data provided via the integrated distributed devices.
Energy Management System	Expansion of the existing EMS system to simply bring control and status monitoring of all automatic protection devices into the EMS system	The GMP proposes the installation of an ADMS system which would manage and control not only these distribution protection data points, but also manage the significant additional operational and performance data that would be available at each device, as well as the advanced control necessary to coordinate and optimize their use towards achieving the grid modernization objectives
Advanced Metering Infrastructure	AMR meters	AMI meters and associated Head End System, Meter Data Management System and necessary telecommunications for integration.

This table illustrates that the incremental cost for grid modernization will be primarily related to additional sensing, controls, meters, telecommunications and back office systems. A subset of specific devices, such as capacitors and reclosers, may be needed in modest amounts over the Baseline Plan to enable the full functionality available in particular situations. Lastly, structural components will only be needed as necessary to support the additional energized and control equipment.

While items such as capacitors have been installed for years and remain a part of the Baseline Plan based upon need, the Baseline Plan does not include devices with the controls necessary to enable grid modernization. The Company plans to add this layer of control to these existing and planned devices as part of the GMP where appropriate, which will minimize stranded asset impacts and maximize equipment utilization. Additionally, advanced control systems such as CVR/VVO, FLISR/ADA and ADMS/DSCADA, and the real-time management of these systems, are not part of the Baseline Plan nor is the infrastructure (communications, controls, sensors, software and associated back office equipment) necessary to support them.

The Company's Baseline Plan also does not include the installation of AMI meters, nor the communications and other systems necessary to support two-way communications with meters. By extension, there is no support in the Baseline Plan to accommodate the increased volume of data that would be generated by AMI meters and the other grid modernization devices, nor the storage, management, use and protection of that data.

There are many reasons why the Company is not otherwise planning to make these investments in the Baseline Plan. These investments involve increased expenditures beyond what is otherwise budgeted, and would increase the systems integration and communications costs above what is otherwise planned. The Company plans its capital investments to meet its obligation to provide safe and reliable service, and to meet its service quality goals, in a prudent and cost-effective manner. The requirements to make measurable progress on the Objectives and to achieve AMF create an additional level of investment obligation, beyond what the Company was otherwise planning.

3. Overall GMP Groupings, Costs, Benefits and Deployment Schedules

National Grid is proposing a ten year GMP, including a five year STIP followed by 5 years of continued investments. In this context, the GMP refers to the entire ten year plan. The Company is proposing four independent GMP scenarios which are presented for the Department.

3.1 Plan Groupings

Each GMP scenario is organized into three primary groupings: field deployments, enabling infrastructure/initiatives and other required components. Field deployments consist of devices and programs which are deployed within the National Grid service territory. These devices and programs provide benefits directly to the system and customers, and are the plan components with significant visibility. Enabling infrastructure is the required back office systems and field devices which enable these field deployed programs to operate, and enabling initiatives (such as the MEO plan and the Project Management Office ("PMO") will help with implementation. These components are inherently dependent on each other. The other required components are other items called for by the Order, including the RD&D proposal, metrics, incorporate of stakeholder input and the separate DG proposal.

3.2 Costs, Benefits and Deployment Schedules

National Grid considered different options that would make measurable progress on the Objectives and that would achieve AMF. National Grid examined different technology scopes, supporting infrastructure, interdependencies, costs, benefits, and affordability to include the four scenarios proposed. An overview of the costs, benefits and deployment schedules for all four scenarios are presented here, in brief.

3.2.1 Balanced Plan Scenario

The estimated costs and deployment schedule for the Balanced Plan scenario are shown in Figure 1, Table 66 and Table 77. In the deployment plan for this scenario, the service territory is broken down into six areas where efforts will be focused, installing field equipment and communications during the STIP period. There is a necessary two year delay before field equipment is installed. During this time, National Grid will be installing the back office IT infrastructure required to support the deployment. This plan provides an estimated 15 year monetized benefit-cost ratio of .90 with an estimated 10 year investment of $1,315M.

Figure 1: Balanced Plan Program Deployment Schedule

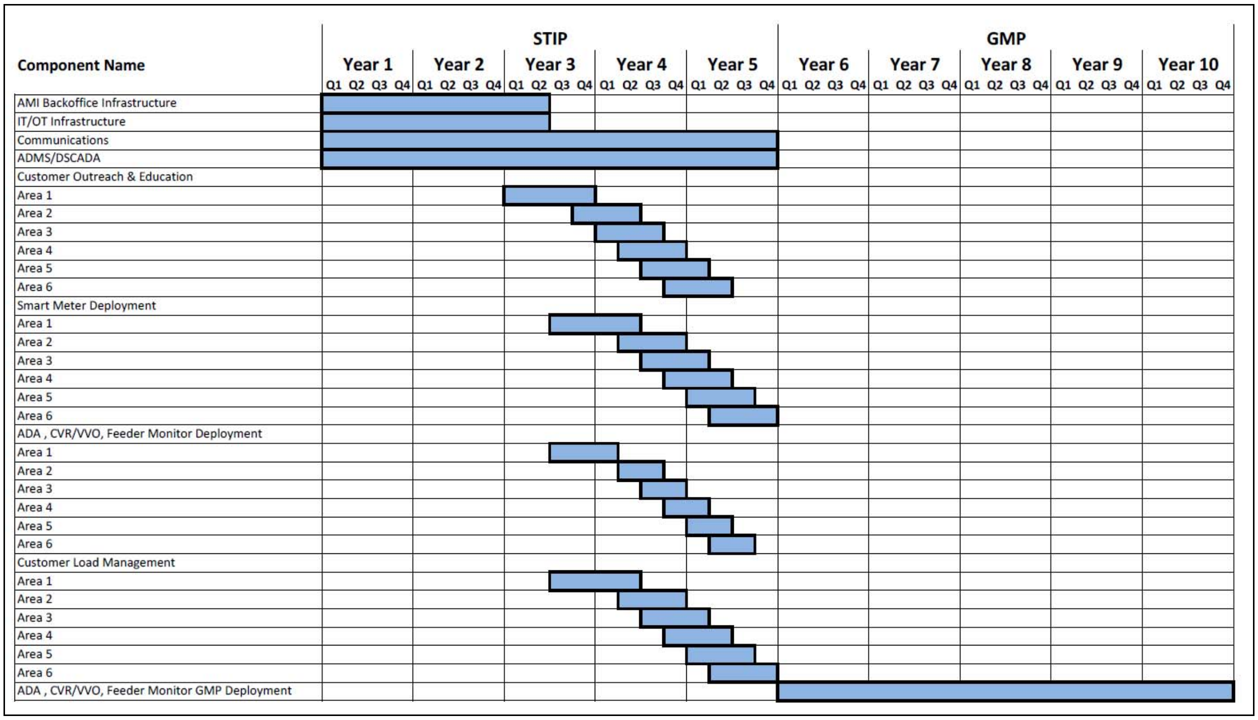

Table 6: “Balanced” Plan STIP Costs

Spending STIP Years 1-5		Year 1	Year 2	Year 3	Year 4	Year 5	Total
Smart Meters and AMI Backoffice	CAPEX	$ 6.65 M	$ 33.47 M	$ 82.54 M	$ 84.83 M	$ 86.70 M	$ 294.19 M
	OPEX	$ 4.33 M	$ 1.37 M	$ 2.00 M	$ 2.22 M	$ 2.44 M	$ 12.35 M
Customer Load Management	CAPEX	$ -	$ -	$ -	$ 4.46 M	$ 5.37 M	$ 9.82 M
	OPEX	$ 1.41 M	$ 1.26 M	$ 10.95 M	$ 9.25 M	$ 9.25 M	$ 32.11 M
CVR/VVO	CAPEX	$ -	$ -	$ 6.93 M	$ 7.92 M	$ 7.52 M	$ 22.37 M
	OPEX	$ 1.78 M	$ 1.82 M	$ 0.06 M	$ 0.13 M	$ 0.19 M	$ 3.99 M
ADA	CAPEX	$ -	$ -	$ 9.67 M	$ 10.71 M	$ 10.08 M	$ 30.46 M
	OPEX	$ 1.78 M	$ 1.82 M	$ 0.12 M	$ 0.24 M	$ 0.35 M	$ 4.31 M
Feeder Monitors	CAPEX	$ 2.60 M	$ 2.65 M	$ 2.71 M	$ 2.76 M	$ 2.82 M	$ 13.55 M
	OPEX	$ -	$ -	$ -	$ -	$ -	$ -
Telecommunications IT/OT	CAPEX	$ 37.31 M	$ 42.84 M	$ 36.41 M	$ 18.80 M	$ 17.29 M	$ 152.65 M
	OPEX	$ 1.64 M	$ 2.30 M	$ 3.65 M	$ 4.35 M	$ 4.97 M	$ 16.91 M
CyberSecurity	CAPEX	$ 12.47 M	$ 10.08 M	$ 12.88 M	$ 10.27 M	$ 13.10 M	$ 58.80 M
	OPEX	$ 7.23 M	$ 7.23 M	$ 8.31 M	$ 8.31 M	$ 8.31 M	$ 39.38 M
DSCADA/ADMS	CAPEX	$ 10.19 M	$ 20.52 M	$ 17.28 M	$ 19.88 M	$ 8.05 M	$ 75.92 M
	OPEX	$ 0.06 M	$ 0.12 M	$ 0.19 M	$ 0.26 M	$ 0.26 M	$ 0.89 M
Training and Asset Management	CAPEX	$ 0.95 M	$ 4.28 M	$ 3.28 M	$ 3.42 M	$ 3.35 M	$ 15.29 M
	OPEX	$ 0.01 M	$ 0.33 M	$ 0.36 M	$ 0.38 M	$ 1.15 M	$ 2.23 M
Marketing, Education, Outreach and PMO	CAPEX	$ 6.74 M	$ 10.05 M	$ 3.79 M	$ 7.17 M	$ 7.32 M	$ 35.08 M
	OPEX	$ 0.56 M	$ 0.57 M	$ 2.97 M	$ 3.03 M	$ 3.09 M	$ 10.21 M
						Total CAPEX	$ 708.12 M
						Total OPEX	$ 122.39 M

Table 7: "Balanced" Plan Years 6-10 Costs

Spending GMP Years 6-10		Year 6	Year 7	Year 8	Year 9	Year 10	Total
Smart Meters and AMI Backoffice	CAPEX	$ 0.65 M	$ 0.67 M	$ 3.74 M	$ 0.69 M	$ 0.71 M	$ 6.46 M
	OPEX	$ 9.97 M	$ 10.08 M	$ 10.20 M	$ 10.32 M	$ 10.45 M	$ 51.02 M
Customer Load Management	CAPEX	$ 8.93 M	$ -	$ -	$ -	$ -	$ 8.93 M
	OPEX	$ 9.25 M	$ 13.50 M	$ 6.32 M	$ 6.38 M	$ 6.44 M	$ 41.89 M
CVR/VVO	CAPEX	$ 13.35 M	$ 21.87 M	$ 21.04 M	$ 16.06 M	$ 16.40 M	$ 88.72 M
	OPEX	$ 0.30 M	$ 0.42 M	$ 0.53 M	$ 0.66 M	$ 0.78 M	$ 2.69 M
ADA	CAPEX	$ 15.53 M	$ 15.85 M	$ 16.18 M	$ 16.52 M	$ 16.86 M	$ 80.93 M
	OPEX	$ 0.55 M	$ 0.76 M	$ 0.97 M	$ 1.19 M	$ 1.42 M	$ 4.89 M
Feeder Monitors	CAPEX	$ 1.77 M	$ 1.81 M	$ 1.85 M	$ 1.88 M	$ 1.92 M	$ 9.24 M
	OPEX	$ -	$ -	$ -	$ -	$ -	$ -
Telecommunications IT/OT	CAPEX	$ 3.98 M	$ 2.97 M	$ 7.56 M	$ 8.84 M	$ 5.46 M	$ 28.81 M
	OPEX	$ 7.22 M	$ 7.39 M	$ 7.57 M	$ 7.74 M	$ 7.93 M	$ 37.85 M
CyberSecurity	CAPEX	$ 5.51 M	$ 5.51 M	$ 5.51 M	$ 3.58 M	$ 3.58 M	$ 23.69 M
	OPEX	$ 8.78 M	$ 8.85 M	$ 8.93 M	$ 6.95 M	$ 7.03 M	$ 40.54 M
DSCADA/ADMS	CAPEX	$ -	$ -	$ 1.88 M	$ 3.46 M	$ 3.60 M	$ 8.94 M
	OPEX	$ 5.75 M	$ 5.87 M	$ 5.99 M	$ 6.12 M	$ 6.25 M	$ 29.99 M
Training and Asset Management	CAPEX	$ 1.19 M	$ 1.02 M	$ 1.04 M	$ 1.06 M	$ 1.08 M	$ 5.38 M
	OPEX	$ 1.70 M	$ 1.73 M	$ 1.77 M	$ 1.80 M	$ 3.06 M	$ 10.06 M
Marketing, Education, Outreach and PMO	CAPEX	$ -	$ -	$ -	$ -	$ -	$ -
	OPEX	$ 0.91 M	$ 0.93 M	$ 0.95 M	$ 0.97 M	$ 0.99 M	$ 4.73 M
						Total CAPEX	$ 261.11 M
						Total OPEX	$ 223.67 M

3.2.2 AMI-Focused ScenarioFigure 2: AMI Focused Plan Program Deployment Schedule

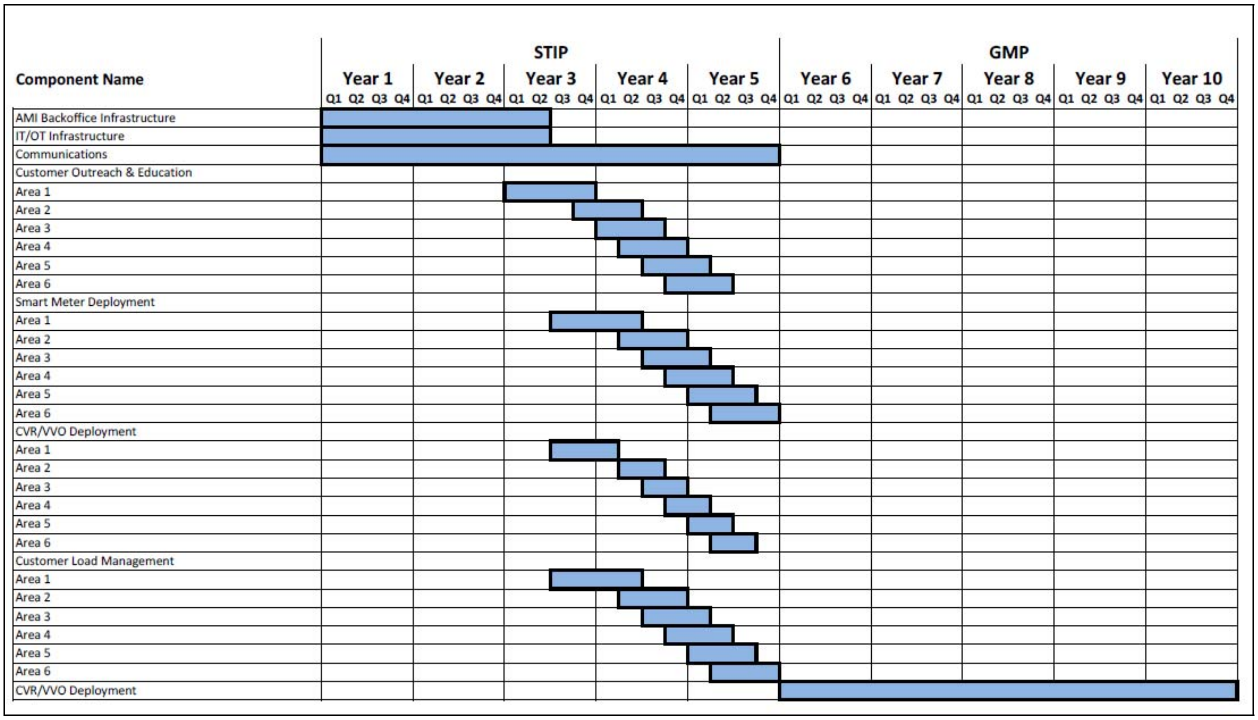

Table 8 and Table 9 outline the costs for the AMI-Focused scenario by year and by program. This plan achieves an estimated 1.02 monetized benefit-cost ratio over 15 years with an estimated 10 year investment of $954M. While this plan provides the highest monetized benefit-cost ratio, the lack of internal infrastructure and significantly lower unquantified benefits will not position National Grid to effectively maximize system benefits beyond year 10. For example, CVR/VVO is still deployed to 10% of customers in this vision, but expansion beyond that scope is expected to be challenging after Year 10. Figure 2 shows the GMP deployment schedule.

Figure 2: AMI Focused Plan Program Deployment Schedule

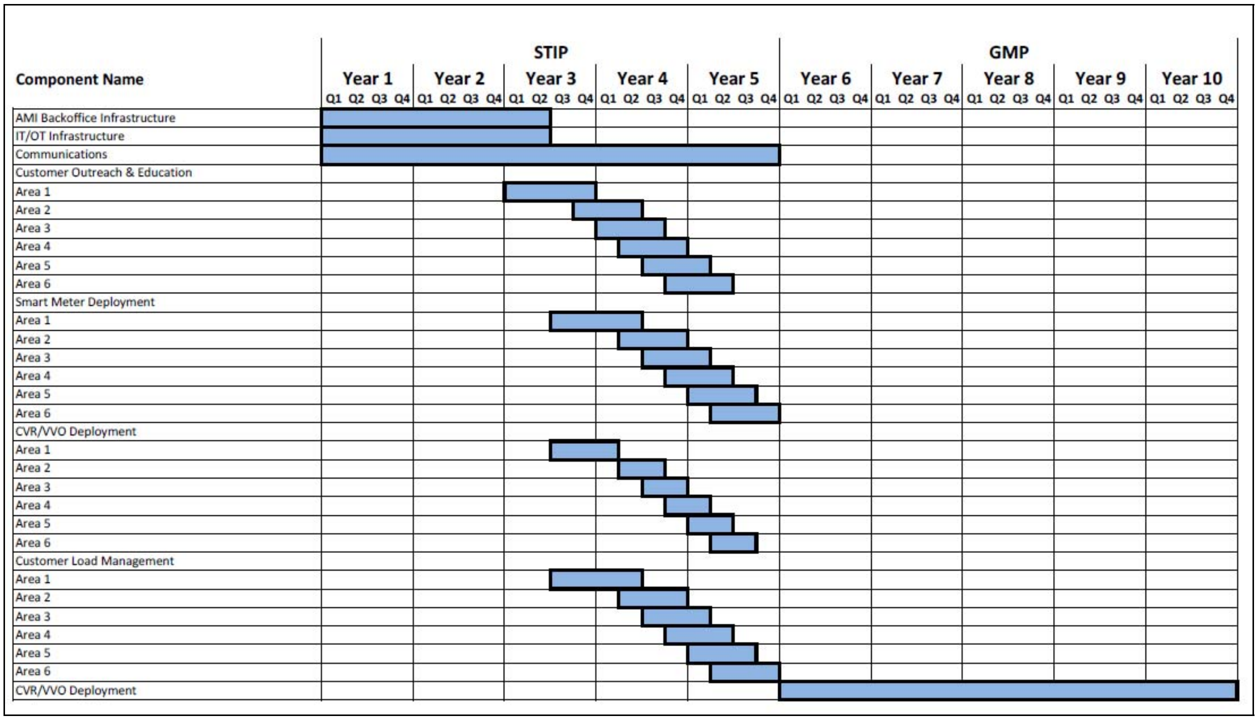

Table 8: "AMI Focused" Plan STIP Costs

Spending STIP Years 1-5		Year 1	Year 2	Year 3	Year 4	Year 5	Total
Smart Meters and AMI Backoffice	CAPEX	$ 6.65 M	$ 33.47 M	$ 82.54 M	$ 84.83 M	$ 86.70 M	$ 294.19 M
	OPEX	$ 4.33 M	$ 1.37 M	$ 2.00 M	$ 2.22 M	$ 2.44 M	$ 12.35 M
Customer Load Management	CAPEX	$ -	$ -	$ -	$ 4.46 M	$ 5.37 M	$ 9.82 M
	OPEX	$ 1.41 M	$ 1.26 M	$ 10.95 M	$ 9.25 M	$ 9.25 M	$ 32.11 M
CVR/VVO	CAPEX	$ -	$ -	$ 3.53 M	$ 4.45 M	$ 4.36 M	$ 12.34 M
	OPEX	$ 1.78 M	$ 1.82 M	$ 0.04 M	$ 0.07 M	$ 0.11 M	$ 3.82 M
ADA	CAPEX	$ -	$ -	$ -	$ -	$ -	$ -
	OPEX	$ -	$ -	$ -	$ -	$ -	$ -
Feeder Monitors	CAPEX	$ 2.60 M	$ 2.65 M	$ 2.71 M	$ 2.76 M	$ 2.82 M	$ 13.55 M
	OPEX	$ -	$ -	$ -	$ -	$ -	$ -
Telecommunications IT/OT	CAPEX	$ 37.31 M	$ 42.84 M	$ 35.78 M	$ 18.16 M	$ 16.70 M	$ 150.79 M
	OPEX	$ 1.64 M	$ 2.30 M	$ 3.64 M	$ 4.33 M	$ 4.93 M	$ 16.84 M
CyberSecurity	CAPEX	$ 9.49 M	$ 7.10 M	$ 8.91 M	$ 6.31 M	$ 9.13 M	$ 40.94 M
	OPEX	$ 4.92 M	$ 4.92 M	$ 4.37 M	$ 4.37 M	$ 4.37 M	$ 22.95 M
DSCADA/ADMS	CAPEX	$ -	$ -	$ -	$ -	$ -	$ -
	OPEX	$ -	$ -	$ -	$ -	$ -	$ -
Training and Asset Management	CAPEX	$ -	$ 0.11 M	$ 0.65 M	$ 0.72 M	$ 0.70 M	$ 2.18 M
	OPEX	$ -	$ -	$ -	$ -	$ 0.02 M	$ 0.02 M
Marketing, Education, Outreach and PMO	CAPEX	$ 6.74 M	$ 10.05 M	$ 3.79 M	$ 7.17 M	$ 7.32 M	$ 35.08 M
	OPEX	$ 0.56 M	$ 0.57 M	$ 2.97 M	$ 3.03 M	$ 3.09 M	$ 10.21 M
						Total CAPEX	$ 558.89 M
						Total OPEX	$ 98.29 M

Table 9: “AMI Focused” Plan Years 6-10 Costs

Spending GMP Years 6-10		Year 6	Year 7	Year 8	Year 9	Year 10	Total
Smart Meters and AMI Backoffice	CAPEX	$ 0.65 M	$ 0.67 M	$ 3.74 M	$ 0.69 M	$ 0.71 M	$ 6.46 M
	OPEX	$ 9.97 M	$ 10.08 M	$ 10.20 M	$ 10.32 M	$ 10.45 M	$ 51.02 M
Customer Load Management	CAPEX	$ 8.93 M	$ -	$ -	$ -	$ -	$ 8.93 M
	OPEX	$ 9.25 M	$ 13.50 M	$ 6.32 M	$ 6.38 M	$ 6.44 M	$ 41.89 M
CVR/VVO	CAPEX	$ 8.91 M	$ 17.33 M	$ 16.41 M	$ 11.34 M	$ 11.57 M	$ 65.56 M
	OPEX	$ 0.16 M	$ 0.23 M	$ 0.29 M	$ 0.36 M	$ 0.43 M	$ 1.47 M
ADA	CAPEX	$ -	$ -	$ -	$ -	$ -	$ -
	OPEX	$ -	$ -	$ -	$ -	$ -	$ -
Feeder Monitors	CAPEX	$ 1.77 M	$ 1.81 M	$ 1.85 M	$ 1.88 M	$ 1.92 M	$ 9.24 M
	OPEX	$ -	$ -	$ -	$ -	$ -	$ -
Telecommunications IT/OT	CAPEX	$ 3.12 M	$ 2.09 M	$ 6.66 M	$ 7.92 M	$ 4.51 M	$ 24.29 M
	OPEX	$ 7.16 M	$ 7.31 M	$ 7.46 M	$ 7.61 M	$ 7.77 M	$ 37.31 M
CyberSecurity	CAPEX	$ 3.15 M	$ 3.15 M	$ 3.15 M	$ 2.37 M	$ 2.37 M	$ 14.19 M
	OPEX	$ 5.72 M	$ 5.79 M	$ 5.87 M	$ 5.40 M	$ 5.47 M	$ 28.25 M
DSCADA/ADMS	CAPEX	$ -	$ -	$ -	$ -	$ -	$ -
	OPEX	$ -	$ -	$ -	$ -	$ -	$ -
Training and Asset Management	CAPEX	$ 0.69 M	$ 0.51 M	$ 0.52 M	$ 0.53 M	$ 0.54 M	$ 2.79 M
	OPEX	$ 0.05 M	$ 0.05 M	$ 0.05 M	$ 0.05 M	$ 0.66 M	$ 0.85 M
Marketing, Education, Outreach and PMO	CAPEX	$ -	$ -	$ -	$ -	$ -	$ -
	OPEX	$ 0.91 M	$ 0.93 M	$ 0.95 M	$ 0.97 M	$ 0.99 M	$ 4.73 M
						Total CAPEX	$ 131.46 M
						Total OPEX	$ 165.52 M

3.2.3 Grid-Focused Scenario

Table 10 and Table 11 outline the costs for the Grid-Focused scenario by year and by program. This scenario achieves an estimated 0.57 monetized benefit-cost ratio over 15 years with an estimated 10 year investment of $994M. Under this scenario, National Grid would expect a significant reduction of participants based on the fact that AMF/TVR would be offered to 30% of customers on an opt-out basis and to 70% of customers on an opt-in basis. The Grid focused scenario deployment schedule is identical to the Balanced scenario, with a reduction of scope for AMI. This is shown in Figure 1.

Table 10: "Grid Focused" STIP Costs

Spending STIP Years 1-5		Year 1	Year 2	Year 3	Year 4	Year 5	Total
Smart Meters and AMI Backoffice	CAPEX	$ 6.16 M	$ 14.64 M	$ 31.55 M	$ 32.78 M	$ 33.83 M	$ 118.96 M
	OPEX	$ 3.13 M	$ 1.16 M	$ 1.38 M	$ 1.46 M	$ 1.54 M	$ 8.67 M
Customer Load Management	CAPEX	$ -	$ -	$ -	$ 4.42 M	$ 5.37 M	$ 9.78 M
	OPEX	$ 1.41 M	$ 1.26 M	$ 5.04 M	$ 2.79 M	$ 2.79 M	$ 13.28 M
CVR/VVO	CAPEX	$ -	$ -	$ 6.93 M	$ 7.92 M	$ 7.52 M	$ 22.37 M
	OPEX	$ 1.78 M	$ 1.82 M	$ 0.06 M	$ 0.13 M	$ 0.19 M	$ 3.99 M
ADA	CAPEX	$ -	$ -	$ 9.67 M	$ 10.71 M	$ 10.08 M	$ 30.46 M
	OPEX	$ 1.78 M	$ 1.82 M	$ 0.12 M	$ 0.24 M	$ 0.35 M	$ 4.31 M
Feeder Monitors	CAPEX	$ 2.60 M	$ 2.65 M	$ 2.71 M	$ 2.76 M	$ 2.82 M	$ 13.55 M
	OPEX	$ -	$ -	$ -	$ -	$ -	$ -
Telecommunications IT/OT	CAPEX	$ 35.94 M	$ 39.49 M	$ 33.90 M	$ 17.17 M	$ 15.62 M	$ 142.13 M
	OPEX	$ 1.59 M	$ 2.07 M	$ 3.22 M	$ 3.73 M	$ 4.13 M	$ 14.74 M
CyberSecurity	CAPEX	$ 9.49 M	$ 7.10 M	$ 8.91 M	$ 6.31 M	$ 9.13 M	$ 40.94 M
	OPEX	$ 4.92 M	$ 4.92 M	$ 4.37 M	$ 4.37 M	$ 4.37 M	$ 22.95 M
DSCADA/ADMS	CAPEX	$ 10.19 M	$ 20.52 M	$ 17.28 M	$ 19.88 M	$ 8.05 M	$ 75.92 M
	OPEX	$ 0.06 M	$ 0.12 M	$ 0.19 M	$ 0.26 M	$ 0.26 M	$ 0.89 M
Training and Asset Management	CAPEX	$ 0.45 M	$ 0.57 M	$ 1.12 M	$ 1.20 M	$ 1.20 M	$ 4.55 M
	OPEX	$ 0.01 M	$ 0.05 M	$ 0.07 M	$ 0.09 M	$ 0.12 M	$ 0.34 M
Marketing, Education, Outreach and PMO	CAPEX	$ 6.74 M	$ 10.05 M	$ 3.79 M	$ 7.17 M	$ 7.32 M	$ 35.08 M
	OPEX	$ 0.56 M	$ 0.57 M	$ 2.97 M	$ 3.03 M	$ 3.09 M	$ 10.21 M
						Total CAPEX	$ 493.72 M
						Total OPEX	$ 79.39 M

Table 11: "Grid Focused" Years 6-10 Costs

Spending GMP Years 6-10		Year 6	Year 7	Year 8	Year 9	Year 10	Total
Smart Meters and AMI Backoffice	CAPEX	$ 0.65 M	$ 0.67 M	$ 3.74 M	$ 0.69 M	$ 0.71 M	$ 6.46 M
	OPEX	$ 7.71 M	$ 7.77 M	$ 7.84 M	$ 7.90 M	$ 7.97 M	$ 39.19 M
Customer Load Management	CAPEX	$ 8.93 M	$ -	$ -	$ -	$ -	$ 8.93 M
	OPEX	$ 2.79 M	$ 7.04 M	$ 4.93 M	$ 4.99 M	$ 5.05 M	$ 24.79 M
CVR/VVO	CAPEX	$ 13.35 M	$ 21.87 M	$ 21.04 M	$ 16.06 M	$ 16.40 M	$ 88.72 M
	OPEX	$ 0.30 M	$ 0.42 M	$ 0.53 M	$ 0.66 M	$ 0.78 M	$ 2.69 M
ADA	CAPEX	$ 15.53 M	$ 15.85 M	$ 16.18 M	$ 16.52 M	$ 16.86 M	$ 80.93 M
	OPEX	$ 0.55 M	$ 0.76 M	$ 0.97 M	$ 1.19 M	$ 1.42 M	$ 4.89 M
Feeder Monitors	CAPEX	$ 1.77 M	$ 1.81 M	$ 1.85 M	$ 1.88 M	$ 1.92 M	$ 9.24 M
	OPEX	$ -	$ -	$ -	$ -	$ -	$ -
Telecommunications IT/OT	CAPEX	$ 3.98 M	$ 2.97 M	$ 7.56 M	$ 8.84 M	$ 5.46 M	$ 28.81 M
	OPEX	$ 6.37 M	$ 6.52 M	$ 6.67 M	$ 6.83 M	$ 7.00 M	$ 33.39 M
CyberSecurity	CAPEX	$ 3.15 M	$ 3.15 M	$ 3.15 M	$ 2.37 M	$ 2.37 M	$ 14.19 M
	OPEX	$ 5.72 M	$ 5.79 M	$ 5.87 M	$ 5.40 M	$ 5.47 M	$ 28.25 M
DSCADA/ADMS	CAPEX	$ -	$ -	$ 1.88 M	$ 3.46 M	$ 3.60 M	$ 8.94 M
	OPEX	$ 5.75 M	$ 5.87 M	$ 5.99 M	$ 6.12 M	$ 6.25 M	$ 29.99 M
Training and Asset Management	CAPEX	$ 0.69 M	$ 0.51 M	$ 0.52 M	$ 0.53 M	$ 0.54 M	$ 2.79 M
	OPEX	$ 0.65 M	$ 0.67 M	$ 0.68 M	$ 0.69 M	$ 1.32 M	$ 4.01 M
Marketing, Education, Outreach and PMO	CAPEX	$ -	$ -	$ -	$ -	$ -	$ -
	OPEX	$ 0.91 M	$ 0.93 M	$ 0.95 M	$ 0.97 M	$ 0.99 M	$ 4.73 M
						Total CAPEX	$ 249.02 M
						Total OPEX	$ 171.93 M

3.2.4 Opt-In Scenario

Figure 3: Opt-In Focused Plan Program Deployment Schedule

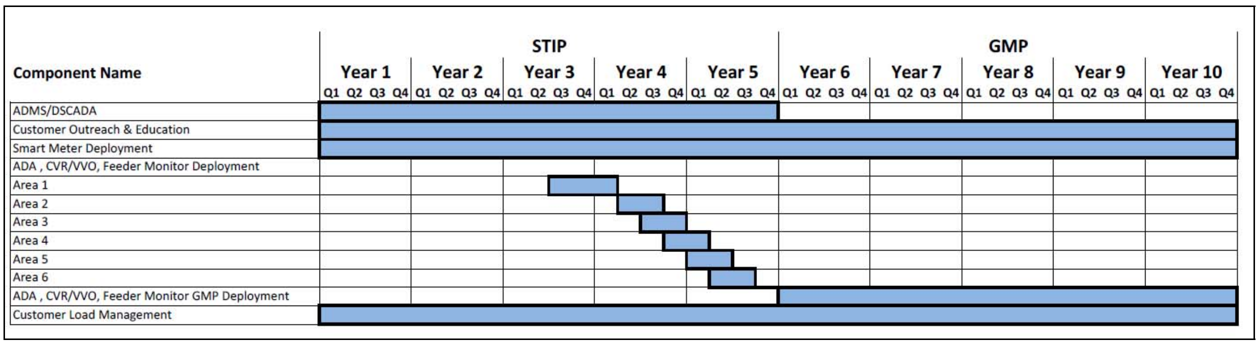

Table 12 and Table 133 outline the costs for the Opt-In scenario by year and by program. This plan achieves an estimated 0.56 monetized benefit-cost ratio over 15 years, with an estimated 10 year investment of $521M. While representing the smallest 10 year costs, this scenario reaches the smallest number of customers and does not have a positive monetized benefit-cost ratio, but it does offer qualitative benefits as well. Figure 3 shows the 10 year program deployment schedule for the Opt-In scenario. Notice that under this scenario, AMI deployment can begin immediately.

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Figure 3: Opt-In Focused Plan Program Deployment Schedule

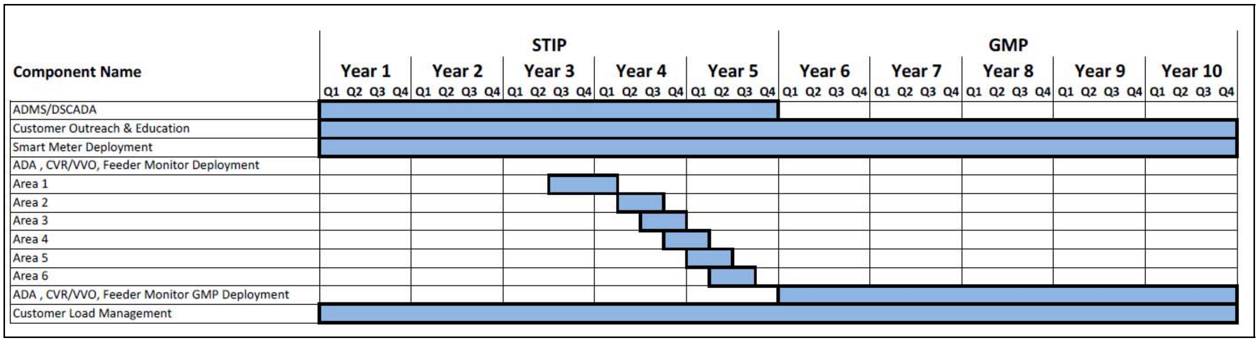

Table 12: "Opt-In" STIP Costs

Spending STIP Years 1-5		Year 1	Year 2	Year 3	Year 4	Year 5	Total
Smart Meters and AMI Backoffice	CAPEX	$ 2.32 M	$ 2.35 M	$ 2.44 M	$ 2.53 M	$ 2.63 M	$ 12.27 M
	OPEX	$ 0.49 M	$ 3.62 M	$ 3.63 M	$ 3.64 M	$ 3.64 M	$ 15.03 M
Customer Load Management	CAPEX	$ -	$ -	$ -	$ -	$ -	$ -
	OPEX	$ 2.40 M	$ 2.40 M	$ 2.40 M	$ 2.40 M	$ 2.40 M	$ 11.99 M
CVR/VVO	CAPEX	$ -	$ -	$ 6.93 M	$ 7.92 M	$ 7.52 M	$ 22.37 M
	OPEX	$ 1.78 M	$ 1.82 M	$ 0.06 M	$ 0.13 M	$ 0.19 M	$ 3.99 M
ADA	CAPEX	$ -	$ -	$ 9.67 M	$ 10.71 M	$ 10.08 M	$ 30.46 M
	OPEX	$ 1.78 M	$ 1.82 M	$ 0.12 M	$ 0.24 M	$ 0.35 M	$ 4.31 M
Feeder Monitors	CAPEX	$ 2.60 M	$ 2.65 M	$ 2.71 M	$ 2.76 M	$ 2.82 M	$ 13.55 M
	OPEX	$ -	$ -	$ -	$ -	$ -	$ -
Telecommunications IT/OT	CAPEX	$ 0.18 M	$ 0.18 M	$ 0.19 M	$ 0.19 M	$ 0.20 M	$ 0.94 M
	OPEX	$ 0.42 M	$ 0.43 M	$ 0.44 M	$ 0.45 M	$ 0.46 M	$ 2.20 M
CyberSecurity	CAPEX	$ 1.25 M	$ 1.01 M	$ 1.29 M	$ 1.03 M	$ 1.31 M	$ 5.88 M
	OPEX	$ 0.72 M	$ 0.72 M	$ 0.83 M	$ 0.83 M	$ 0.83 M	$ 3.94 M
DSCADA/ADMS	CAPEX	$ 10.19 M	$ 20.52 M	$ 17.28 M	$ 19.88 M	$ 8.05 M	$ 75.92 M
	OPEX	$ 0.06 M	$ 0.12 M	$ 0.19 M	$ 0.26 M	$ 0.26 M	$ 0.89 M
Training and Asset Management	CAPEX	$ 0.15 M	$ 0.26 M	$ 0.65 M	$ 0.66 M	$ 0.64 M	$ 2.36 M
	OPEX	$ -	$ 0.03 M	$ 0.03 M	$ 0.03 M	$ 0.05 M	$ 0.13 M
Marketing, Education, Outreach and PMO	CAPEX	$ 3.64 M	$ 5.30 M	$ 2.18 M	$ 3.87 M	$ 3.95 M	$ 18.95 M
	OPEX	$ 0.56 M	$ 0.57 M	$ 2.97 M	$ 3.03 M	$ 3.09 M	$ 10.21 M
						Total CAPEX	$ 182.69 M
						Total OPEX	$ 52.70 M

Table 13: "Opt-In" Years 6-10 Costs

Spending GMP Years 6-10		Year 6	Year 7	Year 8	Year 9	Year 10	Total
Smart Meters and AMI Backoffice	CAPEX	$ 2.32 M	$ 2.32 M	$ 2.32 M	$ 2.32 M	$ 2.32 M	$ 11.61 M
	OPEX	$ 3.96 M	$ 3.97 M	$ 3.98 M	$ 3.99 M	$ 4.00 M	$ 19.90 M
Customer Load Management	CAPEX	$ -	$ -	$ -	$ -	$ -	$ -
	OPEX	$ 2.40 M	$ 2.40 M	$ 2.40 M	$ 2.40 M	$ 2.40 M	$ 11.99 M
CVR/VVO	CAPEX	$ 13.35 M	$ 21.87 M	$ 21.04 M	$ 16.06 M	$ 16.40 M	$ 88.72 M
	OPEX	$ 0.30 M	$ 0.42 M	$ 0.53 M	$ 0.66 M	$ 0.78 M	$ 2.69 M
ADA	CAPEX	$ 15.53 M	$ 15.85 M	$ 16.18 M	$ 16.52 M	$ 16.86 M	$ 80.93 M
	OPEX	$ 0.55 M	$ 0.76 M	$ 0.97 M	$ 1.19 M	$ 1.42 M	$ 4.89 M
Feeder Monitors	CAPEX	$ 1.77 M	$ 1.81 M	$ 1.85 M	$ 1.88 M	$ 1.92 M	$ 9.24 M
	OPEX	$ -	$ -	$ -	$ -	$ -	$ -
Telecommunications IT/OT	CAPEX	$ -	$ -	$ -	$ -	$ -	$ -
	OPEX	$ 0.47 M	$ 0.48 M	$ 0.49 M	$ 0.50 M	$ 0.51 M	$ 2.44 M
CyberSecurity	CAPEX	$ 0.55 M	$ 0.55 M	$ 0.55 M	$ 0.36 M	$ 0.36 M	$ 2.37 M
	OPEX	$ 0.88 M	$ 0.89 M	$ 0.89 M	$ 0.70 M	$ 0.70 M	$ 4.05 M
DSCADA/ADMS	CAPEX	$ -	$ -	$ 1.88 M	$ 3.46 M	$ 3.60 M	$ 8.94 M
	OPEX	$ 5.75 M	$ 5.87 M	$ 5.99 M	$ 6.12 M	$ 6.25 M	$ 29.99 M
Training and Asset Management	CAPEX	$ 0.50 M	$ 0.51 M	$ 0.52 M	$ 0.53 M	$ 0.54 M	$ 2.59 M
	OPEX	$ 0.05 M	$ 0.05 M	$ 0.05 M	$ 0.05 M	$ 0.66 M	$ 0.85 M
Marketing, Education, Outreach and PMO	CAPEX	$ -	$ -	$ -	$ -	$ -	$ -
	OPEX	$ 0.91 M	$ 0.93 M	$ 0.95 M	$ 0.97 M	$ 0.99 M	$ 4.73 M
						Total CAPEX	$ 204.40 M
						Total OPEX	$ 81.54 M

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4. Field Deployment Elements of GMP

4.1 Overview

As part of the GMP, National Grid proposes to deploy five field deployment programs in the service territory. The programs consist of physical devices which are directly providing benefits. These five programs are:

- AMI: This includes the deployment of AMF compatible meters in the service territory. The costs in this program include the costs of the smart meter itself, as well as the labor required to support the deployment.
- CVR/VVO: CVR/VVO is a distribution level program where voltage control devices are intelligently controlled in a coordinated manner to optimize the distribution system. This program is designed to minimize system losses, while simultaneously reducing both demand and energy use of customers.
- ADA: ADA is a FLISR-based advanced distribution automation program where sectionalizing protection equipment is automated and controlled in a coordinated manner, to minimize the effects of outages.
- Feeder Monitors: The feeder monitors program will install interval power monitoring devices on feeders where the Company does not currently have this information. Feeder monitors will be used to inform both operations and distribution design.
- CLM: The CLM program refers to the infrastructure to support in-home devices, such as load control switches, smart thermostats, energy monitoring displays and other consumer devices. The costs for the infrastructure (software service, connectivity to AMI meters, DRMS and gateways) are included in the GMP. The costs related to the in-home devices are proposed to be included in the Company's energy efficiency programs.

These tasks represent the substantial deployment of the program, and are exclusive of ongoing supporting costs. For deployment purposes, the company has divided the service territory into six areas of roughly equal customer population. The scope of the deployment of these programs will vary among the four different GMP scenarios, as described in Section 1 of the Plan.

4.2 Short-Term Investment Plan Years 1-5

4.2.1 Advanced Metering Infrastructure

The Company used lessons learned from its SES pilot in its development of solutions to provide AMF. The Company developed its AMF/CLM/Communications Solution Request for Proposals [11] ("AMF RFP") with these lessons learned while recognizing the potential for technological improvements. Specifically, the Company sought to refresh its understanding of available solutions and the economics for considering a state-wide implementation of AMF.

After review of the solutions and technologies available in the marketplace today, the Company believes that implementation of AMI will achieve the four elements of AMF, provide a platform for the future to support evolution of the digital grid and provide significant value and capabilities for customers.

As noted, investments in enabling infrastructure will need to occur in order to support AMI functionalities. These enabling investments include but are not limited to the communications infrastructure (also known as the head-end system), the meter data management systems (MDMS), billing system interfaces and meter work management and inventory tracking solutions. Once these investments are implemented, deployment of AMI will enable immediate benefits for customers through information on energy use and TVR offerings.

In sum, the Company's proposal to achieve the four elements of AMF is as follows:

- Collection of Customers' Interval Usage Data in Near Real Time – The most cost-effective and efficient way to collect usage data in near real time is through AMI. The Company's experience with AMI and assessment of alternate AMF technologies determined that certain obstacles and complexities exist in seeking a non-AMI option. Across the United States, there are over 50 million AMI meters actively deployed, demonstrating that AMI technology is the best option for collecting interval data in near real time.

[11] See Section 11.5 for a discussion of the three requests for proposals and one request for information that the Company issued as part of its GMP development process.

- Automated Outage Restoration and Notification – The Company analyzed AMI technology and behaviors as they relate to outage and restoration notification. While earlier versions of AMI had some gaps in these notification capabilities, the Company has worked collaboratively with the market, industry groups and other utilities to close those gaps and identify needed business process changes. The solution includes a communications design with certain threshold and minimum criteria to improve performance, integrate metering activity with OMS to filter for known meter work in the field, and developing greater meter capability for how the messages, alerts and alarms are presented.
- Two-Way Communication between Customers and the Company – The Company's AMI and communications proposal will achieve this capability. The Company has demonstrated through the SES Pilot the ability of AMI technology to provide a reliable solution for two-way communication. The Company's Pilot introduced home energy management solutions that can connect to and control appliances through the AMI meter.
- Communication With and Control of Customer Appliances, With Customer Permission - The Company is proposing a forward-looking design where customers can self-select appliances and home technology, and join them with the AMI meter through the home area network ("HAN"). Customers would be able to choose the level of demand response that they would like to enable and participate in.

The Balanced Plan and AMI-Focused scenario would replace all 1.3 million electric premise meters with advanced meters and the associated back office systems to allow their use within a five year period following approval of the GMP. As described in Section 1, Table 1, the Grid-Focused scenario would deploy AMI on a 30% opt-out and 70% opt-in basis, and the Opt-In scenario would deploy AMI on a 100% opt-in basis. New back office systems will be installed, including the meter reading collection system, known as the Head-End system, and the MDMS.[12] The Head-End system collects the data for the premise meters using the common communication system the Company has proposed. The MDMS collects meter data and makes the data available for further processing. The data can be used for settlements at the ISO, calculation of billing determinants, provision of data to customers and system planning. The high level deployment

[12] In the Opt-In scenario, existing back office systems from the Worcester Smart Energy Solutions Pilot will be used.

plan calls for construction of necessary back office systems in the first two years, and meters to be deployed in years 3-5 along with field communications.

4.2.1.1 Current State of Meters in Massachusetts

National Grid has approximately 1.3 million electric meters in service in Massachusetts, of which, approximately 1 million are AMR meters. This meter population is composed primarily of AMR meters and electromagnetic meters retrofitted with AMR devices, and also is divided between residential, and commercial and industrial ("C&I"), meters. A smaller portion of meters are interval, time of use ("TOU") and demand meters which are installed for C&I customers, load research and DG.

Two meter reading systems are in place to accommodate AMR for the majority of the meters: optical or manual reading; and remote interrogation readings for high usage customers C&I and larger DG customers. These meters provide one way communication from the meter back to the Company and any data collected is primarily used for billing, load research and settlement purposes.

4.2.1.2 Meter Plan for Grid Modernization

As part of the GMP, a smart meter would be installed at electric customer premises. All meters will support two way communications. Residential meters would be required to have four channels of Interval/Load Profile recording capability. C&I meters would be required to have five channels of Interval/Load Profile recording capability. All meters would be able to gather and communicate data, exceptions and event logs.

Considerable back office and core communication systems must be implemented for the metering solution to provide required benefits. The actual installation of meters will begin once the communication platform and the MDMS is operational. The communication platform will also be used for the other automated grid device thereby bringing efficiency through shared communication resources. Deployment of meters will occur concurrently with installation of these devices.

To fully leverage the benefits that AMI offers, the Company must use the data collected by the system to enable energy and process efficiency and any associated cost benefits. This data will include event and exception logs and data to enable prompt notification, analysis and action for both the consumer and the Company.

Energy data will include, but is not limited to:

- kW (delivered to the customer, received from the customer, net)
- kVA (delivered to the customer)

- kVAR (delivered to the customer, received from the customer)
- Event logs/exceptions will be capable of the following:
- Voltage sags and swells (+/- 5% of nominal voltage)
- Power outages (power off and power on)
- Meter socket temperature
- GPS location (sensed by/ updated by the meter)
- Meter tampering (tilt/inversion counts)
- Diagnostics (missing phase voltage/ current, low battery voltage, firmware upgrade errors, etc.)
- The ability to collect and transmit data bi-directionally allows the system to interface with AMI head end, as well as customer in-home energy management devices. Data and event logs will be used to support prompt and efficient decision making in the following areas/departments in the Company:
- Power Outage Management/ Storm Restoration
- Distributed Generation
- Energy Efficiency
- Customer Meter Services (CMS)
- Revenue Assurance
- Billing
- Asset Management
- System Planning

On the consumer side, data/event logs will be available to manage energy consumption costs while monitoring energy quality and ensuring minimal interruptions in supply. Smart meters can communicate data and events to a customer in-house display and also to an internet solution for purposes of consumer monitoring and energy control. Consumers will have the option to allow device control and demand limiting by the Company as outlined in the CLM section (Section 4.2.5).

Based on lessons from the Company's SES Pilot, configuration of meters will be performed remotely. This approach eliminates the need for on-site configuration and minimizes manual effort. Modification of many of the Company's legacy systems, including the billing system ("CSS"), accounting/ payment systems (SAP) and meter issues tracking system ("MITS") will be required to accommodate new technology and processes. In addition, the Company will conduct a significant education campaign for customers around AMI meters, as discussed in Section 9.3.2 on the Company's MEO Plan.

4.2.1.3 Back office systems

Multiple back office systems will be required to support the AMI meters. An AMI head end system will collect the meter data and connect to the MDMS, which will be required to manage and store the vastly increased amount of data generated by an AMI system with frequent interval reads.

Currently, with monthly meter readings only, the amount of data needed and/or stored per customer can be as few as 12 data points (or monthly billing reads) per year. AMI interval meters will increase data storage requirements as the amount of data needed and/or stored per customer can be as high as 105,120 data points (or the number of 5 minute intervals in a year) per year. Managing this amount of data for 1.3 million customers simply cannot be done with the existing systems.

The Company's experience in the SES Pilot demonstrates the need for activities including daily data quality reviews, manual interval usage gap fill analysis, meter mitigation of low read rates and ensuring the highest data quality is delivered to customer billing to meet or exceed the expected 99.5 percent actual read rate. In general, daily operational activities will increase in proportion to the projected wide range of meter data sources, tariffs and customer opt-in provisions. The meter data services ("MDS") group in the Company interfaces with billing and field metering teams as well as the Company's current meter vendor to assess meter performance through the many meter data management ("MDM") tools. (e.g., Meter Data Management, Open Way Meter Collection Engine, CGNMS Network Management System, CSS Service Orders, Meter Inventory Tracking (MITS) and MWORK) to identify meter location, commissioning and ensuring appropriate classification and synchronization of meter data. The MDMS will feed upstream and downstream applications and will be the core smart energy service bus for interval metering data.

In the Balanced, AMI Focused, and Grid Focused scenarios, the head end system and MDMS will be new systems installed at National Grid to support the significant number of devices that expect to be installed. Under the Opt-in scenario, National Grid will leverage the infrastructure put in place for the Smart Energy Solutions pilot to provide management services for the more limited number expected to participate under an opt-in offering.

4.2.1.4 Benefits

AMI, in combination with a two-way communication between customers and the Company, will enable peak load reductions on the system through offering TVRs, peak time rebates and notification of pricing changes and emergency conditions. This allows customers the opportunity to reduce their bills with near real time management of their use.

Replacing existing AMR meters with AMI meters will provide additional benefits as well:

- Accuracy of meters: The accuracy of an all new meter plant will be higher than the existing mix of meters of varying ages and technologies. While the existing meter plant is well within the meter accuracy required (+-2.5%) by ANSI standards and state regulations, the Company estimates that the new meters will provide an increase in accuracy of approximately 1% on average for residential and single phase small commercial meters (which represent the large majority of the meters),[13] and 0.3% for polyphase small commercial meters.[14]

- Theft of electric service: The use of specific tools to detect theft will be enabled with AMI. The Company has assumed an increase in theft detection and consequent decrease in theft of approximately 1.5% of delivered energy for residential customers, and approximately 1% for customers with single phase small commercial meters.[15]
- Meter on/off efforts: The Company processes approximately 50,000 requests per year to take a meter out of one name and put it in another when a customer moves in or out of a premise. With an internal disconnect, the Company can turn service off to the premise remotely, and upon notification of a new customer moving in.[16]
- Inactive Use: There are costs savings from avoiding dispatch of an employee to disconnect/reconnect service when a customer moves out. Presently when a customer moves out, the account is considered inactive. The Company may not be able to turn off the meter for various reasons. If another customer moves in without notifying the Company to put the account in their name, use on the account will not be billed. When the meter is read and use is discovered, the Company investigates and ultimately puts the account in the new customer's name. During this period of time, the use on the inactive meter, in many cases, cannot be billed as the ultimate consumer of the electricity during the period when it was inactive cannot be accurately ascertained.
- Avoided capital: This is the value of the current meter plant that will not have to be purchased over the duration of the project as the new meters will be purchased instead.

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[13] The Company has approximately 1.13 million residential meters, and approximately 144,600 single phase small commercial meters.

[14] The Company has approximately 11,700 polyphase small commercial meters. Additionally, the Company has approximately 3,000 digital C&I meters, and the accuracy of this meter population is not expected to change as they are already digital meters.

[15] The Company does not estimate a quantifiable increase in revenue due to increased theft detection for customers with polyphase small commercial meters or other C&I meters that are already digital.

[16] The Company does not propose to use remote connect/disconnect for non-payment or collection activities.

- Incremental CVR/VVO savings: CVR/VVO savings could be increased with the use of AMI to allow for a more granular reduction in losses on the delivery system. This increase in sensing ability will allow the Company to manage voltages to further optimize loss reductions throughout the distribution system once the meter deployment is complete. In order to be conservative, these benefits of AMI were not captured incrementally to the Company's proposed CVR/VVO program.
- Incremental outage management savings: With the ability to communicate with meters, the Company expects to provide additional outage restoration savings. These incremental savings would come mainly from major events where many customers are interrupted as discussed above. These savings can arise from improved outage determination, assignment of crews, confirmation power has been restored, etc.

AMF also will improve the ISO settlement process. Accurate hourly settlement of load and generation at the ISO-NE level is essential. Currently most of the Company's customers (i.e., residential and small commercial and industrial) are settled at the ISO level using a demand profile. This profile is based on load data that shows the average hourly use of customers on the R-1, R-4, and R-20 rates (residential) and the G-1 and G-2 rates (small commercial and industrial) where a standard watt-hour only meter is used. These profiled load customers likely have different actual load patterns versus the average, so having specific interval data for each customer will provide the detail for more accurate settlement, more detailed analysis of system losses and more accurate assessment of local losses on the system.

For those customers with on-site generation (typically solar), hourly data will provide the opportunity to receive actual market prices for excess generation during the day while consuming low cost power at night. This energy is not able to be settled properly with the current metering and billing systems in place, because customers with net metering are settled based on a monthly net usage which does not reflect daily production or consumption. With over 16,000 net metered customers in National Grid's service territory (with some 500+ added monthly), this is becoming a significant issue as improper settlement of load and generation manifests itself as what appears to be lower losses during the day, and higher losses at night. Issues with settlement are picked up in the Basic Service Adjustment Factor.[17] The use of an

[17] Basic Service is the provision of electric supply to the Company's customers who are not receiving their electric supply from a Competitive Supplier, pursuant to the Company's Tariff for Basic Service, M.D.P.U. No. 1161. The Company's cost of providing Basic Service is comprised of several different elements, including payments to the ISO-NE for procuring Basic Service power. Through the Basic Service Adjustment Factor, the Company reconciles

interval meter for all customers will allow proper load settlement as well as proper generation settlement.

4.2.2 Conservation Voltage Reduction/Volt-VAR Optimization

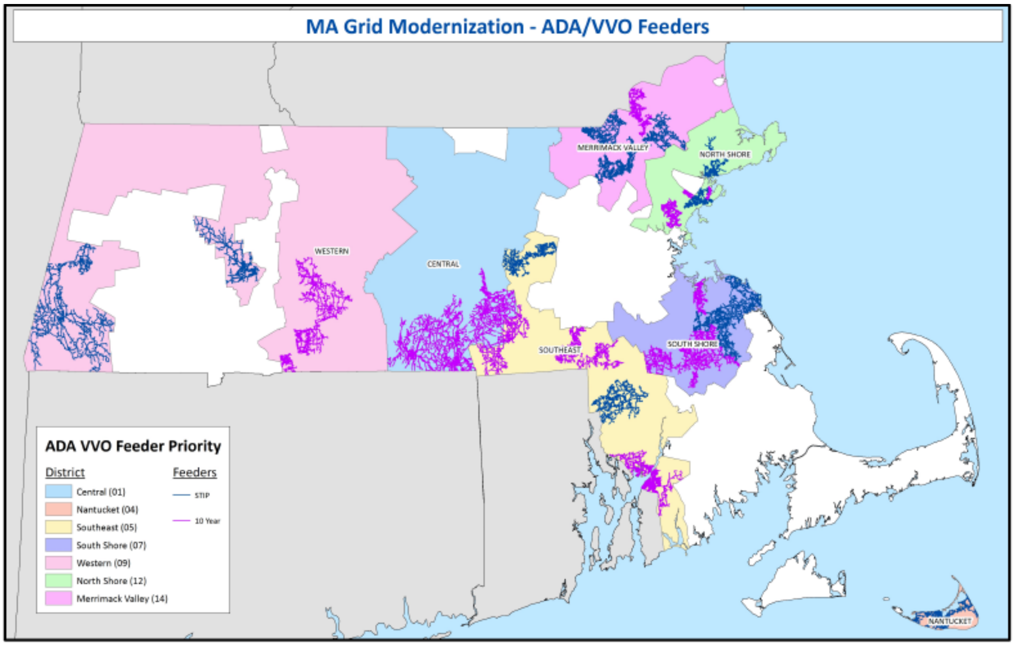
CVR/VVO technology flattens the voltage profile of a feeder by applying intelligent control to capacitors and regulators on the feeder which serves to minimize electrical losses, followed by lowering the source voltage at the substation to provide energy savings for both the utility and the customer. National Grid does not currently coordinate the operation of distribution voltage support devices beyond time of day or local condition feedback. A comprehensive CVR/VVO program would add a layer of coordination, via communication and control, to optimize the use of these devices to respond to system dynamics in real-time.

National Grid proposes to select a group of high value feeders per area for the field deployment of both CVR/VVO and ADA. The total population of initial candidate feeders is 575 15kV class overhead and mixed construction feeders. Of this population, approximately 220 are high value feeders (i.e., heavily loaded feeders that connect to fully or partially automated substations) which would be targeted for combined ADA and CVR/VVO deployments. During the STIP period, ADA and CVR/VVO will be outfitted together on 46 of these feeders.[18]

the power supply cost of providing Basic Service with its Basic Service revenue associated with the recovery of power supply costs, and the excess or deficiency is refunded to, or collected from, all of the Company's retail delivery service customers on a per kWh basis over the following 12 months, with interest at the interest rate paid on customer deposits. See M.D.P.U. No. 1199 (the Company's Basic Service Adjustment Provision).

[18] This would be the case in the Balanced Plan, Grid-Focused scenario and Opt-In scenario. In the AMI-Focused scenario, CVR/VVO would only be deployed on 24 feeders.

Figure 4: Feeder Prioritization for ADA and VVO program



In the first two years of the STIP, the required enabling communications and back office infrastructure to support the STIP scope of the CVR/VVO and ADA deployment will be implemented. Field implementation of CVR/VVO will follow the AMI deployment, two areas per year in years three, four and five of the STIP, resulting in 46 feeders[19] in total.[20] This approach will streamline the engineering analysis required by leveraging the Distribution Planning Area Study process already in place, in order to support the CVR/VVO deployment.

As work force realignments are completed and the DSCADA system becomes available, the rate of deployment of the CVR/VVO scheme would increase to approximately 24 feeders per year for

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[19] In the AMI focused plan, this technology will only be installed on 24 feeders in the STIP period.

[20] Beyond the five year STIP period, National Grid plans to continue this program more aggressively, after the ADMS is available, as discussed in Section 5.2.3.

years 6-10 of the GMP[21]. The candidate feeders were selected using a data model containing the following feeder information:

- Physical characteristics
- Historic and projected loading and capacity
- Inspection and maintenance information
- Historic reliability
- Substation automation levels

Information on the feeder distribution primary voltage level (15 kV class), construction type (overhead), loading and substation automation level were used to create a ranked list by substation (See Attachment 2). National Grid considers the 15 kV class (13.2 and 13.8 kV), overhead, heavily loaded feeders supplied from fully automated substations to be the most favorable candidates. This is due to the expected lower cost to implement CVR/VVO on those feeders and expected higher MWh savings. For the final combined ranking, CVR/VVO ranking was combined with the ADA ranking to select the subset of feeders for the STIP/GMP (See Attachment 1).

The timing of deployment of CVR/VVO is contingent on deployment of other elements of the GMP, including the enabling communications infrastructure and ADMS/DSCADA efforts. The cost estimates associated with the CVR/VVO program are included as Attachment 3.

4.2.2.1 Anticipated Benefits

There are several anticipated benefits of a CVR/VVO deployment, which will make progress on the Objectives. These benefits include:

Optimizing demand:

The implementation of a CVR/VVO system is expected to result in improved feeder power factor, flatter voltage profiles, reduced feeder losses, reduced peak demand and reduced energy consumption by customers. The estimated reduction in energy consumption is expected to be approximately 3% but will vary from feeder to feeder based on the individual characteristics.

[21] This increase in installation rate is not part of the AMI-Focused scenario.

Integrating distributed resources:

The additional operational data collected by automated capacitors and regulators, and displayed in an ADMS, should support the improved management of the distribution system which will assist in the integration of distributed resources. Actively maintaining proper voltage via intelligent centralized control will also improve feeder voltage performance, allowing for more DERs.

Improved workforce and asset management:

The deployment of CVR/VVO schemes will integrate improved system awareness into the daily operations and planning processes. Operational efficiency is expected be improve due to fewer truck rolls related to routine maintenance of remotely monitored equipment. It is possible that the implementation of CVR/VVO schemes could postpone the need for conventional capital investments (equipment upgrades/replacements) based on normal overloads identified in planning studies.

4.2.2.2 Dependencies with other parts of the GMP

The implementation of the STIP CVR/VVO scope is dependent on the deployment of several other elements of the GMP:

- Telecommunications, both back office and FAN.
- ADMS/DSCADA is required for wider scale deployment beyond first 46 feeders.
- Data Management and Operations integration.
- FTEs to support the design and deployment of the systems.
- Training for Distribution Planning and Operations.

4.2.2.3 Preparation for Years Six - Ten of the GMP

Expansion of the CVR/VVO program beyond the initial STIP scope is dependent on the availability of a DSCADA system, due to point limitations (i.e., the number of available points) in the existing SCADA system that is used for both transmission and distribution. The completion of the ADMS/DSCADA effort by year six of the GMP will allow for increased proliferation of CVR/VVO.

4.2.3 Advanced Distribution Automation

National Grid proposes to deploy ADA equipment designed to accomplish FLISR. FLISR reduces the impact of interruptions on the distribution system through the installation of automated switches along the main line and tie points of a feeder. This allows a fault to be automatically isolated into a sub-section of the feeder and the uninvolved sub-sections to be resupplied via automated tie points, significantly reducing both impacted customers and outage durations. National Grid currently has communications capabilities to some of the reclosers on the distribution system, but does not currently coordinate their operation during faults beyond their local protective control. An ADA scheme would replace manual tie points between adjacent feeders, to provide for downstream restoration. It also would integrate enhanced telecommunications and additional control on existing protective switches, and potentially add switch locations as necessary to optimize system reliability.

National Grid proposes to select a group of high value feeders per area for the field deployment of both ADA and CVR/VVO (listed in Attachment 1). As described in Section 4.2.2, during the STIP period, ADA and CVR/VVO will be outfitted together, on 46 of these feeders.[22]

In the first two years of the STIP, the required enabling communications and back office infrastructure to support the STIP scope of the CVR/VVO and ADA deployment will be implemented. Field implementation of CVR/VVO will follow the AMI deployment of two areas per year in years three, four and five of the STIP, resulting in 46 Feeders in total. This approach will streamline the engineering analysis required by leveraging the Distribution Planning Area Study process already in place, in order to support the ADA deployment.

As work force realignments are completed and the DSCADA/ADMS system becomes available, the rate of deployment of the ADA scheme would increase to approximately 24 feeders per year for years 6-10 of the GMP. The candidate feeders were selected using a data model containing the following feeder information:

- Physical characteristics
- Historic and projected loading and capacity
- Inspection and maintenance
- Historic reliability
- Substation automation levels

4.2.3.1 Anticipated Benefits

There are many anticipated benefits of ADA that align with the Department's Grid Modernization objectives. These include:

[22] This is the case for the Balanced Plan, Grid-Focused scenario and Opt-In scenario. The AMI-Focused scenario does not include ADA, and it only includes CVR/VVO for 89 feeders in the ten year GMP period.

- Reducing the effects of outages – National Grid anticipates a 25% reduction in main line customer minutes of interruption ("CMI") on the individual feeders targeted for the ADA deployment. This projected reduction is based on historical analysis of actual past performance in the SES, as well as calculated anticipated reductions from historic outages.
- Optimizing demand – The additional operational data collected by the automated switches will support the improved management of the distribution system, assisting in demand optimization.
- Integrating distributed resources – The additional operational data collected by the automated switches will support the improved management of the distribution system, assisting in the interconnection of DG and potential integration of distributed resources as a tool to operate the system.
- Improving workforce and asset management – Operational efficiency will improve due to fewer truck rolls related to faults, outage restoration, and planned switching.

4.2.3.2 Dependencies with other parts of the GMP

The deployment of ADA is contingent on the deployment of several other elements of the GMP, as follows:

- Telecommunications, both back office and FAN
- ADMS/DSCADA is required for wider scale deployment beyond first 46 feeders
- Data Management and Operations integration.
- FTEs to support the design and deployment of the systems
- Training for Distribution Planning

4.2.3.3 Preparation for Years Six - Ten

Expansion of the ADA program beyond the initial STIP scope is dependent on the availability of a new ADMS/DSCADA system. National Grid anticipates that deployment of the ADMS/DSCADA for ADA will be complete by the end of the STIP.

4.2.4 Feeder Monitors

National Grid has 1108 distribution feeder circuits in Massachusetts. Of these circuits, less than half are monitored by an interval sensor and therefore do not report live data to the operational control centers or inform electric planning with interval data. This lack of historic and live interval data represents a gap in National Grid's situational awareness. While the electric system of the past has been operated and maintained without this data, having this data available in the future is important to enabling the modern electric grid, which has increased reliability requirements and proliferation of DERs. Installing feeder monitors will fill this awareness gap and assist in more efficient operation and maintenance, planning and storm recovery, in furtherance of the Objectives.

Currently, there are 606 Feeders (469 overhead) in National Grid's distribution system which lack sensing capabilities. As large upgrades are made to substations and circuits, often this need is addressed with sensing and communicating equipment. National Grid proposes to deploy head-end mainline feeder monitors which would be used to capture real time voltage, current and power. The operations control center will use this information, as will electric system planners, to help optimize the control and design of the electric system. While this section will focus on the feeder monitor deployment scale and scope, the cost of the data storage and transport will be captured as part of the enabling investments of the GMP.

4.2.4.1 Introduction to Technology

In recent years there have been significant advances in wireless and mobile technology. There are now several options for clamp-on wireless primary distribution feeder monitors for overhead circuits. The Feeder Monitors selected by the Company use advanced technology that allows them to avoid separate communications wiring, power supply wiring or voltage reference cabling. In other words, the device itself is self-contained and can be installed with minimal expertise and present minimal safety risk. These feeder monitors clamp into the primary conductors (individually) and wirelessly communicate to a control box located on a nearby pole. Further, unlike most other clamp-on type devices, the feeder monitors proposed not only capture information on current, but also voltage, power, and harmonic content.

The lack of additional wiring requirements is a key benefit of these feeder monitors. In addition to being low cost to install, they present minimal safety concern for workers interfacing with them due to the lack of ground and communication wiring needed. It is estimated that installing and commissioning these types of feeder monitors could take less than an hour, a significant net reduction from today's traditional feeder monitors[23]. National Grid currently is piloting these advanced feeder monitors in parallel with the equipment installed in its SES Pilot area in Worcester.

[23] Estimates do not include travel time, job briefs, safety reviews and training.

4.2.4.2 Scope and Schedule of STIP Deployment

Of the 1108 circuits in Massachusetts, 469 of them are overhead circuits that do not have real time power monitoring, and therefore are eligible to have this technology installed immediately. These 469 circuits are not part of the circuits proposed to have CVR/ VVO or FLISR installed. As part of the STIP, National Grid proposes that these feeder monitors will be deployed on the eligible overhead circuits following the field deployment schedule, within the first five years.[24] Feeder monitors are incorporated in all scenarios except the AMI focused scenario, where they are not included.

These feeder monitors will necessarily need to be integrated into the Company's existing Energy Management System ("EMS") and PI Database during the first five years. In this time period, the EMS and PI will be the only Company systems available to integrate and log the data for use by operations and engineering. Following the five year development effort to implement a DSCADA and ADMS, these feeder monitors will be migrated over to the new ADMS, once operational in year 5. The Company's existing EMS is space-constrained, so a minimum data set will be captured during the first five years, and full data will be captured in the new ADMS.

During the first two years of the GMP, National Grid will evaluate the feeder monitors in the market and establish a standard device through a competitive procurement process. The costs presented in the estimated GMP budget are based on cost information from the SES Pilot as well as other Company trials.

4.2.4.3 Anticipated Benefits

This program will provide the operations control center with real-time information to assist in performing system reconfiguration following contingencies and during peak loading periods. The Company's electric planning group also will benefit directly from the historical logging of data, which will assist in designing systems solutions. This will lead to a more efficiently planned system, using direct time interval feeder data, instead of annual and peak usage data as is done currently.

[24] Feeder monitors would not be deployed in the AMI-Focused scenario.

4.2.4.4 Dependencies with other parts of the GMP

These feeder monitors are designed to be easily integrated into an existing substation, or distribution circuit. The impact on the workforce will be minimal and therefore extensive training will not be necessary. These Feeder Monitors are flexible in their ability to communicate, and the Company will leverage the FAN for communications where possible. Otherwise, cellular services will be used for remote locations.

4.2.4.5 Preparation for Years 6-10

National Grid currently anticipates that Years 6-10 of the GMP will consist of the installation of feeder monitors on the more complicated and site-specific underground feeders. During the STIP period, the Company will investigate underground feeder monitor options through limited field experimentation and a competitive procurement process. Further, in Years 6-10 the data will need to be migrated to the new ADMS system.

4.2.5 Customer Load Management

Research shows that customers are interested in having more visibility into, and control over, their energy usage. In a study in which National Grid surveyed Massachusetts residential and commercial customers, 60% of customers surveyed stated interest in energy management devices that allow them to see and control their usage, which would help to meet the number one need identified in the survey, which was for more information.[25] Additionally, more than 60% of all customers surveyed stated interest in interactive and programmable thermostats with remote control and self-programing capabilities.[26]

National Grid proposes to offer a CLM solution, in order to give customers more information about and control over their energy use, to maximize potential energy savings and ultimately to leverage the potential opportunities made possible through AMF. The CLM solution will integrate customer-facing devices and demand response services in a way that simplifies

[25] National Grid, Value Proposition Research: A Study of 3 Energy Solution Areas for Massachusetts (May 29, 2014), p. 20 (“Value Proposition Research”).

[26] Value Proposition Research at p. 20.

customers' energy management experience and enables customers to become more engaged in their energy management, either actively and/or passively through technology and intelligent automation. Customers will save on energy supply costs and realize other benefits[27] including increased information, control and convenience. National Grid plans to offer this solution as an extension of its successful energy efficiency programs[28] which have been shown to increase customer engagement and customer satisfaction.[29] Successful implementation of CLM will enable customers to reduce the supply portion of their bills.

4.2.5.1 Description/Functionality of CLM

The CLM solution will include devices, appliances, equipment, services and electronic portals that will be rolled out in a phased approach for both residential and commercial customers. Customer devices can include programmable controlled thermostats ("PCTs"), smart plugs, demand response-enabled appliances and DR-enabled commercial equipment. The Company plans to seek funding for customer-facing equipment through its 2016-2018 energy efficiency plan and it proposes to pay for the CLM gateway, portal and DRMS through its GMP. The Company proposes to build out a flexible program platform that can grow as more technologies and vendors enter the market.

In addition to the devices noted above and as further described in Attachment 6, the Company proposes to offer a fully-integrated, web and mobile platform that makes it easy for customers to install, program, and remotely control devices through the devices and mobile applications of their choice.[30] Together, the platform and mobile capabilities will provide customers with an

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[27] Value Proposition Research at pp. 14-15.

[28] As the Department is aware, the Company and the other energy efficiency Program Administrators (PAs) filed a draft of the statewide energy efficiency three-year plan with the Energy Efficiency Advisory Council (EEAC) on April 30, 2015. This draft includes a National Grid-specific proposal to offer broader demand response solutions to reduce customer usage during times of peak demand. National Grid and the other PAs will file their statewide and individual three-year energy efficiency plans for the years 2016-2018 with the Department in October 2015.

[29] JD Power, "2015 Consumer Engagement Study", p. 7, 8, 11

[30] In a National Grid survey, 60% of all Massachusetts customers stated interest in energy management devices that allow them to see and control their usage. 84% of business customers and 69% of residential customers showed the most interest in energy management devices that are hosted on computers, while 68% of business customers and

enhanced view into AMI and billing data, and control over smart devices and equipment, with the option to automate that control. This platform solution would display individual energy usage in near-real time. The platform would also be integrated into National Grid's customer management systems – including billing, meter services, storm response and call centers. The Company believes that this would improve customer relations and satisfaction.

In addition to allowing customers to plug in their preferred devices and equipment, the Company proposes to enable vendors to compete to provide preferred demand response solutions. At different stages of the grid modernization roll-out, demand response capability will range from messaging customers with customized energy usage analyses and management tips, to fully-integrated direct load control with TVRs (described below). While the Company and its vendors will have the ability to remotely control customers' DR devices, customers will have the capability to override DR events. The details of customer participation will be subject to individual customer-vendor agreements.

There are many components of an integrated CLM solution. The Company plans to implement these components in a phased roll-out described below.

4.2.5.2 Years 1-5

For CLM program purposes, the Company is dividing roll-out into two time periods: the time before TVRs are available and the time after TVRs are available. For the STIP period, the Company plans to help prepare the market for AMF by building out its customer-facing load management devices and services. Currently, the Company is offering customers PCTs through its energy efficiency programs. The Company proposes to build on the success of these programs by broadening these offerings to include a wider range of both Wi-Fi- and Zigbee-enabled devices as well as vendor-managed demand response solutions. National Grid plans to include near-term customer load management equipment in its energy efficiency three-year plan, which it will file with the Department in October 2015. The Company will propose to have costs associated with customer-facing CLM devices and equipment recovered through its energy efficiency programs. Please see Attachment 7 for more information on CLM devices and equipment.

63% of residential customers showed the most interest in energy management devices that are hosted on a Smartphone/Tablet App. Value Proposition Research at p. 20.

In parallel to these activities, the Company also plans to install AMI infrastructure, roll out TVR and purchase and implement a DRMS. While AMI and TVR are discussed in other sections of this Plan, the proposed DRMS roll-out is specific to CLM and described below. DRMS is a software system that communicates with customer devices to dispatch demand response events that occur during selected times, such as peaks on the utility's system and or during economic peak opportunities for customers. A more detailed description of a DRMS can found in the Attachment 8. The DRMS will enable better integration and control of demand response, whether performed by National Grid or by a third party.

In the STIP period, the Company will partner with vendors to administer load curtailment on a voluntary basis, with time varying rates as AMF becomes available. Signals and messaging will be sent through customers' Wi-Fi networks or through other means of communication administered by vendors. By the end of Year 5, the Company expects to have fully integrated AMF, including AMI and TVR, leading to the second phase of its roll-out in Years 6-10, described in Section 4.3.4.

4.2.5.3 Benefits

By the end of the STIP period, the Company believes that its energy efficiency DR programs will have increased the penetration of DR-enabled devices, appliances, equipment and messaging services. This increased market penetration will position customers and the collective system to realize savings from real-time AMI data and TVR on a more meaningful scale than if the CLM devices and services did not exist. This assumption is validated in part by a survey National Grid conducted with its Massachusetts customers, which shows that most customers are willing to shift their energy usage to avoid higher costs on their bill. Specifically, the survey found that more than 60% of residential customers are extremely or very willing to shift some demand in response to time-varying rates.[31] For this reason, National Grid believes that when given the opportunity to shift energy usage through the use of devices, equipment and TVR, customers will take advantage of the opportunity. The magnitude of this opportunity is demonstrated through the business case analysis.

[31] National Grid, Value Proposition Research: A Study of 3 Energy Solution Areas for Massachusetts (May 29, 2014), pg. 19.

4.2.5.4 Funding Source

The Company has proposed, in its draft three year Energy Efficiency Plan, to offer incentives on the up-front costs of customer end use devices through energy efficiency funds. The Company has included the costs of a DRMS in its GMP budget.

4.2.5.5 Access to Customer Consumption Data

As part of the fully-integrated, open web and mobile platform, customers will have a detailed view into their AMI and billing data, including displaying individual energy usage in near-real time. Customers will be able to see their energy usage in an hourly and daily kwh/cost format for the current daily period. Customers will be able to view comparable daily historical usage patterns for consumption and costs over a weekly rolling period.

As stated in the Order, National Grid will make customer consumption data available to third parties, with customer permission. Third party vendors will be required to sign a Non-Disclosure Agreement (NDA) which prohibits the vendor from disclosing any customer information without the consent of National Grid or the customer, and which is consistent with current vendor agreements. All third parties will be required to adhere to National Grid security procedures and customer privacy guidelines, which meet all federal and state requirements. National Grid will develop commercial agreements with third parties with reasonable terms and conditions.

Regarding the Department's direction to make aggregate data available to third parties, National Grid will do so after receiving customer consent. Any individually-identifiable customer information will be removed using National Grid standard business practices in order to ensure that no individual customer can be identified by a data set supplied by the Company. National Grid will work with the Department to implement procedures for sharing aggregate data with third parties.

4.3 Field Deployment Years 6-10

4.3.1 Conservation Voltage Reduction /Volt-VAR Optimization

National Grid proposes to continue the deployment of CVR/VVO in years six through ten of the GMP by continuing to work through the remaining high value feeders, at approximately 24 feeders per year.[32] The CVR/VVO design will be integrated into the planning process in order to fully support the increased rate of deployment. This is dependent on the ADMS/DSCADA system being available to support the ramp up of the CVR/VVO deployment. A review of the feeder selection process will be undertaken using information from the completed installations to fine tune the targeted deployment of the CVR/VVO program.

4.3.2 Advanced Distribution Automation

National Grid will continue the deployment of ADA/FLISR in years six through ten of the GMP by working through the remaining high value feeders, at a rate of approximately 24 feeders per year.[33] As with CVR/VVO, the ramp up of FLISR deployment in years six through ten is contingent on the new ADMS/DSCADA system being available. A review of the feeder selection process will be undertaken using information from the completed installations to fine tune the targeted deployment of the ADA/FLISR program.

4.3.3 Feeder Monitors

In years 6-10 of the GMP National Grid will expand its feeder monitors program to include two initiatives: underground feeders and step down transformers. [34]

National Grid anticipates that the remaining 137 underground feeders without interval metering will be fitted with mainline sensing devices. However, underground feeders have specific environmental requirements that are challenging for technology to easily solve today. Therefore, the feeder monitors which could potentially fit this need will be explored and evaluated during the STIP period.

[32] This would be the case in the Balanced Plan, Grid-Focused scenario and Opt-In scenario. In the AMI-Focused scenario, CVR/VVO would only deploy an additional 65 feeders in years 6-10.

[33] This would be the case in the Balanced Plan, Grid-Focused scenario and Opt-In scenario. In the AMI-Focused scenario, no ADA programs are planned.

[34] This would be the case in the Balanced Plan, Grid-Focused scenario and Opt-In scenario. In the AMI-Focused scenario, no Feeder monitor programs are planned.

In addition, the Company currently has 370 step-down transformers distributed across its feeders. These transformers step down voltage from 13.8KV to 4KV to serve local loads. These system designs are challenging to support operationally, and monitoring them will greatly help electric planning, as they are often points of congestion on the electric system due to their inherent current limitations. Adding low-cost feeder monitors to these areas will allow electric planning to better assess these areas, identify more accurately when upgrades will be necessary, and determine the most effective upgrade paths.

While the exact costs of these two programs will be determined during the first five years of the GMP, it is estimated that this scope will be similar in cost to the first five years.

It is anticipated that the scope and schedule for this program will be similar to that undertaken in years one through five. Implementation of this program will be targeted to selected feeders, and will be deployed at a reasonable rate.

4.3.4 Customer Load Management

In year six, the Company plans to build on its energy efficiency demand response programs by allowing customers and vendors to “plug and play” new devices, technology, and applications into its CLM solution.

By year six, as distribution system planning and operations, procurement and other capabilities become more dynamic, customer load, along with generation and storage, will begin to be able to be managed more optimally for both economic and reliability purposes. The integration of AMI, TVRs and DRMS will enhance the sophistication of CLM capability at this time. National Grid and/or its vendors will be able to administer DR events and pre-programmable criteria that are paired with TVR to enable customers to dynamically lower their energy usage during periods of high demand. Functionality may also have expanded to include the potential for environmental dispatch through other technologies.

5. Enabling Infrastructure Investments

5.1 Overview

In order to support the investments being proposed in the field deployments portion of the GMP, specific investments must be made in the Company's internal infrastructure. These investments have been generally grouped and categorized as follows:

- Communications: This includes all infrastructure to connect National Grid IT/OT infrastructure with field devices in the service territory. This includes additional backhaul networks, substation fiber installations, a multi-tiered field based wireless communication network, and radios for devices without embedded communications.
- IT/OT: This refers to internal investments made integrating all of the above systems together, as well as integrating the Company's existing systems to new ones. This also includes comprehensive data management, cybersecurity and data analytical functions. This also incorporates the AMI back office systems, includes the MDMS, the head end system and the labor costs to install and maintain them, which were discussed in Section 4.2.1. Communications and IT/OT are discussed together in the remainder of this section.
- WTAM: Grid modernization technologies will require numerous changes to the Company's existing workforce, including hiring additional personnel and training of impacted personnel. In addition, advances in asset management and system operations toolsets will require higher levels of data granularity and accuracy than in the past. To accommodate this, National Grid proposes the expansion of computer-based operating functions through the use of accurate near real time data and the use of mobility services for the workforce.
- ADMS/DSCADA: This refers to the collection of investments required to bring a fully incremental DSCADA and ADMS online. This includes foundational investments such as preparation of GIS data, as well as the installation and integration of the system itself. It also includes integrated functions such as OMS.
- Billing and Systems: Changes will be required to National Grid's billing systems and customer service support in order to accommodate the new rate structures, greatly increased volumes of data and new functionalities that will result from grid modernization.
- Cybersecurity and privacy: Cybersecurity and privacy provisions will support the grid modernization efforts of National Grid by maintaining a reliable and secure electricity infrastructure and ensuring the protection needed for the confidentiality and integrity of the digital overlay. National Grid is proposing a series of investments and services in support of grid modernization.

- Other initiatives which will enable the GMP include the MEO Plan and a program management office to manage the deployment of the GMP. These efforts are discussed in sections 9.2 and 9.8, respectively.

5.2 Short-Term Investment Plan Years 1-5

5.2.1 Communications, Information and Operation Technologies

A fundamental component of grid modernization is a systems architectural framework that can deliver "any data, any service, anytime." Building this technology foundation is at the infrastructure cornerstone for delivering the capabilities of the proposed grid modernization investments, including AMF, CVR/VVO, ADA, feeder monitors, ADMS/DSCADA, CLM and integrating DG. The major components of the systems architectural framework are:

- Comprehensive Integration Services (CIS) - The integration services to enable the exchange of information between systems, services and devices.
- Enterprise Analytics (EA) - The big data analytics capabilities to allow for the analysis of the data gathered from grid modernization investments combined with existing and third party data sources, providing valuable output reflecting current state as well as predictive and prescriptive outcomes.
- Communications and Networking - A set of communication services that transfer information with the correct prioritization and quality of service to the appropriate destination.
- Integrated Network Operations Center (INOC) - To actively monitor, manage and maintain the integrated set of services and infrastructure and provide a single point of contact for support and operations through a cross functional set of people, processes and technologies.
- Applications and devices - The deployment of distribution solutions supporting the monitoring, management and control of the distribution grid.
- National Grid is using the Smart Grid Architectural Model ("SGAM"), as defined by National Institute of Standards and Technology ("NIST"), to help define the building blocks for its grid modernization systems architectural framework. The SGAM uses an enterprise-wide, service-oriented approach to describe the smart grid architecture. This enterprise architecture approach mitigates stranded costs typically experienced in "one-off" soloed solutions, and minimizes the expense, configuration and management complexity that individual built-to-purpose applications often experience. The enterprise services proposed as part of the GMP are aligned to this approach.

5.2.1.1 Current and Future States

Figure 5 below is the adapted view of National Grid's current systems architecture state. National Grid has many point to point (P2P) solutions in place that have been developed over the years, as opposed to fully integrated systems that connect through a central point. Many of these solutions do not move data in real time, which inherently limits their capabilities.

Figure 5: Architecture Framework (SGAM): Current State Conceptual View

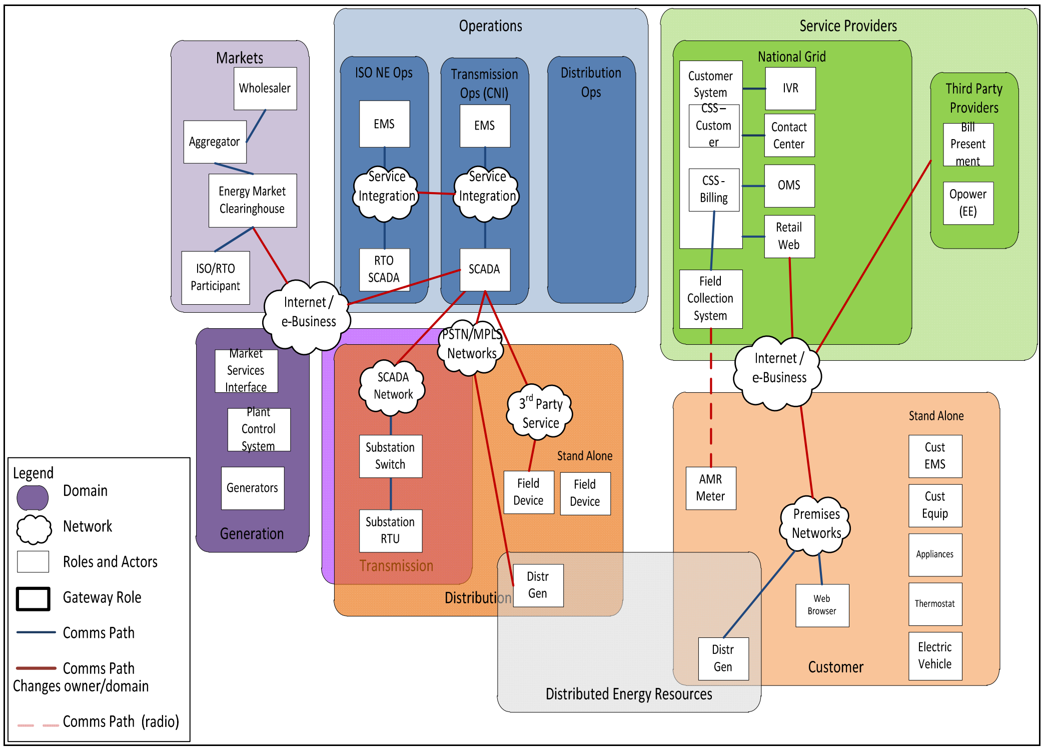
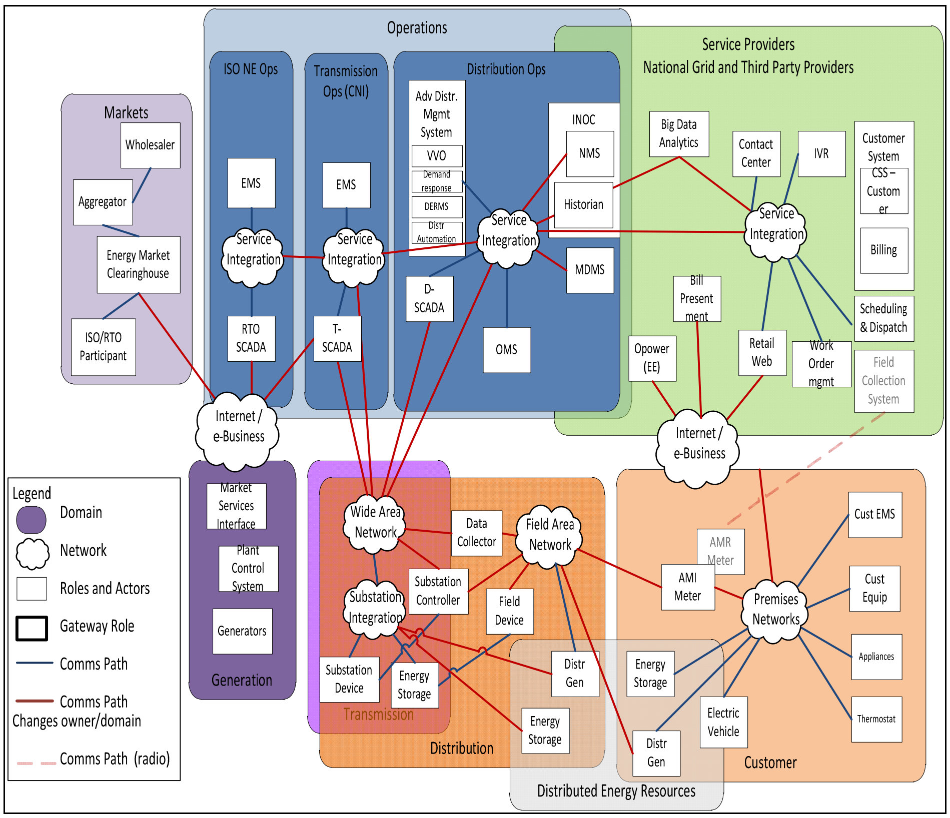


Figure 6 below is an adapted view of National Grid's proposed future state of the systems architecture for grid modernization. The figure shows that by using reusable integration services along with a new common communications network, data can move in real time to many different applications. These new services, communications and capabilities are the foundation of grid modernization. The figure identifies some of the key changes that will occur, including the implementation of new systems, communications and services that will enable grid modernization.

As represented in the figure, one example is an AMI meter that will be installed on a premise. This meter will communicate wirelessly to the FAN collection device. The collectors are deployed in the neighborhoods and communicate to the devices in that neighborhood. The collectors communicate to the wide area network ("WAN") where data is backhauled through the network to waiting service integrations or CIS. As illustrated, many applications will have services requesting data, many of which would be real time. In this example, meter data would traverse the network and could be ingested by varying applications such as MDMS, VVO, Retail Web[35], INOC and EA based on real time requests, simultaneously.

The FAN, WAN, CIS and EA would be used for many different devices and many different services, and could be used any time.

Figure 6: Architecture Framework (SGAM): Future State Conceptual View



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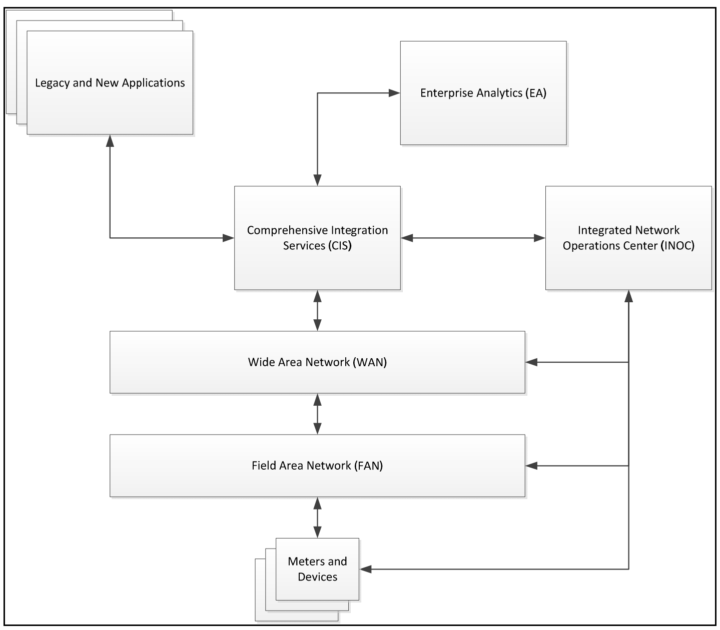
[35] 'Retail Web' refers to customer facing online applications.

The framework diagram below (Figure 7) represents a more detailed view of how the services and components fit together, starting with the devices in the field. Each of the devices will require connectivity to communications services, on to either other devices (sometimes called machine-to-machine communications) or to applications and the EA platform. Communications will be available at various levels, from the neighborhood via meter-to-meter communications, to the FAN and finally to the WAN.

In the current architecture environment, data is made available through the development of batch interfaces, for ingestion into other applications. In this environment, development of interfaces must be done on an application by application basis. Data is not available for real-time use. In the proposed systems architecture framework for grid modernization, the combined uses of the key components noted earlier allow for a service-based architecture and make data available to applications in real time.

Figure 7 below represents the proposed design of a service-oriented architecture supporting grid modernization.

Figure 7: Grid Modernization Framework Overview



The remainder of this Section describes the five components of the proposed systems architectural framework for grid modernization.

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5.2.1.2 Comprehensive Integration Services

CIS is the middleware that is required to move data between systems, automate and manage business processes, transfer files between entities and enable real-time and batch integration of data. National Grid will develop these capabilities to enable real time integration, automation and orchestration of business processes enterprise-wide for existing legacy systems, and implementation of new systems building on process and systems efficiencies, needed for grid modernization.

The main expected benefits are:

- A service-driven architecture establishes a framework that supports business service orientation. Standard methods of integration are leveraged.
- Business services are aligned to repeatable business tasks – e.g. Outage, Customer notification. Reusable services can be called from various processes.
- Modular applications with a set of related and integrated information services ("IS") are constructed to be flexible in supporting the business process. There is an ability to orchestrate processes across lines of business.
- Service thinking becomes the way of integrating the business through linked services with the value outcomes and agility that they bring. There is an ability to respond quickly based on information availability.

National Grid has an established enterprise standard for CIS. Some of the components that make up a CIS are: an enterprise service bus (ESB) which delivers a standards-based integration where performance, scalability and reliability are critical requirements; business process management (BPM); managed file transfer; business activity monitoring; and complex events processing.

5.2.1.3 Enterprise Analytics

Grid modernization will introduce new data that previously was not available. This includes interval consumption data that can be captured multiple times an hour (e.g., in 15 minute intervals), data from feeder monitors and other sensors deployed on the grid, grid devices providing status information and a growth in DER information. National Grid can use this information to improve efficiencies in operations and reduce costs. Data and analytics will provide insight to optimize distribution operation, asset condition health, asset performance information and work management, to name a few examples.

EA architecture is a storage repository that holds a vast amount of raw data in its native format until it is needed. Data can be pulled pushed directly from the data sources into the storage area. All data in raw form will be available in one place. Once all data is brought into the storage repository, users can access relevant data for analysis and derive new insights through analytics.

The four major components of EA are:

- Data platform – This is based on Hadoop[36] architecture to store data and perform analytics, and includes the following functions:
- Store data in its native form
- Ingest information in both streaming and batch, structured or unstructured
- Execute complex data analysis processing tasks
- Master data management – This provides processes for collecting, aggregating, matching, consolidating, quality-assuring, persisting and distributing data throughout an organization to ensure consistency and control in the ongoing maintenance and application use of this information.
- Utility data model - This is a pre-built, standards-based data framework to establish a foundation for business and operational analytics across the enterprise, allowing users to leverage common analytics and pre-defined cross-domain relationships.
- Visualization analytics and business intelligence – This provides flexible reporting, dashboards, data exploration and visualization capabilities, which allow business users to leverage data for decision making and perform actionable analytics.

The proposed scope of the EA platform includes:

- Implement a big data platform based on Hadoop.
- Provide the toolsets to manage data governance, quality and master data.
- Establish the utility data model, which defines the data and relationships providing a flexible platform in order to be able to quickly and easily enable future changes as requirements change over time.
- Provide analytics based visualization tools
- Use a set of services to extract, transform and load (ingest) data from various sources and various data types.
- Provide an environment to enable collaboration and sharing analytics across the Company.

[36] Hadoop is an open-source software framework written in Java for distributed storage and distributed processing of very large data sets on computer clusters built from commodity hardware.

- Provide self-serve data, which empowers the business to leverage data while minimizing IS involvement.

Deployed communications and network capabilities will enable data to be analyzed as it becomes available, allowing the information to be used to predict and potentially avoid outages or disruptions in service, improve operational capability and the potential to better inform distribution planning. National Grid envisions that this environment will be used by internal and external users who require access to the data, such as consumption data, with appropriate security protocols in place. An example of external users is third party vendors who produce consumption reports and provide energy efficiency tips. Today, the data is extracted from current systems and stored by the third party provider. The analytics platform will have the capability for third parties to access the data with appropriate security provisions built-in to support the required business functionality/capability. Any data managed by the third party would be subject to similar security protections outside the National Grid environment and available for use in a secure manner. The analytics platform also will be the staging source of data for existing and new data warehouses and databases.

5.2.1.4 Communications and Networking

Communication between devices in the field and Company systems is essential to the overall success of the GMP. The design of the network is driven by the communications requirements from all parts of the GMP. The main drivers for the telecommunications ("telecom") network plan are:

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

The telecom network will be comprised of two main layers. The FAN will provide "last mile" communications to the end devices. Meters and field installed grid controls are the endpoints on this network layer. The WAN provides the backbone and ties the end devices to major field communications nodes and ultimately the CIS and back end data systems. Substations and other Company facilities make up the major nodes of the WAN.

Due to the nature of the service territory, no one telecommunications and networking system will meet all requirements in all areas. National Grid therefore is planning for a hybrid network. Lessons learned from the SES Pilot and other initiatives highlight the need for a flexible strategy when deploying communications systems. On the FAN, the Company will design several connectivity options for field devices that will be transparent to the end systems which receive the data. At the WAN layer, the same philosophy will be followed. There will be a mix of both private network infrastructure and public network services where they make sense. The goal is to have a "toolbox" of options and solutions to provide robust two-way communications capability where it is needed to support the goals of the GMP.

5.2.1.5 Field Area Network Overview

After reviewing the market and the vendor responses from the AMF RFP process, the Company proposes to deploy a hybrid communications network that will provide multiple options for meters and distribution grid controls. The main method of communication for both types of devices will be a mesh network. National Grid will install the mesh infrastructure primarily on distribution poles and in substations. The Company expects to reach up to 95% of the field devices using this method. Mesh networks offer a number of attractive benefits including routing around device failures, redundant communications paths and low power operation. Meters and grid controls on the mesh network will communicate with each other and with collectors/data concentrators which will backhaul the operational data. The head end system will continually monitor devices on the network and alert operators if there are any issues. The mesh collectors/data concentrators will backhaul their data using several means including direct connection to substation routers, private radio and public cellular service.

In areas where a reliable mesh network cannot be formed, the Company will utilize cellular communications. These areas could include rural areas or areas where there are only a few isolated devices making it cost prohibitive to reach with mesh technology. The Company has identified hardware for both meters and grid controls that can leverage public cellular networks.

The head end system deployed will manage meters, grid controls and network infrastructure seamlessly whether they utilize mesh or cellular communications.

5.2.1.6 Wide Area Network Overview

The WAN acts as the communications backbone for all grid modernization technologies. It will transport meter and grid control data from various points in the field back to corporate IS systems. Communications nodes on the WAN will be interconnected through a variety of means. These include fiber, microwave, private wireless, public wireless, public Multi-Protocol Label Switching (MPLS) service and possibly satellite communications. During detailed design, the best communications technology for each location will be chosen based on a number of criteria. Factors include proximity to existing fiber, anticipated data load, terrain, mesh collector locations, and proximity to other nodes.

As part of the WAN build out, the Company proposes to extend communications to most, if not all, substations in its Massachusetts service territory. The Company will tie a number of substations together with fiber and microwave technologies creating major communications nodes. This will form a high capacity backhaul capability to transport meter and grid control data from the field back to the appropriate IT systems. The expansion of fiber connectivity will use existing private fiber, dark fiber rights obtained previously and the installation of new fiber where needed and cost justified. Smaller substations will use existing communications capability or be upgraded to MPLS service. In addition, some substations may utilize cellular service or satellite technology to establish connectivity. Along with backhauling the meter and grid device data, the substation network will support multiple substation automation, security and distribution grid technologies. The implementation of the WAN will provide a high capacity, secure, high availability, end-to-end path for the field technologies deployed as part of the GMP.

5.2.1.7 Integrated Network Operations Center

The INOC ensures proper operation of a communication infrastructure supporting multiple business services over a hybrid network. It provides a single point of contact for support and operations through a cross-functional set of people, processes and technologies. The INOC is a central location from which network administrators manage, control, troubleshoot and monitor one or more networks. The overall function is to maintain optimal network performance across a variety of platforms, mediums, networks, network segments and communications channels. An INOC is similar to a Dispatch Control Center used for managing the electric grid, and the Network Operation Center for all IS-related items that support the grid. The INOC would monitor the health and behavior of all aspects of the grid using an Operation Support System (OSS) and have the capabilities to provide a first level of incident response. Monitoring, provisioning and configuring are accomplished by computer-based tools that create alarms when anomalous activity, performance issues or system failures are detected. National Grid's grid modernization investments will provide many new business services and providing a single point of contact for these services is key to their efficient operation, will eliminate the risks of a point to point system in an electric grid with a greatly increased number of systems and will provide a better customer experience.

An INOC is typically a secure physical room or facility with computers along with dedicated systems and appliances that monitor the network and communication systems using various software such as commercial off the shelf (COTS) management suites and open source applications, along with the built in logging mechanisms of all network infrastructure systems themselves. Screens display real-time systems information and have the ability to display alarms for sub-optimal performance.

The key capabilities the INOC should have are:

- Service management (e.g. service desk, service assurance and overall ownership)
- Technical support groups, which represent the delivery services that are required to perform the technical roles to support, maintain, enhance and operate the overall service

To enable the key capabilities, support processes are performed by the service center including:

- Incident management, problem and request management
- Problem, asset and configuration management
- Service transition, including change management and new service introduction
- Governance processes and forums to report on service performance
- The scope of services provided by the INOC encompasses all applications, communications, network and home devices. In addition, while this group may not operate demand response events, they will be a critical part to their successful execution.

5.2.1.8 Applications

To support the CIS, Communications and Networks, EA and INOC efforts, it is important to have a fully-integrated application suite. Changes to current legacy applications to support real-time movement of data are needed in order to increase capabilities of those applications. New applications identified will have the capabilities to handle real-time data movement. National Grid has identified and reviewed key legacy and new applications and has assessed them for initial impact. These include applications like STORMS, ESRI, Cascade, Ischeduler, PI, CrossBow, and other National Grid deployed applications.

The main expected benefits of the applications proposal are:

- Standard methods of application integration including more real-time integration services.
- Leverage CIS capability for consistent feeds and updates between new and legacy applications.
- Streamlining current processes.
- Ability to orchestrate processes across lines of business.

5.2.1.9 Cost Estimates

The estimated capital and operations and maintenance costs for National Grid's proposed communications and networking, and IT/OT solutions for grid modernization are included in the tables in Section 3.2. These costs are based on the AMF RFP that National Grid issued for these items. The AMF RFP response used in the benefit-cost analysis is included in Attachments 24 of the GMP.

The communications/IT/OT proposal has embedded within it the use of cloud services in a number of places. Cloud Computing services allow users to access and use resources over the Internet rather than having the same resources in-house or managed by an external provider. The industry has further popularized the phrase "in the cloud" to refer to software, platforms and infrastructure that are sold “as a service.” Typically, the Cloud Service Provider (CSP) has actual servers, storage, etc. which host products and services from a remote location, so end users do not have to do so. Instead, end users can simply log on to the network without installing anything. The primary models of cloud computing service are known as software as a service (SaaS), platform as a service (PaaS) and infrastructure as a service (IaaS). National Grid recently went to market with an RFP for Cloud Services. Infrastructure as a Service (IaaS) costs were determined for grid modernization based on the needs to fully support applications. IaaS pricing was based on the output from a recent enterprise wide Cloud RFP process.

National Grid also went to market with an RFP for the four major components of EA. The costs are comprised of EA licensing, which were determined based on responses to the RFP. The level of support needed was determined based on contracts with National Grid Application Management Support (AMS) provider as well as supporting middleware hosting requirements. The documentation for the costs for Enterprise Analytics is included in Attachment 26.

CIS costs are comprised of middleware licensing and support costs (which were determined based on the existing commercial contracts) as well as supporting middleware hosting requirements.

For legacy application integration, function business owners estimated the level of effort required to integrate and update their applications. National Grid then assigned relative costs to each of these based on previous experiences for the purposes of estimating costs for the GMP. For the Integrated Network Operation Center, the resources and support necessary were estimated using other utility experiences with similar deployments.

5.2.2 Workforce, Training and Asset Management

Improving workforce and asset management is one of the four Objectives for grid modernization. The deployment of grid modernization technologies will require numerous changes to the Company’s existing workforce. This will include training existing and additional personnel to ensure knowledge of the latest installed equipment, tools and techniques, as well as the hiring of additional personnel to perform new tasks, provide support and conduct maintenance services.

In addition, advances in asset management and system operations toolsets will require higher levels of data granularity and accuracy than in the past. This chapter touches on both the changes the Company expects its workforce to undergo as well as the expansion of computer-based operating functions through the use of accurate near real time data and through mobility services. These changes will be key in ensuring a successful GMP deployment which will make progress on the Objectives.

5.2.2.1 Incremental Staff and Training

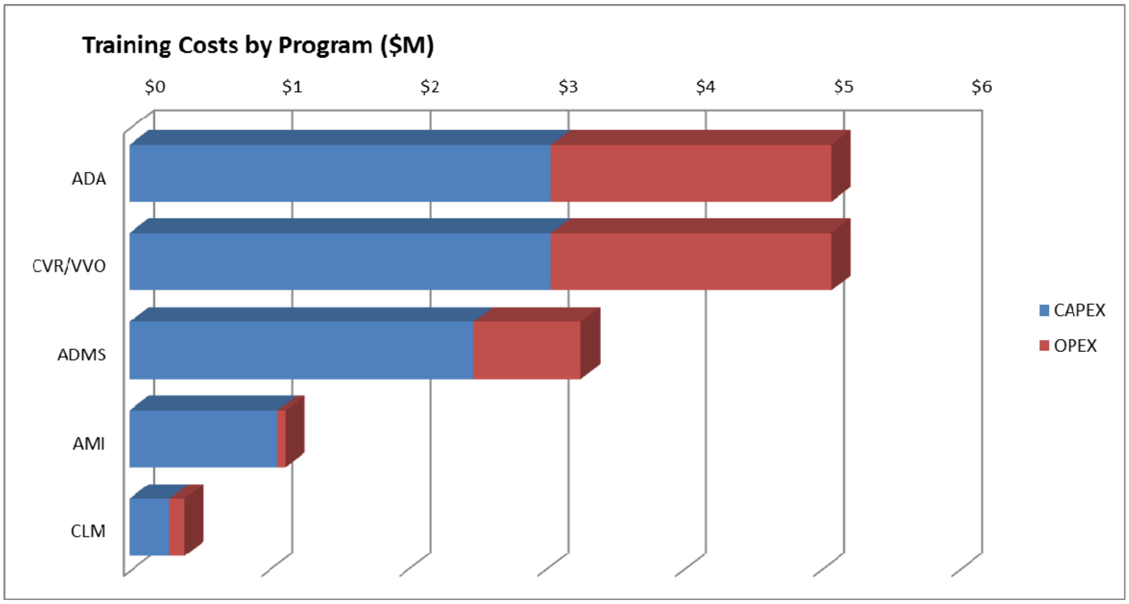
In order to determine the needs for training, ongoing support and maintenance, and incremental resources required by grid modernization, National Grid considered the needs within each of the components of its GMP. Information from the ongoing SES Pilot was incorporated, as well as past experience with project rollouts and significant change management efforts. These provided the basis of the analysis and shaped recommendations about whether to propose contractor or new Company resources.

The results of the Company's high level analysis indicated the need for training resources to both develop and deliver technical and process content, in order to operate successfully new grid modernization technologies and systems and to enable new ways of working in this modernized environment. Personnel in support and maintenance roles will fulfill a variety of needs in the GMP including: network planning to determine where smart devices are most beneficial; engineering design and support services; customer outreach; and program management.

Training

Though training is a small portion of the estimated total cost of the GMP, it will encompass an important change management effort. Estimates indicate that at least 1500 employees will need formal training across multiple Company departments. The field, network control center and customer contact center personnel will need the most education on the new technologies and processes; however training will be important for selected members of the wider organization as well. The Company estimates that over 135,000 hours of in person and online training will be required, and that training will cost approximately $14.9 million.

Figure 8: Training Costs by Program Balanced, Grid Focused, and Opt-In Scenario[37] ($M)



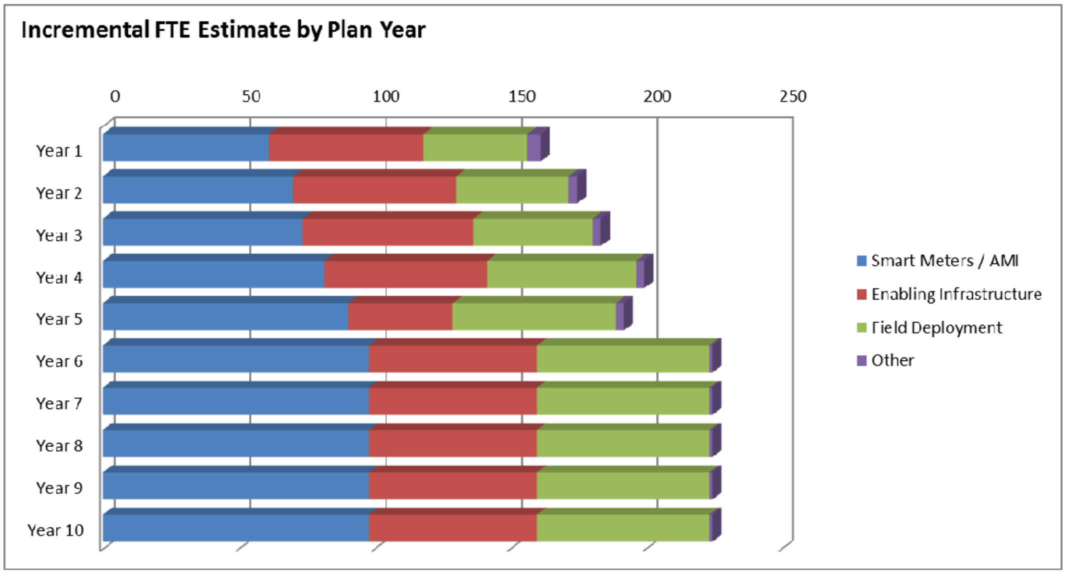
The Company expects that the training will be delivered in the most efficient and cost-effective manner possible by incorporating necessary changes into ongoing refresher training and existing curriculums where possible. Training will be held either at centralized training facilities or at Company field offices, operating locations, depending on which location makes the most sense for delivery of training. Other considerations, like access to the required training equipment and time to return employees to their primary assignments, will be used to help determine specific facilities that will be used in addition to training centers.

Incremental Staff

As noted above, additional training, deployment, maintenance and support staff will be needed to support the Plan. These costs are estimated at approximately $265 million over a ten year period for the Balanced Plan. Figure 9, below, illustrates the breakdown of estimated incremental full-time equivalent ("FTEs") personnel per plan program.

[37] Note that the costs for Training were kept constant for the AMI-Focused, Grid-Focused and Opt-In scenarios, however the Grid-Focused and Opt-In scenarios will require more training for ADA/VVO and ADMS/DSCADA.

Figure 9: Incremental FTE Estimate by Plan Year – Balanced Scenario



The cost for the estimated incremental FTEs was also captured per Plan program. Figure 10 below captures that breakdown for the Balanced Scenario.

Figure 10: Incremental FTE Cost Estimate by Plan Year– Balanced Scenario

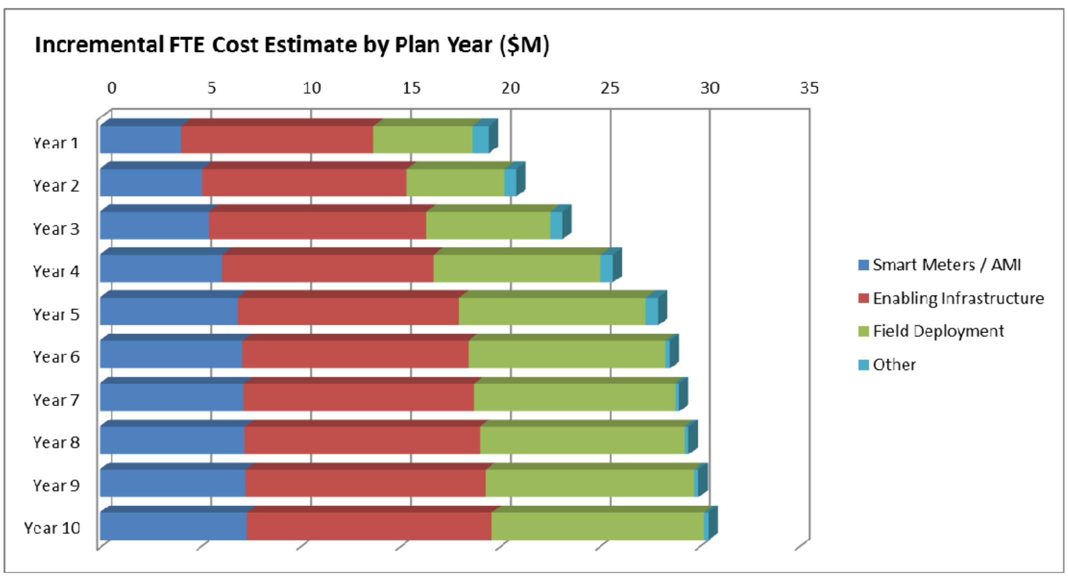


Figure 11 and Figure 12 show the incremental FTEs and costs for the AMI Focused scenario. This scenario has $197M allocated to incremental FTEs over ten years.

Figure 11: Incremental FTE Estimate by Plan Year – AMI Focused Scenario

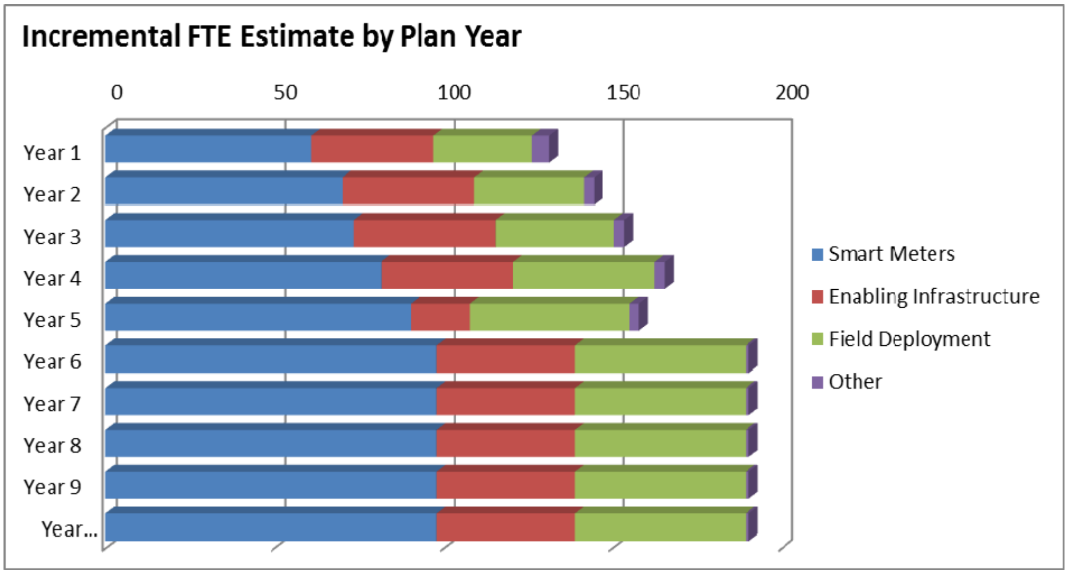


Figure 12: Incremental FTE Cost Estimate by Plan Year– AMI Focused Scenario

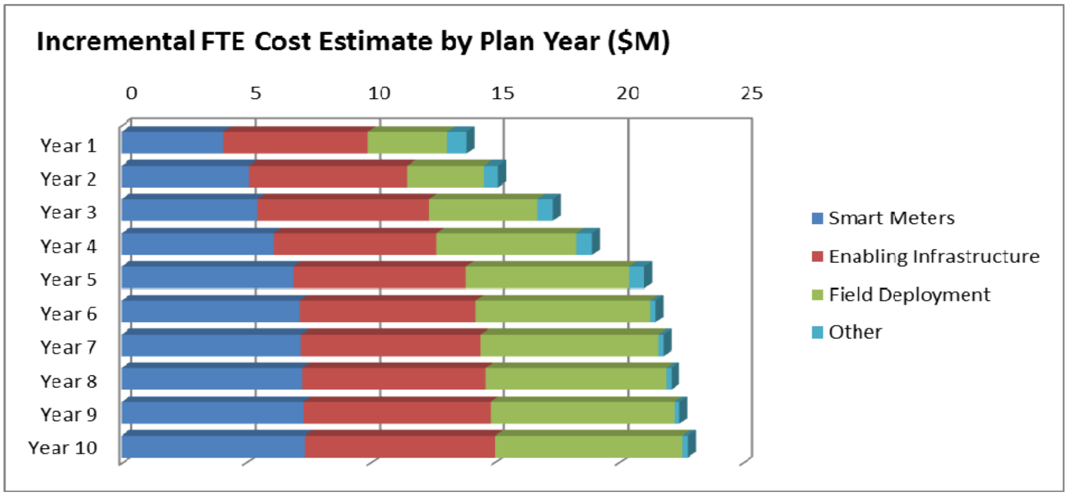


Figure 13 and Figure 14 show the incremental FTEs and costs for the Grid-Grid-Focused scenario. This scenario has $254M allocated to incremental FTEs over ten years.

Figure 13: Incremental FTE Estimate by Plan Year – Grid Focused Scenario

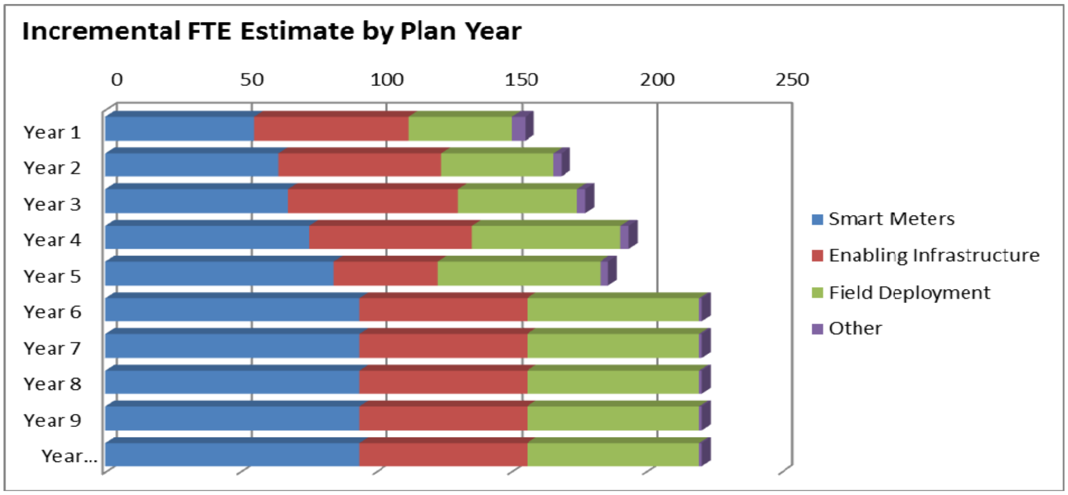


Figure 14: Incremental FTE Cost Estimate by Plan Year– Grid Focused Scenario

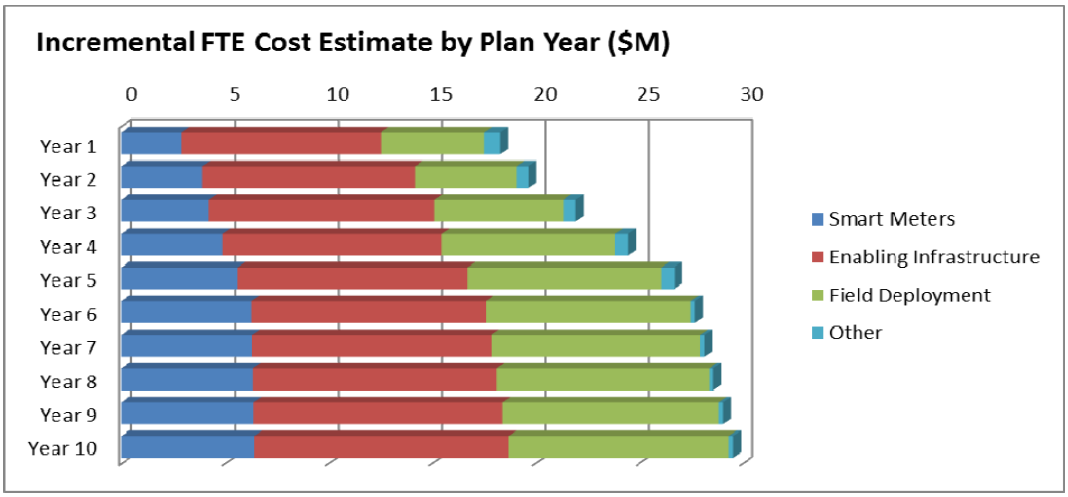


Figure 15 and Figure 16 show the incremental FTEs and costs for the Opt-In scenario. This scenario has $102M allocated to incremental FTEs over ten years.

Figure 15: Incremental FTE Estimate by Plan Year – Opt In Scenario

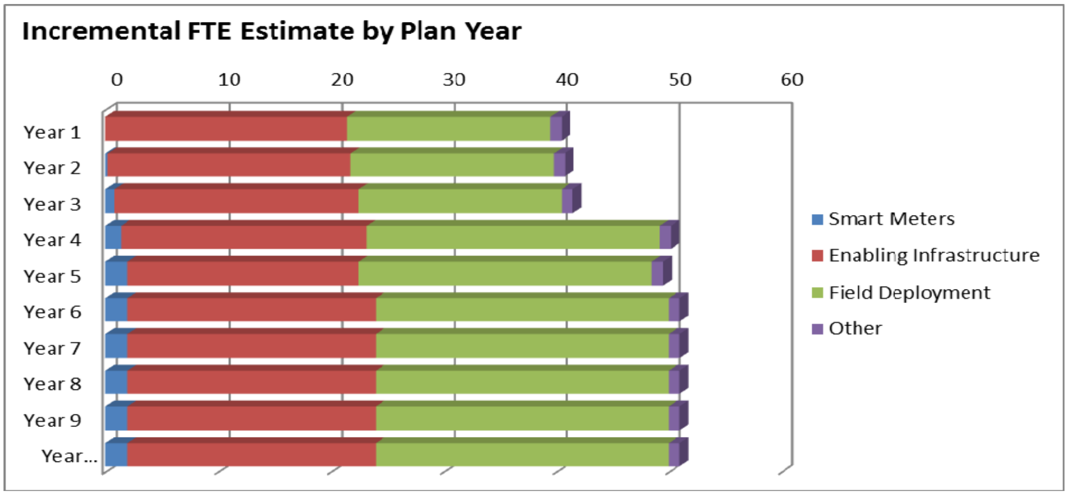
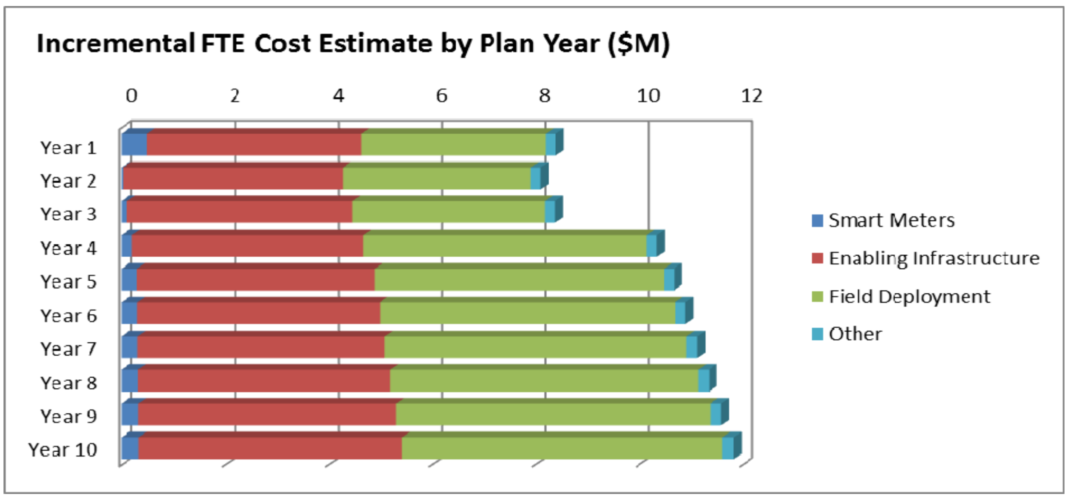


Figure 16: Incremental FTE Cost Estimate by Plan Year– Opt-In Scenario



Additional contractor and National Grid FTEs will support the grid modernization initiatives by providing services including program management, engineering services and analytical/systems support. In addition, the Company will continue to identify and deploy process improvements and implement effective change management as part of the GMP, which these resources also will support.

5.2.2.2 Asset Management

National Grid proposes to deploy electronic tools and mobile tablet devices to improve the Company's capabilities for key workforce and asset management processes, in order to advance the Objectives. Each of these tools will be built with the needs of the field workforce in mind. The deployment will focus on intuitive solutions that, while enabling the collection of data for necessary processes, will do so in a user-friendly manner and facilitate their efficient use. Expansion of mobile tools will allow the Company to build validations into processes at the source of data collection, which will reduce the likelihood of errors and undue delays. The Plan addresses process areas where there is an opportunity to achieve cost-effective benefits for customers and the Company.

As part of the Plan, the Company will invest in asset tools and related management tools to improve data capture capabilities, which will facilitate greater insight into equipment performance and/or reduce the time required for related processes. The proposed tools are:

Electronic as built data collection:

This involves the deployment of a tool to capture asset information in the field when facilities are constructed, replaced or retired. Field workers will be able to electronically capture structure location using GPS, associate equipment to these locations and capture operating attributes. The tool will be built to leverage barcoding or RFID technology as much as possible, reducing the effort on the part of the field worker and driving greater data accuracy. This capability enables benefits associated with reductions in time to close and capitalize assets, improvements to data accuracy and greater supply chain insight, especially during storms.

Full electronic asset inspections:

The Company will further deploy tools to capture all asset inspection data electronically. Part of this effort will include improvements to the accessibility of inspection data for system planners / engineers and enablement of feedback loops for asset record improvements based on field observation. Capturing all inspection data in this way will increase compliance with established procedures and improve clarity of information.

Map access and feedback:

Deployment of an application to provide access to the latest operating maps from the field will vastly reduce reliance on paper processes. Additional functionality would give field personnel an electronic feedback tool to report discrepancies between map records and real world observations for expedited correction.

Electronic standards and Electric Operating Procedures ("EOPs"):

Deployment of tools to electronically manage and track updates to standards and operating procedures. As part of this initiative the Company will provide access to the latest information on tablets in the field. This capability will eliminate the need for paper-based update processes and help reduce unintentional compliance and safety issues.

Time entry

Deployment of an application to allow field personnel to electronically capture their time worked including a feed to the time entry system. This would vastly reduce the need for associated back office support and avoid unnecessary delays in processing.

The devices would be deployed to overhead, underground, protection\telecom and complex construction crews. Additionally, the map access and feedback, electronic as built data collection and time entry applications would be device-agnostic (i.e., available on multiple operating systems approved by National Grid) and will be made available to already deployed field devices used by substation crews and customer meter service workers.

Proposed development would begin in year 1 of the STIP with full field rollout and stabilization by the end of year 5. The proposed approach seeks to balance change management and resource availability to achieve a positive rollout.

5.2.2.3 Mobile Tools

The Company plans to build the proposed tools by leveraging commercial off the shelf ("COTS") software. Supporting processes and configuration of these tools will be needed to deliver the functionality. However this approach has been successful on previous projects, most notably the deployment of the Company's IMAP solutions built utilizing technology from the Environmental Systems Research Institute ("ESRI"). Using existing vendor relationships and licensing will help control costs while also providing a framework on which other functionality could be built in the future. The familiar look and feel of already-licensed software packages will also help shorten the learning curve and change management effort. For the electronic standards and EOPs tool the Company proposes to use third-party software from a content management vendor with experience working with other utilities. The Company's analysis has shown that the goals of this investment can be achieved at a lower cost with a commercially available package.

Work on the initial deployments will leverage existing National Grid and contract resources. These resources will work directly with stakeholders and field personnel to design and deploy the solutions. Once deployed the Company will retain support personnel to continue refinement of the tool functionalities based on business need, update system content, provide training and support field hardware.

During stakeholder discussions the use of a tablet was preferred to a laptop. Estimated project costs include the tablet, a ruggedized case and both material and labor. The Company proposes to procure approximately 573 tablets as well as contract for mobile network access. The Company's proposal includes costs associated with break/fix replacements and a five year field hardware lifecycle.

The project would have five phases – (i) procure\design\develop, (ii) pilot, (iii) rollout, (iv) stabilize and (v) maintain. After the year and a half development period, the Company would conduct a full-scale pilot for six months. The roll out to the rest of the organization would be conducted over the following year. A one-year stabilization (bed-down) period also has been included in this proposal.

Change management and training will be a significant and necessary part of the effort. While the exact sequencing will need to be determined during the project, the Company will need to cycle personnel through the initial training on use of the tablets and software tools. Training will be sequenced as additional material during annual refresher training at main training centers, in order to most efficiently manage costs where possible. Where this will not be possible, trainers will conduct training at operating centers, minimizing travel costs and allowing return to the field as soon as possible. In addition, the estimated cost includes an incremental two hours of refresher training annually after the initial training. Delivery of training will be completed by the resources previously identified in this section.

5.2.2.4 Component Benefits

Quantifiable benefits of the plan include material cost reductions and savings associated with Construction Work in Progress dollars by reducing cycle times. In addition, there are a number of unquantifiable benefits. These include:

- Reduction in Customer Minutes of Interruption (CMI) associated with a delay due to maps or records not being readily available in the field
- Safety and compliance improvements associated with having access to the latest maps and operating procedures
- Positive impacts to customer satisfaction associated with reduced response times
- Enhancements to data quality due to system quality controls, reduced closeout cycle times and auditable map feedback loop
- Reduction in or elimination of the need for back office time entry

5.2.3 Advanced Distribution Management System

Currently, National Grid operates an Energy Management System (EMS) and Supervisory Control and Data Acquisition (SCADA) system. SCADA is a database where information is acquired from remote devices and stored in a centralized location. This information is a replication of the control panels, meters, outputs and inputs from devices and substations in service. It also has the ability to send commands and thus mimics what a technician would do to complete operations at the remote location, but instead this is done from a central location where the SCADA system resides. SCADA actions are designed to mimic all actions that would be completed at the remote locations such as applying tags, interlocks and controls. EMS is an application that sits with SCADA and uses intelligence to manipulate the SCADA data in a way that is beneficial to a system operator in a control center environment. The transmission operator uses EMS to maintain the security of the transmission network.

National Grid's SCADA system is not designed to incorporate the vast amounts of data that grid modernization distribution devices and investments will create. Other companies have experienced the same increase in data brought on by an increase in smart devices and have elected to pursue a DSCADA system and accompanying ADMS. An ADMS will work with a DSCADA just like an EMS works with a SCADA system as described above. ADMS will be dedicated to the distribution network.

Within the GMP, there is a significant dependency on the ADMS system being activated in year five to allow for an increase in the deployment of distribution-level devices to support the field deployment of feeder monitors, CVR/VVO and ADA/FLISR. The ADMS includes centralized control modules for these programs. In years one through five, these programs are limited in scope, and use decentralized control technologies which are more challenging to maintain.

National Grid therefore proposes a five year deployment effort to implement an ADMS and DSCADA system to support the increased number of distribution devices (FLISR, CVR/ VVO, AMI, telecommunications and feeder monitors) proposed in the GMP (as well as DERs) to meet the requirements for grid modernization.[38] In addition, an effort to modernize, ensure compatibility, and integrate the Company's GIS database will be required, in order to support the ADMS.

5.2.3.1 Introduction to Technology

ADMSs are available with numerous applications that can enhance the planning and operation of an increasingly complex distribution system. To meet the Objectives, additional capabilities will be required with respect to monitoring, automation, dynamic voltage control, integration of DG and other DERs which create changing load profiles and two-way power flow, all enabled with two-way communications and appropriate information system technology. While it may be possible to implement technologies to address each of these functionalities independently, there are significant operational efficiency savings to be realized by utilizing a common platform that

[38] An ADMS/DSCADA system is not included in the AMI-Focused scenario.

integrates all distribution data. In the context of the GMP, ADA/FLISR and CVR/VVO components will be enhanced by this system.

ADMS functions include:

- Distribution network model
- Distribution power flow (DPF)
- Short circuit analysis
- VVO
- CVR
- FLISR
- Switching order management (SOM)
- Load shed
- Short-term load forecast
- Distribution operator training simulator
- Outage management applications

SCADA functions include:

- Data acquisition
- Supervisory control
- Tagging
- Periodic calculations
- Disturbance data collection
- ICCP data exchange
- Historical information system/historical archiving and playback functionality

5.2.3.2 Scope and Schedule of STIP Deployment

National Grid's proposes to implement an integrated ADMS system that will provide a DSCADA, a set of advanced distribution network applications and integrated outage management functionality. This will be a multi-phased initiative guided by the following steps:

- Implementation of a DSCADA, closely interfaced with the existing SCADA (which will transition to a Transmission SCADA system, or TSCADA) to provide basic visibility and control of distribution-level devices and assets
- Phased implementation of advanced distribution management applications that will provide operators with a set of analytical tools and data to help them make real-time decisions to support the safe, reliable and efficient operations of the distribution network
- Enabling the outage management components/modules of the ADMS and retiring the existing National Grid OMS

Specifically, National Grid is proposing three core releases in order to achieve the desired DSCADA/ADMS capability. The planned releases are as follows:

Release 1: DSCADA Core – Approximately Years 1-2 of the GMP

- Data acquisition
- Supervisory control
- Periodic and disturbance data calculations
- ICCP data exchange
- Tagging
- Historical information system/archiving/playback functionality

Release 2: ADMS Core – Approximately Years 2-3 of the GMP

- Distribution network model
- Distribution power flow
- Short circuit analysis
- Short-term load forecast
- CVR/VVO
- FLISR
- SOM
- Load Shed
- Integration with existing OMS

Release 3: ADMS Full – Approximately Years 4-5 of the GMP

- Distribution operator training simulator
- Outage management applications

5.2.3.3 GIS Data

ADMS requires complete and accurate GIS data to operate correctly and make decisions, as ADMS utilizes GIS data at a foundational level. GIS data currently exists in an asset repository, which many other systems use as well. The additional upgrades and refinements of the GIS data necessary for the ADMS to operate properly are also important for applications like: power flow studies; CVR/ VVO; ADA/FLISR; thermal analysis; distribution state estimation; distribution system modeling; predictive fault location; optimal network reconfiguration; dynamic equipment rating; ADMS control of protection settings and protection coordination; and other modules. Therefore upgrades and refinements to the GIS data are necessarily included as part of the GMP.

The Company plans to use the connected model maintained in GIS to both create and maintain the network in ADMS. This model not only represents the geospatial properties of assets, but also includes accurate connectivity between them. This tight integration with the systems used in the design and work closure process will help deliver benefits but requires significant change in how the Company uses and manages the GIS data today. An investment is required to update the system with new attributes, model the networks more robustly and enhance systems and processes to facilitate near real time updates to the ADMS. Some specific data areas that will be addressed include populating detailed geographic substation models, improvements to the current underground network model and physical and operating attribute level validation. System investments will include development to facilitate the use of the new models, necessary system data model changes to accommodate ADMS needs and creation of methodologies to facilitate seamless translation from a geographic based model (GIS) to geographic diagram model (ADMS). In addition, the Company will onboard additional personnel to help support system performance and enhancements, embed modern data management principles/processes and provide ongoing training to personnel. This effort will be substantial and will involve detailed review of over 17,800 circuit miles of National Grid's network involving millions of network-related equipment attributes. In order to accomplish this work, the Company will leverage network planning models, operating and engineering knowledge and, when necessary, field observation.

5.2.3.4 Anticipated Benefits

The ADMS/DSCADA system is intended to overcome many of the limitations of the EMS/SCADA system currently in service. The new ADMS/DSCADA system will complement and work in parallel with the existing SCADA system (which will be transitioned to transmission assets only). The major limitations with the current EMS/SCADA system are:

- SCADA data limit
- Separation of NERC CIP assets
- Functional GIS connectivity model

SCADA Data limit

The current SCADA system is limited in the amount of data it can support. Any future SCADA database has to be adequately sized to efficiently handle all the data points created by the GMP.

Separation of NERC CIP assets

The North American Electric Reliability Corporation ("NERC") has the responsibility to develop and enforce Critical Infrastructure Protection ("CIP") standards. Certain assets associated with the bulk electric system ("BES") are considered NERC CIP assets. With the NERC CIP assets completely isolated from the distribution network, to accommodate control center operations, separate DSCADA and TSCADA consoles will reside in the transmission and distribution control rooms.

The TSCADA will be used to operate the Transmission Network and the BES and is not needed to operate the distribution network. This allows for the separation of NERC CIP assets, isolating the transmission control from Distribution control, and resulting in lower required operating costs for the proposed ADMS system. This will allow NERC CIP information to be isolated from other systems, allowing grid modernization information to be more transparent to other departments, enabling other groups to use the ADMS for their various needs. For example, the Company's planning group could use ADMS to do planning studies without the need for NERC CIP compliance. ADMS could be made available to the decentralized storm rooms during major events. The separation of TSCADA and DSCADA would mean that NERC CIP standards apply to TSCADA only, which has operational and financial benefits including improved efficiency when completing the NERC/NPCC compliance audit done every three years. NERC empowers the Northeast Power Coordination Council to complete compliance audits of the NERC CIP standards. With the separation of NERC CIP assets from the distribution assets this process will be less complicated.

Functional GIS Connectivity Model

An ADMS system relies on a functional GIS model with proper connectivity. Historically, GIS models did not require this level of detail as they were not integrated into real time operations. The GMP addresses this issue with a GIS compatibility effort to create a functional GIS connectivity model.

5.2.3.5 Dependencies with other parts of the GMP

The ADMS/DSCADA deployment is dependent on a number of other parts of the GMP, as follows:

CVR/VVO:

An ADMS system can implement CVR/VVO via a model-driven approach. The model-driven approach contains two parts: a physical model of all the distribution assets (obtained by interfacing with the active GIS system); and a load model containing all information about customer loading (obtained from the AMI infrastructure, historical load profiles and statistical loading surveys). This approach also enables a single controller to preside over the CVR/VVO program, which makes operation and maintenance of the program more streamlined. In years on the through five, the Company plans to start deploying CVR/VVO technology on the system utilizing an independent controller, and once an ADMS is online, the decision can be made to transfer these programs to the centralized integrated ADMS controller with all new installations after year 5.

ADA/FLISR:

The projected number of additional points for the FLISR GMP program will far exceed the number of points available in the Company's current SCADA system. For years one through five, while the ADMS is being deployed, the Company will utilize decentralized controllers to manage the ADA deployed during these years. These controllers will provide very high level information to the Company's EMS system. Once the proposed ADMS/DSCADA system is in place, years six through ten of the GMP will see the FLISR functions embedded in the ADMS. This will reduce the costs associated with FLISR as the current, non-ADMS based solution requires additional hardware, software, licenses and engineering support to operate.

DG / Distribution Energy Resource Management System (DERMS):
Currently, there is no infrastructure within National Grid that coordinates distributed energy resources at the distribution level. The need for an ADMS (centralized or de-centralized at a substation level with a supervisory system) becomes essential to ensure the integrity of the system under high levels of DG penetration. This is also true with respect to microgrids. Due to the challenges DG and microgrids put on a distribution system operator an advanced application within the ADMS will be beneficial and, possibly, a requirement. An ADMS will ensure the system operator can maintain the system while performing planned or emergency switching and also provide protection to workers and the public.

The Company evaluated DERMS modules for ADMS and found all of them currently to be lacking in maturity to meet the needs of the Company. The Company will re-evaluate a potential DERMS during the GMP period to determine what capabilities potentially could be incorporated.

5.2.4 Billing and Customer Service Systems

Changes will be required to National Grid's billing systems and customer service support in order to accommodate the new rate structures, greatly increased volumes of data and new functionalities that will result from grid modernization. National Grid has implemented TVRs) or Peak Time Rebates ("PTRs") for the approximately 15,000 customers in its SES Pilot in Worcester, and made changes to its billing and customer service systems to accommodate these rates. National Grid used its experience and learnings from the SES Pilot to inform the development of its billing and customer service needs for its GMP. Before the rest of National Grid's approximately 1.3 million customers can be billed using TVRs, PTRs, inclining customer block charges and the appropriate cost recovery factors for grid modernization, the necessary supporting AMI meters and infrastructure will have to be installed, and a multi-year process will be required to make the necessary changes to National Grid's billing and customer service systems, including: requirements and design; development and implementation; programming; integration testing; user acceptance testing; system testing; data conversion; internal communications; and training. The estimated costs for these upgrades are included in Attachment 9.

Additional personnel also will be required to: process accounts given the increased and varied volume of data that will be generated; answer customer calls and questions given the changes that customers will experience with TVRs and PTRs and the more complicated bills that customers will receive; manage the increased meter data; bill customers; and handle issues that arise in any of these areas. National Grid has estimated the costs to do this work, as well as the additional personnel required, and included these estimates in its GMP budget and in the personnel requirements in the WTAM Section of the Plan.

The Company anticipates that the AMI system and supporting infrastructure, when integrated with the billing and customer service systems, will result in a number of qualitative benefits for customers when it comes to billing and customer service. Educated customers with TVRs will make informed decisions on managing and shifting their consumption to reduce overall cost, as well as voluntary reductions during PTR periods. Having these options can lead to better overall customer satisfaction compared to standard flat rate service bills. Additionally, customer service representatives will have better information available to them regarding customers' usage, enabling them to better respond to customers' billing questions. During outages, customer service representatives also will have more real-time information for customers about their outage status using information from the AMI system, leading to higher customer satisfaction. Overall, having more metering data coupled with new rates and access to real-time system information can reduce bill impacts and improve response to customer inquiries.

5.2.5 Cybersecurity and Privacy

The Order identifies cybersecurity and privacy protections as key components of GMPs.[39] Threats to the cybersecurity of critical infrastructures emanate from a wide spectrum of potential sources, including: state-sponsored espionage and sabotage, international terrorism, domestic militants, malevolent 'hacktivists' or even disaffected insiders. A reliable and secure grid is necessary to safely enable both the customer-facing and grid-facing aspects of grid modernization, including automated demand response, providing customers a myriad of options to manage their energy costs through technology-enabled programs, limiting outages with a self-healing resilient transmission and distribution network, and other strategically important functions.

Cybersecurity and privacy provisions will support the GMP by maintaining a reliable and secure electricity infrastructure and ensuring the protection needed for the confidentiality and integrity of the digital overlay. Mere compliance with cybersecurity standards will not assure security;

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[39] Order at 34.

cybersecurity provisions must evolve as technology advances and as threats to grid security inevitably multiply and diversify. OT as a result of the GMP will differ from 'traditional' information security and will require separate architectures to support and address challenges posed by the new threat landscape.

In response to the Order, a risk-based cybersecurity framework is proposed across people, process and technology that:

- Sets forth a set of policies and standards to ensure the Company is working to a common set of security objectives for the GMP
- Provides architecturally secure cybersecurity and privacy services for an efficient, easy to consume and agile way to deliver the required capabilities to manage cyber risks
- Looks to build and enhance capability, including reusing current security capabilities where possible and investing where capability is absent
- Addresses privacy throughout the lifecycle
- Massachusetts is not the first state to address grid modernization.[40] For the purpose of this report, National Grid has researched and evaluated the approaches of other utilities that have made significant progress in the area of grid modernization, taking into consideration any measures relating to cybersecurity and privacy.
- Current Cybersecurity and Privacy Provisions

National Grid currently has developed a multiyear security strategy outlining a program of investment to strengthen the control environment across the Company. This program focuses on several key themes or initiatives which address common areas of risk/threat, as follows:

- Unauthorized access / insider attack: This includes threats to National Grid facilities, personnel, systems and data due to unauthorized access or from a source within the National Grid security perimeter.
- System availability / malfunction: These are threats to National Grid systems or data due to system malfunction.

[40] See Order at 35 ("Grid Modernization activities are beginning in other states and, therefore, that companies in Massachusetts will likely not be the first to address cybersecurity measures related to these activities and should learn from other states' experiences.")

- Malware / virus attack: These include threats to National Grid systems or data from an indirect attack via malware or virus infestation.
- Advanced persistent threat / external attack: This includes threats to National Grid facilities, personnel, systems or data via a directed attack by an outside party from outside the security perimeter with the intent of causing damage or destruction.
- Data leakage / loss: These include a threat to National Grid data confidentiality and integrity when sensitive data is disclosed to unauthorized personnel either deliberately or inadvertently.
- Regulatory non-compliance: These are fines or sanctions resulting in monetary loss or negative reputational impact.

5.2.5.1 Cybersecurity & Privacy Grid Modernization Objectives

National Grid has developed cybersecurity & privacy business objectives to align with the four grid modernization objectives set forth by the Department of Public Utilities in D.P.U. 12-76-B. The table below provides a high level business objective mapping with the Grid Modernization objectives and the relevant Cybersecurity and Privacy objectives.

Table 14: Cybersecurity Business Objectives and DPU Objectives Mapping

Grid Modernization Objective	Aligned Cybersecurity and Privacy Objective
Reducing the effects of outages	Operation of the distribution grid must continue with high availability (e.g., 99.99 % for SCADA and higher for protective relaying) regardless of any compromise in security or the implementation of security measures that hinder normal or emergency power system operations Deploy cybersecurity services and mechanisms at multiple locations to resist known threat vectors
Optimizing demand, which includes reducing system and customer costs	Distribution system operations must be able to continue during any security attack or compromise (as much as possible) Distribution system operations must recover quickly after a security attack or the compromise of an information system Balancing risk with cost and re-use existing security capability where possible
Integrating distributed resources	Distribution system management, monitoring, and control will increasingly extend away from the Company's traditional physical and security environments into external environments that the Company has little or no influence and control over and integration needs to be seamless Provision of detection, reporting, analysis, assessment and response infrastructure enabling rapid detection and response to intrusions and other anomalous events, and providing situational awareness of the electric grid Guarding against improper information modification or destruction, and ensuring information non-repudiation and authenticity
Improving workforce and asset management	Ensuring timely and reliable access to and use of information to improve field workforce and assets A comprehensive security program of education, training, practical experience and awareness Addressing insider threats in securing critical infrastructure

5.2.5.2 Cybersecurity and Privacy Strategy and Benefits

The National Grid Cybersecurity and Privacy strategic vision is based on the National Institute of Standards and Technology "Framework for Improving Critical Infrastructure Cybersecurity" ("NIST Framework") and has been tailored to meet the needs of grid modernization. The NIST Framework enables National Grid to apply the principles and best practices of risk management to improving the security and resilience of critical infrastructure. Development of the strategy required examination of domain or business function-specific and common security requirements across the complex infrastructure that National Grid has today. The strategy has been applied to the plans proposed in the GMP.

National Grid has created a dedicated team with the responsibility to cultivate a rich information feed from multiple sources, evaluate emerging threats against National Grid's control environment and identify appropriate mitigating actions to address those threats.

By integrating various existing networks, systems and touch-points that are capable of exchanging information seamlessly, the older proprietary and often manual methods of securing utility services will give way to more open, automated and networked solutions. The benefits of this increased connectivity depend upon robust security services and implementations that are necessary to minimize disruption of vital services and provide increased reliability, manageability and survivability of the electric grid and customer services. Recognizing the unique challenges of grid modernization is imperative to deploying a secure and reliable solution.

The key benefit in incorporating cybersecurity and privacy provisions will ensure the reliability of the power grid, with information integrity built in and the confidentiality of customer information maintained within various business processes addressing any privacy concerns.

The provisions built into the National Grid GMP will provide for:

- Availability: avoid denial of service
- Integrity: avoid unauthorized modification
- Confidentiality: avoid disclosure
- Authenticity: avoid spoofing/forgery
- Access control: avoid unauthorized usage
- Audit ability: avoid hiding
- Accountability: avoid denial of responsibility
- Third party protection: avoid attacks on others
- Segmentation: limiting the scope of attacks on the solution
- Quality of Service: maintaining a reasonable latency and throughput
- Privacy: maintaining customer data in a fashion that keeps confidential customer data confidential

5.2.5.3 Meter Data Access

National Grid abides by the strictest guidelines for customer data privacy, data security and safety for our customers and employees. The Company has protected private data about its customers' accounts for decades, always improving systems to meet the changing technologies, and will continue to do so as new advanced technologies are offered to customers. The new smart meters and the information communicated through these devices are subject to the same regulatory security standards that keep the electric grid secure. Access to meter data is maintained by making sure it is appropriate, properly authorized, reviewed and maintained following a robust business process that supports the access requirements to perform the required function.

The proposed smart metering system will be designed with robust security to ensure data is safe and consumers are protected. All data transmitted via the smart meters will be encrypted to ensure the privacy of customer information.

5.2.5.4 Proposed Cybersecurity Services and Investments

The security service management approach will allow National Grid to deliver the various security services in a manner that will enable a business-driven structured inter-relationship between the technical and procedural security solutions to support the long-term needs of grid modernization. A successful security solution implementation based on a thorough understanding of the business requirements will provide for:

- Modularity
- Scalability
- Ease of security component re-use
- Operability
- Usability
- Inter-operability both internally and externally
- Integration with the enterprise IT architecture and its legacy systems

The service model is layered and all the security controls that will be implemented to support a particular security service are based on the "NIST SP 800-53 Rev. 4: NIST Special Publication 800-53 Revision 4, Security and Privacy Controls for Federal Information Systems and Organizations".

The proposed security services below are incremental to the Company's current cybersecurity and privacy programs. In order to ensure the cybersecurity of new grid modernization investments and to protect the privacy of the new information that these investments will generate, National Grid will need to build and enhance capabilities, including reusing current security capabilities where possible and investing in new capabilities where current capabilities are insufficient or non-existent. For example, additional firewalls will be required to secure the increase in GMP infrastructure endpoints. National Grid plans to adopt new cybersecurity technologies and best practices to help ensure uninterrupted service delivery during a cyber-attack due to the use of new grid modernization technologies that are still maturing. These incremental security provisions are intended to reduce the exposure to remote and external cyber threats from the utilization of new internet and related IP and wireless technologies as part of the

GMP. Enhanced security capabilities will be required to monitor, identify, isolate and respond to a cyber-attack as a result of new two-way communication points, data and infrastructure endpoints for all GMP-related investments. The increased amount of digital data collected from multiple sources as part of the GMP will require additional data security elements to be provisioned. The additional security provisions required by the GMP also will need an uplift to the skillsets required to identify, manage risk, and maintain this expanded cybersecurity infrastructure, and the Company has accounted for this in this cybersecurity proposal for its GMP. Lastly, additional incremental privacy provisions will be required in order to protect the privacy of customers and the confidentiality of the system data and programs that will be introduced as a part of the Company's proposed GMP.

Short-Term Investment Plan (Years 1-5)

The following incremental security services have been identified as Phase I Services that are essential to the implementation of any grid modernization effort within National Grid. They are critical to maintain the security posture of the organization and will need to be implemented to support the Company's proposed new GMP investments. These include:

Network Security Services:

Network Security Services provide network security solutions to protect endpoints, applications, systems, networks from unauthorized access, exploitation, modification or the denial of any network resources. Components include: Secure Web/Network Proxies, Firewalls, NIDS/NIPS, Network Access Control (NAC), Netflow Analytics, Full Network Capture, Virtual Private Networks, Network Segregation, SSL Inspection, Network Discovery, Anti Malware Protection, Network Entry Authentication and Authorization.

Data Security Services:

Data Security Services provide the protection of data from accidental or intentional but unauthorized modification, destruction or disclosure through the use of data protection solutions and other safeguards to ensure that confidentiality and integrity is maintained. Components include: Secure Ad-Hoc File Exchange, Secure File Transfer, Data Leak Prevention (DLP) and File Encryption.

Identity and Access Management Services:

Identity and Access Management Services provide the management of individual identities, and their authentication, authorization, and privileges/permissions within or across system and enterprise boundaries, with the goal of increasing security and productivity while decreasing cost, downtime and repetitive tasks. Components include: Authentication Services, Access Control Services, Provisioning Services, De-Provisioning Services, Authorization Services, Directory Services and Identity Management.

Threat and Vulnerability Management Services:

Threat and Vulnerability Management Services provides proactive threat management and reactive response capabilities. This service will analyze logs and monitor applications/systems for abuse/misuse, provide intelligence around cyber threats, scan both internal/external systems for vulnerabilities and compliance, analyze and support security patching and provide a 24x7 response. Components include: Logging & Monitoring, Hardening Services, Threat Intelligence, Vulnerability Management, Patch Management, Cyber Investigations, Digital Forensics, Network Risk and Compliance, e-Discovery and Penetration Testing.

Security Operations Center Services:

This service provides Security Operations Center Services that are staffed by experienced, well-trained and well-equipped security professionals. This service provides unlimited remediation support and consultation to mitigate the threat before damage is done, which enables faster, accurate detection and response to security incidents to protect assets. Components include: Reconnaissance Services, Behavior Analysis, Situational Awareness and Security Information and Event Management.

Years 6-10

The following incremental Phase II services complement the Phase I services to support the Company's proposed new GMP investments. Design and implementation of these services may start within the 5 year STIP but rollout will be phased over the 10 year plan. These include:

Host and Endpoint Security Services:

This service extends the monitoring and controlling of hosts and endpoints to meet the required standards. The service will monitor the state of endpoints (host assets like servers, laptops, desktops, smart devices) for threat indicators, investigate events to determine severity, accuracy and context and ensure critical events can be escalated to suggest a host or endpoint compromise to ensure effective management of security vulnerabilities. Components include: Mobile Security, Device Hardening, Anti-Malware, Device Management, Host Intrusion Detection/Prevention, File Integrity Monitoring, Application White Listing, and Behavior Monitoring.

Security Policy Management Services:

The security policy management process consists of activities that are carried out and controlled by the security management function. This process outlines the specific requirements and rules that have to be met in order to implement security management. This can include items such as Security Policies, Standards, and material specifications, among others. The governing principle behind this service is that National Grid can design, implement and maintain a coherent set of policies, processes and systems to manage risks to its information assets, thus ensuring acceptable levels of information security risk. Components include: Security Policies, Risk Management, Security Standards and Material Specifications.

Cryptography Services:

This service forms the foundation of securing data in transit (secure communications) and data at rest (secure storage). Using sophisticated mathematics, they provide the capability to encrypt and decrypt data so that it cannot be understood by an outside observer and verify that data has not been modified since it was originally sent by hashing, signing and verifying._Components include: Key Management, Email Transport Layer Security (TLS), SSL Encryption, Device and User Authentication, PKI Services, Encrypted Management Interfaces, Full disk encryption and Removable media encryption.

Platform Security Services:

Platform security enables the securing of an entire platform by using a centralized security architecture or system. Unlike a layered security approach, in which each layer/system manages its own security, platform security secures all components and layers within measures and use of multiple applications/services to secure different layers of an IT environment. Components include: Secure Management Network, Cloud Computing and Security Analytics.

Change and Configuration Monitoring:

This service provides proactive, continuous security configuration management and real time protection making it harder for attackers to compromise National Grid assets. The service will include a suite of Security Configuration Management ("SCM") solutions continuously monitoring the integrity of systems. It will also increase operational efficiencies by reducing configuration drift and unauthorized change and maintain compliance with security policies and standards. Components include: Software Management (E.g. System Center Configuration Manager or "SCCM") and Configuration Management Database ("CMDB") for Assets.

Security Awareness and Training Services:

Training services are responsible to reduce the risk of a human error resulting in security breach by ensuring that customers, employees, contractors and third party users are aware of information security policies, threats and concerns as well as their responsibilities and liabilities. Components include: internal central website, external awareness website including social media links, public awareness messages using advertisement methodology, printed materials, computer based tutorial packages and video training.

Application Security Services:

This service provides the user of software, hardware, and procedural methods with a means to protect applications from external threats. This service will embed itself within the software development process to protect the various applications that might be vulnerable to a wide variety of threats. Security measures built into applications and a sound application security routine minimize the likelihood that unauthorized code will be able to manipulate applications to access, steal, modify or delete sensitive data. Components include: Web Application Firewalls, XML Validation Web Services Gateway, SOA Services, SDLC (E.g. OpenSAMM), CMDB for applications, Static Code Analysis, Dynamic Code Analysis / Runtime Analysis, Application Logging and Code Escrow.

Third Party Assurance Management Services:

This service provides a robust and properly implemented third-party assurance program to ensure that the data and systems it entrusts to third parties are maintained in a secure and compliant manner. Proper due diligence, risk analysis and assurance relevant controls are critical components of this service. Components include: Due Diligence Review and Vendor Assurance Services.

Remote Access Service:

This service provides for secure remote access solutions to provide great levels of security, a greater range of access methods, a broader range of device support and the ability to provide differentiated, identity-based access tailored to the needs of multiple businesses within National Grid and their requirements to perform the required business functions. Components include: Two factor authentication, Client VPN and virtualization technologies.

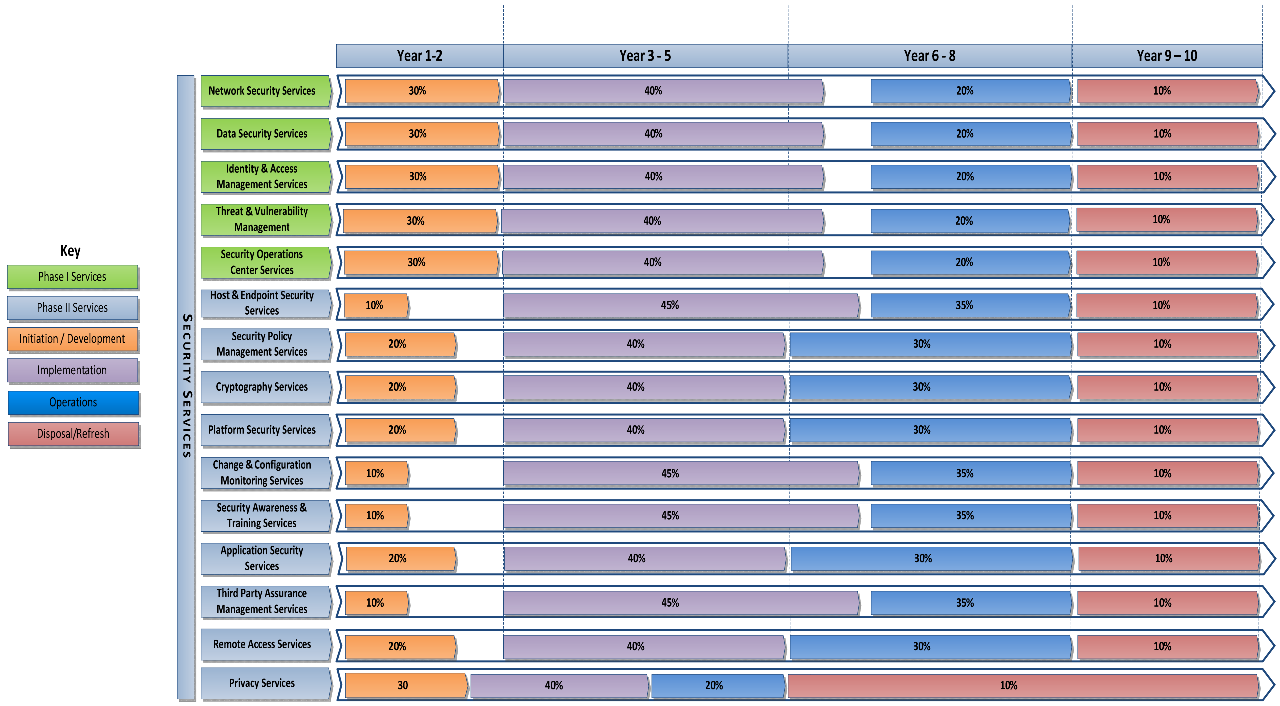
5.2.5.5 Implementation Plan

The services will be implemented in a phased manner looking at analyzing the requirements at the outset, and creating a chain of traceability through the strategy and concept, design, implementation and on-going management and measurement phases of the lifecycle. This phased approach will be based on business priority (e.g. AMI, ADA/FLISR, etc.), with the Phase I Services being established throughout the STIP and Phase II Security Services being layered on top of the Phase I core foundation over the course of the ten year plan. Both the categories of security services mentioned are critical to the grid modernization efforts of the Company and are essential to maintain the security posture of the organization.

The various security lifecycle stages include four phases: (1) initiation/ development; (2) implementation/assessment; (3) operations/maintenance; and (4) disposal/refresh. Each phase includes a minimum set of security tasks needed to effectively incorporate security in the system development process. Note that phases may continue to be repeated throughout a system’s life prior to disposal.

Below is a proposed plan to support a scalable approach to the implementation of the security services. Both the Phase I Security Services and Phase II Security Services will progress through the life cycle stages identified below, however at different periods throughout the ten year plan.

Figure 17: Cybersecurity and Privacy Services Deployment Timeline



(1) Initiation/Development:

During the STIP period, focus will be geared towards the initiation/development of the aforementioned security services. In this first phase, security considerations are key to diligent and early integration, thereby ensuring that threats, requirements and potential constraints in functionality and integration are considered. Requirements for confidentiality, integrity and availability of information are further evaluated at this stage, building upon existing requirements, as well as identifying and mitigating potential gaps that may exist. Early consideration and planning of security and privacy concerns can result in cost and timesaving through proper risk management planning.

The development phase helps to reduce opportunities for attackers to exploit a potential weak spot or vulnerability through thorough analysis of the overall attack surface. Risk assessments and analyzing security requirements are conducted to identify security vulnerabilities, determine risks from those threats and establish appropriate mitigations. This phase also includes the design of the security architecture.

(2) Implementation:

In this phase, National Grid will configure and enable system security features, test the functionality of those features, integrate and implement the system, and obtain a formal authorization to operate the system. Design reviews and systems tests will be performed to ensure that all required security specifications are met. If new controls are added to the application or support system, additional testing shall be conducted to ensure the new controls meet security specifications and do not conflict with or invalidate existing controls.

(3) Operations:

Operations is the third phase, when systems will be in place and operating, enhancements and/or modifications to the system will be developed and tested, and hardware and/or software is added or replaced if needed. The system will be monitored for continued performance in accordance with security requirements and needed system modifications will be incorporated. The operational system will be periodically assessed to determine how the system can be made more effective, secure and efficient. Operations will continue as long as the system can be effectively adapted to respond to the organization's needs while maintaining an agreed-upon risk level.

(4) Disposal/Refresh:

During disposal/refresh, the final phase, plans will be developed for discarding system information, hardware, and software and making the transition to a new system, if needed. The information, hardware and software may be moved to another system, archived, discarded or destroyed. If performed improperly, the disposal phase could result in unauthorized disclosure of sensitive data.

Usually, there is no definitive end to a system. Systems normally evolve or transition to the next generation because of changing requirements or improvements in technology. System security plans continually evolve with the system. Disposal activities ensure the orderly termination of a system and preserve vital information about the system so that some or all of the information may be reactivated in the future. Particular emphasis is given to proper preservation of the data processed by the system so that data is effectively migrated to another system or archived in accordance with applicable records management regulations and policies for potential future access.

Along with the design and implementation of Phase II Services which have yet to achieve an operational state, years 6-10 will focus on the Operations and Disposal/Refresh of both the Phase I and Phase II Security Services as they progress through the remaining life cycle stages.

The costs for the cybersecurity investments are included in the GMP costs presented in Section 3.2 and in Attachment 29. The cost estimates for an array of the services and components, including Identity and Access Management, Network Security Services, and Security Operations Center services, were derived from existing National Grid partner agreements. These partners were selected through prior competitive processes. The costs were also derived from past investment proposals created to support the Company's Cybersecurity program. The service costs have been scaled and adjusted to meet the requirements of grid modernization. There are also a variety of services and components that currently do not exist within National Grid and therefore detailed cost information was not available through existing partner agreements. The costs for these services and components were based on industry/market research and best practices specifically for cybersecurity and privacy hardware, software and services. Documents such as the Department of Educations and NIST's "information Technology Cost Estimation Guide" were leveraged and used as references to develop some of the proposed costs.

5.2.5.6 Privacy Controls

The proposed security services that are part of National Grid's GMP are delivered using a breadth of security and privacy-related controls to fundamentally strengthen and support the security posture within the various infrastructure environments that the Company's systems operate. The controls are based on "NIST SP 800-53, Rev 4" to help provide a greater flexibility and agility to defend against an ever-changing threat landscape. This provides National Grid with the ability to provide a structured approach to tailor any provisions required to specific missions/business functions, environments of operation and/or technologies using industry standards and best practices.

The cybersecurity and privacy controls provide a comprehensive range of countermeasures for the organization and its information systems to avoid, counteract or minimize loss or unavailability due to threats acting on vulnerabilities. The controls are designed to be preventative, detective or corrective and protect the confidentiality, integrity and/or availability of information. They involve aspects of policy, oversight, supervision, manual processes and actions by individuals or automated mechanisms implemented by information systems/devices.

The security controls are focused on the fundamental countermeasures needed to protect organizational information during processing, storage and transmission. The privacy controls ensure that privacy protections are incorporated into information security planning. The use of standardized privacy controls provides a more disciplined and structured approach for satisfying privacy requirements and demonstrating compliance with those requirements. The controls are also categorized into families and are listed below.

5.2.5.7 Privacy Framework

National Grid has adopted an integrated approach to data privacy based on people, process and technology perspectives to classify privacy and information management components into four primary categories:

- Key compliance program elements and culture
- Key data handling and identity theft risks
- Consumer privacy awareness and rights
- Security safeguards.

The supporting data privacy program utilizes a cross-functional framework that seeks to address not only legal and regulatory requirements, but also the ever-changing landscape of privacy and identity theft vulnerabilities that can result in information and data compromise. The framework for compliance, privacy, security and identity theft prevention incorporates accountabilities[41], policies, procedures and business practices, and a fabric of technical and operational controls[42] to manage data privacy-related risks more effectively.

Table 15: Framework for compliance, privacy, security and identity theft prevention

Compliance & Culture	Key Data Handling & Identity Theft Risks	Consumer Privacy Awareness & Rights	Security Safeguards
Policies and procedures Governance & accountability Due diligence Communication, training and awareness Monitoring, auditing & reporting Discipline and incentive policies Incident response/crisis management	Collecting/ Processing more information than necessary Social Security Number/sensitive information masking Call centers, social engineering and pretexting Market list handling 3rd party oversight Phishing, web and email vulnerabilities Mobile and home-based workforce Paper handling and dumpster diving Records retention and destruction Data Classification based on sensitivity Use back-up tapes Peer to peer software	Notice Choice Access and change of address Redress complaints investigations Onward transfers of information	Conduct risk assessments Access controls Physical security Encryption in storage and transit Dual controls/ segregation of duties Background checking Intrusion detection, attack and penetration testing Independent testing /review of key controls, systems and procedures Business Continuity Management and Disaster Recovery planning

The key components of a cross-functional data privacy framework approach seek to address three main challenges: (1) continually provide up-to-date privacy and security guidance with legitimate access to information including incident management and reporting; (2) prevent accidental misuse / loss / exposure of information through inconsistent internal or outsourced

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[41] Based on: the United States Federal Sentencing Guidelines'("Sentencing Guidelines") standards for an effective corporate compliance and ethics program; "White Paper: The, Seven Principles for an Effective Compliance and Ethics Program," available at http://www.compliance360.com/downloads/case/seven_elements_of_effective_compliance_programs.pdf (describing principles from the Sentencing Guidelines); and federal, state and international breach notification laws and guidance material. & US Federal, State and Global Breach Notification Laws / Guidance

[42] See, e.g., 201 Code of Mass. Regs. (standards for the protection of personal information).

processes; and (3) ensure that the information risks are clearly understood and the technologies selected keep pace with the threats and changing legislative environments.

5.2.5.8 Implementation Timeline and Costs

The vast majority of the grid modernization data privacy enhancements are front-loaded, i.e. in years one to three of the GMP, and will need to be developed, tested and embedded into the Company's data privacy policies and practices including third party interactions, which are fully aligned with the technical designs and technology deployed. The specific data privacy related investments will continue to be embedded with the rest of the proposed security services throughout the entire 10 year cycle to ensure adequate privacy protection is in place throughout the data lifecycle of any process.

5.2.6 Program Management Office

One of the important lessons learned from the SES Pilot is the necessity of having a Program Management Office ("PMO") to handle the implementation of large, complex projects such as grid modernization, which will have a multi-year, highly interdependent implementation effort. The Company therefore proposes to have a PMO that will oversee the implementation of the GMP. For the purposes of the Plan, the Company issued an RFP for an implementation partner who would work with the Company to ensure the successful rollout of GMP initiatives. These services include: program management, business process design / requirements definition, solution architecture, requirements management, change management, testing management, training and transfer planning and coordination, deployment operations, vendor technical implementation coordination and performance monitoring. The costs for these services are included in the Company's estimated GMP budget.

5.3 Enabling Infrastructure Investments Years 6-10

National Grid's proposed GMP is designed such that most of the enabling infrastructure is substantially completed within the STIP period. This includes all application integrations, ADMS/DCADA installation, field communications network, necessary backhaul and AMI data services. For these components, years 6-10 will consist of the necessary O&M required to sustain operation and update systems as necessary. As mentioned in a prior Section, cybersecurity will continue to deploy new services in years 6-10.

6. Business Case Analysis for Short-Term Investment Plan

In this section, the Company presents a composite business case for all STIP investments, in line with the Department's direction in D.P.U. 12-76-C and the Business Case Filing Requirements. This section will describe and focus on the Balanced Plan as it is the most comprehensive scenario, with the full suite of investments proposed, and will provide a comparison to the other three scenarios as well. The investments proposed will: increase the Company's ability to operate the distribution network efficiently and effectively; increase customers' engagement in their energy use and give them the opportunity to save on energy costs; and help better integrate DER and enable a future of two-way power flow. All four scenarios create operational and customer-facing benefits. Among them are operations and maintenance savings, reduced energy and demand benefits accruing to customers, deferred capital investments and reliability benefits from reduced outages. In addition, there are numerous qualitative benefits that will result from the STIP investments including: (i) improved customer convenience and satisfaction; (ii) higher crew productivity; (iii) enhanced integration of DERs; (iv) better optimized system planning; (v) the acceleration of future beneficial technology; (vi) safety and compliance improvements; and (vii) improved quality of electricity delivery. These benefits, as well as the costs to achieve them, are described in this section.

6.1 Goal and Drivers for Investments

6.1.1 Summary of Investments in the STIP Proposal

For the STIP period, the Company is proposing to invest in field deployment and enabling internal infrastructure and initiatives. These investments and initiatives are also described in Sections 4, 5, 9 and 10 of the Plan.

In sum, field deployment investments include:

- AMI: AMI meters for approximately 1.3 million customers in the STIP period.[43]
- CVR/VVO: In the STIP period, this is limited to 46 feeders of the Company's 1,100 feeders.
- ADA/FLISR: In the STIP period this is limited to the same 46 feeders.

[43] In the Balanced and AMI-Focused scenarios.

- Feeder monitors: This will include approximately 500 interval feeder monitors which will provide interval load and voltage monitoring at the substation end of feeders that are not currently monitored via SCADA.
- CLM: Participating customers will receive a gateway and have access to an E-portal for connectivity both at the meter (once installed) and through Wi-Fi. Other in-home devices are proposed to be paid for through the energy efficiency programs.

Enabling infrastructure investments include:

- ADMS: As discussed in Section 5.2.3, the proposed ADMS is expected to take 5 years to fully deploy. The ADMS, once operational, will allow the Company to continue to expand the ADA/FLISR and CVR/VVO programs as well as integrate more renewables through enhanced situational awareness.
- GIS updates
- DSCADA
- MDMS
- Communications/IT/OT investments, including CIS, EA, communications and networking, INOC, applications and devices (See Section 5.2.1)
- Billing and Customer Service System upgrades
- Cybersecurity
- Enterprise Service Bus and Legacy Applications: Upgrades to back office software to provide for sufficient support of the increased data analytics that will be necessary to leverage AMI metering data.
- OMS upgrades: Using the AMI outage data to integrate with the OMS to provide additional system awareness during outages.
- WTAM: This includes additional personnel required supporting the above programs and mobile tools to enhance the abilities and efficiency of the Company’s workforce.

The enabling initiatives include:

- MEO Plan, with a joint statewide and company-specific communications strategies (see Section 9)
- A project management office (“PMO”) to manage implementation of the GMP (see Section 5.2.6)

6.1.2 Drivers for Proposed STIP Investments

Overall, National Grid sought to optimize customer value in its proposed STIP. The investments proposed will provide customers with increased information, choice and control over their energy use, and simultaneously increase the Company's ability to operate its electric distribution network more efficiently and effectively. Investments in AMF are the foundation for customer engagement and maximizing the value from customer-enabling technologies such as energy efficiency and demand response. Investments in grid-facing technologies such as CVR/VVO will enable operators to manage the flow of electricity to those customers more effectively, and will help reduce overall energy use. Behind these, improved systems and telecommunication will unlock the full capabilities of these new technologies.

The value of enabling technology is great. Although some of these technologies do not appear to have direct benefits, they are enablers of a network of systems and provide the backbone to achieve the benefits identified in the STIP as well as future benefits of grid modernization. For example, an ADMS will provide system modeling and control to further enable CVR/VVO and ADA in years 6 through 10 and beyond. It may also accelerate the deployment of these technologies. The Company similarly anticipates benefits from data analytics, though it does not quantify them.

The five year STIP proposed by National Grid has many interdependencies. It seeks to maximize benefit impact, make progress on the Department's objectives and achieve AMF, while positioning the electric system towards sustained modernization. The Company evaluated the options for achieving AMF and determined that AMI meters and the related supporting systems are the best way to achieve AMF, as discussed in Section 6.2.3 The four scenarios each propose different amounts of AMI deployment (see Sections 1.4 and 3). In order to most effectively support AMI deployment, a comprehensive communications network is necessary. The communication network should be interoperable and open to allow for other grid modernization programs. Network backhaul and back office systems to support and integrate the AMI data into OMS and billing systems are also necessary. Based on the Company's experience through the SES Pilot, the Company also recognizes the requirement for customer outreach and education, as well as dedicated full-time personnel to support the deployment.

The Company also considered and incorporated significant additional benefit programs, namely CLM, ADA, CVR/VVO and feeder monitors, which would take advantage of the network and data systems proposed for the AMI system. The Company can leverage these assets to incrementally create a valuable total GMP package.

The Company also sought to best position the system investments in order to continue to advance these programs beyond the STIP and 10 year GMP period. In order to do so, investment in an ADMS/DSCADA system is necessary to sustain the growth of benefits in the ADA, CVR/VVO and feeder monitor programs.

6.2 Technology/Project Descriptions

6.2.1 Detailed Description of Technologies/Projects

Please refer to Sections 3, 4.2, 5.2, 9, and 10 of the Plan for detailed descriptions of the proposed technologies and projects proposed for the STIP, as well as deployment schedules.

6.2.2 CAPEX Tracker: Proposed STIP Investments

The Company proposes to include the STIP investments identified in Sections 1, 4.2, 5.2, 9 and 10 in a STIP Tracker based upon approval of DPU. These components are aggregated into the following investment categories, consistent with the categories presented in the Department's template: Advanced Metering Systems, Communications Systems, Electric Distribution System, and Integrated Crosscutting Systems, as well as Metrics and Customer Marketing, Education and Outreach.

The Company is proposing to recover all incremental STIP costs, including capital, O&M and GMP development costs, through a proposed STIP recovery tariff. Please see Section 12.4 of the Plan for additional detail on this proposal. Please see the tables included in Attachment 10, the Business Case Template, which summarize the estimated costs of the GMP, inclusive of STIP costs and list in more detail the investments proposed. Per the Department's instructions in the Business Case Summary Template, the costs presented for the tracker are the present value of 15 years of GMP investment costs. The table below summarizes, by technology the present value cost items proposed for inclusion in a STIP tracker[44].

[44] Note these are present value ("PV") costs as the instructions for the Department's Template directed these numbers to be presented in NPV. They are not the stream of costs used for revenue requirement calculations.

Table 16: Cost items proposed for recovery in STIP Tracker, by Technology

Technology	Balanced Scenario STIP PV Costs	AMI Focused Scenario STIP PV Cost	Grid Focused Scenario STIP PV Cost	Opt-In Scenario STIP PV Cost
Advanced Meters	$ 238,781,655.58	$ 238,781,655.58	$ 103,919,479.60	$ 29,092,849.38
Automated Capacitors	$ 3,717,910.13	$ -	$ 3,717,910.13	$ 3,717,910.13
Automated Voltage Regulator	$ 1,487,164.05	$ -	$ 1,487,164.05	$ 1,487,164.05
Backhaul Communications System	$ 47,489,721.20	$ 46,004,800.49	$ 37,116,323.90	$ -
Customer EMS/ Display/ Portal	$ 35,365,861.34	$ 35,365,861.34	$ 20,954,352.00	$ 11,035,780.39
Data Analytics	$ 384,257.40	$ 384,257.40	$ 384,257.40	$ -
Data Management	$ 12,448,010.34	$ 12,448,010.34	$ 12,448,010.34	$ -
Distributed Energy Resource Interface/ Control Systems	$ -	$ -	$ -	$ -
Distribution Automation	$ 27,072,547.77	$ -	$ 27,072,547.77	$ 27,072,547.77
Distribution Management System	$ 48,881,435.08	$ -	$ 48,881,435.08	$ 48,881,435.08
Geographic Information System	$ 3,990,889.67	$ -	$ 3,990,889.67	$ 3,990,889.67
Head-End System	$ 14,413,002.03	$ 14,413,002.03	$ 10,127,433.44	$ -
IT Security	$ 80,347,423.26	$ 52,632,715.12	$ 52,632,715.12	$ 8,034,742.33
Line Monitoring Equipment	$ 26,521,325.50	$ 23,911,420.59	$ 26,521,325.50	$ 26,521,325.50
Meter Data Management System	$ 9,627,225.48	$ 9,627,225.48	$ 9,627,225.48	$ -
Mobile Workforce Management	$ 14,022,177.13	$ 1,691,829.16	$ 3,881,703.02	$ 1,957,726.52
Outage Management System	$ -	$ -	$ -	$ -
Plug-In Electric Vehicles	$ -	$ -	$ -	$ -
Program Management	$ 28,895,918.06	$ 28,895,918.06	$ 28,895,918.06	$ 15,601,468.35
SCADA Communications Network	$ 10,347,887.17	$ -	$ 10,347,887.17	$ 10,347,887.17
Software - Advanced Analysis/ Visualization	$ 23,520,284.88	$ 23,520,284.88	$ 23,520,284.88	$ 1,803,165.45
System Integration	$ 25,933,878.43	$ 25,933,878.43	$ 25,933,878.43	$ -
System Test and Enterprise Architecture	$ 14,458,572.50	$ 14,458,572.50	$ 14,458,572.50	$ -

6.2.3 Alternative Technologies Considered for the STIP

National Grid examined several alternative technologies to those proposed in the STIP. These alternatives were not carried through a detailed cost/benefit analysis, as it was determined early on that they were not worthy of pursuit.

Towards achieving the goal of AMF, bridge meters were the most significant alternative investigated. These bridge meters are customer meters which include two communication radios. One radio interfaces with the Company network (via Cell or FAN) and the other radio is designed to emulate the Company's existing AMR reader. These bridge meters are then installed in sparse physical intervals, with the intent of being able to link to existing AMR meters without the mobile AMR infrastructure. This system allows for interval meter reading, but does not provide for two way communications to most end points, thus not meeting the Department's requirements for AMF.

Towards achieving communications to the devices in the service territory, the Company investigated purchasing a dedicated spectrum from the FCC which would support a wireless FAN. This alternative was discarded as the market provided sufficient confidence for the

Company to utilize a spectrum currently supported by the market. In addition, the Company investigated leveraging the existing fiber and cable networks rather than wireless technology. The Company determined that the partnering structures required to support this would be sufficiently challenging and not result in any significant cost or performance benefits.

For optimizing demand and improved workforce and asset management, National Grid evaluated expanding the grid-supporting programs (ADA, CVR/VVO and feeder monitors) without an ADMS control system, instead leveraging distributed controls and limited central information. This strategy was abandoned due to the significant challenges presented for proper operation and maintenance when compared to a centralized control system. Further, as the penetration of smart devices grows and the complexity of the distribution system increases, the Company expects to gain many unquantifiable benefits through the increased knowledge and awareness from the proliferation of these grid devices and the ability to capture and examine the information from them in one place.

The Company also investigated more comprehensive energy storage and microgrid programs. However, it was determined that the technology and implementation were better utilized as a smaller pilot which can provide experience and learning with these items, rather than a territory-wide deployment. These programs were then moved to the RD&D portion of the Plan.

6.2.4 Criteria for Selecting the Proposed STIP Investments

National Grid considered different options that would make measurable progress on the Objectives, and that would achieve AMF within five years of the Department's approval of the GMP, if justified by a business case analysis. National Grid examined the different technologies it could deploy, the necessary supporting infrastructure, the interdependencies of these components, the scope and scale of these potential deployments, their costs and benefits, and affordability of different options, among other considerations. Please also see Section 6.1.2 above, "Drivers for Proposed STIP investments."

In addition, please see Section 2, "Baseline Capital Plan without Grid-Modernization Specific Efforts", which describes the Company's distribution planning process, the Company's baseline capital plan and the nature of the incremental grid modernization investments in which the Company was not otherwise planning to invest, absent the requirements of D.P.U. 12-76-B.

6.3 Costs and Benefits

The Company developed a comprehensive benefit cost model for assessing the cost-effectiveness of the STIP, and populated it with cost and benefit information on the various components of its proposed Plan. This section describes the estimated costs and benefits assumptions and methodology used to determine the cost effectiveness of the STIP, as well as the actual costs and benefits of the proposed investments. The Business Case Summary Templates in Attachment 10 also provide detail on the estimated costs and benefits.

6.3.1 General Assumptions

The following company-specific information was used to calculate costs and benefits, in line with the Department's direction in the Business Case Filing Requirements in D.P.U. 12-76-C:

- The Company-specific weighted average cost of capital ("WACC") is used as the appropriate discount rate. National Grid used the Company's Department-authorized after-tax WACC, based on the Company's authorized capital structure and cost of capital, and reflecting the after-tax cost of debt.
- For AFUDC cost of capital, the Company used 1.45%. This is the fiscal year 2013 AFUDC rate for the Company.
- National Grid used company-specific demand and energy forecasts, which are consistent with forecasts supplied in other Department dockets. The peak forecast is used for the Company's annual reliability filing and the kWh forecast is used for rate adjustment filings.
- The Company used 15 years as the time horizon to discount costs and benefits for all STIP investments.
- Baseline information used to calculate the costs and benefits of proposed STIP investments is supported and defended. Baseline is consistent with distribution planning framework above, and that analysis is truly incremental.

The Department's Business Case Filing Requirements also directed the utilities to use a number of common assumptions and common analysis methods. The following information was used jointly by the Massachusetts utilities:

- Moody's GDP deflator was used as the rate of inflation in the benefit-cost analysis. The rate used was 2.07% for the forecast horizon. This was determined by calculating the 15-year compound annual growth rate for the GDP deflator from 2015-2030, using Moody's March 2015 forecast release.
- Energy prices, capacity prices, demand reduction induced price effects ("DRIPE") and renewable energy portfolio standard ("RPS") compliance costs were developed by

Tabors, Caramanis, and Rudkevich ("TCR") jointly with Eversource and Unitil. Values leverage and assume the same market structure and dynamics as assumed for The Avoided Energy Supply Costs in New England: 2015 Study Report ("AESC 2015 Report").[45] There are differences in the treatment of energy efficiency in the load forecast, and consequently, modeling of RPS. The TCR report, "Electricity Market Price Forecasts for Massachusetts" is provided as Attachment11. As this references the AESC 2015 Report, the AESC 2015 Report is provided as Attachment 12.

- With respect to TVR assumptions, the benefit-cost analysis includes the implementation of a TVR framework as directed in D.P.U. 14-04-C. In keeping with the Department's directive to use common analysis methods for the key assumptions and inputs to the analysis of TVR impacts, the utilities commissioned a detailed survey of the results from TVR pilots and programs in other jurisdictions (see Attachment 13 for the report produced for the Joint Utilities). The key assumption[46] for the TVR analysis is the level of customer peak demand reduction anticipated during peak events. For this element of the TVR analysis, the Massachusetts utilities relied on regression models developed based on the data compiled on past TVR results. The regression analyses modeled the percentage reduction in customer peak demand as a function of the ratio of peak event to non-peak event prices. The utilities similarly collaborated on the other TVR-related assumption in furtherance of common analysis methods. The utilities held joint discussions of their TVR analytical approaches to foster alignment, relied on publicly available research studies and shared their detailed methodologies and assumptions. The Company's approach to quantifying the benefits from TVRs is discussed in more detail below and in Attachment 14, which is National Grid's "Grid Modernization Plan Benefit-Cost Analysis Time Varying Rate Assumptions and Approach."

The Company apportioned benefits consistent with Department guidance. If a technology/enabler does not produce benefits on its own but enables benefits through other technologies, the Company attributes the value of the benefit to the enabled technology and does

[45] 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" or "PAs"). The sponsors, along with non-utility parties and their consultants, formed an AESC 2015 Study Group to oversee the design and execution of the report.

[46] Per D.P.U. 12-76-C, at 21.

not allocate a portion of the benefit back to the enabling technology. This approach was duplicated throughout the Business Case Template. This approach avoided double counting of benefits. In allocating costs, the Company carefully mapped the costs to enabling technologies, and did not double count costs.

6.3.2 Cost Estimations

To support its estimation of costs for its proposal, the Company issued three RFPs and one RFI to leading equipment and system vendors and service providers. The RFP/RFI effort is discussed in Section 11.5 of the Plan, "Requests for Proposal and Request for Information."

For system components not covered by RFPs or RFI, the Company developed its cost estimates based on research, its own experience with these components and through other information from third parties, in particular from vendors with whom the Company currently has contracts for similar equipment which were established through prior competitive processes. These component areas include ADA and CVR/VVO. In addition, in a number of instances the Company used costs for other components and resources based on experiences with similar grid modernization projects of various sizes and scope in other states. National Grid reviewed and validated these costs prior to final incorporation in the benefit cost model. The documentation for these cost estimates is included in Attachments 3 and 5.

Cost estimates provided are on the unit of property level as found in the Uniform System of Accounts ("USOA"), wherever possible. Individual costs are grouped and summed by technology, while individual benefits are grouped and summed by function, per template.

The costs included are the incremental investments included in the STIP. Costs do not include costs for investments in a "business as usual" case which would be what the Company would invest in absent the requirements of the Order. Incremental investments are addressed separately in the Business Case Filing Requirements and included in the bill impacts. In particular for CLM technologies, where some investments are anticipated to be supported through future energy efficiency programs, the costs in the STIP are only the incremental costs with adding grid modernization functionality to that equipment.

6.3.3 Monetized Benefits

In evaluating the business case and selecting the portfolio of projects in its Plan, the Company considered benefits that can be monetized, quantified but not monetized and benefits that are qualitative. Monetized benefits from the STIP stem from avoided wholesale energy and capacity market costs, improved reliability and deferred capital and O&M costs. Benefits provided in this STIP also include the avoided costs of replacing current technologies with like technologies for those investments that will reach the end of their useful lives within the benefit-cost analysis time horizon. Additional benefits that are quantified but not monetized or qualitative are described in Section 6.3.4.

The monetized benefits are described in the following sections.

6.3.3.1 Operations and Maintenance Benefits

O&M benefits are associated with AMI meters. After the initial deployment of AMI meters, it is assumed that meter readings will be more accurate and consequently, there will be fewer calls to the call center. There will also be fewer labor and vehicle costs associated with disconnect and reconnects of service on/service off, as these will be handled remotely. Shutoff for non-payment will still be associated with an on-site visit. Furthermore, the Company expects a reduction in meter re-reading expenses with AMI meters.

O&M benefits are also associated with telecommunications equipment. Because of the replacement of analog systems and associated infrastructure, there are avoided operations cost of the analog circuits as well as the cost of the MPLS service and an anticipated one time conversion of MPLS systems. This is avoided O&M rather than deferred capital. There are also O&M benefits resulting from ADA/substation automation. Because of the improved identification of outages, there will be reduced call volume. The customer, operations and workforce areas will also see O&M benefits. Mobile tools and processes will help reduce costs currently incurred for staff, contractors' material, open work orders, truck rolls and elimination of duplicate field visits.

The beneficiaries of the reduced O&M costs are customers and the Company.[47] Customers also will benefit from reduced inconvenience though that has not been monetized.

6.3.3.2 Deferred Capital Benefits

Deferred capital benefits are associated with the installation of AMI meters. Absent the AMI meter installation initiative as part of grid modernization, the Company would have to replace its meters based on a current replacement schedule. The AMI meter deployment recalibrates this

[47] The beneficiaries are the entities that realize the direct benefits of the grid modernization component. Cost reduction to the utility is anticipated to be passed on to customers.

schedule. While there are costs associated with AMI meter deployment, there is also deferred capital investment in replacing the AMR meters currently in place. The beneficiaries of the deferred capital investment will be customers.

6.3.3.3 Enhanced Revenue

Revenue will be enhanced due to installation of digital AMI meters with built-in tamper alarms. Aging analog meters typically run slow, thus underestimating electricity consumption. Digital AMI meters will correct this underreporting and, consequently, will lead to more accurate billing and increased revenue. In addition, it is assumed that the theft of electricity will be reduced because of the AMI meter tamper alarms that will better alert operators when theft may be occurring. This will result in better cost allocation across customers as it will reduce the unaccounted for electricity factor in customer billing, and will enhance revenue to the Company. In addition, when electricity users who formerly were not paying for electric usage are newly exposed to electricity costs (whether through improved metering or reduced theft), it is assumed that they will reduce their consumption. The beneficiary of the investment will be customers.

6.3.3.4 Energy and Demand Benefits

With the use of CLM devices enhanced TVR, customers who opt to shift consumption timing will be able to shift their consumption from higher price periods to lower price periods. The same benefit will accrue to owners of electric vehicles who will shift their vehicle charging to lower priced periods. These benefits will accrue to customers, and will be seen on their bills.

CVR/VVO technology will improve management of voltage on the distribution system. Consequently, energy purchases, including at times of peak, decrease and may lead to energy and peak load savings. Energy and demand benefits also are associated with improved meter accuracy and theft reduction. More accurate meters will provide proper price signals to consumers and, consequently, provide the opportunity for customers to reduce their electricity consumption.

6.3.3.5 Improved Reliability Benefits

Reliability will be improved as a result of the deployment of grid modernization technologies. Using AMI meters and ADA, the Company will be able to detect, isolate, and respond to outages more quickly than current capability allows. The Company also may have greater ability to repair certain conditions remotely. The Company anticipates that this will result in reduced customer outage minutes, which will improve System Average Interruption Duration Index ("SAIDI") performance. Residential and business customers will benefit from reduced outages. National Grid expects approximately a 20% to 30% reduction in SAIDI on the feeders targeted for the ADA/FLISR deployment.

The Company expects outage duration to be reduced by approximately 8 minutes per customer per year over the 15 year analysis period or 10.4 million minutes of outage reduction annually as a result of its STIP[48]. The Company valued the reduction in outage minutes using the Interruption Cost Estimate ("ICE") Calculator model developed by Lawrence Berkeley National Laboratory ("LBNL") for the Office of Electricity Delivery and Energy Reliability, US DOE. The ICE model is based on two LBNL studies on the value of electric service reliability carried out for the DOE in 2009 and 2015.[49] These studies integrate the results of 34 customer surveys on electric service interruption costs conducted by utilities throughout the United States between 1989 and 2012. The ICE Calculator model incorporates these results into an on-line tool (available at icecalculator.com) that allows electric reliability planners to estimate customer interruption costs based on location, SAIDI, System Average Interruption Frequency Index ("SAIFI"), customer mix, the distribution of outages by time of year and other factors. Results of the ICE model include average outage costs per event by customer type. These are then translated into costs per minute based on the Customer Average Interruption Duration Index ("CAIDI") in order to value the reduction in customer outage minutes attributable to various grid modernization programs[50].

6.3.4 Quantified but not Monetized Benefits

Grid modernization will reduce greenhouse gases through reduced energy consumption and reduced peak demand. Reduction of use will reduce the dispatch of less efficient and dirtier peaking and/or intermediate load power generation. This will benefit customers and others in the Commonwealth.

The Company anticipates that greenhouse gas production will be reduced by about 950,000 tons over the 15 year analysis period due to energy consumption reduction associated with CLM

[48] This is true in Balanced, Grid Focused, and Opt-In scenarios. There is no ADA component to the AMI Focused scenario. This is a system-wide benefit.

[49] The studies are: M.J. Sullivan, Ph.D., M.G. Mercurio, Ph.D. and J.A. Schellenberg, M.A., Freeman Sullivan & Co. (now Nexant, Inc.), "Estimated Value of Service Reliability for Electric Utility Customers in the United States," June 2009, and "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States," January 2015.

[50] In the Business Case summary, all of these factors in outage reduction are represented as SAIDI.

devices, CVR/VVO and TVR. The value of greenhouse gas reductions are incorporated into the avoided cost values developed by TCR. These values forecast Regional Greenhouse Gas Initiative ("RGGI") prices throughout the Plan horizon, as well as represent anticipated EPA rulemaking under Section 111(D) of the Clean Air Act. The Company does not incorporate a value for greenhouse gas reduction beyond that anticipated by the TCR avoided costs, as described below.

The Company and the other utilities will be consistent with the outcome of D.P.U. 14-86[51] when that docket is decided. The utilities have stated in D.P.U. 14-86 that there is insufficient information to accurately estimate the cost of compliance with GWSA, and therefore do not include that avoided cost in the monetized BCA, either as an embedded cost within the electricity price forecast or through a method similar to that contemplated in D.P.U. 14-86.[52]

6.3.5 Qualitative Benefits

There are many qualitative benefits associated with grid modernization, including benefits that are difficult to quantify and as well as benefits that are not typically quantified. These benefits add significantly to the monetized benefits and further support approval of the proposed STIP, and are discussed below.

Crew productivity: It is possible that ADA and substation automation will improve fault detection, and allow quicker repair of faults. In addition, with AMI meters, the Company expects that, for some functions, physical access by meter readers to meters will lessen. The Company has not estimated the percentage improvement in crew productivity that may result; this may only be apparent with field experience.

Customer convenience: Grid modernization offers the prospect of increased customer convenience. CLM interfaces will give customers better information on consumption and

[51] D.P.U. 14-86, Joint Petition of the Department of Environmental Protection and the Department of Energy Resources requesting the Department of Public Utilities to adopt the avoided costs of complying with the Global Warming Solutions Act, using the marginal abatement cost curve method, in assessing the cost effectiveness of energy efficiency programs.

[52] The Company notes that some of the cost of GWSA compliance may be captured in the TCR avoided costs values that incorporate the anticipated value of 111(D) regulations.

increased options to manage their energy use, both remotely and on-site, and better feedback mechanisms. Better outage detection will reduce customer inconvenience from needing to call the call center to report outages as well as in reducing the duration of outages. CMI associated with a delay due to maps or records not available in the field will be reduced. In addition, increased accuracy of meter readings will reduce customer inconvenience from tracking inaccurate billings and reducing the need for customers to be present for disconnects and reconnects associated with their relocation.

Customer satisfaction: Educated customers with TVR will make informed decisions on managing and shifting their consumption to reduce overall cost, as well as voluntary reductions during PTR periods. Having these options can lead to better overall customer satisfaction compared to standard flat rate service bills. Reduced outage time will increase customer satisfaction and lessen bill complaints. In addition, during outages, customer service representatives will have more real-time information for customers about their outage status using information from the AMI system, leading to higher customer satisfaction.

Integrating DERs: The additional operational data collected by automated capacitors, regulators and automated switches, and displayed in the EMS, should support the improved management of the distribution system which will assist in the integration of distributed resources and storage.

Acceleration of future beneficial technology: Grid modernization presents the opportunity to deploy and install technologies that the Company was not otherwise planning to install. This will advance the deployment of the future generations of optimizing technologies for years into the future.

Avoided T&D capacity investments: Load reduction resulting from grid modernization installation could prolong the life of certain system components or, in some situations, address load growth needs, thus potentially serving to defer or avoid some planned investments in new T&D equipment. While the Company expects to observe and study the potential impact of demand reduction from its GMP on its T&D investment planning, for now it is an unquantified benefit.

Optimizing system planning: The additional operational data collected by the automated switches will support improved management of the distribution system, improved situational awareness and demand optimization. In addition, potential T&D deferrals may enable the Company to install some beneficial projects that otherwise would not have fit into its capital budgets.

Deferred capital replacement: While the Company has monetized some deferred capital value, ADA/FLISR schemes could postpone the need for conventional capital investments (equipment upgrades / replacements) based on contingency overloads identified in planning studies. Until the locations of these systems are identified, it is difficult to quantify this benefit.

Electricity delivery quality: It is anticipated that with grid modernization technology the Company will be able to confirm that electricity delivered is of acceptable voltage, current and frequency, and identify sags and swells. In addition, systems offer improved load balancing.

Safety and compliance: The Company anticipates that there may be safety and compliance improvements associated with having access to the latest maps and operating procedures and enhancements to data quality due to system quality controls, reduced closeout cycle times and auditable map feedback loop

6.3.6 Summary of Benefits and Costs

Below, in Table 17, the Company summarizes the benefits and costs of the Balanced Plan that can be monetized, for the STIP (5 years), the GMP (10 years) and the 15 year benefit-cost analysis period. The total CapEx costs, OpEx costs and benefits presented for all three time frames are simply the streams of costs and benefits summed over the time period, undiscounted. For the 15 year analysis period, the present-value benefits and costs, and the resulting benefit cost ratio are presented. Please also see the Business Case Summary Templates (Attachment 10), which provide additional detailed information on the estimated costs and benefits.

Given the deployment plan, many of the investments in the first five years do not yield the majority of their benefits until a greater number of devices have been deployed and enabling and/or coordinating systems have been deployed. For this reason, the STIP costs outweigh the benefits over the initial five year period, but over time (in the GMP case) benefits increase relative to costs.

Costs continue to be incurred after the fifth year of the GMP for a number of reasons. First, while AMF meters are fully deployed in the first five years, other systems such as CVR/VVO, ADA and load management technologies continue to be deployed after year five. Second, operations and maintenance costs are incurred in each year in order to maintain and capture grid modernization benefits. Finally, as some devices – such as MDMS, DSCADA, and some customer facing systems - reach the end of their useful lives even within the 15 year analysis period, the Company assumes refresh costs in capital investment in order to maintain grid modernization functionality. In order to align the refresh costs reflected in the business case with the resultant stream of benefits that fall within the business case timeframe, the Company assumes refresh costs are proportional to the fraction of resultant benefits that occur within the business case timeframe.

In the tabular presentations of benefits and benefit-cost ratios below, the Company provides total benefits that are the sum of the monetized benefits, including reliability. Reliability benefits comprise approximately 15% of the total benefits in the Balanced, Grid-Focused and Opt-In Plans. It comprises only about 5% of the benefit of the AMI-Focused Plan due to the absence of some of the advanced monitoring technology in that plan which would help detect outages and restore power more quickly. In addition to monetized benefits, for each plan, there are a range of non-monetized and qualitative benefits beyond those in these ratios.

Table 17: Balanced Plan Cost and Benefit Summary

STIP (5 YEARS)	
Total Costs	$830,506,000
CapEx costs	$708,119,000
OpEx costs	$122,387,000
Estimated cumulative bill impact for a typical residential customer (600 kWh/month)[53]	3.9%
GMP (10 YEARS)	
Total Costs	$1,314,749,000
CapEx costs	$968,695,000
OpEx costs	$346,054,000
15 YEAR ANALYSIS PERIOD	
Total Costs	$1,587,809,000
CapEx costs	$1,001,499,000
OpEx costs	$586,310,000
Benefits	$1,900,982,000
NPV Costs	$1,066,490,000
NPV Benefits	$956,452,000
Benefit Cost ratio	0.90

Please see Attachments 10a-10d, which list the benefits at a summary level and in detail. Additionally, this information is provided for the other three scenarios as well in Section 6.6.

6.4 Sensitivity Analyses

The Company performed sensitivity analyses around the reference case as directed by the Department in the Business Case Filing Requirements for the Balanced Plan, as follows:[54]

[53] Includes RD&D impacts as well.

- Time horizon. 20 year time horizon for costs and benefits.
- Discount rate. Sensitivity analysis using the 20-year Treasury bond rate of 2.19% as the discount rate for all benefits accruing directly to customers, as a means to illustrate how the value stream may be influenced by use of a different discount rate.
- Lower and higher customer response rate to TVR, and a scenario that assumes that all distribution customers are subject to a TOU rate with CPP: The Company assumed TVR customer response rates 25% higher and 25% lower than the reference case customer response rate in the Balanced Plan.

Table 18: Balanced Plan Sensitivity Analysis, 20 year Treasury Bond discount Rate and 20 year time horizon

STIP (5 YEARS)	REFERENCE CASE	20 YEAR TREASURY BOND DISCOUNT RATE	20 YEAR TIME HORIZON
Total Costs	$830,506,000	$830,506,000	$830,506,000
CapEx costs	$708,119,000	$708,119,000	$708,119,000
OpEx costs	$122,387,000	$122,387,000	$122,387,000
GMP (10 YEARS)			
Total Costs	$1,314,749,000	$1,314,749,000	$1,315,279,000
CapEx costs	$968,695,000	$968,695,000	$969,225,000
OpEx costs	$346,054,000	$346,054,000	$346,054,000
15 YEAR ANALYSIS PERIOD			TWENTY YEARS
Total Costs	$1,587,809,000	$1,587,809,000	$1,621,511,000
CapEx costs	$1,001,499,000	$1,001,499,000	$1,035,202,000
OpEx costs	$586,310,000	$586,310,000	$586,310,000
Benefits	$1,900,982,000	$1,900,982,000	$3,213,828,000
NPV Costs	$1,066,490,000	$1,387,251,000	$1,167,267,000
NPV Benefits	$956,452,000	$1,515,742,000	$1,346,927,000
Benefit Cost ratio	0.90	1.09	1.15

[54] Please also see Attachment 10e.

Table 19: Balanced Plan Sensitivity Analysis, TVR/CPP

STIP (5 YEARS)	REFERENCE CASE	HIGH TVR ADOPTION RESPONSE	LOW TVR ADOPTION RESPONSE	100% CPP ADOPTION
Total Costs	$830,506,000	$830,506,000	$830,506,000	$830,506,000
CapEx costs	$708,119,000	$708,119,000	$708,119,000	$708,119,000
OpEx costs	$122,387,000	$122,387,000	$122,387,000	$122,387,000
GMP (10 YEARS)				
Total Costs	$1,314,749,000	$1,314,749,000	$1,314,749,000	$1,314,749,000
CapEx costs	$968,695,000	$968,695,000	$968,695,000	$968,695,000
OpEx costs	$346,054,000	$346,054,000	$346,054,000	$346,054,000
15 YEAR ANALYSIS PERIOD				
Total Costs	$1,587,809,000	$1,587,809,000	$1,587,809,000	$1,587,809,000
CapEx costs	$1,001,499,000	$1,001,499,000	$1,001,499,000	$1,001,499,000
OpEx costs	$586,310,000	$586,310,000	$586,310,000	$586,310,000
Benefits	$1,900,982,000	$2,066,531,000	$1,735,433,000	$2,222,738,000
NPV Costs	$1,066,490,000	$1,066,490,000	$1,066,490,000	$1,066,490,000
NPV Benefits	$956,452,000	$1,039,866,000	$873,038,000	$1,124,619,000
Benefit Cost ratio	0.90	0.98	0.82	1.05

The sensitivity analyses demonstrate the robustness of the Company's proposals. A longer time horizon and/or lower discount rate enhance the cost effectiveness of the proposal. The variability of the results to assumptions about TVR adoption clearly indicates the dependency of benefits with TVR adoption.

6.5 Achievement of Performance Metrics and State Policy Goals

The Company's proposed STIP investments and initiatives will make progress on the objectives and the Company's proposed performance metrics, in the following ways:

(i) Reduce the effect of outages: The STIP investments will reduce the effects of outages by providing automated outage and restoration notifications, assisting with locating outage locations and damage, and automatically rerouting power during outages in order to minimize the number of customers impacted and the length of outages. The ADA program is specifically designed to reduce the minutes of customers interrupted in a significant way by automatically re-routing power in a dynamic way that our current system is not capable of doing, on the most high value feeders. In addition, the AMI deployment will provide real time status updates to a new OMS, which will direct crews to trouble before the Company receives customer supplied outage notifications.

(ii) Optimize demand: The STIP investments will optimize demand with more real-time monitoring and control, better-managed system voltage and fewer losses. The CVR/VVO program will seek to intelligently switch reactive power and voltage support devices to reduce waste, improve power factor and reduce demand in a way that the current system in unable to do. This program, which can be viewed as a feeder- wide energy efficiency program, is designed to provide peak and demand savings to customers, without them having to take any active steps. In addition, the Company will be creating a system-wide CLM program, which will provide customers the opportunity to reduce their load including during peak times, which can help optimize demand. The proposal for TVRs also creates the opportunity for reductions in peak demand and customer energy savings.

(iii) Interconnect distributed resources: The STIP investments would help interconnect DERs by providing more real-time information and awareness about the distribution system. The increased operational system awareness from the deployment of feeder monitors, ADA/FLISR, CVR/VVO and AMI will collectively allow for much more data to be utilized when determining DG impact studies. Additionally, National Grid's separate proposals on DG, would improve the distribution system's ability to accept distributed resources and provide customers with more information about interconnecting DER.

(iv) Improve workforce and asset management: The STIP investments will improve workforce and asset management by providing more-real time and detailed asset information, which will help improve operational efficiency, provide advance warning of potential equipment issues that could otherwise result in failures and/or outages, and help with system planning. The information available to the Company as a result of the key GMP investments will be used to more efficiently utilize the Company's workforce. The investment in mobile tools for the operations workforce will allow the Company to more effectively capture accurate information on assets. In addition the Company will update and overhaul its GIS, one of the key tools used by the Company's asset management group, in preparation for an ADMS.

Additional information about how the proposed investments will advance the Objectives (and the related proposed performance metrics, which are contained in Section 10) is contained in Sections 1, 4 and 5 of the Plan.

The Department's Business Case Filing Requirements also direct the utilities to consider how the Company's proposed STIP investments and initiatives will make progress on State policy goals and statutory requirements. The State policy goals and statutory requirements referenced in the Business Case Filing Requirements are:[55]

- Renewable Energy Portfolio Standard, 225 C.M.R. § 14.00, which promotes renewable energy and implements state goal to interconnect 1,600 MW of solar generation by 2020
- An Act Relative to Green Communities, St. 2008, c. 169, which contains statewide energy efficiency and demand response goals
- An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298, § 6, codified as G.L. c. 21N, § 3, which contains greenhouse gas emissions reduction requirements
- Executive Office of Energy and Environmental Affairs, Global Warming Solutions Act Five-Year Progress Report at 47 (December 30, 2013)
- State Zero-Emission Vehicle ("ZEV") Program, Memorandum of Understanding (October 24, 2013), available at http://www.nescaum.org/documents/zev-mou-8-governors-signed-20131024.pdf/, which is an agreement between Massachusetts and seven other states to coordinate and achieve adoption of 3.3 million ZEVs by 2025
- Massachusetts Electric Vehicle Initiative, Mid-Year Report (June 2014), available at http://www.mass.gov/eea/docs/doer/clean-cities/2014-06-ev-task-fiorce-report.pdf, with a goal of 300,000 ZEVs registered in Massachusetts by 2025
- The Department's service quality standards, D.P.U. 12-120-C
- The Department's emergency response standards, D.P.U. 14-72-A
- The Department's DG interconnection standards, D.P.U. 11-75-G.

The proposed STIP investments will help advance the Commonwealth's climate, reliability, and resiliency goals and statutory requirements by creating a more efficient, self-healing distribution system with the ability to restore power more quickly to customers, isolate outages and reduce the length of outages and number of customers impacted, operate more efficiently and reduce energy usage, and incorporate more distributed renewable energy resources. The benefits of the STIP are described in detail in Section 6.3, which include benefits related to these state policy and statutory requirements.

[55] D.P.U. 12-76-C, Business Case Filing Requirements at p. 7, n. 8.

Specifically, regarding climate, the proposed GMP will reduce greenhouse gas emissions by approximately 950,000 tons over the time horizon. This will be the results of reduced energy consumption, as well as the shifting of energy usage to off-peak periods as a result of TVR. This shift will reduce the need for relatively less clean peaking generation.

Regarding reliability, the improved outage management, ADA, AMI and customer responsiveness features of the proposed GMP will reduce customer outages on average by about 8 minutes per customer per year over the 15 year analysis period, or 10.4 million minutes of outage reduction annually.

The proposed STIP will advance the integration of DERs, including renewables, through facilitating the interconnection of incremental amounts of DG into the grid. Similarly, demand response capabilities will be enhanced through the use of AMI meters and TVRs.

The proposed STIP also will improve the resiliency of the system not only by reducing outages, but also in the long term by enabling improved strategic planning about capital investments on the grid. The enhanced diagnostic capabilities of the smart grid will help the Company focus its attention on areas of need better than it can with current tools and technologies.

National Grid's RD&D proposal,[56] although not part of the STIP, will help advance the adoption of electric vehicles as well as the state's other policy goals and statutory requirements, through projects that focus on alternative fuel vehicles, integration of DERs, microgrids, battery storage, environmental benefits and safety as it relates to workforce and asset management.

6.6 Additional Scenarios

As described in Section 1.4, along with the Balanced Plan, the Company simultaneously offers three additional scenarios for Department consideration: the AMI-Focused, Grid-Focused and Opt-In scenarios. In order to satisfy the achievement of AMF as directed by the Department, these plans feature varying amounts of prescribed AMI deployment, in some cases with the balance of the customers being offered AMI on an opt-in basis.

Table 20 below compares the key parameters of these plans to the Balanced Plan.

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[56] See Section 8.

Table 20: Scenario Comparison[57]

STIP (5 YEARS)	BALANCED	AMI-FOCUSED	GRID-FOCUSED	OPT-IN
Total Costs	$830,506,000	$657,185,000	$573,109,000	$235,383,000
CapEx costs	$708,119,000	$558,890,000	$493,716,000	$182,687,000
OpEx costs	$122,387,000	$98,295,000	$79,394,000	$52,696,000
Estimated cumulative bill impact for a typical residential customer (600 kWh/month)[58]	3.9%	3.1%	2.6%	1.2%
GMP (10 YEARS)				
Total Costs	$1,315,279,000	$954,187,000	$994,053,000	$521,326,000
CapEx costs	$969,224,000	$690,369,000	$742,733,000	$387,088,000
OpEx costs	$346,054,000	$263,817,000	$251,320,000	$134,239,000
15 YEAR ANALYSIS PERIOD				
Total Costs	$1,587,809,000	$1,148,124,000	$1,231,484,000	$645,125,000
CapEx costs	$1,001,499,000	$716,817,000	$773,396,000	$391,864,000
OpEx costs	$586,310,000	$431,307,000	$458,088,000	$253,261,000
Benefits	$1,900,982,000	$1,585,824,000	$938,723,000	$458,438,000
NPV Costs	$1,066,490,000	$784,275,000	$811,730,000	$408,762,000
NPV Benefits	$956,452,000	$801,163,000	$463,326,000	$228,784,000
Benefit Cost ratio	0.90	1.02	0.57	0.56

The AMI-Focused scenario satisfies the Objectives, while scaling back the deployment of some systems and functionality. It lowers bill impacts to customers and its benefit cost ratio exceeds that of the Balanced Plan. However, the cost savings are achieved by removing components – primarily the ADMS/DSCADA and ADA – that provide longer term qualitative benefits including: improved efficiency of grid operations and capital investment decisions; improvements in knowledge regarding the capability of the system to integrate load and

[57] Unless noted, these numbers represent the stream of costs in nominal terms and cumulative bill impact for the STIP period.

[58] Includes RD&D impacts as well.

generation; facilitating promotion of renewable and other types of DG; and creating the best platform for enabling the distribution system and customers to take advantage of the benefits of automation, advances in technology and data analytics, into the future. Additionally, some of the functionalities are achieved with manual processes as opposed to automated processes. This leads to increased risk of human error, increased time required to perform certain functions and added costs of maintaining multiple systems for longer periods of time. With this alternative, there will be fewer total customer benefits, less grid automation and potential loss of future benefits from absence of enabling technologies. This lowers costs in the short term at the cost of future benefits in years 16 and later.

The Grid-Focused scenario has AMI on an opt-out basis in the 30% of the service territory in which CVR/VVO will be deployed, with no ADA. For the balance of the customer base, AMI will be offered on an opt-in basis. This option has potentially lower stranded costs because assets are depreciated longer and the assumption is that fewer meters will be replaced. Because of the alignment with CVR/VVO, the Company would expect to see synergies in value with deployment and communications. National Grid may evaluate the success of targeted deployment and propose further deployments of CVR/VVO and AMI after 5 years. The disadvantages of this option are that AMI would not be deployed for all customers, and cost savings are not proportional to the reduced scope. This option also has a benefit-cost ratio that is approximately .57.

The Opt-In Scenario has grid investments that are the same as the Balanced Plan, but AMI is opt-in only, and the CLM, communications, IT/OT, cybersecurity and billing proposals would be expansions of the SES Pilot. This approach spreads out bill impacts over a longer time period and stranded costs are potentially lower because assets are depreciated longer and the assumption is that fewer meters will be replaced. Beyond AMI not being deployed to all customers as an opt-out option, cost savings will not be proportional to the reduced scope and it will take a longer time required to deliver benefits to customers. This option also has a benefit-cost ratio of approximately .56.

6.7 Overall Assessment of the STIP

6.7.1 Overall Assessment of the Business Cases

The STIP portions of the four scenarios offer significant benefits. They achieve AMF; leverage the functionalities of AMI in other areas for increased benefits; reduce outages; build IT/OT infrastructure to meet needs of the future; increase automation which reduces manual handoffs; give customers greater visibility and control of energy usage; facilitate reductions in peak demand; and make measurable progress on Department objectives. Additionally the Balanced and Grid-Focused scenarios include workforce and asset management mobility services which improve the efficiency and accuracy of multiple processes.

The Company's has identified greenhouse gas reductions. Furthermore, as described in Section 6.3.5, the Company has identified multiple categories of qualitative benefits that are significant, and which support the business case in favor of these investments. The Company believes that the combination of monetized, quantified but not monetized and qualitative benefits from all four GMP scenarios merit consideration of each of these alternatives.

6.7.2 Summary Tables of Quantified Benefits and Costs[59]

Please see Section 6.6, for summary tables of the quantified benefits and costs of the four proposed scenarios.

6.7.3 Stranded Cost Analysis

National Grid has identified two categories of stranded costs that would result from National Grid prematurely retiring assets that are used and useful to customers, in order to meet the requirements of the Order. These categories are: (1) costs for AMR meters that are not yet fully depreciated and that would be removed from service prematurely in order to install AMI meters; and (2) OMS costs related to the roll out of the ADMS/DSCADA system. Please see Tab 6, "Stranded Costs", of the Business Case Summary Template in Attachment 10 for the details of the stranded costs that the Company has identified, including the Plant Investment, Accumulated Depreciation, Retirement Cost, Unrecovered Asset Value, Remaining Depreciable Life, and Carrying Charge. These are estimated costs only, and the timing of plant retirements will be determined by the final deployment schedule as actually implemented.

Stranded assets are excluded from the main cost-benefit analysis and business case based on the Department's direction, and because they are not going-forward costs. Any investment that results in stranded assets poses a challenge for the Company, however. Stranded costs (absent appropriate cost recovery) can constitute a financial disincentive to invest in grid modernization in furtherance of state and Department policy goals, and customer benefits.

The Company should be allowed to recover all of the undepreciated value of these assets as well as appropriate carrying charges. Absent the requirements of the Order, National Grid would not

[59] The D.P.U. 12-76-C Business Case Filing Requirements identify the summary tables as a required element of the overall assessment of the STIP.

be prematurely retiring the assets identified above, which are otherwise still used and useful assets. It would be counterproductive to disincentivize utilities from furthering the Department's grid modernization objectives and delivering benefits to customers, by requiring utilities to carry stranded assets on their books for multiple years with no return on the capital that is tied up in those assets.

The Department therefore should depart from some of its past precedent on stranded costs, and should allow recovery of carrying charges on these assets[60]. Approval of the Company's STIP and GMP should include approval of the Company's proposal for recovery of the undepreciated costs of these assets and carrying charges. The Company proposes to be allowed to recover the remaining net book value of assets that have been used and useful in providing service to its customers but that must be retired prematurely as a result of the Order. The Company proposes that it be allowed to establish a regulatory asset for the undepreciated value of the assets being prematurely retired, and to initially amortize that asset in an annual amount equal to the then current level of rate recovery of those assets (depreciation allowance) included in either base rates or the Company's CapEx tracker mechanism. At the time of the Company's next base rate filing, the remaining value of such regulatory asset would be amortized over a period of three years and earning a return using the Company's weighted average cost of capital, adjusted to reflect the income tax rates in effect for the applicable year throughout this period. Other utility regulators with similar general policies regarding the recovery of costs associated with abandoned plant or early retired assets, such as the California Public Utilities Commission, have adopted provisions specifically in the case of advanced meter deployment to allow for a return of and on investments in stranded meters.[61]

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[60] See D.P.U.96-25-A (1997) (approving restructuring settlement agreement which included a return on stranded assets)

[61] California Public Utilities Commission Decision 11-05-018, at 55-57 (May 5, 2011) (Costs can be stranded in a number of different ways, but when they become stranded due to Commission desires or actions that fact should be taken into consideration when determining appropriate ratemaking." ; allowing for return on equity investment in retired meters in the case of electromechanical meters prematurely retired due to smart meter rollout).

6.7.4 Bill Impact Analysis

The Company has calculated bill impact analyses for its four proposed scenarios, using incremental grid modernization investments only, for each year of the five year STIP. Please see Exhibits AST/SMM 15-18 attached to the testimony of Company witnesses Scott M. McCabe and Amy S. Tabor, for the Company's bill impact calculations for the four proposed scenarios.

6.8 Amendments to DPU Template

Per the Department's request, excerpts from the Department's templates have been provided above to illustrate those costs for which STIP treatment is requested and to identify the different categories of benefits expected to accrue from investment in the four scenarios. Full templates will be provided with this Filing and Summary Costs and Benefits are included in Attachment 10 for each of the four scenarios.

In the templates, following the Department's structure, benefits are identified as: 1) quantified and monetized; 2) quantified but not monetized; or 3) not quantifiable/qualitative. The Company has added new categories of benefits, costs, functions and technologies where needed. Among these additions are: improved customer satisfaction; increased integration of DER in the service territory; SAIDI improvement; information access; reduced distribution equipment maintenance cost; safety; and compliance.

The Company notes a few conventions used in completing the templates. Notes in the "Costs" and "Benefits" tab highlight areas from which these were aggregated into other subcategories. The Company's cost estimation (through the RFPs/RFI or other methods described in Section 6.3.2) was aligned with this aggregation. For example, the Advanced meter cost subcategory "Develop new or modify systems to support TVR," is captured in the "Develop new or modify existing CIS & billing systems" line item cost.

Some of the subcategories are identified as network system enabler or "NSE." Row 6 of the tab labeled "2.Key Terms" contains a more detailed definition. While these do not provide direct benefits, they enable some of the advanced functionality of the grid modernization investments.

6.9 Request for Preauthorization

Based on the business case, the proposed STIP and the testimony and exhibits filed with this Plan, National Grid respectfully requests that that Department preauthorize its proposed STIP investments.

7. Distributed Generation

The amount of DG in Massachusetts is increasing year upon year, particularly with respect to solar photovoltaics ("PV"). The Company attributes this growth to a set of conditions that include, among other things, state and federal incentives to promote renewable energy, utility tariffs that authorize net metering and virtual net metering, overall market developments, relatively low interconnection costs to date, and reductions in cost of solar PV technology.

National Grid is proposing new investments in technology tools and systems, as well as enhancements to existing business processes and new business processes, can help meet the increasing interest in and penetration of DG. The Company also is proposing targeted system upgrades to improve the readiness of the distribution system for DG. These investments include ground fault detection (3VO Protection) and Point to Multi-Point Power Line Carrier Permissive Direct Transfer Trip ("P2MP PLCP DTT") protection. These investments are not included in the Company's GMP costs because the investments would normally be recovered through the Company's Standards for Interconnection of Distributed Generation tariff, M.D.P.U. No. 1248 ("Interconnection Tariff"), for those customers contemplating construction of DG facilities requiring interconnection to the electric system. The Company is not proposing to recover the cost of these investments in this filing, but anticipates submitting a proposal to the Department for their recovery in the future. Until such time as the Company has a recovery mechanism for the costs of these DG Investments, it proposes to recover the costs through its Interconnection Tariff.[62]

7.1 Overview of DG in National Grid's Service Territory

Quantity and Type of DG Applications and Interconnections

As of July 30, 2015, approximately 16,561 DG facilities are interconnected with National Grid's electric distribution system, with an overall capacity of 475.7 MWs (AC)[63]. Ninety-eight percent of the interconnected DG facilities, or 16,349, are solar PV systems which represent approximately 375.5 MWs of capacity. Since 2010 there has been a significant increase in

[62] Any proposal for a change in the Company's Interconnection Tariff would be brought before the Distributed Generation Collaborative.

[63] In this chapter, all DG capacity is reported in AC.

interconnection applications, particularly with respect to solar. In 2014 the Company received approximately 793 solar applications each month, which grew to approximately 1,200 solar applications each month for the first half of 2015. Similarly, the Company has interconnected increasingly more DG facilities each year. In 2014 the Company interconnected approximately 5,277 DG facilities[64], accounting for approximately 124.3 MWs of capacity. In the first 6 months of 2015, the Company interconnected approximately 6,070 DG facilities and anticipates interconnecting a total of approximately 9,246 DG facilities by year end. As of July 30, 2015, an estimated 523 MWs of solar project applications remain pending.

Quantity and Type of DG Facilities and Customers

There are a variety of types and configurations of DG systems interconnected with the Company's electric distribution system. Some DG systems are designed to provide on-site generation to offset on-site customer electric load,[65] while others are stand-alone generating systems with little or no on-site customer load.[66] Most of the DG systems are net metering facilities, and state law compensates most net metering facilities at approximately the retail rate for any electricity that they net or export, whether they partly or completely offset on-site customer electric load, or are stand-alone generating systems with little or no on-site customer load. This compensation to net metering customers is then recovered from all electricity

[64] This amount represents approximately 1/3 of the total number of interconnected DG facilities.

[65] Under net metering, electricity produced on-site by DG is credited against electricity consumed on-site over a billing period, whether or not it provided power during all hours of a billing period. Depending upon the customer load and the DG capacity, DG may partially or completely offset electricity consumed over that period, or may produce a net surplus of generation. Few DG systems serve all of a customer's on-site electricity needs without ever drawing from the grid, and as is widely known, solar PV only generates electricity during certain hours of the day. When net metered solar is not producing but customers are using electricity on-site, that electricity is drawn from the utility's electric distribution system. If solar DG produces more electricity than is consumed during the day, the excess electricity is exported to the grid. Net metering in Massachusetts allows exported electricity to be credited against imported electricity (drawn from the grid) over a given period

[66] Under virtual net metering, a stand-alone facility generating electricity in one location can apply net metering credits at an altogether different location, allocating kWh credits to a separate customer account without paying any delivery charges. In this situation, neither party is paying an appropriate share of the fixed costs of the distribution system. In National Grid's view, this construct is far removed from the original concept of net metering, which was to allow the netting of behind the meter generation from the usage at that same location. As a result, virtual net metering systems result in a higher cost to distribution company customers than if the generation were behind the meter.

customers. The Company estimates that the vast majority – more than 15,000 DG systems – are partly or completely offsetting on-site customer electric load and approximately 110 are stand-alone solar PV systems which represent approximately 180 MWs of the total 475.7 MWs of interconnected DG systems. Customers associated with stand-alone DG facilities using virtual net metering or DG facilities that offset on-site load are either not paying or paying significantly less for electric distribution services that they receive from the electric distribution system.

At present, DG customers represent about 1.2% of the Company's 1.3 million Massachusetts customers.[67] These DG customers report high levels of satisfaction due to savings on their monthly electric bills,[68] and other customers report high levels of interest in DG, and especially in solar PV.[69] National Grid expects that the current level of interest and adoption of solar PV will continue. The Company recognizes the need to invest in advanced tools and systems to facilitate the increasing growth of DG.

Interconnecting DG into National Grid's Electric Distribution System

National Grid's primary responsibility for DG has been the safe and reliable interconnection of DG to the Company's electric distribution system. The Company's current business processes focus on receiving and reviewing applications for proposed DG installations, studying potential electric system impacts from proposed projects, estimating and constructing system upgrades to accommodate proposed projects (when needed) and authorizing customers to interconnect their systems.

As the prevalence of DG increases, National Grid anticipates the need to develop its current interconnection-focused process into a more comprehensive set of integrated processes that enable the effective incorporation of DG into the Company's planning and operations.

[67] This estimate is based on a simple ratio of the number of DG systems to the number of National Grid electric customers, reflecting that the vast majority of installed DG projects represent unique customers. It is worth noting, however, that a small but meaningful number of customers (for example, governmental entities) pursue more than one DG project. Approximately 92% of all DG systems are associated with residential customer accounts, 7% are associated with commercial accounts and approximately 1% are associated with governmental accounts.

[68] Internal customer research study conducted by National Grid in early 2015.

[69] Internal customer research study conducted by National Grid in late 2014.

7.2 Investments to Facilitate Interconnection of DG

New investments in technology tools and systems, as well as enhancements to existing business processes and new business processes, can help meet the increasing interest in and penetration of DG,[70] if appropriate cost recovery is in place. These include interconnection application processing, system analysis and planning, grid operations and targeted system upgrades to improve readiness of the electric system for DG:

- Application processing capability for DG interconnection: While National Grid met state standards regarding interconnection application processing timelines in 2014, the number of applications is increasing and customers request faster administration, technical review and approval from the Company for their DG systems. National Grid proposes several new capabilities to address these issues.
- System analysis and planning: As the amount of DG grows on the system, the Company sees a benefit in monitoring, analyzing, simulating and forecasting DG energy and capacity (from both operating and expected DG systems) into distribution system planning and operations.[71] The increasing penetration of DG must be evaluated from an operational stability perspective. DG systems will require interval meter data reporting and real-time monitoring (with customer agreement) in order to achieve effective control and integration. Information systems and advanced analytics are needed to provide understanding of real-time output of DG systems for distribution control center operators. Part of this functionality will be provided by the capability the Company has identified as part of the proposed ADMS described in the Section 5.2.3.
- Online tools and information for customers: This proposal includes making available simple, convenient information and online tools for customers considering DG as well as

[70] All systems will need to be capable of meeting National Grid's data security protocols as set forth in Section 5.2.5 Cybersecurity and Privacy, including the protection of customer data.

[71] Real-time visibility and forecasting of DG output can assist in the operation and stability of the grid. Real-time monitoring and management of DG output can be provided through AMI and controls. However, at present, the Company only has real-time information from DG systems above 1,000 kWs. Meters can report interval data from DG systems larger than 60 kWs, but not in real-time. The Company does not have data on smaller customers except monthly billed usage. Thus, it is very difficult to monitor conditions in real-time and in specific situations, such as residential neighborhoods with a large concentration of DG. In these conditions, the Company will only know of abnormal conditions if customers call and report a service issue to the Company.

other cost-effective clean energy solutions, which may help facilitate their consideration and adoption of DG. These tools will provide more information to customers and developers on the feasibility and economic value of installing DG and other solutions.

- Targeted system upgrades to improve readiness of the electric system for DG: Certain substation upgrades could facilitate the interconnection of increased levels of DG such as high voltage ground fault protection (3VO protection schemes) and prevention of unintentional islanding of DG (Direct Transfer Trip or DTT).

Additional detail on these proposals is contained in the rest of this Section 7.2. The discussion of alternative means to fund these costs and for DG to provide adequate funding for the value from the distribution system is addressed in Section 12.4 and the testimony of Company witnesses Peter T. Zschokke and Scott M. McCabe.

7.2.1 Application Processing Capability for DG Interconnection

This project proposes development of several capabilities: an application portal for customers to submit applications, a work management tool and an internal pre-application reporting tool. The project would also enable the integration of the internal information systems necessary to interconnect DG.

7.2.1.1 Interconnection Online Application Portal, Work Management Tool and Pre-Application Reporting Tool

The application portal will enable customers or developers to submit interconnection requests online and receive automatic notifications of certain required steps. The portal will have the ability to store attachments uploaded by customers and process electronic payments.

The work management tool will establish a system for processing applications which also supports associated internal cross-functional activities. This tool will enable customers to track the progress of their application.

This project will also create a simple map-based pre-application reporting tool utilizing the Company’s existing GIS data to provide customers an online portal to assess potential DG locations, similar to the current pre-application report process for proposed large DG projects.

7.2.1.2 Interconnection Information System Integration

This project will integrate internal information systems and associated data needed for the DG interconnection process. This project will support application processing, project screening, impact study analysis, and construction estimates. An integrated data environment will also enable interconnection data to be more readily accessed by other internal departments such as engineering, planning, billing, metering, accounts processing and analytics.

7.2.2 System Analysis & Planning

7.2.2.1 Advanced Analysis & Study Tools for Distribution Planning

Enhanced analytical knowledge of DG could help evaluate DG in short and long-term planning as well as day-to-day electric distribution system operations. Planning and operating a distributed, two-way power system is more complex and dynamic than in a traditional one-way grid setting. While the Company has always analyzed interactions between generation and load as part of its planning, the increase in the number and MWs of DG sources on the system call for understanding of the potential interactions between DG, customer service quality and the utility's distribution system equipment. The intermittency of solar PV impacts the distribution system in ways that the broader industry is still working to understand.[72]

An analytical approach has been identified that enables complex simulation of DG technologies and their interaction with customer energy use and the distribution system. By investing in the development of these modeling tools and analytical infrastructure, National Grid will be prepared to more effectively plan for a future with substantial customer adoption of DG.

This initiative will:

- Improve knowledge of current and expected DG energy and capacity to inform planning efforts across the business, including:
    - Rooftop solar PV market potential and adoption forecast; and
    - Large-scale ground-mount solar PV market potential.
- Enable dynamic simulation of DG impacts on the electric system to enhance distribution planning, including:
    - Voltage profile analysis by feeder by source – all DG, capacitor banks and required customer needs;

[72] Pursuant to Public Utilities Code 769 and California Public Utilities Commission order instituting ratemaking (R. 14-08-013), by July 1, 2015, California electric utilities were required to file proposed distribution resource plans to identify optimal locations for distributed energy resources. *See* http://www.cpuc.ca.gov/PUC/energy/drp/index.htm.

  - Summary of loading with ("net") and without ("gross") DG by feeder, and comparison to measurements from meters/sensors on the distribution primary system;
  - DG hosting capacity analyses; and
  - Potential future system modifications required as a result of forecasted DG growth.
- Support the application screening process to further increase the efficiency of customer application processing.

Models, analyses and tools also will enable other system DG investments by providing the underlying data and dynamic analysis required for customer tools, planning software integration, operational tools, and marketing, education and outreach.

Analytical Tools & Approach

The Company proposes new tools that can integrate a broad set of analyses and analytical approaches into a holistic simulation of the entire distribution system, all the customers on the system with and without DG, and other distributed resources.

The Company has selected a new open-source simulation and analysis tool to perform advanced distribution system simulation. This "big data" tool is uniquely capable of time series analysis of DG (and other distributed resources) in interaction with weather, markets and consumer behavior, encompassing thousands of data models and millions of instances of data.

Using these tools, the analytical approach for DG begins with a determination of the market potential for DG and its projected timing both at the state and parcel/structure levels. This entails an analysis of DG potential for each customer account in the territory with a forecast of DG adoption necessary to meet state policy targets. Forecasted adoption rates will then be represented geographically to enable distribution planning with scenario analysis, including future policy scenarios. The approach then would model the impacts of DG on each customer's energy usage, demands and costs. The initiative can then model impacts of DG on the transformers, feeders and substations, as well as provide input to revenue impacts from customer adoption of DG.

Initial Development

The Company has conducted initial development and demonstration of rooftop solar PV adoption forecasting using novel "big data" advanced analysis methods. Using a tool, National Grid performed an advanced simulation of a part of the Company's distribution system integrated with the rooftop PV market as a proof-of-concept. This simulation forecasted PV growth and feeder impact on a small scale, providing a blueprint and initial models for tools and analyses, as described below.

Data Acquisition & Modeling

Data models will be developed for every individual feeder, customer and DG system, including hourly performance forecasts. This will include up to 1,227 feeder models and 1.3 million customer models.

These models are built using data types that include, but are not limited to:

- Interval meter data on the feeders[73]
- Customer level billing data
- Customer level DG adoption data
- Weather data
- Remote sensing data, including hyperspectral image and light detection and ranging ("LIDAR") data
- Internal and external geospatial data

Once built, data models will support every subsequent analysis in this multi-year initiative.

Customer-Driven DG Market Potential Analyses and Forecasts

This analysis comprises a bottom-up DG customer potential and likelihood analysis at the distribution level by examining: (1) technical potential for rooftop PV based on the customer's structure's solar footprint (square footage of rooftop, orientation, tilt, shading, irradiation, etc.); (2) the age and condition of the roof; (3) the design and interconnectivity of an appropriate PV system for the structure; (4) the financial viability of the PV system based on the economics for installing the system; and (5) each customer's propensity to install the system based on other factors such as demographics, firmographics and external influences. In addition to analyzing immediate potential for rooftop PV given conditions as they exist today, this approach can analyze customer-specific PV potential in response to changes in propensity, costs and financing structures.

[73] Interval meter data is stored in the Company's PI Historian, which makes it accessible on-demand to system operators, planners and engineers. To ensure production system reliability (server capacity and priority) for existing users while supporting the big data computing requirements of this new analytical initiative, the Company will need to replicate the existing PI Historian production system.

System-wide DG Market Potential Analyses and Forecasts, Using Policy Targets

Results of the customer-driven DG market potential analyses can then be compared to a policy-driven forecast for DG capacity and energy, to validate the spatial and temporal forecasts, and observe how different approaches can influence/target the spatial growth of DG.

Impact of DG on Individual Customer Accounts

This modeling effort will analyze and assess DG impacts at each individual customer home and business, to understand and forecast the effect of DG on energy usage, energy demand and energy cost. This will provide input into forecasting customer bill impacts, understanding end-uses and modeling the impacts of complementary technologies.

DG Impacts and Hosting Capacity Analyses

DG Impacts on the Distribution System: Determining the impacts of DG on the system is essential to planning future system development and consideration of the degree and value from potential integration of these technologies into the distribution system. This analysis will apply forecasted DG potential and growth at each of the customer's homes and businesses to individual feeders, integrating into local transformers and then up to feeders and substations. Analyses can be carried out with respect to the current state of the system or to potential future states.

DG Hosting Capacity Analysis: This analysis will evaluate prospectively the quantity of DG that can be interconnected to the system before further system upgrades are necessary, or with proposed system upgrades included. This analysis will support internal evaluation and planning, as well as external reporting, described below.

Day-Ahead DG Forecast

This project will provide day-ahead DG forecasting (starting with solar PV) for Company operators.

7.2.2.2 Planning Software Integration and DG-Related Training

Planning Software Integration Project

This project will align the Company's planning tools and processes related to DG with the planning tools and processes related to distribution lines and distribution substations. The project will align these planning software tools with new models described above.

Training for Distribution Planners, Field Engineers and Others

This project will develop training and documentation for distribution planners, field engineers and others, as appropriate, to improve the ability to interconnect DG and begin the process of integrating DG that could potentially be used as a resource in ongoing functions. Focus areas include operations/dispatching, load and generation forecasting, distribution planning (mid and long-term) and interconnection processing.

7.2.2.3 External Reporting

DG Hosting Capacity

The term "hosting capacity" is used to refer generically to the amount of electrical capacity of DG that can be safely and reliably interconnected to the utility's distribution system without major upgrades. As long as required upgrades are funded and constructed, there is no set limit on hosting capacity. Despite its seeming conceptual simplicity, however, hosting capacity is a complex topic. The ability of a given feeder, feeder segment or substation to safely and reliably accommodate DG depends upon many specific attributes of that portion of the system, as well as its relation to the larger system of which it is a part. These attributes and relationships form the basis of the Company's interconnection study analysis process, which is conducted on a point-by-point basis as projects are proposed. The task of identifying hosting capacity on a prospective basis for some or all of the distribution system is a challenging one, both from an analytical perspective and because system conditions change regularly as part of the Company's baseline operations[74] and interconnection of new DG.

As of the time of this report, the approach to measuring or reporting "hosting capacity" is currently being reviewed by the Massachusetts utilities. The Company anticipates the need to invest in advanced analysis for the investigation of DG hosting capacity.

Hosting Capacity Reporting

National Grid proposes to begin with an annual illustrative report to be filed at the Department that provides a summary by feeder and substation of potential hosting capacity. This report will provide a "snapshot" of opportunity, showing possible areas of potential interconnection at low cost. However, because many factors will affect hosting capacity, the information should be considered indicative (rather than definitive) in nature, based on the always-changing nature of the system.

Over time, the Company could provide more dynamic reporting and presentation of hosting capacity to stakeholders, developers, and customers. The Company could develop these reporting tools and offer them via the Company's website. Tools will also require integration with internal systems to provide the most up-to-date distribution system information possible.

[74] For example, connecting new customers, various public works projects, normal and emergency switching requirements, new construction, voltage and reliability enhancements.

7.2.2.4 Operational Tool Development & Analysis

DERMS: Business Requirements and Evaluation

As a supplement to the ADMS, the Company also proposes to evaluate the potential for real-time monitoring of all non-traditional energy resources using the ADMS infrastructure with allowance to manage and dispatch participating non-traditional energy resources for system benefit where applicable. These capabilities are referred to in the industry as a DERMS. The Company therefore proposes to conduct business requirements specification and evaluate potential system designs for a DERMS capability, in coordination with the ADMS project.[75]

DG Voltage Mitigation

This project would evaluate DG-related voltage impacts (e.g., intermittent sources such as PV) based on available meter/sensor data, and the feasibility of using the CVR/VVO system (once installed) or other tools (for example, customer-owned advanced inverters) to manage the impacts of DG.

7.2.3 Online Tools, Marketing, Education and Outreach for Customers

National Grid would provide simple, convenient information and online tools for customers considering DG as well as other clean energy solutions, in an effort to facilitate their consideration and adoption of DG. These tools would provide more information to customers and developers on the feasibility and economic value of installing DG and other solutions. Marketing, education and outreach also will be important to help customers learn about DG and the interconnection process.

7.2.3.1 Online Tools

As Section 11.4, Customer Knowledge describes, customer expectations are increasing across the utility industry. Through interactions with other industries, National Grid's customers are growing accustomed to conducting their personal and business needs online and through their mobile devices.

[75] As noted in Section 5.2.3.5, the Company evaluated DERMS modules for ADMS and found all of them currently to be lacking in maturity to meet the needs of the Company.

The Interconnection Online Application Portal project described previously in Section 7.2.1.1 will bring more convenient, interactive and automated web features to DG customers, supporting continued high-quality service to customers through today's interconnection process. The Company proposes to expand beyond this application portal to provide the following online tools.

"DG Potential" Estimator Tool

The Company proposes to build an interactive online tool using the models described in the Advanced Analysis and Study Tools for Distribution Planning Section 7.2.2.1 of this chapter, enabling potential DG customers to assess the feasibility and economic value of installing DG. The initial tool would help customers assess their solar PV potential. Subsequent enhancements could help evaluate the economic value of DG compared to energy efficiency products, as well as other types of DG. This tool would help customers by providing an independent analysis of the value potential from various resources.

Site Screening Map Tool

This proposed tool would provide dynamic information to customers, developers and other stakeholders about the existing distribution system assets and interconnected DG to facilitate screening of individual sites (addresses) and areas for their potential to interconnect new DG. This tool should enable outside parties to search by address, or browse in an online map, for selected electric distribution feeders and substations and the relevant attributes included in simple interconnection screens. The map must also reflect the dynamic nature of the electric system and be automatically updated on a periodic basis.

7.2.3.2 Marketing, Education and Outreach

The Company communicates information about DG to customers through quarterly seminars/webinars and frequently updates its DG website. The Company proposes to expand its communication offerings to allow more opportunities for customers to learn about DG and the interconnection process. National Grid proposes a combination of MEO activities to support continued growth in DG participation including the following:

Product marketing for existing and new services

National Grid would expand customer communications on existing DG interconnection and billing/crediting, including:

- Ongoing web updates to streamline and improve access to information on the interconnection process;
- Customer-friendly presentment of planned interconnection online application portal;
- Educational materials on billing/crediting statements and total bill impact; and

- Training for customer service representatives on helping customers understand the interconnection process and billing/crediting statements.

Broad-based education and awareness-building

The Company would provide education and outreach to customers on types of DG (with a focus on solar PV) and how DG operates and interacts with the electric system. This would help customers understand the Company's activities related to DG, as well as plans for DG in the future.

Table 21: MEO Goals and Channel Strategies

	Marketing, Education & Outreach Plan
Goal	Educate customers and stakeholders (vendors, contractors, etc.) actively engaged or seeking information on the benefits of DG, costs, available technologies, interconnection requirements, billing, etc. Increase DG awareness and interest among the general customer base by educating on basic principles, the value of the grid and the Company's role to achieve their energy goals, while continuing to address Targeted Plan goals.
Channel Strategy	**Expanded Customer Engagement Tactics:** • Company web/app • Bill messaging/bi-monthly customer newsletter • Direct mail (mail/email) • Learning events (webinar, lunch and learn, etc.) • Social media • Local events/sponsorships • Call center (IVR, outbound calls) • Third-party messaging (Mass Save, Opower, etc.) **Industry partnerships:** • Engage key industry players (builders, vendors, installers, large customers) to co-brand highly visible and sophisticated communications programs **Advertising (1 campaign/ first year):** • Radio • Newspaper • Digital/Social Media • Outdoor

Data analytics will be used to further refine the target audience, and develop an effective channel and message strategy. The optimal channel mix, message strategy and communications schedule will be determined based on the timing of implementation and related considerations. The Company would seek alignment with state-wide partners whenever appropriate.

7.2.4 Targeted System Upgrades to Improve Readiness of the Distribution System for DG

National Grid's interconnection application review process analyzes the feasibility of proposed DG interconnections based on any potential impacts to the distribution system and system modifications needed to accommodate the DG. Large DG systems, such as multi-megawatt "stand-alone" PV installations, or the cumulative amount of multiple smaller DG systems (residential or small commercial) can pose localized distribution system risks depending on the attributes of the feeder and substation to which they propose to interconnect. If these risks are identified, the Company's Interconnection Tariff requires that the customer(s) or developer(s) pay National Grid to make system modifications before interconnecting.

National Grid has identified two common types of significant system modifications that can be required to mitigate the risks if identified in a system impact study, and which could be installed in order to improve the readiness of the electric system for DG: ground fault detection (3V0 protection) and direct transfer trip point to multi-point power line carrier permissive system ("DTT P2MP PLCP").

7.2.4.1 Ground Fault Detection (3V0 Protection schemes)

Increasing penetration of DG is already causing reverse power flow onto the transmission system in certain locations. 3V0 protection relay schemes are designed to detect the line-ground faults on the ungrounded system where the fault current contribution of DG to the line-ground faults is negligible. These systems are required to protect the Transmission system, allowing more DG onto the Distribution system. 3V0 protection schemes installed at a substation is a significant system modification especially if the high side voltage of the substation transformer is greater than or equal to 115 kV. Above this voltage capacitance-coupled voltage transformers ("CCVTs") are required to be installed to accommodate the 3V0 relay.

National Grid reviewed 292 substations in Massachusetts to assess the potential DG capacity increase associated with installing 3V0 protection. The capacity increase is calculated at the substation based on the amount of DG that can be installed as a result of adding the 3V0 protection to the substation. This study identified the potential to install 3V0 protection at 27 substations, which could result in approximately several hundred MWs of DG capacity increase on the distribution system.

7.2.4.2 Direct Transfer Trip Point to Multi-point Power Line Carrier Permissive System

Direct transfer trip ("DTT") is a required form of protection to prevent unintentional "islands" if DG could continue to operate after a grid outage. Unintentional islanding results in a serious public and worker safety condition. DTT uses communications technology to shut down the DG that is still operating during a grid outage, according to the most recent IEEE 1547 standard. The commercialized DTT options that are currently available in industry consist of radio and phone line DTT which can have relatively high installation and ongoing communication costs, and ongoing maintenance challenges.

A DTT P2MP PLCP system could provide an alternative approach to robust anti-islanding protection for large DG installations. The cost of these systems is comparable when compared to a single traditional DTT installation. The PLCP technology is designed such that only a single transmitter is needed to provide DTT protection for multiple projects which has the possibility of reducing the cost of DTT for multiple projects.

8. Research, Development and Deployment/Pilot Initiatives

8.1 Overview

The Order directs utilities to include in their GMPs proposed RD&D efforts "that focus on the testing, piloting and deployment of new and emerging technologies."[76] In response to this directive, National Grid proposes to adopt an expanded RD&D program which will further the Objectives. National Grid's RD&D Program will seek to promote the development of promising new technologies and processes that will provide positive benefits to customers and advance the Objectives. This proposal also addresses concerns raised in prior Department orders regarding RD&D proposals,[77] while also seek some flexibility in light of the Department's statement that "attaining the benefits of the modern grid may require reconsideration of [Department] precedent,"[78] by proposing:

- Projects which National Grid believes will result in net positive benefits to customers.
- Increased collaboration among the electric distribution companies.
- A focus on projects that will benefit customers, as opposed to other parties.
- Specific RD&D proposals with associated estimated costs and qualitative benefits, while also recognizing that research needs and costs may change over time and that the expected benefits of RD&D efforts cannot be quantified precisely in monetary terms.

National Grid is proposing a series of projects that target areas of innovation identified as key to the modernization of the grid,[79] as described in more detail in this Section 8.

The Department has offered the opportunity to increase funding for RD&D activities which will provide utilities the necessary funding to conduct larger scale pilot and demonstration projects

[76] D.P.U. 12-76-B at 28.

[77] See D.P.U. 12-76-B, at 29-30 (2014); D.P.U. 10-55, at 154-158 (2010).

[78] D.P.U. 12-76-B, at 29-30.

[79] National Grid currently has a small baseline RD&D program, which leverages collaborative funding from other utilities via the Electric Power Research Institute ("EPRI") and the Centre for Energy Advancement through Technological Innovation ("CEATI").

than before. These larger scale projects such as DER integration including battery storage will provide the necessary lessons for potential full-scale deployments.

8.2 Past Industry and National Grid RD&D Practices

Historically the electric utility industry has funded R&D at levels well below other industries, typically at less than 1% of revenues. Suppliers typically have done more RD&D than have electric utilities. Enabling utilities to conduct more RD&D can help further the deployment of new technologies on utility systems, benefiting the customers as described in more detail below.[80]

National Grid's current RD&D efforts take place with subject matter experts within their department in the Company. A centralized RD&D function exists to guide, monitor and report on these activities. National Grid's current annual RD&D spending is approximately $910,000 inclusive of spending by its affiliates in New York, Rhode Island and in the generation business.

The Company's current annual RD&D investments are primarily in collaborative programs lead by EPRI or CEATI. This approach has maximized the Company's investments by combining investments with those from other utilities facing the same or similar issues. For example, the collaborative approach with EPRI means that the Company contributes only 8% of the total cost of the projects in which the Company elects to participate.

To date, National Grid's RD&D efforts have focused on: (i) reducing the overall cost of delivering energy both now and in the future; (ii) including safety in the design process; (iii) operating the network more efficiently; and (iv) offering a sustainable design. These goals often are accomplished through collaborating with partners including government agencies, universities, technical organizations, the vendor community, industry committees and leveraging the Company's international reach. These goals are in line with the Objectives, and continued pursuit of these goals will help further the Objectives going forward.

8.3 Decision-Making Process for Identifying Promising New Technologies

The Order also requires grid modernization RD&D proposals to specify "a decision-making process that outlines how the companies will conduct RD&D and identify promising new

[80] 2011 MIT study on "The Future of the Electric Grid"

technologies." Section 8.4 describes the framework National Grid will use to administer its RD&D program in this changing environment.

For the grid modernization RD&D program, project ideas were accepted from internal and external sources and filtered to ensure they were consistent with the Objectives. Project justifications and estimates of costs and benefits were required. The Company's RD&D team, along with the project sponsor, then developed a more rigorous project scope and definition resulting in a proposed Terms of Reference.

Projects that reached this stage were then ranked against other projects in the pipeline to ensure the Company only progressed those projects with the greatest positive impact. The ranking process evaluated each project against the four Objectives using a scale of 1 (Does not support the objective) to 5 (Fully supports the objective). Each of the Objectives received a score of between 1 and 5 based on how well the proposed project supports that specific objective. Projects that met more than one Objective received higher scores than projects that only met one Objective, and therefore were ranked higher. Examples of items that were considered within each objective are:

- Reduction in the frequency and duration of outages
- Empowerment of customer choice while reducing demand and increasing grid efficiency
- Enabling integration of DERs and protection of the grid against any negative effects of DER integration
- Reduction of operational costs while increasing efficiency of our asset management capabilities and our workforce.

Projects that ranked sufficiently high were then selected to be included in this proposal. The Company's Project Filtering and Scoring Methodology are attached as Attachment 16. The Company will use this same methodology to select projects in the future as well.

If the Company's RD&D proposal is approved, the selected projects will be assigned a project manager. Once the project is complete, a "lessons learned" process will be conducted and if the project is successful and intended to stay in service, it will be integrated into the normal business processes.

8.4 Scope of Grid Modernization RD&D Proposal

The RD&D Program will seek to advance technologies, processes, systems and work methods that show promise for furthering the Objectives. The Company will collaborate with technical organizations, university partners, other utilities and various vendors in these efforts. The collaborative approach leverages RD&D investments in organizations that tailor research to the common needs of multiple utilities, all of whom contribute a portion of the total investment. The Company also will pursue government funding opportunities when possible.

The Company proposes a ten year RD&D plan, in line with the GMP. The Company will review its RD&D plan annually to ensure the effectiveness of RD&D investments, and will adjust its RD&D efforts as necessary based on new developments. This will further improve the RD&D investment strategy in future years.

National Grid is also keen to pilot and demonstrate new technologies on its grid. Pilots and demonstrations provide several key lessons to utilities, including:

- Provide employees an opportunity to become familiar with the new technology and identify any nuances not generally known.
- Provide feedback to vendors on equipment performance based on real-world installation and operational experience.
- Identify interoperability and integration challenges resulting from the adoption of new technology.
- Permit evaluation of the value from new technology.
- Inform design and operational considerations for future deployments.

National Grid's RD&D Program will focus on the areas discussed in the remainder of this Section.

8.4.1 Integration of Distributed Energy Resources (DER)

Over the next ten years, the continued integration of DER will be a key driver of change in the energy industry. Migration to an industry where energy sources and consumption will be intertwined and distributed throughout the grid is fundamentally changing how the electric grid is designed and operated. The RD&D program will seek novel approaches to integration of DER, and will seek to provide better information on how this migration will impact the electric grid and customers. Research areas will include but not be limited to:

- Microgrids
- DER integration to the grid
- Large and small scale energy storage
- Advanced control/forecasting technologies

Projects in this area will address the complexities of integrating variable renewable generation sources with the existing electric grid. The temporal nature of renewable sources and the real-time balance between generation and consumption can create imbalances in the grid. The application of energy storage equipment and advanced control systems will be required to maintain this balance.

8.4.2 Alternative Fuel Vehicles

Another key driver of change in the industry will be the potential adoption of electric or electric-hybrid vehicles. As adoption rates increase, the Company will have an opportunity to better study impacts that electrified vehicles have on the system. In addition, how electric vehicle batteries can be used as an alternative source of energy or capacity also will be studied.

Projects in this area will address the impact of electric vehicle charging on the electric grid. If customers adopt electric vehicles, the demand on the grid will increase. Depending on the rate of charge and the battery capacity of the electric vehicles, there may be situations where the local distribution network becomes strained or overloaded. It will be important to understand how to efficiently manage the timing of this demand to avoid local power quality issues. National Grid will also consider the case where an electric vehicle's battery can be used as a means of energy storage that can be fed back into a home or the local distribution grid during outages or times of high electricity demand.

8.4.3 Cost savings/environmental benefits

National Grid will continue to look at ways to minimize electric losses and at how the business will operate with an eye towards lower carbon emissions. These projects help achieve the Commonwealth's environmental goals, providing benefits to customers.

While the Company already considers the impact to the environment for each project it undertakes, it is possible to improve processes and to consider the impact the changing climate may have on National Grid's operations. For example, the predicted rise of sea levels could threaten substations situated in low-lying areas. As the need for refurbishment or reconstruction of substations in this situation arises, National Grid will consider how to design the substation such that it will be less susceptible to flooding other climatological damage, which will also help with asset management.

8.4.4 Workforce and Asset Management/Safety

Finally, the Company will continue to pursue "Safety by Design", seeking to improve tools and processes to ensure safety to employees and the public, and thereby improve its overall workforce and asset management. Research in this area also will help National Grid improve its asset management techniques resulting in the ability to extend asset life and better predict when replacements are necessary. Key to this capability will be advanced analytics and the ability to monitor discrete points throughout the electric system. Data from distributed sensors coupled with advanced analytics will enable the Company to improve the management of high value assets, lower operational costs and better manage its workforce while allow employees to operate in a safer environment. For example, analytics could predict the near-term failure of a station breaker possibly resulting in catastrophic damage to the breaker and surrounding equipment or personnel. Predicting this failure would permit replacement to be undertaken in a safe scheduled manner.

8.5 Proposed Projects

The specific projects the Company proposes to include in its grid modernization RD&D Program are as follows:

- V2G Study and Demonstration
- Microgrid
- Renewable-Integrated Distribution Energy Storage (“DES”) Demonstration
- Targeted inverter conversion
- High Density Community Energy Storage (“CES”)
- Short Term Renewable Forecasting
- DC to DC Charging
- Fault Location Analysis
- Sensor Analytics Development Program
- Analytics for Asset Management

Attachment 17 provides further details on the Company’s proposed list of projects, including details on each proposed project. The list includes projects that can be implemented within a five year timeframe as well as projects with longer timeframes. Projects are listed in their ranked order and will be implemented based on the availability of sufficient RD&D funding.

Later stage projects will be ranked against new projects entering the pipeline to ensure the most valuable projects are properly prioritized. RD&D needs do change over time, and if necessary certain projects will be removed from the pipeline to be replaced by higher valued projects. The Company will make this decision based on how new projects are ranked. As time progress and needs change, the ranking mechanism will change so new projects can align with current needs.

Regardless of whether particular projects are added to or removed from the list, the Company will manage its overall RD&D budget to remain with the funding levels contained in this proposal.

8.6 Expected Benefits

There are demonstrable qualitative benefits of RD&D which ultimately can lead to benefits for customers. Key among the benefits of the proposed projects is the advancement of technologies capable of enabling the integration of customer DER, and in particular the bi-directional and temporal flows of electricity resulting from customer DER connections to the electric grid. This is key to the Objective of integrating distributed resources, and enables the vision of the future state of the distribution system while also providing customers the cost-saving, environmental and other benefits of DER. The technological advances necessary to achieve this key goal will also enable the other three Objectives, to the benefit of all customers.

Customers benefit from advances in technology in many other ways as well. For example, the application of energy storage can allow a large energy consumer to flatten their demand curve creating a monthly savings on their electric bill. Energy storage can also support grid stability by storing excess energy generated at off-peak times to be used during on-peak times. The energy storage demonstration projects that the Company is proposing can be used to advance learning on the use of energy storage as a distributed resource, and these learnings can be used to enable the benefits of energy storage for customers and the distribution system going forward. Other ways customers benefit is through advancements in feeder protection devices and application of sensor technology throughout the grid. These enable the grid to be managed with greater efficiency and reliability. Customers can thereby realize savings in their monthly bill from technology advancement, and the power delivered to them can be of higher quality.

The proposed investments also result in learning new techniques, developing new equipment and increasing the knowledge of employees. As noted in the Objectives, improving workforce management is a key element of grid modernization. The Company recognizes that new skills are critical to modernization success. Computer technology is now firmly embedded into equipment that only a generation ago was electro-mechanical. One of the key benefits of an RD&D program is that employees gain first-hand knowledge of new technologies, as well as design and operational experience. Employees will require not only knowledge of how a power system operates but will also need to understand computer networking and communication systems. The proposed RD&D program will generate the necessary new technologies and ideas to deliver a modern grid, and the Company will need to make an investment in the people and tools to enable that vision. That is a key goal of the RD&D program.

Each project within National Grid's proposed portfolio will offer its own individual risk/reward profile based on the specific goal for the individual project; however the expectation is that the portfolio as a whole will provide benefits over and above the requested level of investment. The nature of RD&D is that some projects will not realize the anticipated outcomes, however this in itself can be viewed as a success as it eliminates incorrect hypotheses. As the Department recognized in its Order, cost recovery for RD&D projects should not be denied because of a lack of success, and the "used and useful" standard does not apply to these projects, but the projects still should be (and will be) prudently managed.[81]

A short summary of the potential benefits for each of the specific projects is provided below.

Vehicle to Grid: This study will help to determine whether V2G is technically feasible in the near future. In the event that the Company determines it is feasible and adoption rates are adequate then the Company will propose a pilot.

Microgrid: Microgrids potentially are critical components of a resilient grid. They may help improve the grid reliability/resiliency by allowing DERs to operate once the utility power source is disconnected due to storms or for other reasons. With the increasing amount of DG being interconnected to the area electric power system, islanded microgrids must be capable of using the potential renewable energy resources, which are currently planned to be disconnected during system outages. This proposal is to deploy a microgrid which would enable the local generators to provide power to a customer as well as nearby critical facilities for five days during utility outages. In addition to the existing generators, 1MW CHP and 1MW PV are also proposed to be installed. The proposal may help advance the grid resiliency improvement and DG deployment goals.

Distributed Energy Storage: The development of this project will provide the following benefits:

- Experience on the technical and operational aspects of integration of battery storage in areas with generation variability.
- Quantification, with real data, of the total cost of ownership and benefits of a utility-sized battery storage used to complement renewable generation and improve power quality.
- Development and benefit quantification of diverse charging/discharging algorithms/strategies that could be used for capacity relief, improvement of assets utilization, participation on the ancillary services market, reduction of renewables' interconnection costs and improved system operations.

Targeted Inverter Conversion: The development of this project will provide the following benefits:

[81] D.P.U. 12-76-B at 29.

- Experience on the technical and operational aspects of converting passive generation sites into active assets capable of supporting the electric system.
- Quantification, with real data, of the total cost for the customers and the utility of this type of conversion. This could help National Grid to understand how to improve its integration practices to take advantage of the benefits that this new technology could have for the customer and the overall system.
- Development and benefit quantification of the use of a coordination system to establish diverse control strategies using the converted units. It is expected that such coordination could allow National Grid to use these units as part of its Planning and Operational portfolio to accomplish objectives such as capacity relief, improvement of assets utilization, reduction of renewables' interconnection costs and improved system operations.

High Density Community Energy Storage: The development of this project will provide the following benefits:

- Experience on the technical and operational aspects of installation and integration of distributed energy storage.
- Quantification, with real data, of the total cost of ownership and benefits of distributed energy storage in areas with a considerable number of distributed small solar installations.
- Development and benefit quantification of diverse charging/discharging algorithms/strategies that could be used for capacity relief, improvement of asset utilization, participation on the ancillary services market (as a block), reduction of renewables' interconnection costs and improved system operations.

Short Term Renewable Forecasting: The development of this project will provide the following benefits:

- Development of a forecasting tool that will help National Grid and other organizations to make technical and economic decisions to optimize operations.
- Potential for National Grid's usage to improve of assets utilization and system efficiency. This could translate into operational costs savings, extended life of existing assets and improved reliability of service.
- Increase the ability to reduce uncertainty on the energy market for entities such as the ISO-NE. This could potentially translate into savings on energy costs.

Sensor Analytics: This project will provide the data to enable better asset utilization and to maximize operational limits of the grid. By applying analytics to real-time grid data, asset condition can be better managed while improving reliability by identifying incipient or actual system failures.

Fault Location Analysis: This project is the continuation of work that has already been done by EPRI. Below is a brief description of the research that has been completed. This project will move the research to the implementation phase.

Existing fault-locating methods for underground cables and overhead lines were reviewed. The arc voltage-based method formed the basis of the analysis. This algorithm was derived, implemented and validated with monitoring data, fault information and circuit data collected from the actual distribution field. Time-domain simulation models also were validated. Advanced signal-processing techniques were explored to identify the best possible numerical techniques that will lead to the most accurate fault-location results. Pre-processing of waveforms and post-processing of impedance-to-faults estimates were employed for this purpose. Both of these methods led to significant improvement in the fault-location results. This algorithm was applied to a large number of precursor incipient fault events selected from the voluminous distribution system waveform database. The results were seen to be quite useful in predicting the actual fault location based on the precursor events. In this project, a modified version of the arc voltage-based algorithm will be used that takes into account a more realistic model for the distribution line. It is expected to improve the fault-location results, hence, increase grid resiliency.

DC to DC fast Charging: The project is expected to demonstrate the ability of PV and batteries to support drivers' EV charging requirements. Use of solar will provide environmental benefits, avoiding carbon emissions from the generation of energy through conventional power plants.

Analytics for Asset Management: One of the most important objectives of grid modernization is the reduction of customer interruption frequency and duration. Critical assets can create long outages upon failure. Hence, developing tools that could help estimate the life cycle of an asset is critical for reducing premature asset failures. In addition to developing tools, this project will also identify methods to improve the life cycle of the asset. National Grid will collaborate with EPRI to develop the asset life management tool. This project will start with focusing on the critical assets that have the potential to create long outages upon failure. The areas where the equipment reliability and the customer resiliency have been low will be targeted for the data collection purposes.

8.7 Funding

8.7.1 Proposed Funding Mechanism

National Grid proposes to fund its grid modernization RD&D efforts through an RD&D provision in a new tariff.[82] The details of the funding mechanism for RD&D are in Section 12 of the Plan, and in the testimony and exhibits of Company witnesses Scott M. McCabe and Amy S. Tabor.

8.7.2 Funding Level

National Grid's current annual budget for RD&D is approximately $910,000, including spending by National Grid's affiliates in New York, Rhode Island and the generation business. National Grid has identified an additional $29.3 million, over ten years, of projects that it proposes to pursue through the grid modernization RD&D program. Attachment 18 contains the proposed annual funding requirements.

8.7.3 External funding opportunities

National Grid will continue to leverage RD&D investments by joining with other utilities (through industry organizations or other means) to seek to fund work that, by itself, would be too expensive for a single utility. These include the DOE, EPRI and CEATI International. National Grid also will seek external grant sources on its own, where appropriate.

8.8 Collaboration

8.8.1 Joint Utility Collaborative Learning

The Order requires RD&D to include a process among the electric distribution companies in Massachusetts for collaborative learning, both from each other and more broadly.[83] Therefore, in addition to their individual plans, the three investor owned utilities[84] ("the Utilities") propose to

[82] DPU 09-35 approved $355k for RD&D

[83] D.P.U. 12-76-B at 29.

[84] The three investor owned utilities are comprised of Eversource Energy, National Grid and Unitil Corporation.

collaborate and share their RD&D findings, both privately with each other and with external stakeholders. Collaboration will maximize the benefits from collective RD&D investments, to the benefit of Massachusetts electric customers.

To facilitate collaboration, periodic confidential meetings will be held among the Utilities to facilitate the free flow of information that may be sensitive in nature or may discuss specific products, technologies or funding sources. It is anticipated that each utility will provide a brief overview of each project in their portfolio including lessons learned and best practices. Discussion will also encompass identifying new technologies and funding opportunities for RD&D and how the Utilities can collaborate on additional research that benefits all Massachusetts customers. These opportunities may include responding to opportunities from Federal or State programs or could arise from public/private partnerships. Collaboration will also permit sharing of knowledge learned from other utility initiatives such as energy efficiency and electric vehicle programs.

In addition, in order to ensure that the Utilities incorporate the broadest possible stakeholder engagement, the Utilities will conduct an annual forum where a stakeholder group will be invited to inform the Utilities on the challenges they foresee and discuss the innovation and partnership models necessary to potentially meet the challenges. The first such stakeholder engagement forum was conducted on June 25th, 2015 with great success. This forum engaged the clean energy community and solicited ideas on clean energy innovation. Stakeholders also are always welcome to present ideas to any of the three Utilities. Further, the Utilities may invite specific stakeholders or vendors to meetings when there is a need for specific information on a technology or funding opportunity.

8.8.2 Participation in relevant state and regional efforts

National Grid encourages its employees to engage the electric industry by participating in standards committees and other organizations, and collaborating with peers, often through industry entities such as the Institute of Electrical and Electronics Engineers (IEEE) and Cigré, among others. The Company will continue to look to participate in state and regional initiatives as opportunities arise, in addition to continuing its existing memberships with EPRI and CEATI. Finally, the Company will leverage RD&D knowledge from work that other National Grid companies conduct in other jurisdictions.

In order to maximize knowledge acquisition, National Grid's engineers will continue to seek to attend and present at appropriate industry forums which provide an opportunity to connect with peers across the region or country and share experiences and ideas. By presenting at these forums, the Company can demonstrate Massachusetts' industry leadership in key areas.

8.9 Concerns Expressed regarding Previous RD&D Requests

In the past, the Department expressed several concerns about utility requests for RD&D funding. These concerns included:

- Benefits that would result from RD&D efforts were speculative and there was no showing that the benefits would outweigh the costs.
- There was a lack of collaboration among the Massachusetts distribution companies on RD&D proposals.
- The RD&D efforts would not only benefit customers but could benefit shareholders or other third parties.
- The RD&D proposals were not specific enough in terms of specific research proposals and the associated costs and benefits for those proposals.[85]

National Grid's RD&D proposal in its GMP addresses the concerns that the Department has expressed in the past. It also recognizes that the Order contemplates reconsideration of past Department precedent on RD&D in order to obtain the benefits of grid modernization.[86]

The RD&D program proposed here focuses on areas identified as priorities in the Order, where there are likely to be customer benefits. Given that technology is rapidly changing however, National Grid also seeks some flexibility to determine the specifics and scope of the projects identified, and to substitute other projects if a more promising project arises subsequent to the approval of the GMP.

National Grid's proposed list of projects encompasses projects that are of common interest to all Massachusetts electric distribution companies, and that present an opportunity to share new knowledge and lessons learned among the companies. With the need to modernize the grid more evident now than ever before, RD&D has become a key means to seek and acquire underlying technologies and practices, which enable utilities to meet increasing customer expectations. The qualitative benefits from RD&D investments, including gaining first-hand knowledge of new

[85] D.P.U. 10-55 at 155-158 (2010).

[86] D.P.U. 12-76-B, at 29-30 (2014).

technologies coupled with design and operational experience, hold sufficient value to meet the overall objectives as described in the Order.

8.10 Department Role in facilitating adoption of new technologies

The Department can facilitate the adoption of new technologies by supporting funding for research, development and demonstrations of technologies that have the promise of unlocking customer value. In addition to financial support of the RD&D program, the Department can encourage effective knowledge transfer between the three Utilities and also sharing with cooperative municipal electric distribution companies. This could consist of periodic workshops between the parties and attending industry forums.

9. Marketing, Education and Outreach Plan

The Order requires the utilities to include MEO plans in their GMPs "with a timeline and strategies for educating customers and motivating them to become full participants in grid modernization."[87] The MEO plan is required to have a component common to all the companies, as well as company-specific components.[88] In line with these requirements, National Grid's grid modernization MEO plan's objective is to build awareness and interest in grid modernization among customers, in order to promote and support the adoption of smart energy technologies and active customer participation in the programs and services proposed in the GMP.

The Company's customer-centric MEO plan is based on customer insights and analytics gained through a comprehensive set of research activities including quantitative surveys measuring customer satisfaction, reputational sentiment, customer message testing and social media.[89] These insights have been combined with learnings from the SES Pilot, grid modernization stakeholder engagements[90] and the Company's experience building awareness and promoting adoption of energy efficiency programs, marketed both individually as National Grid and collectively with the other Massachusetts electric distribution utilities as part of the Mass Save initiative.

Research points to a future landscape for electric utilities focused on options for customers based on information and personal choices. Utilities will need to emphasize personalized and actionable information that customers want and that provides greater transparency, convenience and customer control.[91] However, getting consumers to recognize the benefits of grid modernization is challenging, given that customers often view their electric company as a

[87] D.P.U. 12-76-B at 26.

[88] Id.

[89] See Section 11.4, Customer Knowledge.

[90] See Section 11.2, Stakeholder Engagement and Input.

[91] OPower, "Five Universal Truths about Energy Consumers," 2013, pg. 7.

transactional, low interest category.[92] Therefore proactive customer communications will be a crucial piece of a successful implementation of grid modernization initiatives.

Further, a strong brand built on a foundation of trust will enable National Grid to have a high level of engagement with its customers and ensure the relevance of its grid modernization offerings.[93] Creating trust is critical to connecting with customers so that they are receptive to "what, when and why" – what is happening, when will it happen and why is it important to them. Building awareness and interest will help establish this important connection and help customers understand the benefits of grid modernization and smart energy technology, as well as their options, and ultimately lead them to take control of their energy usage by participating in the programs and/or adopting the technologies available to them. For this purpose, the Company will conduct additional research during the GMP implementation. This research will be used to optimize the communication plan and ensure that it is tailored to evolving customer needs.

This MEO plan focuses on the customer as its stakeholder. It has been developed in conjunction with National Grid's stakeholder engagement processes, which encompassed outreach to a variety of critical stakeholders. The goals of the MEO plan are to:

- Educate customers on grid modernization offerings in advance of the deployment of AMI and AMI meter installations in their communities to eliminate potential adoption barriers.
- Build interest in and awareness of the elements of grid modernization using both traditional media advertising and social media marketing activities in targeted markets. These channels may be supported by digital, direct mail, social media and other advertising and grassroots tactics such as local events and sponsorships. Additional outreach to other stakeholders also will support these activities as needed.
- After a period of driving awareness and building interest among customers, the focus for MEO will shift to supporting continued customer engagement and satisfaction by leveraging digital channels to provide immediate access to the information needed. This communications lifecycle will be repeated multiple times throughout National Grid's service territory at different times as customers become engaged in the process at

[92] Pike Research, "Effective Customer Engagement Utilities Must Speak Customers' Language," A White Paper Commissioned by OPower, 2013.

[93] Deepa Prahalad, "Why Trust Matters More Than Ever for Brands", Harvard Business Review, December 2011.

different times over the first five years of the GMP, as determined by the AMI/meter deployment plan.

The Company's MEO plan also will incorporate a common statewide component agreed upon by the electric distribution companies in order to ensure the consistency and timing of messages in market.

9.1 Customer Insights Research

National Grid undertook a comprehensive customer knowledge initiative that included speaking directly to Massachusetts customers through marketing research, external research and studies and analysis of the Company's own internal data. The findings from this research were used to inform the GMP.[94] The Company also conducted a variety of stakeholder engagement initiatives to drive awareness.[95] These efforts provided National Grid with the opportunity to secure additional stakeholder feedback on key elements of the GMP, and to shape its MEO Plan accordingly.

Customer and stakeholder insights will remain a constant component of the MEO process to measure the effectiveness of the communications efforts and to identify changes in customer perceptions about grid modernization solutions. Periodic surveys will allow National Grid to listen to customers, and align with a "listen, test, learn" approach, which refers to listening to what customer needs are, using that information to test and measure different messages and communication tactics, and using the results to improve approaches along the way.[96] The survey results will be used to understand customer awareness, sentiment and interests so that communication and channel strategies can be adjusted as needed over the course of the five year meter installation period leading up to TVR offerings. Surveys will focus on the following topics:

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[94] See Section 11.4.

[95] See Section 11.2.

[96] The "listen, test and learn" approach arose out of the Green2Growth Summit that the Company held in conjunction with the City of Worcester in 2011 in order to inform the development of the Company's Smart Energy Solutions Pilot proposal.

- Messaging studies will be conducted three times over the five year period. In years one and three, the Company will test messages to understand customer priorities, language effectiveness and communications preferences for the early stages of grid modernization rollout. In year five the Company will test messages that are likely to have changed as the market is maturing and awareness is building.
- Awareness studies will be conducted three times over the five-year installation period. Year one will be to establish a baseline and years three and five will be to check in to see whether National Grid's MEO efforts have helped to build greater overall awareness of grid modernization.
- Satisfaction studies will be conducted two times over the five-year period. This will be done after customers have had meters installed in order to assess customers' overall satisfaction with the AMI meter installation and changes, if any, they have made in their energy use.

9.2 Leveraging Relationships and Prior Experiences

Years of experience in developing and evaluating programs, raising awareness, and promoting customer adoption of various energy efficiency offerings in Massachusetts, have resulted in a wealth of valuable education and outreach lessons, as well as partnerships with internal and external stakeholders critical to the success of GMP initiatives. Among those are:

Smart Energy Solutions: A critical input into the MEO plan comes from the Company's learnings the SES Pilot, discussed in Section 11.3 of the Plan. From a customer education perspective we learned that by delivering capabilities to customers in phases, National Grid was able to introduce customers to different aspects of the SES pilot in a more focused and better articulated manner, which supported a less confusing and complicated customer experience. Additionally, National Grid uses a digital platform to provide customers with data-driven insights into their energy use, personal comparisons and solutions to motivate them to better manage their energy use through active participation. National Grid also built a Sustainability Hub in Worcester, as a place where customers, the community and interested stakeholders can learn about the Pilot and how a smarter grid will deliver greater choice, control and convenience. The Sustainability Hub has been a very positive success story with over 4,000 visitors since it opened.

Mass Save Collaborative: National Grid's participation in the Mass Save statewide energy efficiency collaborative offers a unique perspective into the benefits of marketing at both the macro (state) and micro (utility footprint) level to create a climate conducive to driving results. By working together with the other state electric and gas utilities, and energy service providers, program administrators build awareness and understanding of energy efficiency statewide while also allowing National Grid to drive action within its markets and local communities. These insights have led to productive discussions among the electric distribution companies on ways in which a collaborative effort could be used to support grid modernization.

9.3 MEO Plan Components

In order to achieve the goals of the MEO plan, the Company envisions a comprehensive effort that includes the use of data and analytics, distinct communication strategies and supporting tactics. Below are the descriptions of each of these components of the MEO Plan.

9.3.1 Data and Analytics

National Grid's customer targeting strategy is founded on advanced analytics and data. These tools are pivotal to identifying the most probable candidates for specific programs and services based on the customers' likelihood to adopt products and services from a financial and technical feasibility standpoint.

With the introduction of the GMP initiatives, this targeting strategy will use advanced data mining technologies to identify customers with higher propensities to adopt the technologies and initiatives proposed in the GMP, based on others who have already done so. Advanced analytics also will provide insights into how customers behave under a variety of circumstances and conditions. Through market testing of education and outreach efforts, these findings will serve as input to the "listen, test, and learn" approach, and inform necessary improvements to the MEO and targeting efforts.

9.3.2 Communication Strategies

9.3.2.1 Common Statewide Communications

National Grid, Eversource and Unitil have discussed options for a statewide marketing campaign for grid modernization. A collaborative statewide MEO process for grid modernization has many potential benefits, including pre-positioning strategy discussions and the development of common messaging concepts promoting the need for grid modernization and customer benefits.

At this time the approach agreed to involves the development and use of a common messaging strategy promoting both the customer benefits and future opportunities of grid modernization. The companies agree that the variation in implementation schedules makes it unlikely that joint marketing activities – messaging at the same time statewide – can happen early in the grid modernization implementation process. However, future meetings will be held to continue to refine the strategy and message development and provide status updates on individual implementation plans, looking for opportunities to collaboratively activate certain marketing channels as appropriate.

9.3.2.2 Company-specific communications strategy

National Grid's company-specific strategy will be carefully planned to match the geographic deployment of AMI technologies, and will be broken into distinctive phases over a five year meter installation period as customers will be in various stages of engagement, and their communications needs will differ. Some customers will have new meters in year three, while others will be connected in years four and five. A communications lifecycle will start multiple times throughout the territory until installation process is completed. These communications will use the marketing tactics described in earlier sections of the MEO Plan and will focus on the following: 1) pre-implementation – build awareness and generate interest prior to meter installation; 2) early implementation – drive participation as meters are installed while continuing to build interest; and 3) sustainability – focus on satisfaction and energy use while continuing to drive participation.

Pre-Implementation: Engaging customers and stakeholders prior to the launch of a new program is a general best practice in outreach, engagement and communications methodologies. National Grid will have a period of advertising and other communications tactics in the months leading up to implementation of AMI and meter installations. Currently customers have low familiarity with grid modernization, and the goal is to eliminate adoption barriers by educating them on the benefits of modernizing the grid, as well as the what, why, when and where of grid modernization initiatives. Driving awareness and a willingness to participate will be challenging as most customers view energy as a low interest category.[97]

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 initiatives. To achieve this goal the pre-implementation advertising phase will include radio, newspaper and digital advertising and social media tactics. National Grid will use the latest research, messaging strategy and market factors to evaluate and adjust the media channel mix in order to optimize the education and outreach efforts, while staying within the proposed budget.

Early Implementation: As technologies are deployed, it will be important to engage customers through education and outreach. MEO activities will begin to move in parallel paths, continuing to drive awareness and interest for those who do not yet have the new technologies, while also marketing to those who can now take advantage of the new technologies.

[97] Pike Research, "Effective Customer Engagement Utilities Must Speak Customers' Language," A White Paper Commissioned by OPower, 2013

Sustainability: Continued communication will create and maintain trust with the customer, which will enable deeper customer engagement. After a number of years driving awareness and building interest among customers, the focus for MEO will shift to supporting continued customer engagement by addressing any ongoing customer issues while also promoting and sharing success stories about highly-engaged customers.

9.3.2.3 Supporting Communications and Tactics

In addition to the high visibility mass media and stakeholder engagement tactics outlined previously, other targeted communications channels and tactics also will be employed to drive awareness and participation throughout the education and outreach process. These supporting channels and tactics can also be used to highlight success stories, further encouraging customer participation.

Digital Channels

Education and engagement website: The website will serve as an integrated way to share profile, usage, community and educational information. The website will also be an integral component of the social media strategy, linking to two-way communications channels such as blogs, Facebook, and Twitter.

Email and e-newsletter: This channel will be the main distribution channel for customers who have email as their preferred communication channel. An E-Newsletter can be distributed periodically. Content will include program information, tips, success stories and more.

Web/Mobile (Applications and Text): In order for grid modernization to succeed, it is imperative that MEO efforts have a web component that will enable customers to easily access the information they need from any location and at any time. On average, National Grid's web/mobile sites receive 200,000 visits per day. In Massachusetts, more than 20,000 customers login to view and/or pay their bills, report outages or perform other types of self-service transactions. While some customers reach the website organically through search engines, many others are directed to the site through email, radio, social media, bill message marketing, flyers and more. For the purpose of the MEO plan, the National Grid website will serve as a location to post important program information, important contact information, downloadable forms and more. National Grid will use tools to track customer behavior on the website, and will use this information to help set MEO goals and track against those goals. In addition to marketing education and outreach, the website will play an important role in providing information on CLM, outage communications, DG, electric vehicles and more. National Grid will continue to identify areas of potential improvement and opportunities for new functionality. Enabling the customer to self-serve through the website is vital and had historically been shown to decrease calls to the call centers and increase customer satisfaction. Additionally, mobile channels like apps and texting will be used to engage customers and promote action.

Social Media: Social media platforms such as Facebook, Twitter and Instagram are an effective way to reach wide audiences, while collecting and analyzing real-time data, which is critical for social listening. National Grid currently communicates with customers, influencers, energy partners and stakeholders through these channels to engage in two-way conversations and share valuable content such as customer service, safety education, energy efficiency programs, special offers, new products and services, payment options, community events and ways to stay connected during blue sky days and during storms. Through social media the Company also promotes self-service options like its mobile website and app, outage central map and texting programs to help reduce call volumes and increase customer satisfaction.

National Grid currently has 72,000 active Facebook fans, 24,000 active Twitter followers and close to 1,400 Instagram followers.[98] The Company will create customized social audiences and share personalized updates through paid social media. National Grid will offer customized products and solutions to defined groups. Facebook and Twitter will serve as test platforms for education, awareness and participation in demand response, solar, alternative fuel vehicles and TVR. Platform performance, customer sentiment and program perception will be quickly analyzed and messaging strategy revised if needed.

Collateral

Bill inserts and customer newsletters: Bill inserts and customer newsletters will be included in customer bills. Content will include program information, tips, success stories and more.

Brochures: Brochures will be distributed to customers and stakeholders at community events, town hall meetings and presentations, trade shows, etc.

Call center support: Scripts will be developed for both inbound and outbound customer calls related to grid modernization. This will ensure that call center staff is fluent on all grid modernization customer-facing issues and aligned with external communications, and that customers receive important information regarding services and implementation.

[98] National Grid's social media engagement numbers as of June, 2015.

In-Person

Mobile Sustainability Hub: National Grid proposes to deploy a mobile Sustainability Hub, in order to bring the benefits of such a Hub to a larger number of customers, to educate customers in person on grid modernization and to answer any questions customers may have.

Events: Face-to-face learning activities such as lunch and learn sessions and town halls will offer the opportunity to educate and inform customers regarding the benefits of grid modernization, while also obtaining immediate valuable feedback and data to feed the "listen, test and learn" process. Events will be a critical tactic for reaching certain customer groups including elderly and low-income customers.

9.3.3 Supporting Staff Requirements

National Grid's current customer marketing and education organization supports a variety of communications activities related to energy efficiency, gas growth and customer education on topics such as electric and gas safety, storm preparedness and billing programs and services. To effectively incorporate and manage MEO activities into the Company's existing organization, National Grid proposes the creation of two full-time staff positions to strategically manage grid modernization education and outreach activities. These positions will report to a Director in National Grid's marketing department. These positions are accounted for in the numbers of additional personnel detailed in Section 5.2.2, Workforce, Training and Asset Management.

9.3.4 Budget

The MEO budget and supporting cost information can be found in Attachment 19 and Attachment 20 of the plan.

10. Metrics

The Department's Order requires that a GMP must include, among other elements, proposed infrastructure and performance metrics, including statewide as well as company-specific metrics, tied to the Company's GMP goals.[99] Infrastructure metrics track the implementation of grid modernization technologies and systems, and performance metrics measure progress towards the Objectives.

This section includes a description of the process National Grid used to develop both the company-specific and statewide metrics, the common definitions and formulas employed, and an explanation of how each proposed metric relates to the Objectives.

As required by the Order, National Grid has included metrics that measure outcomes that may not be within the Company's complete control, as well as metrics for grid modernization goals that are not easily quantified in order to account for these benefits. The Company has solicited stakeholder input in developing both the statewide and company-specific metrics. The purpose of these GMP metrics is to record and report information, both internally and to the Department.

Infrastructure metrics were developed to track the Company's installation of grid modernization technologies. Examples include counts for the numbers of AMI meters, feeder monitors, CVR/VVO and other approved technologies installed on the Company's system. In addition, the Company will track spend against the budget plan for grid modernization technologies. Performance metrics have been developed that track the benefits anticipated to result from the Company's grid modernization implementation. Examples of performance metrics include reliability measures and load reduction among customers participating in TVR.

10.1 Development of Company-Specific Metrics

The Company's metrics working group, formed for the purpose of development grid modernization metrics, oversaw the development of proposed company-specific metrics which (i) measure progress on the Objectives and (ii) were capable of being effectively captured and reported. These efforts included:

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[99] D.P.U. 12-76-B at 30.

- Identifying existing Company metrics
- Defining new metrics that measure the GMP
- Evaluating proposed metrics against the Objectives
- Refining and consolidating the proposed metrics

Working groups for each potential GMP technology and/or system were established with the overall objective to identify a robust set of potential metrics to be evaluated in task 3 (evaluating proposed metrics against the Objectives). The metrics working group held brainstorming sessions and follow-up meetings with each of the other working groups established to develop the Company's GMP proposals, in order to (i) establish expectations of their deliverables, (ii) provide a framework for their development of proposed metrics, and (iii) act as a resource to review incremental work product. The groups also reviewed and considered the existing Company metrics that are reported to the Department and aligned with the objectives outlined above.

The metrics working group used a decision tree process to organize the proposed metrics into manageable components of information. Bottom-up and top-down evaluation approaches were used to populate each level of the infrastructure and performance metrics and ensure that the proposed metrics developed from the bottom-up approach met the highest level objectives utilized in the top-down approach. The proposed infrastructure metrics were then compared against the performance metrics to ensure consistency across the population of proposed metrics.

The potential metrics were then reviewed and refined. Each working group evaluated and modified, where appropriate, their proposed metrics based on their evaluation of the following:

- Metrics working group recommendation of metrics to be prepared.
- Each working group was asked to complete and return a matrix template for each of the metrics identified.
- Correlation of benefit-cost analysis to proposed metrics.
- Correlation of GMP infrastructure and systems installed to proposed metrics.
- Internal feedback regarding proposed metrics.
- Alignment of the proposed metrics and the components of the Company's recommended GMP
- Feedback from stakeholder engagement.

The metrics working group reevaluated each working group's proposed modification to any metric and consolidated any common metrics across each of the Working Groups. The results are presented below in Section 10.5, Infrastructure Metrics, and Section 10.6, Performance Metrics.

10.2 Development of Statewide Metrics

The Department directed the electric distribution companies to jointly propose a common list of statewide metrics to include in their GMPs. National Grid's metrics working group, along with appropriate subject matter experts, completed an internal evaluation of the proposed statewide metrics and the Company's ability to produce the metrics prior to the initial Joint Utilities Working Group meeting. On March 15, 2015 the Joint Utilities Working Group met to kick off the cross-utility review process of the fifteen statewide metrics that the Department initially proposed in its Order.[100] During the initial meeting the Joint Utilities Working Group identified the need to develop a set of alternative metrics. This decision was based on two factors: (i) certain metrics were not applicable to all of the electric distribution company's GMPs and (ii) certain proposed metrics were not capable of being effectively captured and reported.

For example, the Joint Utilities do not recommend using the Department's proposed system peak demand and reduction in peak demand resulting from GMP investments as common metrics because there are multiple factors that influence the calculation that cannot be normalized to yield a fair comparison resulting from GMP investments alone. Factors including customer behavior not related to GMP investments (such as personal economics), trends in weather (such as multiple days of temperatures higher than 90 degrees versus a single day, or a heat wave occurring first in late summer versus early in summer) and impact from DG installations where they are not primary metered would make consistently measuring system peak demand and reduction in peak demand impossible. In addition, not all utilities make the same investments with respect to system peak demand.

The Department's proposal to measure the number of interruptions avoided due to the GMP investments also would be very difficult, if not impossible. For example utilities can see that lightning arrestors were impacted during a storm, but are not able to identify how many interruptions were avoided.

Regarding the Department's proposal to calculate the DG hosting capacity, the hosting capacity per circuit at any given time is a dynamic and constantly changing number, and each application's specific attributes will determine if a circuit can accept it or not. Hosting capacity

[100] D.P.U. 12-76-B at pp.31-32.

depends on the type of DG, the amount of output anticipated and the location on the circuit where it is to be installed. Including this as a metric therefore would not be meaningful.

At the March 15th, 2015 meeting, the utilities also decided that each utility should create four sub-teams, one for each Objective and comprised of subject matter experts, to evaluate the Department's proposed metrics and define alternative statewide metrics where necessary. Over the course of April, May and June 2015, the sub-teams met multiple times, both internally and externally, to explore potential statewide metrics, establish common definitions and evaluate progress toward alternative statewide metrics.

Once the utilities' GMPs are approved, the metrics working groups, both internal to National Grid and the joint utility group, will continue to refine the details of the performance metrics as needed as the GMPs are organized for implementation.

10.3 Reporting of Company and Statewide Metrics

National Grid proposes to report to the Department on an annual basis the statewide and Company-specific metrics. Each involved internal department in the Company will be responsible for the systems and resources required to produce and manage each individual metric. One incremental FTE position will be required to facilitate the gathering and reporting process of the metrics. This position is included in the proposal for additional FTEs in Section 5.2.2. The Company proposes to (i) prepare and report on the metrics to the Department for the prior year, and (ii) establish internal goals for the upcoming year to ensure that the Company remains on pace with the proposed GMP implementation.

10.4 Stakeholder Input Process

Section 11.2 (Stakeholder Engagement and Input) overviews the Company's stakeholder engagement process for its GMP. Each working group responsible for the proposal of a grid modernization technology and/or system collaborated with representatives responsible for the development and implementation of the stakeholder engagement process to identify the potential stakeholders and to solicit their input during the development and refinement of the technologies and/or systems to be proposed in the GMP. The stakeholder input is reflected in the resultant proposed metrics in Sections 10.5 and 10.6.

10.5 Infrastructure Metrics

10.5.1 Statewide Metrics

Infrastructure metrics were developed with the goal of tracking the implementation of grid modernization technologies and systems. National Grid worked with Eversource and Unitil to develop statewide infrastructure metrics that are applicable to all three companies' GMPs and that are measurable. The three companies' joint proposed statewide metrics are detailed in Table 22.

Table 22: Statewide Infrastructure Metrics

GM Objective	Metric	Description
Reduce impact of outages	System Automation Saturation	Illustration of the amount of automation on the electric distribution system. As more automation is installed, the result of this metric will be reduced. This measure includes all automation on the system, not just investments under the GMP. $\frac{\text{Customers Served}}{\text{Fully Automated Device + 0.5*(Partially Automated Device)}}$ **Grid Modernization Device:** Any device that meets the requirements of either a fully automated or partially automated device **Fully Automated Device** Meets all of these requirements: • Reacts to system conditions to isolate or restore portions of the electric system • Communicates system quantities (e.g., voltage, trip counts) to a central location, such as SCADA • The state of the device can be remotely controlled by dispatch **Partially Automated Device** Meets at least one of following requirements: • Reacts to system conditions to isolate or restore portions of the electric system • Communicates system quantities (e.g., voltage, trip counts) to a central location, such as SCADA • The state of the device can be remotely controlled by dispatch • AND capable of upgrade to a fully automated device without full replacement
Optimize Demand	Total number and percent of customers on TVR (Company administered or other)	Department recommendation. Counts of the number and percent of customers who are signed up for TVRs.
Integrate DER	Total number of grid-connected distributed generation facilities, nameplate capacity and estimated output of each unit, and type of customer-owned or operated units.	Department recommendation. Counts the number of DG interconnections to the electric system, organized by nameplate capacity, estimated outputs and type of customer-owned or operated units. The metric will include all DG connections, not just those occurring during the GMP period. Note: Cross-utility DG Working Group efforts and the Department's Time Enforcement Mechanism provide additional insights to utility efforts in connecting distributed resources.
Workforce / Asset Management	Number/Percentage of Sensors Installed vs. what's planned in the GMP	Department recommendation. Number, percentage of sensors installed on the electric distribution system as specified in approved GMP.
Workforce / Asset Management	Percentage of circuits with installed sensors	Measure is a variation of a Department-recommended metric. Percentage of electric distribution circuits with installed sensors, which will provide information useful for proactive planning or intervention. This measures all sensor installations, not just those within the GMP.

Sensors are defined as equipment that sends or records information of the electric system that can be used to improve the efficiency of effectiveness of workforce or asset management (e.g. fault locators that would help pinpoint a problem for more efficient crew deployment).

10.5.2 Company-Specific Metrics

In cases where statewide infrastructure metrics did not sufficiently cover National Grid's GMP implementation, company-specific infrastructure metrics were developed with the goal of tracking the implementation of grid modernization technologies and systems. The National Grid metrics working group collaborated with other internal working groups and internal subject matter experts to develop company-specific infrastructure metrics.

Metrics that report the percentage of technologies installed either by plan year or overall plan would apply to the GMP technologies and/or systems installed, such as: AMI meters, ADA by circuit, CVR/VVO by circuit and Telecom IT/OT.

Table 23: Company Specific Infrastructure Metrics

Grid Modernization Metric	Description
Percentage of Technology installed (Planned Year)	Measure the progress of the installation of the GMP technology against the current plan year.
Percentage of Technology installed (Overall Plan)	Measure the progress of the installation of the GMP technology against the overall plan.
Percentage of Technology installed by spending (Planned Year)	Measure the progress of the installation of the GMP technology spending against the current plan year budget.
Percentage of Technology installed spending (Overall Plan)	Measure the progress of the installation of the GMP technology spending against the overall plan budget.

10.6 Performance Metrics

10.6.1 Statewide Metrics

Performance metrics were developed with the goal of measuring progress towards the four Objectives. National Grid worked with Eversource and Unitil to develop statewide performance metrics that are applicable to all three companies' GMPs and that are measurable. The Utilities are proposing two statewide performance metrics, detailed in the following table.

Table 24: Statewide Performance Metrics

Grid Modernization Objective	Metric	Description
Reduce impact of outages	Customers Benefitting from Grid Modernization Devices	Department recommendation. Number of customers and percentage of customer base whose electric service can benefit by a Grid Modernization Device minimizing or preventing an electric service outage. This measure includes all Grid Modernization Devices on the system, not just investments under the GMP. The metric will count the customers served who can benefit from Grid Modernization Devices that either proactively (i.e. sense and prevent) or reactively (i.e. wait and react as needed) will prevent or minimize an outage situation. • Customers who can benefit from multiple devices are counted once only. • Not limited to the primary/back-bone infrastructure; will include customers in the secondary networks as well • Includes devices deployed on no-load circuits and DSS lines
Optimize Demand	Load reduction due to TVR customers participating in declared critical peak pricing (CPP) event	Calculation of load reduction among only those customers who participated in a declared CPP event. Measures the difference between the expected load and the actual load for TVR rate customers during a CPP event. Methodology to determine the 'expected load' to be determined, potentially based on ISO NE formula.

10.6.2 Company-Specific Metrics

In cases where statewide infrastructure metrics did not sufficiently cover National Grid's GMP, company-specific performance metrics were developed with the goal of measuring progress towards the Objectives. The National Grid metrics working group collaborated with other internal working groups and subject matter experts to develop company-specific performance metrics, listed below.

Table 25: Company Specific Performance Metrics

Grid Modernization Objective	Grid Modernization Metric	Description
Improve Workforce and Asset Management	Total meters with estimated reads per cycle	Operational - measure of meters where there are estimated reads due to missing intervals.
Reduce the Impact of Outages	CKAIDI and CKAIFI for feeders enabled by grid modernization	Measure of effect of outages by using CKAIDI and CKAIFI for feeders with ADA or AMI with 5 minute exclusion to allow automated schemes to operate.
Optimize Demand and Improve Workforce and Asset Management	% of peak load reduction by feeder	Measure of peak load reduction of VVO-enabled feeders.
Improve Workforce and Asset Management	Employee Training	Measure the progress of the GMP training program against the overall plan using a count of employees trained.

National Grid proposes to submit a written report summarizing the RD&D, CLM and MEO grid modernization efforts in lieu of hard metrics. This is largely due to the difficulty in defining meaningful, quantifiable metrics as well as the variable nature of these pieces of the GMP. These reports are detailed in the following table.

Table 26: Grid Modernization Reports

Grid Modernization Metric	Description
RD&D - Project Portfolio	Identify the number and budget of projects in each stage of the RD&D framework. Will include active projects and planned projects. Project write ups will include information such as description of project, expenditure for the year, technical areas addressed, types of innovation, probability of success, and expected benefits.
CLM - Project Portfolio	Identify the number and budget of projects in each stage of the CLM framework. Will include active projects and planned projects that will be used to encourage load reduction through behavioral messaging.
MEO - Project Portfolio	Identify the number and budget of projects in each stage of the MEO framework. Will include a summary of the reporting year's MEO activities as well as high level results from any voice of customer work conducted during the report year.

11. Grid Modernization Plan Development

This Section addresses other items required by the Order, as well as National Grid's considerations in developing the GMP. These include: (i) the internal Company working group process; (ii) stakeholder engagement and input; (iii) learnings from the SES Pilot; (iv) customer knowledge; and (v) the RFPs and RFI processes.

11.1 Internal Company Working Groups

The Company formed multiple working groups, which included 60+ Company employees, to evaluate the elements that the Company could include in its GMP that would make progress on the Objectives and achieve AMF, and that the Company could implement successfully. Where appropriate, groups developed the preliminary technical and business case analyses for the options they considered. Each of the technology-related working groups was tasked with creating an array of investment options of various scopes and durations. Each option was accompanied by a cost/benefit analysis.

The following work groups were created to complete this work:

- AMI
- ADA
- CVR/VVO
- ADMS
- RD&D
- Telecommunications/IT/OT
- Cybersecurity
- DG
- WTAM
- CLM
- EVs
- Storage
- MEO
- Energy Procurement
- Rate Design and Tariff Changes
- Billing and Systems
- Metrics
- Stakeholder engagement
- Customer knowledge
- Benefit-cost analysis

The work of each of these groups fed into the proposals included for consideration in the GMP.

11.2 Stakeholder Engagement and Input

The Department's Order directed the electric distribution companies to engage stakeholders in the development of their GMPs. Specifically, the Order stated that electric distribution companies should: (1) establish a clear and effective process to solicit stakeholder input; (2) clearly communicate this process to stakeholders; and (3) include in their GMPs a summary of this solicitation process, the stakeholder input provided and the integration of stakeholder input into the GMP.[101] National Grid has incorporated these elements into its GMP.

National Grid has a long history of engaging with stakeholders, communities and customers in order to develop plans and make investments that align with customer needs. National Grid approached a broad group of stakeholders to participate in its GMP stakeholder engagement process. The stakeholders who chose to participate largely fell into the following categories: environmental/energy related organizations, academia, state government, vendors, municipalities/urban planning and large customers. National Grid held multiple meetings with stakeholders, both at its offices and in the communities where its customers live and work. The predominant inputs from participating stakeholders regarding grid modernization were: (1) environmental benefits are a primary catalyst for grid modernization[102]; (2) invest significantly in MEO both directly from National Grid as well as through communities and community leaders using simple messages; (3) leverage existing energy efficiency programs to proliferate smart devices; (4) establish time varying price signals to better mirror market prices and encourage energy efficiency, conservation and shifting energy use to ultimately save money; (5) build trust by improving outage response and sharing accurate outage information; (6) use demonstration projects to build trust in new technologies; (7) phase deployment in order to work out any start-up issues; and (8) enable third party participation through vendors and other partners by designing a modernized grid that allows others to interact with the utility and with customers, including on customers' behalf with their permission. National Grid incorporated appropriate elements of this feedback into its GMP, as discussed in this Section.

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[101] D.P.U. 12-76-B at 51.

[102] However, as discussed in the Customer Knowledge chapter of the GMP, Section 11.4, the broader customer base is more interested in other sources of value such as information, convenience, control, and cost savings.

11.2.1 Stakeholder Engagement Process

National Grid historically has embraced robust stakeholder engagement as part of the execution of major projects. For example, the Company engaged stakeholders and customers around its SES Pilot. Through that process, it identified the community's desire for sustainability and enhancing customer engagement. Based on that input, National Grid established a learning center (the Sustainability Hub) to assist customers in better understanding the opportunities available in SES.

National Grid built on its prior stakeholder engagement processes to engage with stakeholders in different forums and through multiple means of communication to obtain input for the GMP. These efforts included: (1) inviting key statewide energy influencers to a series of "Energy Influencer Summits" held at National Grid on November 20, 2014, March 6, 2015 and March 20, 2015; (2) hosting four Community Connections events in Brockton, Lowell, North Adams and Petersham which included information on grid modernization and the opportunity to talk with National Grid representatives about grid modernization; (3) providing information on grid modernization at other National Grid community meetings; (4) leveraging National Grid's presence at approximately 60 community events to do additional customer outreach around grid modernization and obtain customers' feedback, through a team of employee Grid Modernization Ambassadors; (5) continuing to leverage the Sustainability Hub in Worcester for customer engagement and input; and (6) reaching out to a number of municipal leaders to educate them on grid modernization. Each of these processes is described in further detail in Section 11.2.3.

11.2.2 Communication of Engagement Process to Stakeholders

National Grid identified a broad group of key stakeholders who were invited to participate in the first grid modernization Energy Influencers Summit. Following the first summit, stakeholders were invited to participate in a survey to provide feedback on this event, and were invited to the two follow up summits.

In addition, National Grid used several channels to invite customers to Community Connections events. For each event, National Grid identified a group of 5-10 neighboring communities to invite, obtained all available email addresses for customers in those communities and sent email invitations. The invitations led to a registration page with further information. The Company also sent follow-up invitations to customers who did not register and reminders to those who did. National Grid used targeted social media advertising on Facebook to raise awareness about the events and direct interested users to the registration website. Finally, the Company created flyers that Company personnel who are Customer and Community Managers could hand out and post at strategic locations in the towns such as cultural centers, churches, etc.

For events orchestrated by third parties where National Grid was a participant, the third parties were responsible for advertising the event. At each event, National Grid employees captured customer comments and concerns and developed write-ups to summarize them.

11.2.3 Stakeholder Engagements

11.2.3.1 Energy Influencer Summits

National Grid hosted three energy influencer summits at its Waltham headquarters. Each of these engagements was designed to solicit and capture stakeholder input, and each focused on unique subject matter areas.

The first Energy Influencer Summit was held on November 20, 2014. The goal of this engagement was to introduce the concept of grid modernization, feature some of the lessons learned both from the SES Pilot and Central Maine Power's Smart Grid deployment and share customer knowledge. There were two tabletop exercises which were intended to (1) gather input on the perceived benefits from grid modernization and (2) define requirements for grid modernization. The first table top exercise began with stakeholders identifying and prioritizing the benefits of grid modernization. The session also provided a snapshot of the learnings from National Grid's customer knowledge work as described in Section 11.4. The second table top exercise sought input from stakeholders on what they felt were key features of a successful grid modernization implementation and recommendations on stakeholder engagement.

After the first summit, participants were invited to take a post-event survey to provide their preferences for continuing input into National Grid's GMP development. The survey results indicated that most participants wanted to remain actively engaged and were receptive to learning more and providing additional input. Therefore, National Grid held two additional engagements, on March 6 and March 20, 2015. The focus of the March 6 session was to discuss with stakeholders potential options for AMF, CLM, ERs and EVs, and to introduce additional lessons learned from the SES outreach and education tactics. Stakeholders expressed their priorities and guidance around these topic areas. The second follow-up session on March 20 involved a discussion of potential options for ADA, CVR/VVO, energy storage, communications, cybersecurity and MEO. Stakeholders again shared their perspectives around the benefits of these enhancements as well as their guidance around communicating these benefits to customers. Included in Attachment 21 are the attendee lists for each of the three summits. In addition, as of June 30, 2015 there have been two SES Pilot updates emailed to stakeholders invited to the energy influencers summits in order to provide on-going insight into the SES Pilot.

11.2.3.2 Community Events

National Grid, in collaboration with community leaders, arranged a series of "Community Connections" events. At these events, National Grid shared local updates, answered customers' questions and had a trade show which presented information about grid modernization as well as other topics. The first meeting took place in Brockton on October 23, 2014. Subsequent events were held in Lowell on January 21, 2015, in Petersham on April 7, 2015 and in North Adams on May 28, 2015.

In addition, National Grid's permitting and siting group organized community meetings focused on transmission/substation projects in Andover, Tewksbury, Dracut and Somerset and included a table where customers could learn about grid modernization. The Company also leveraged the many community events in which National Grid already planned to participate, in order to discuss the topic of grid modernization and to obtain feedback from customers. This effort built on the Community Connections concept and that of the SES Pilot.

11.2.3.3 Employee Grid Modernization Ambassadors

In order to further leverage existing events planned across the Commonwealth, the Company invited employees to become part of a network of employee volunteers to speak to customers about grid modernization. Approximately forty individuals participated in a two-day training program in January 2015 featuring Company experts in grid modernization and energy efficiency. The volunteers thereafter participated in approximately 60 events,[103] and spoke to approximately 2000 customers. Ambassadors used a template to capture the customer perspectives and questions which were later shared with additional Company employees who were developing the GMP.

11.2.3.4 Municipal Outreach

National Grid Jurisdictional Managers reached out to approximately 40 municipalities to familiarize municipal leadership with grid modernization. Jurisdictional Managers are Company personnel focused on developing close working relationships with the cities and towns in National Grid's service territory. They were trained in grid modernization concepts and were

[103] See Section 9.4.3.2.

provided a toolkit consisting of a grid modernization fact sheet, video and power point. This outreach was done in part based on stakeholder feedback previously received which recommended that National Grid identify and work with local leaders who could help deliver information about grid modernization messages in a localized and focused manner.

11.2.4 Stakeholder Input Provided

Participants in the three Energy Influencer Summits provided input on a range of topics.

The feedback was captured and distilled into documents. After reviewing the detailed feedback from each event, a list of recurring energy influencer stakeholder comments emerged, which were listed in the introduction to this Section 11.2. Attachment 22 includes the comments captured, grouped into categories or themes as appropriate.

At the community events, customers generally were interested in the concept of grid modernization, in particular around potential costs and cost savings, energy audits, outage reporting, outage restoration and greater visibility of their energy use. Customer questions included the timing of the arrival of grid modernization, costs, safety and security/hacking potential. Customers seemed very interested in the availability of off peak rates but stated that in order for grid modernization to work, customers will need to save money. Customers also drew on parallel experiences comparing grid modernization to past experiences. Anecdotally, customers were interested in AMI meters and in having real-time information about their energy use, which could give them greater control. Customers also had suggestions for education and recommended energy workshops as a method to teach customers more about energy and available programs.

11.2.5 Integration of Stakeholder Input into GMP

The input received from stakeholders was shared with internal grid modernization working group leads both in group overview meetings and in some cases with reports tailored for a particular grid modernization working group. This feedback is included in the GMP the Company is proposing, specifically in the MEO Plan which includes recommendations for simple and relatable messaging, community-based social media and working with communities to partner on grid modernization. The GMP also proposes using the energy efficiency programs as an effective mechanism to promote smart devices. Other feedback TVRs, demonstration projects such as battery storage and a phased deployment of grid modernization has also been included in the Company's GMP.

Stakeholder feedback which was not associated with electric service was not included in the GMP.

11.3 Learnings from Smart Energy Solutions Pilot

National Grid's SES Pilot formally launched on January 1, 2015. This was the formal start of the two year evaluation period for both the Pilot customer-facing and grid-facing components as provided in DPU 11-129. The Company performed an assessment and lessons-learned effort through to the launch, and informed the GMP with these learnings. Specific areas that were most relevant to the Company's assessment and analysis included:

- AMI
- Multi-tier advanced communications
- Grid-facing technology: ADA, feeder monitors and CVR/VVO
- Outreach and education
- CLM
- Training
- Management of numerous vendors
- Security
- Timeline and resources

The key learnings from the Pilot which National Grid incorporated into its GMP include: (1) ensuring the communications network for all tiers is installed, tested and enabled to provide for an efficient deployment of meters and distribution automation; (2) the need for a broader set of roles and capabilities than exists in the current utility workforce, in order to deliver and manage the enhanced solutions and technologies; and (3) outreach and education must be a constant and evolving dialogue with customers and stakeholders, in order to progress the opportunities and benefits that are enabled through these investments in energy infrastructure, and in order to maintain a collective focus on sustainability and energy supply needs for future generations.

11.3.1 Advanced Metering Infrastructure

In the Pilot, the Company successfully deployed AMI meters with a combination of RF mesh and a small population of cellular meters for communications. The Pilot made clear the need to have a multi-tiered communications approach to support the diversity of the Company's operating areas, taking into account the availability of specific public/private communications infrastructure and the cost to enable the metered points. The Company has enabled a number of different data collection time frames in an effort to identify the optimal data collection frequency (e.g. 5 or 15 minute intervals) in order to support customer preferences and to deliver advanced analytics and asset management value. The Company undertook a thorough end-to-end business analysis to ensure customer services (e.g. budget billing, move in/out, payment plans) can be supported by any chosen solution. The Company found that the opt-out approach to the Pilot was instrumental in simplifying the planning, scheduling, communication and initial technology successes, including the early field trial ("EFT") for testing AMI data collection and communication technology.[104]

In its GMP development, National Grid carefully considered its SES Pilot experiences and incorporated many of the key resulting success factors and learnings into its grid modernization AMF RFP process. As a result of these learnings, the AMF RFP sought proposals for a third party to aid in the management and deployment of the chosen technology and required that specific elements be incorporated into the process including location identification, signal verification for meter reading and processes to identify and resolve exceptions in meter communication. The AMF RFP also sought information on how successful bidders could support the diverse operating areas, customer density and topographical challenges of National Grid's service territory to deliver a solid operating platform.

11.3.2 Multi-tier Advanced Communications

In the SES Pilot, National Grid was successful in implementing a multi-tiered advanced communications network consisting of WANs, LANs and HANs. These technologies were implemented using WiMAX, cellular, RF mesh and Zigbee communications. In order to build out the various networks, the Company first completed a working prototype of all the protocols and technologies at the Company training center. This lab environment enabled both the engineers and the installation and maintenance work force to engage in training and testing of all the new protocols to be deployed. It also supported the ability to perform some preliminary cybersecurity testing, validation of the technology functionality and verification of manufacturers' claims. The development of the lab was invaluable in resolving integration issues between grid controls and the communications devices that carry their data. The experience the Company gained in the development and deployment of the communications network for the Pilot enabled the Company to better assess the communications options for its GMP.

[104] As described in D.P.U. 11-129, Exhibit CAW-1 at pages 36-37, through the EFT the Company tested its proposed AMI data collection and communication technology updated with the latest interoperability and security protocols, to evaluate its success in communicating meter information to the Company. This early installation of approximately 5,000 meters provided insight into any potential issues related to the physical deployment of the meters and communication devices, allowing for the Company to revise and evolve the training and instructions provided to field crews, communications technicians and other impacted roles.

The Pilot also validated the overall effort necessary to perform a communications assessment and the importance of engineering the network designs for a multi-tiered communications network. Despite best efforts to factor in known risks to obtaining optimal communications and quality of service, there were many unknown factors that came to light during network design, testing, deployment and activation. The Company identified the need for a broader mix of personnel with a new set of skills and capabilities to install, configure, manage and troubleshoot all of the components' discrete connections, sites and requirements, and as a result has incorporated more personnel training into its GMP proposal. The Pilot also made clear that there will be greater security considerations, risks and concerns as National Grid extends the capability to access the Company's distribution network from its secured substations to many public and readily accessible locations. The GMP incorporates the needs identified for providing cybersecurity, privacy and physical access controls in order to respond to the evolving risks to the system and IT.

11.3.3 Distribution Automation

One of the objectives of the Pilot was the introduction of an advanced suite of equipment and automation into the Company's distribution system. The Company successfully installed and enabled over 180 grid devices representing three main areas of focus:

- ADA: Intelligent protection schemes to improve reliability and operational efficiency
- Advanced capacitor control: Coordinated control to reduce losses, reduce peak and average demand and to improve power factor and voltage performance
- Advanced grid monitoring: Additional feeder monitors to monitor loading on capacity bottlenecks, provide improved inputs into system planning activities, develop "real time" ratings and collect data on DG and EV installations

The Company also was successful in integrating these devices and all the real-time communications into the Company's Energy Management System (EMS), in order to provide information to the distribution system control center on the status, operation, performance and restoration of enabled feeders. The Company recognized the value of the Pilot process in identifying the high impact feeders, designing solutions based on the specific needs for that feeder and ultimately engineering solutions that address the known and future load growth and system performance criteria. The Company has applied experience from the Pilot to account for new activities and coordination with the commissioning of the devices to enable the communications.

The Company leveraged the learnings from SES when incorporating the timeframes in its GMP necessary to plan, engineer, construct and maintain the grid modernization technologies. This includes earlier identification and clarification of each local zoning board's requirements when seeking permits and easements. The Pilot also provided information on the requisite knowledge, skills and abilities for future workforce planning. Finally, while the Company supported integration of these technologies with the Company's EMS, the Pilot made clear that a larger-scale deployment of these technologies will require a different solution that can support and manage a larger number of new devices and their accompanying advanced features, capabilities and communications. The GMP therefore proposes an ADMS/DSCADA system to address these issues.

11.3.4 Outreach and Education

The Company was focused on achieving a positive customer experience and delivering on the Company's outreach and education ("O&E") plan for the Pilot. The Company used the "listen, test and learn approach" for all O&E activities. Using this approach when reviewing the results and feedback received from stakeholders through focus groups, surveys or unsolicited feedback, the Company then reassessed specific approaches or incorporated the feedback in future outreach. Additionally, by delivering capabilities to customers in phases, the Company was able to introduce customers to different aspects of the Pilot in a more focused and better articulated manner, which supported a less confusing and less complicated customer experience. Additionally, some of the recent fluctuations in Basic Service prices have helped raise visibility regarding the bill impacts of energy commodity prices. This creates an evolving opportunity to create customer understanding of the opportunity for bill savings that dynamic pricing, demand response and CLM solutions provide.

The Sustainability Hub also has been a very positive success story. Stakeholders participating in the Green to Growth Summit, which the Company held in Worcester in September 2011, generated the concept of the Sustainability Hub. With well over 4,000 visitors since it opened, the Hub has been a place where customers, the community and interested stakeholders can learn about the Pilot and how a smarter grid will deliver greater choice, control and convenience. The GMP proposes to deploy a mobile Sustainability Hub, in order to bring the benefits of such a Hub to a larger number of customers.

11.3.5 Customer Load Management

The Company has received very positive feedback from customers who chose many of the in-home energy management solutions[105] that are part of the Pilot. The Company's review of prior

[105] These in-home solutions are in-home display units (digital picture frames), programmable communicating thermostats and load control devices.

smart grid pilots and the incorporation of those learnings and market review led the Company to select an in-home picture frame technology which displays real-time energy information to customers. This solution appears to have the strongest use by customers, as compared to handheld devices. The Company has also had some preliminary experience in executing the demand response features of the Pilot. The Company has called a number of demand response events using the model designed in the Pilot, and has been able to successfully engage customers and control in-home technology for the events.

11.3.6 Timeline, Resources and Training

Based on the Company's experience in the Pilot, the Company recognized the need to incorporate revised time estimates for easements, permitting, construction and testing of advanced communications equipment. The GMP field deployment timeline incorporates the additional time and testing necessary to commission and enable advanced communications between each device and the distribution control center. The Company also identified new skills and resources required to deliver the GMP. Many of these skills and abilities must be scaled to the quantity of technology and equipment being delivered, and to support the timeline and scale of the GMP. The Company has also identified the need for a robust training strategy and plan. This training touches many areas of the Company and varies in level and intensity depending on an individual's role and their specific interaction with the proposed GMP components. National Grid has incorporated these additional personnel and training requirements in its WTAM proposal in Section 5.2.2.

11.3.7 Vendor ecosystem

The Pilot uses a large portfolio of vendors and third party service providers, some of which are providing SaaS. The Company has learned from this approach with regards to how to identify the right partners, recognize and managing vendor risk, and develop a solid process capability around procurement and vendor management. The Company also was successful in the Pilot in developing partnerships that were based on shared risk and reward, in order to incentivize vendors to deliver on expectations and commitments. For grid modernization, the Company initiated its AMF RFP effort with the goal of selecting a solution provider who could demonstrate interoperability with other technology partners selected by the solution provider. This RFP process sought to identify and assess solutions that meet the core business requirements for the GMP capabilities proposed. Based on the Pilot, the Company learned that there is a benefit to reducing the number of individual vendor relationships, and to instead seek solutions from fewer vendors and partners that deliver more mature integration and capabilities, rather than the Company having to perform this function for multiple separate vendors.

11.4 Customer Knowledge

Understanding the needs of customers is key to developing a grid modernization plan that creates sustainable value. While affordability, reliability and safety remain important for customers, the Company found through its customer knowledge research for its GMP that an expanded range of needs including information, convenience and control are becoming increasingly more relevant to customers. Information emerged as a top need across the utility customer experience spectrum, from energy usage management to adoption of new technologies to outages. It is also reasonable to infer that customers' expectations and preferences are increasing and continue to be shaped by daily interactions with other industries which have been using technology and data to improve customers' experiences.

The Company's customer knowledge effort helped validate the Department's approach to grid modernization and the Company's GMP development. For example, foundational elements of the GMP such as AMI will provide relevant and actionable information, and TVRs will leverage behavioral science as well as industry and the SES Pilot learnings to achieve higher participation rates. In addition to providing information and opt-out default options, the Company will offer simple and convenient solutions to facilitate customer decision making, unlock value for customers and help achieve the Commonwealth's policy goals.

11.4.1 Approach and Background

National Grid has been building its customer knowledge on an ongoing basis. Beginning with a kick-off cross-functional internal workshop in November 2013,[106] the Company undertook a focused effort to synthesize its customer knowledge for the development of the Company's GMP.

The Company used a holistic and comprehensive approach to customer knowledge. This included: gathering fundamental customer information such as demographics; researching current and anticipated future customer needs and expectations; and gauging customer awareness, interest and behavior around grid modernization, DG, storage and AFVs. The Company accomplished this by: analyzing primary research, secondary research and customer data; speaking with customers at local events; and engaging energy influencers in a series of grid

[106] See Attachment 23.

modernization conversations. National Grid's comprehensive stakeholder engagement process also supported the development of the customer knowledge base.

11.4.2 Findings

11.4.2.1 Current Customer Expectations

Energy is a low engagement category for customers. While energy plays a vital role in customers' lives and businesses, it has not always been top of mind for customers as utilities have consistently provided safe, reliable service at reasonable prices. In a recent industry report, 54% of survey respondents "stated that they have not interacted with their electricity provider in the past 12 months,"[107] illustrating the persistence of an engagement gap. Active and passive engagement will become more important as customers come to expect a twenty-first century service experience and they consider new energy technologies to meet their diverse and evolving needs in an increasingly dynamic energy system.

Customers are experiencing new and higher levels of service and convenience in other industries that have been using technology and big data to continuously enhance customers' experiences. Multi-device capabilities and channel integration cater to individual customer preferences anytime, anywhere. Visibility and transparency of information also have shaped the landscape and have become the new normal of sophisticated customer service. Customers' day-to-day interactions will continue to set and re-set expectation levels for all experiences across many industries.

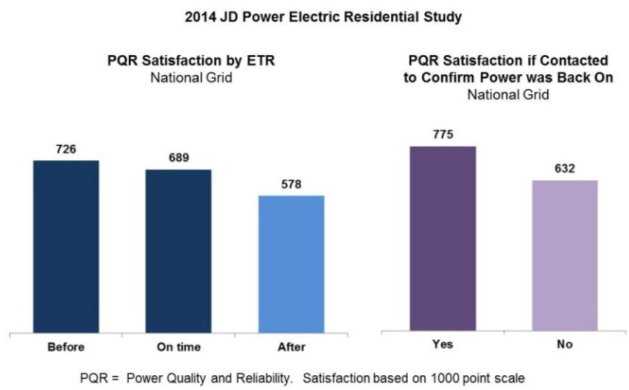
In the utility industry, these expectations manifest in various ways. Fundamentally, utility customers have an expectation that their power will not go out. For example, 95% of consumers surveyed in a national study indicated that there should be "no" or "rare" outages with the exception of storms.[108] According to JD Power, only 28% of National Grid customers called the utility when they had an outage.[109]

[107] Accenture, "Actionable Insights for the New Energy Consumer," 2012.

[108] Bates White Economic Consulting, "Willingness to Avoid Outages: Reliability Demand Survey," June 2012.

[109] JD Power, 2015 JD Power Electric Residential Study.

Figure 18: Satisfaction when informed of ETRs and Restoration



Information is the most important customer need during outages. The Company's customers have indicated that their most desired information is the estimated time of restoration ("ETR").[110] As illustrated in Figure 18, customer power quality and reliability ("PQR") satisfaction as measured by JD Power is noticeably higher when there is an outage if customers receive accurate estimated time of restoration and they are informed when power is restored.[111]

In general, customers want actionable and relevant information from their utilities. An industry white paper found that utilities are customers' preferred source for energy information.[112] The paper also found that customers rated personalized, insight-based information as highly valuable, and inferred that information needs to easily accessible for customers to review.[113]

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[110] JD Power, 2012 JD Power Electric Residential Study.

[111] JD Power, 2014 JD Power Electric Residential Study.

[112] OPower, "Five Universal Truths About Energy Consumers," 2013, p. 6 ("OPower").

[113] OPower, pp. 7-8.

11.4.2.2 Customer Awareness and Expectations

Through National Grid's customer research which surveyed Massachusetts customers' perspectives on grid modernization, DG and AFVs (including plug-in EV), the Company found that there was low familiarity with many of these emerging technologies, with the exception of solar and plug-in EVs for both residential and commercial customers (Figure 19 shows residential results). About half of the customers surveyed were interested in solar panels and about 60% are at least somewhat likely to consider a plug-in EV for their next purchase.[114]

National Grid also found that most customers had either a positive or neutral opinion of smart meters and smart grid. This is consistent with national findings from a Smart Grid Consumer Collaborative ("SGCC") survey, which found that 54% of those surveyed "who are familiar with the term say their general feelings toward smart grid are favorable."[115] Furthermore, other utilities that have deployed smart meters have found that when communicating with customers, it is important to: avoid over-promising; focus on the value that the smart meter will deliver rather than the fact it is smart; build trust in the community through proactive outreach to inform customers, stakeholders and employees early in the process; and listen to the customer to find out what they know and what they need to know.[116]

The Company's research also shows that customers expect National Grid to play a key role as a provider of information and of solutions across energy management services, customer generation, storage of electricity and installation/provision of plug-in EV charging services.[117]

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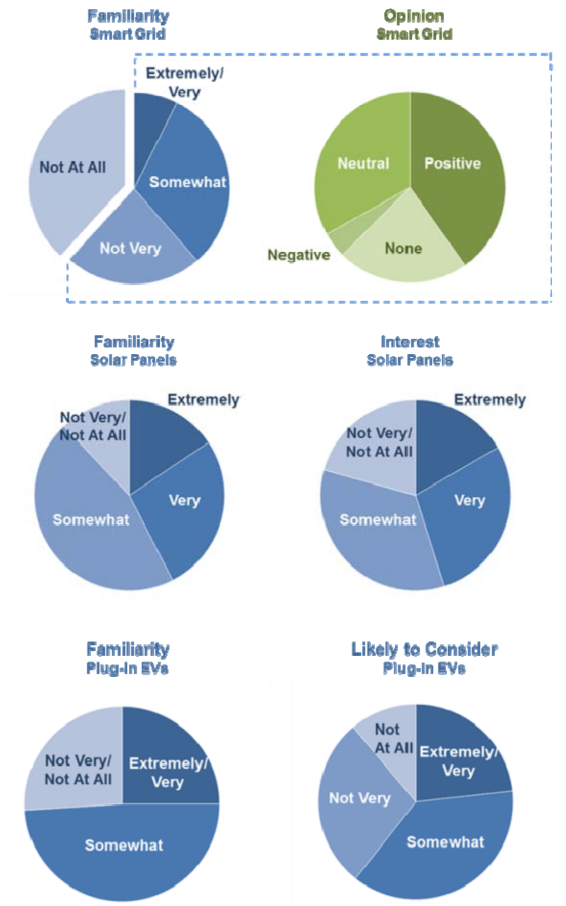
[114] National Grid, Value Proposition Research: A Study of 3 Energy Solution Areas for Massachusetts (May 29, 2014), pp. 37, 52 ("Value Proposition Research").

[115] Smart Grid Consumer Collaborative, "Consumer Pulse and Segmentation Research Program Wave 4" (Executive Summary), November 2013 ("Smart Grid Consumer Collaborative").

[116] Esource, Kim Burke, "Smart Meter Messaging Comes of Age," December 2, 2010.

[117] Value Proposition Research, pp. 24, 39 and 54.

Figure 19: National Grid MA Residential Customers' Perspectives on Technologies



In terms of customers' needs for grid modernization, the National Grid's customers indicated that they wanted to be informed energy consumers with pricing and solution options that would help them better manage their energy use to achieve cost savings.[118] Commercial customers

[118] Value Proposition Research, p. 12.

additionally expressed a willingness to turn up their thermostat if it would help avoid a power outage and liked the convenience that energy management technologies could provide to their business.[119] Customers also expressed interest in time of use rates, indicating a willingness to shift some of their electricity use from high demand times to avoid higher costs.[120] Given commercial customers' operational considerations, they were less willing to shift their usage. A majority of both residential and commercial customers expressed an interest in devices that can help them manage their energy use, including interactive and programmable thermostats that they can control remotely and program themselves based upon usage patterns.[121]

Willingness to pay is difficult to gauge. When asked directly about willingness to pay more for grid modernization benefits, about a third or less of National Grid customers surveyed were agreeable, but most of those would only pay about 2% more.[122] Other studies have found a greater willingness to pay. For example, a SGCC national survey found that 51% of residential customers would be willing to pay $15 more per month to improve the utility's reliability.[123] In fact, customers see a need for infrastructure investment and reliability of delivery. In a national JD Power study, customers were found to be more satisfied with communications of rate increases if they were coupled with infrastructure and reliability improvements (see Figure 20).[124]

[119] Value Proposition Research, p. 15.

[120] Value Proposition Research, p. 19.

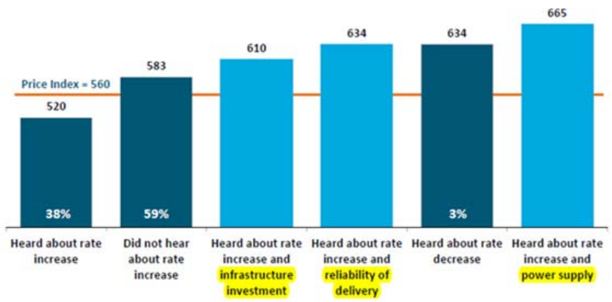
[121] Value Proposition Research, p. 20.

[122] See Attachment 23.

[123] Smart Grid Consumer Collaborative.

[124] JD Power, JD Power 2014 Electric Residential Survey.

Figure 20: Satisfaction With Utility Prices when Hearing About A Rate Increase



National Grid also sought to understand customers' views on DG. Both residential and commercial customers in Massachusetts saw value in being able to generate their own electricity if it would help them to more cost effectively heat their homes or businesses and would save them money.[125] National Grid's residential and commercial customers expressed the need for convenient options, given limited time to be involved in energy management.[126] Residential customers were more likely than commercial customers to have recalled an extended power outage, and also were interested in the potential for DG with energy storage to provide backup power during an outage.[127] Subsequent research was conducted with a segment of Massachusetts residential customers considered early adopters of distributed generation solutions – mostly solar – who had a different demographic composition[128] than the overall population. This research showed that in addition to savings, environmental benefits were also key motivators in the decision to generate their own energy. The security of knowing their electricity is cleanly generated at home is also important.[129]

[125] Value Proposition Research, pp. 31-32.

[126] Value Proposition Research, pp. 31-32.

[127] Value Proposition Research, pp. 31 and 35.

[128] Early adopters were more likely to be male, older, Caucasian, more educated, have higher household income, have children, and be homeowners living in single family homes.

[129] National Grid, Distributed Generation Research Among Early Adopters (April 2015), p. 3.

11.4.2.3 Customer Decision Making and Choice Architecture

Behavioral science, utility studies and examples from other industries including financial services and consumer products show the importance of good default options for TVRs and other customer choices, simple choices overall and automation of decisions for repeatable actions. These items all help facilitate better customer decision making as three decades of behavioral science [130] help explain why individuals may not always choose the economically rational decision.

Default options can increase participation and enrollment as individuals tend not to change the status quo.[131] A recent utility industry analysis of customer enrollment patterns in time-based rate programs as part of the DOE Smart Grid Investment Grant Programs ("SGIG") showed that for the nineteen solicitation efforts that had occurred for the SGIG consumer behavior studies so far, recruitment rates range from 5% to 28% for opt-in offers, while those using opt-out offers have recruitment rates that range from 78% to 87%.[132] In the Company's SES Pilot over 97% of eligible customers stayed on the default critical peak pricing rate plan, while under 3% opted out.[133]

[130] Richard H. Thaler, "Unless You Are Spock, Irrelevant Things Matter in Economic Behavior," The New York Times (online) (May 8, 2015).

[131] For example, the use of automatic enrollment (opt-out default) in 401(k) plans has been used to help increase savings rate. According to its *How America Saves 2014* report, Vanguard reported that overall participation rate was 82% in retirement plans with automatic enrollment vs. 65% in voluntary enrollment plans (Vanguard, "Vanguard: 401(k) plan auto enrollment paying off in getting more Americans to save for retirement," 10 June 2014).

[132] U.S. DOE, "Analysis of Customer Enrollment Patterns in Time-Based Rate Programs – Initial Results from the SGIG Consumer Behavior Studies"(July 2013).

[133] As of July 8, 2015.

While customers express interest in greater levels of choice, overloading customers with too many choices can result in decision inertia and less satisfaction with their choice if one is made. Behavioral science research on choice illustrates these points.[134]

Automation provides further decision optimization by simplifying or reducing repeatable actions. For example, auto-pay on bills allows customers to set up recurring payments on their accounts. 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.[135]

11.4.3 Incorporation of Customer Knowledge Plan Development

The Company's customer knowledge work has validated the Department's approach to grid modernization and informed the Company's GMP development in several key areas including the proposals for TVR, AMI, CLM, DG and the MEO plan.

The Company's learnings validate the effectiveness of opt-out TVR as a default pricing plan. The Company's customer knowledge learnings also support the AMI and CLM proposals (as described in Sections 4.2.1 and 4.2.5) which will provide greater visibility into energy usage and enable improved outage management. The AMI solution will enable the collection of customers' interval usage data, and the automated outage restoration and notification functionality that will be provided through AMI will lead to an improved outage experience for customers. As part of

- [134] See 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. In a well-known field experiment with specialty jams arranged at a grocery store, 60% of customers approached the jam sampling booth when offered 24 different flavors compared to 40% when offered 6 varieties; however, 30% of those offered the limited selection purchased a jar of jam in contrast to 3% of those offered the extensive assortment. A subsequent experiment with gourmet chocolates found that participants who chose from a limited assortment of six chocolates were more satisfied with their sample than those who chose from an extensive assortment of thirty chocolates.
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[135] Accenture, "The New Energy Consumer Architecting for the Future," 2014, pg. 26.

the CLM proposal, the Company is proposing energy management devices that meet customers' need for relevant information that will help them control their energy use. In addition, as the Company considered demand response solutions, the customer knowledge work reinforced that there is customer appetite for shifting energy usage in response to TVRs in particular for residential customers.[136]

The Company's proposed DG tools described in Section 7 will help to make the process of evaluating and installing DG more convenient for customers. Consistent with the Department's Order, the Company's proposed MEO plan will play a crucial role in engaging customers on the benefits of grid modernization. National Grid customers want simple, convenient solutions and relevant information that will support them in their energy decisions. Customers surveyed also indicated low familiarity with smart grid and a limited willingness to pay more for its benefits, but there was interest in learning more about grid modernization. The proposed MEO plan addresses these needs in several ways (see Section 9, MEO Plan).

11.5 Requests for Proposals and Requests for Information

In D.P.U. 12-76-C, the Department directed the electric distribution utilities to "attempt to monetize all costs and benefits [of a proposed STIP] to the extent possible using vendor quotes, estimates from in-state pilot projects, and data from relevant case studies in other jurisdictions," and to include a single dollar value for the present value of each monetized cost and benefit included in its Business Case Template.[137] For these purposes, the Company used a number of approaches to develop cost estimates for the major components of its GMP necessary to make progress on the Objectives and to achieve AMF. The Company developed cost estimates by formally engaging the wider vendor community to develop competitive, market based quotations for the major components and new capabilities necessary for grid modernization. For other

[136] National Grid, Value Proposition Research: A Study of 3 Energy Solution Areas for Massachusetts (May 29, 2014), pg. 19.

[137] D.P.U. 12-76-C at 12-13.

components of the GMP, the Company developed estimates based on actual cost experience from the SES Pilot and other relevant program or incumbent services.[138]

As described in this GMP, given the emphasis on specific capability requirements for grid modernization solutions, the Company developed a high level technology and services capability map that was segmented and clustered by product interrelationship, interdependency and integration. The segments were overlaid by market capability and market structure intelligence. In addition, the Company used ecosystem/supply chain principles to feed into a market engagement strategy.

The Company's market engagement hypotheses also incorporated experience and lessons learned from the SES Pilot, previous AMR meter deployment and other complex multi-faceted transformation programs.

11.5.1 Vendor Community Engagement

The Company reviewed each GMP component to determine if it had a suitable technology solution and incumbent vendor or partner, procured as part of a prior competitive process. Products and services including MEO, integration services, CVR/VVO and ADA/FLISR were identified as suitable components for estimates based on incumbent vendor solutions.

The Company then developed three requests for proposals ("RFPs") and a request for information ("RFI") for other GMP components. The RFPs and RFI were constructed in such a way to give the Company maximum flexibility in changing the vendor ecosystem model and removing or decoupling components should this be advantageous at a later time.

The Company conducted four formal procurement events to establish competitive market-based cost estimates for components of the GMP. These procurement events were:

- Integrated AMF/CLM / Communications Solution RFP
- ADMS/DSCADA/DERMS Software RFI
- Data Storage and Analytics Platform RFP

[138] Recognizing that the scale of the GMP is very different from the SES Pilot, the Company did not rely only on extrapolations of the SES costs, but also relied on the other sources identified.

- Program Management Office (Implementation Partner) RFP

11.5.2 Vendor Pre-Selection for RFP's and RFI

The Company carefully selected the appropriate vendors to whom to issue the RFPs and RFI, based on the following research and efforts:

- Integrated AMF/CLM/Communications Solution RFP: The Company used research from multiple market intelligence sources to identify the most appropriately-sized market leaders with the necessary core competencies in AMF and FANs and/or WANs, who could provide an integrated solution.
- DSCADA/ADMS/DERMS Software RFI: The Company selected vendors based on Gartner research. Gartner is a leading information technology research and advisory company.
- Data Storage and Analytics Platform RFP: The Company selected vendors based on Gartner research.
- Program Management Office (Implementation Partner) RFP: The Company looked to proven incumbent National Grid partners with managed services agreements or frameworks covering program management.

11.5.3 Evaluation process

An evaluation process was established for each procurement event to evaluate vendor responses received by the Company. The evaluation processes were designed to drive a consistent approach and predetermined score weighting to ascertain whether vendors had the ability to satisfy the functional requirements specified by the Company and the demonstrated ability and capability to deliver the solutions proposed, as well as to compare the proposals' pricing and conditions. The evaluation process and predetermined weighted evaluation criteria for all three RFP events were designed to identify the most effective and economically advantageous market offering. The RFI evaluation was designed to identify the vendors with the most effective and economically advantageous potential for subsequent procurement processes/events.

11.5.4 Integrated AMF/CLM/Communications Solution RFP

This RFP included the technologies and services that are foundational to the GMP. The Company relied heavily upon lessons learned from the SES Pilot in structuring the scope of this RFP, which included the following technologies and services:

- AMF addressing three aspects: Meters (radio frequency and cell), head end system and MDMS, which included three work packs and three questionnaire spreadsheets.
- CLM addressing in-home equipment (gateway), related web-based portal software, presentation software, installation and services which included one work pack and one

questionnaire. Vendor responses for CLM services took into consideration equipment and full implementation services including design, build/installation, configuration, commissioning and operations.

- Communications (Comms) addressing the complete network solution for the GMP. National Grid sought a solution that would provide an integrated communication network that includes FAN to grid devices, substations, meters and unified backhaul to National Grid's enterprise data network.
- Digital Risk and Security (DR&S) addressing National Grid's digital security requirements which would apply to all of the other three areas mentioned above. This included one work pack and one questionnaire.

In order to minimize delivery risks and integration costs, the Company encouraged qualified suppliers to take responsibility for complete solutions that included the technical elements listed above as well as the service elements listed below:

- Overall solution design and leadership to document business requirements
- Integration services between each new element of scope
- Configuration, testing, installation and commissioning services for each element of scope
- Program management services that cover all elements of scope
- Support and maintenance, and in some cases managed services
- Collaboration with National Grid business, IS, PMO, implementation partner and all vendors

The Company issued the RFP to nine vendors and received three bids. The Company subsequently conducted a number of clarification and level-setting sessions with each of the vendors. The Company selected an appropriate indicative bid for use in the monetized BCA. However the Company received lower priced bids that may present better value once the evaluation process is complete.[139] This bid is included as Attachment 24 to the GMP.

[139] The bids received turned out to have significant variety and integrated complexities. The Company therefore is conducting a thorough evaluation of these bids, and if necessary will update its cost estimates based on this evaluation.

11.5.5 DSCADA / ADMS / DERMS Software RFI

The Company determined it was not currently in a position to present sufficiently detailed requirements for ADMS to the market for an RFP. Therefore, the Company issued an RFI to ascertain indicative costs and to identify a vendor shortlist for subsequent selection processes.

The RFI included several major elements of functionality: DSCADA, Core Distribution Management System (DMS), ADMS, Advanced Outage Management (AOMS) and DERMS.

DERMS was included in the RFI as a separate scope component with separate pricing. The Company concluded that a DERMS will not be included in the GMP at this time and may not be included in any subsequent evaluation process due to the lack of maturity of the technology.

The Company sent its RFI to eight potential vendors and received seven proposals. Based on technical evaluation, four vendors emerged as shortlisted candidates. The Company has selected an appropriate indicative submission from the four short listed vendors to use in the monetized BCA. As this was a RFI rather than a RFP, the Company has added a contingency to the selected submission for the monetized BCA. This bid is included as Attachment 25 to the GMP.

11.5.6 Enterprise Analytic Architecture Data Lake RFP

The Company issued an RFP which contained four elements necessary to provision licensing for the GMP EA architecture. The four major elements are:

- Data Platform - Based on Hadoop architecture to store data and perform analytics.
- Master data management
- Utility data
- Visualization analytics and business intelligence

The Company sent out an RFP to eleven vendors. The Company received six bids, of which only one bid included complete pricing. The Company has used this vendor’s pricing in the monetized BCA. This bid is included as Attachment 26. The Company is currently working with the vendors to obtain comparative pricing.

11.5.7 Program Management Office/ Implementation Partner RFP

This RFP requested estimates for project management and associated services to assist the Company with coordination and implementation of the GMP. These services include:

- Overall program management
- Overall business process design/requirements definition

- Overall solution architecture
- Overall requirements management
- Organizational change management
- Testing management
- Training and transfer planning and coordination
- Deployment operations
- Vendor Technical implementation coordination and performance monitoring

The Company has included a bid for these services in the cost benefit analysis.[140] This bid is included as Attachment 27.

11.5.8 Opt-In Scenario

In order to provide cost estimates for the Opt-In scenario that the Company has examined, the Company leveraged the SES Pilot to identify the technology and ascertain the vendor pricing. Pricing is based on a similar solution to the SES Pilot but using cellular meters and cellular backhaul. The Company requested a vendor quote for the AMF portion of the solution based on an estimated two percent of the Company's customers opting in to the AMI meters, and communication infrastructure for ADA and CVRVVO to 30% of the Company's customers. Other costs were extrapolated and estimated based on the SES Pilot. The documentation for these costs estimates is included in Attachment 28.

[140] Based on the information received, the Company intends to further evaluate these proposals, and if necessary it will update the cost estimate for these services.

12. Rates, Cost Recovery and Bill Impacts[141]

In this Section, National Grid presents its proposed revenue-neutral changes to rate design for distribution service in order to more toward rates that are fair to all customers and that reflect actual relative costs to serve each customers, including customers with and without DG. National Grid is proposing four-tiered customer charges for its residential and small C&I customers based on a customer's maximum monthly use, as well as a charge applicable to large stand-alone DG facilities that will be based upon the size the DG facility.

National Grid also discusses in this Section: its TVR proposal for effect following the deployment of AMF; illustrative revenue requirements for future cost recovery filings for its GMP and RD&D Program; proposed tariffs to implement its cost recovery proposals and to allow AMI opt-out; and illustrative typical bill impacts of the Company's proposed GMP scenarios and of the proposed RD&D Program.

12.1 Distribution Rate Changes

As part of this GMP, National Grid is proposing revenue-neutral changes to rate design for electric distribution service rates to more effectively and appropriately recover the costs of distribution service. The Company's objective in proposing new rates is to begin to move towards rates for distribution service that are fair and equitable across all customers and are designed to reflect the actual relative cost to serve each customer, both for customers with and without DG. In brief, the Company proposes as follows:

- The Company's proposed rates will shift the recovery of costs from variable (per kilowatt-hour (kWh)) charges to customer charges yet will create a distinct incentive for customers to conserve their use of energy.
- The Company will implement the proposed rates for Residential Regular Rate R-1 ("Rate R-1"), Residential Low Income Rate R-2 ("Rate R-2") and Small Commercial and Industrial ("C&I") Rate G-1 ("Rate G-1") using currently installed metering for each class.

[141] The Company's proposals in this Section are further detailed in the jointly-sponsored testimony and exhibits of Company witnesses Peter T. Zschokke and Scott M. McCabe ("Zschokke/McCabe Testimony"), and the jointly-sponsored testimony of Company witnesses Mr. McCabe and Amy S. Tabor ("McCabe/Tabor Testimony").

- The designs for Rate R-1, Rate R-2 and Rate G-1 include a tiered customer charge.
- The Company designed the proposed rates so the bill impact on any individual customer will be no more than plus or minus approximately five percent annually.
- The Company is proposing a charge applicable to large stand-alone DG facilities that will be based upon the size the DG facility. In addition, the Company proposes that DG facilities, unless they are specifically enrolling in net metering, not net the station service usage against the amount of electricity generated by the DG facility.
- No changes are proposed for the following rate classes:
  - Residential Optional Time-of-Use Rate R-4 ("Rate R-4");
  - General Service Demand Rate G-2 ("Rate G-2");
  - Time-of-Use Rate G-3 ("Rate G-3"); and
  - Street and Area Lighting Rates S-1, S-2, S-3, S-5, S-6, or S-20.

The Company supports greater use of DG, which can provide benefits for customers and help meet customer expectations. The Commonwealth of Massachusetts has successfully created significant growth in DG through its many programs and policies, and National Grid expects deployment of renewable DG and DERs to continue its substantial growth in its service territory, as discussed in Section 7 of the Plan. The experienced and expected increase in DG in Massachusetts necessitates a change in the nature and use of the distribution system to allow greater amounts of customer generation feeding into the system, while also preserving safe and reliable delivery of electricity for all customers.

12.1.1 Distribution System Services to DG Customers

The Company's distribution system is designed and constructed to serve the expected maximum needs of all of its customers (i.e., customers' peak demand) as a group and individually, as part of the Company's obligation to maintain the distribution system to serve all of its customers including customers with DG. For customers with generation, the amount of infrastructure required to serve that customer may be based not only on the demand of the customer, but also on the capacity the customer is generating. In some instances, a customer's load (use) at a given point in time may be less than the output of its generator at the same point in time. When the customer's generation exceeds its usage, that energy is being fed into the distribution system, which is now being used to transport electricity away from the customer rather than towards the customer, as is the case in the traditional role of the distribution utility. In the event the customer's generator trips off-line due to a failure within the generator system, the amount of electricity needed from the distribution system would increase very quickly as all of the customer's energy requirements would now have to be met by the distribution utility, even for a short period of time. Therefore, proper cost allocation and rate design must recognize the cost responsibility of the customer for facilities and services to meet the customer's total electricity needs, including when the generator's output exceeds the customer's usage on-site, and when the generator is not operating at all.

In addition, the distribution utility provides other services to DG customers, including: reliability; voltage quality; access to energy markets; startup power; and efficiency. A small renewable DG facility at a customer's location would need to spend four to eight times more than the cost of generation alone to provide these services themselves in an islanded state.[142] This is due to the fact that renewable energy systems (without any energy storage) cannot be used to provide the large start-up power (inrush current) needed by air conditioning compressors and other typical customer motor-driven equipment. The parallel connection to the distribution utility provides this needed start-up power. Thus, the distribution utility is a required complement to the expansion of clean renewable power because it lowers the overall cost for an individual or company considering renewable self-generation.

12.1.2 Rate Design

All customers who are connected to the distribution system (i.e., customers with DG, customers without DG and directly connected DG facilities) should contribute their fair share to the utility's costs to operate, maintain and invest in the distribution system upon which they all rely. However, under the current rate design which relies primarily upon delivered per kWh charges, especially for residential and small C&I customers and stand-alone generators, DG customers may contribute significantly less to support the distribution system as a result of their reduced kWh usage, thereby shifting the recovery of distribution system costs to all non-DG customers. Establishing the appropriate level of contribution toward these fixed costs by all customers – those with DG and those without DG – is essential to ensuring that the distribution system can be built, operated and maintained in a manner that allows for DG interconnection in a safe and reliable manner to achieve the clean energy goals of the Commonwealth.

The industry has long accepted principles of rate design first put forth by James C. Bonbright, which are:

- Rate attributes: simplicity, understandability, public acceptability, and feasibility of application and interpretation;
- Effectiveness of yielding total revenue requirements;
- Revenue (and cash flow) stability from year to year;

[142] Electric Power Research Institute. The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources (February 2014) (See Exhibit PTZ SMM-4).

- Stability of rates themselves, minimal unexpected changes that are seriously adverse to existing customers;
- Fairness in apportioning cost of service among different consumers (rates based on cost causation);
- Avoidance of "undue discrimination"; and
- Efficiency - promoting efficient use of energy by the customer (e.g., such that utility's infrastructure and resources are not strained).[143]

Using these principles as a guideline, the ideal rate design for all customer classes would consist of a customer charge designed to collect (1) customer-related distribution system costs, such as the cost of a meter, billing, and customer service, plus (2) a demand charge that recovers the demand-related or capacity-related system costs. The demand charge would be assessed on a measurement of customer size, such as maximum connected load or maximum use during a 15-minute interval, and would reflect the customer's contribution to system costs relative to other customers' demand.

The Company does offer rates with demand-based charges to its medium and large C&I customers,[144] but the Company is limited in its ability to implement demand-based rate designs for residential and small C&I customers because the metering necessary to measure kW is not typically installed for customers in these rate classes. The Company's GMP would resolve this situation and, if implemented, would allow the Company to move towards demand-based rates for these customers. Any move to demand-based rates will take time to implement given the need for stability in rates and customer ability to comprehend and act on the new designs.

The Company's rate design proposals generally reflect a shift away from recovering distribution system costs through variable per-kWh charges, and toward customer charges that reflect customer size. The proposed charges are based upon the size of the customer, as determined by metered kWh, and will be applicable to all customers, including those customers who have installed DG. Customer and demand charges are more reflective of the underlying cost of the distribution system and therefore communicate more accurate price signals to customers regarding the costs that customers impose upon the system.

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[143] James C. Bonbright. Principles of Public Utility Rates (1st ed. 1961).

[144] See M.D.P.U. Nos. 526, 527, 567, 1152, 1153 and 1251.

The result of the Company's revenue-neutral changes to rate design and proposed new rates, base distribution rate proposals in this Plan is that the proportion of the revenue requirement billed through customer charges will increase modestly from the current design. The Company is proposing a four-tiered customer charge for the Rate R-1, Rate R-2 and Rate G-1 rate classes. Each tier is defined by a kWh range intended to reflect customers' monthly maximum use. The customer charges are designed to recover most or all customer-related revenue requirement and a portion of the demand-related revenue requirement based upon the billing determinants of the applicably-sized customers in each tier. As a result, customers will be billed the customer charge associated with the tier that is representative of their maximum monthly use over a 12-month period. The remaining distribution revenue requirement is recovered through a uniform per-kWh charge.

12.1.3 Four-Tiered Customer Charge Proposal

Under the Company's four-tiered customer charge proposal, each of the four tiers would be defined by a kWh range intended to reflect customers' monthly maximum use. The customer charge for each succeeding tier will be higher relative to the prior tier and is intended to approximate what customers would be charged through a combination of a customer charge and a demand (per kW) charge. The customer charges would be designed to recover most, if not all, of the rate class's customer-related revenue requirement from the last rate case and a portion of the demand-related revenue requirement associated with the applicably-sized customers in each tier. The tiered customer charge design will more accurately reflect customer distribution system cost responsibility and will also encourage customers to manage energy use wisely in order to remain in their current tier or move to a lower tier.

The current distribution rate structure for both residential Rate R-1 and R-2 includes a monthly customer charge and an energy charge. Under a rate structure where a customer's monthly bill is based upon maximum demand, each customer's monthly charges would consist of a customer charge and a per-kW charge based upon the customer's maximum kW demand. Typically, this demand charge would be the same every month and would not vary with kWh consumption. However, larger sized customers would pay a higher demand charge than smaller customers reflecting their higher demands on the distribution system and, consequently, the greater cost that they impose on the distribution system. The tiered customer charge design mirrors this design. However, given that the Company is establishing bill impact limits as part of its proposal, Rates R-1, R-2 and G-1 will still include a per-kWh charge to mitigate the bill impacts on smaller customers of increases in the customer charge component.

The Company determined that using a customer's maximum monthly kWh is a good approximation for kW by analyzing the relationship between kW and maximum kWh for approximately 12,300 residential and 300 small C&I load research customers using a single year of data. Although there is much variation in the data, meaning that for any given level of kW, there is a wide range in the associated maximum kWh use, the bulk of the observations are clustered around trend lines.[145] Therefore, the Company concluded that maximum kWh use can be reasonably expected to approximate customer size, as measured in kW.

12.1.3.1 Rates R-1 and R-2

The current Rate R-1 and R-2 customer charge of $4.00 per month is less than what the full cost of service customer charge would be, of $8.15 per month.[146] Therefore, customers with low average annual usage, whose total monthly distribution charges are less than $8.15 per month, are currently being subsidized by larger customers. In addition, the revenue requirement not recovered through the customer charge component is currently recovered through a per kWh charge, which is applied to monthly kWh deliveries and does not necessarily reflect the customer's maximum demand.

Under the Company's four-tier customer charge proposal, the proposed tiers and charges for R-1 and R-2 customers are as follows:

- Tier 1: 0 kWh to 250 kWh $4.20 per month
- Tier 2: 251 kWh to 600 kWh $8.15 per month
- Tier 3: 601 kWh to 1,200 kWh $13.00 per month
- Tier 4: kWh in excess of 1,200 $18.00 per month

The tiers' ranges are designed to be broad enough to allow customers to manage their monthly use to remain in their current tier, but narrow enough to allow for the opportunity to move to a lower tier through implementation of energy efficiency measures. The second step in the rate design for Rates R-1 and R-2 was to design the energy-based rate, which consists of inclining blocked kWh charges that will recover the remaining rate class revenue requirement not recovered through the customer charge.[147]

[145] See Exhibit PTZ/SMM-6 (attached to the Zschokke/McCabe Testimony).

[146] Exhibit PTZ/SMM-10, page 1, line 8.

[147] The rates necessary to produce the rate classes' revenue are shown on Exhibit PTZ/SMM-12, filed with the Zschokke/McCabe Testimony.

12.1.3.2 Rate G-1

Rate G-1 is available for all purposes; however, the Company may require customers with 12-month average monthly use exceeding 10,000 kWh or who have 200 kW of demand for three consecutive months to take service on the Rate G-3 (Time of Use). Rate G-1 includes customers receiving unmetered service. The current distribution rate structure for Rate G-1 includes a monthly customer charge and inclining block kWh charges. There is an additional charge if the kVA transformer capacity needed to serve a customer exceeds 25 kVA. Unmetered customers pay a location charge, which is intended to reflect the customer charge less a credit for meter-related costs, in place of paying a customer charge.

The Company is proposing to implement the same four-tier design for the Rate G-1 customer charge as it is proposing for Rate R-1 and R-2. The proposed tiers and charges are as follows:

- Tier 1: 0 kWh to 75 kWh $10.50 per month
- Tier 2: 76 kWh to 500 kWh $11.55 per month
- Tier 3: 501 kWh to 2,000 kWh $16.00 per month
- Tier 4: kWh in excess of 2,000 $32.00 per month

The proposed customer charge for the initial tier is less than the customer-related cost of service unit charge of $11.55 per month; therefore, the Company is proposing the initial tier be limited to customers with maximum use less than 75 kWh to limit the number of customers being subsidized. Analysis of the Company’s billing data indicates that approximately 15 percent of small C&I customers have a monthly maximum use within that range. Approximately twenty-nine percent of the small C&I customers will fall into the second tier, with approximately fifty-six percent of the customers falling within the two upper tiers.

The initial tier’s customer charge is set at $10.50 per month which is an increase of $0.50 per month from Rate G-1’s current customer charge. The customer charges for the second, third and fourth blocks are designed to recover the customer-related cost of service costs plus a portion of the demand-related costs, subject to the limits imposed by bill impact criteria. The Company also designed the energy rates which are the rate necessary to produce the rate class’ revenue requirement.[148]

[148] See Exhibit PTZ/SMM-12, filed with the Zschokke/McCabe Testimony.

12.1.3.3 Rates R-4, G-2, G-3, S-1, S-2, S-3, S-5, S-6, or S-20

The Company is not proposing any changes to Rate R-4, Rate G-2, Rate G-3 Street and Area Lighting rates. The Company's rate design proposals in this proceeding are intended to shift cost recovery through variable (per kWh) charges to customer and/or demand per kW charges to ensure that customers who reduce kWh consumption either through implementation of DG or energy efficiency will pay their fair share of the Company's distribution system.

The current distribution rate structures for rate classes G-2 and G-3 include demand (per kW) charges in addition to customer and per kWh charges, and approximately 90% of the distribution revenue requirement is recovered through the customer and demand charges of those classes. Therefore, the Company does not believe that it is necessary to propose new rates at this time to further increase the percentage of distribution system costs recovered through the customer and/or demand charges. However, the Company intends to propose rate design changes applicable to Rates G-2 and G-3 in its next base rate case.

The street and area lighting classes listed above have limited opportunities for implementation of DG or energy efficiency. In addition, the rate design for these classes already consists primarily of fixed charges; therefore, it is not necessary to propose new rates for outdoor lighting.

Rate R-4 is an optional time-of-use rate available to residential customers whose monthly usage exceeds 2,500 kWh. Rate R-4 serves a small number of customers, approximately 165 so the Company did not contemplate any changes at this time. However, the Company will consider appropriate changes to the design of Rate R-4 in conjunction with other proposals regarding TVRs.

12.1.4 Rate for Stand-Alone Generators

The Company is proposing to implement an Access Fee applicable to stand-alone generators (i.e., DG facilities that are directly connected to the distribution system, and have no associated on-site load for any DG facility enrolled in any of the DG programs, i.e., Qualifying Facilities, net-metered facilities, as well as any new programs approved in the future by the Commonwealth). The Access Fee will be based upon the nameplate capacity of the DG facility, adjusted for expected availability, and will be a fixed amount each month. Each DG facility will be required to sign an Access Service agreement with the Company that will specify the nameplate capacity of the unit, the availability capacity factor that will determine the needed distribution system capacity and the monthly Access Fee.

Each stand-alone net metered DG unit is assigned a billing account for retail delivery service, and the billing rate class assigned to such accounts typically is Rate G-1. The assignment of a rate class generally is based upon the expected delivered energy to the location. Since a stand-alone DG facility generally has only parasitic load,[149] the account is eligible for Rate G-1. As such, a stand-alone DG facility is billed only a monthly customer charge of $10.00, plus associated taxes, which does not provide an adequate contribution to the DG facility's use of the distribution system or recovery of the costs that the Company incurs to serve these customers. Further, there is little on-site use, and therefore the DG facility's use would not qualify it for a demand-based rate schedule.

Customer demand can be either the result of the customer's load, represented by inflow kWs (a customer taking energy from the distribution system), or generation, represented by outflow kWs (a customer needing the distribution system to facilitate the amount of DG on-site, or to export energy to the system which exceeds the customer's on-site electric usage). In either case, the distribution system must be sized to accommodate that maximum demand imposed on it from either inflow or outflow kWs. Therefore, proper cost allocation and cost recovery should recognize demand that results from either inflows or outflows of energy. This provision allowing an Access Fee would contribute towards the support for the distribution system that the DG facility relies upon for the movement of generated energy from the site of generation to other locations, as well as contributing towards the recovery of ongoing O&M and replacement costs of interconnection equipment.

In addition, the current use of Rate G-1 for these large projects does not compensate the Company for the cost of the interval metering required for these DG facilities to settle the corresponding generation asset at the ISO-NE. In addition, the management of DG on the distribution system requires changes to the Company's dispatching requirements, coordination with ISO-NE, outage and maintenance scheduling, as well as planning of the system. Allowing net metered customers to allocate excess credits to other accounts also causes changes in the Company's customer service and billing needs. Although the Company would prefer to bill

[149] Parasitic load, also referred to as station service load, is energy used to operate auxiliary equipment and other load that is directly related to the production of energy by a DG facility.

these generators on a regular service rate, the issue of interconnection costs requires this proposal at this time.

This proposal is intended to be revenue-neutral to the Company. As part of this proposal, the Company will credit any revenue billed through this Access Fee to its Revenue Decoupling Mechanism ("RDM") reconciliation,[150] which is designed to capture all revenue billed and categorized as distribution revenue. Therefore customers, in this case stand-alone DG customers, will contribute a reasonable share of revenue for the use of the system that is reflected in the distribution rates of all other customers, and through the RDM reconciliation that revenue will be credited to customers and reflected in a lower RDM Adjustment Factor. Therefore, the Company will not realize incremental revenue from this proposal, but the stand-alone DG facility will pay for its use of the system that all other customers have been funding.

The Company is including typical bill impacts, proposed tariffs and proposed tariff provisions to implement these proposals, in the testimony and exhibits that it is filing with this Plan.[151]

12.2 Time Varying Rates and Tariffs for Basic Service Commodity

In D.P.U. 14-04-C, the Department required that, following the deployment of AMF, electric distribution companies must offer to Basic Service customers: (1) a default time of use ("TOU") rate with a critical peak price ("CPP") component; and (2) an option to opt out of the default rate and choose a flat rate with a peak time rebate ("PTR") component.[152]

For the TVR portion of its GMP, the Company is proposing to use the Smart Energy Pricing options from its SES Pilot that the Department approved in D.P.U. 11-129 and D.P.U. 14-84-B. The methodology and design of these options were first proposed in Docket No. D.P.U. 09-32.[153] The CPP and PTR options to be proposed once AMF is available will be based upon this

[150] M.D.P.U. No. 1231, Revenue Decoupling Mechanism Provision.

[151] Exhibits PTZ/SMM-13, PTZ/SMM-14 and PTZ/SMM-15, filed with the Zschokke/McCabe Testimony.

[152] D.P.U. 14-04-C at 2 (2014).

[153] The Company provides as Exhibit PTZ/SMM-16 an excerpt from its Smart Grid Pilot proposal in D.P.U. 09-32 which explains the methodology for determining CPP and PTRs.

methodology subject to two further considerations. First, the Company will consider adjustments to its proposal from experience in the operation of its ongoing SES Pilot. Changes may result from customer feedback, effectiveness in reducing costs, risks associated with reducing costs or other reasons. Second, the Company may propose to bid for CPPCPP offers from third party suppliers.

The Company proposes CPP and PTR offerings for residential and small to medium sized C&I customers in rate classes R-1, R-2, G-1 and G-2. The Company will consider appropriate pricing options for customers on its Time-of Use Rate G-3. The Company received approval from the Department to not offer any time varying rate structure to the Rate G-3 largest customers in its SES Pilot area given the small number of customers on that rate in the SES Pilot area and the cost of doing so.[154] However, the Company will consider whether implementation of TVRs would be applicable and cost effective for customers in this large commercial and industrial class given the level of supply by third party providers to this class.

Additionally, the Company is investigating whether wholesale suppliers would bid to provide Basic Service with a CPP structure. If the Company could structure a process that would bring forward adequate competitive response from wholesale suppliers, the Company would not design a rate but would propose to use bids from the suppliers. If bids from the wholesale suppliers are not forthcoming, the Company would need to perform rate design based on the flat Basic Service rate prices as it current does for the SES Pilot.

If the Department approves roll-out of AMF in any of the four GMP scenarios proposed by the Company, the Company will submit final prices that will reflect the Basic Service rates in effect at the time for approval prior to the final stages of AMF implementation. If the Company decides that changes in its current CPP are warranted based upon its SES Pilot results, the Company will file these changes at an appropriate time for the Department to review and approve any changes in methodology and structure of prices.

[154] D.P.U. 14-84-B at 16-17 (2014).

12.3 Revenue Requirement

National Grid also is filing in its accompanying testimony and exhibits[155] an illustrative version of the revenue requirement calculation that will be used for any cost recovery filings. A revenue requirement was done for each of the four GMP scenarios as well as the proposed RD&D Program. These are for illustrative purposes only and dollar amounts and rates used within the actual cost recovery filings will be updated to reflect only actual amounts being requested for recovery and the most appropriate rates at that time.

12.4 Cost Recovery Tariffs

The Company is proposing three tariff provisions associated with cost recovery for its GMP, which are: the Short Term Investment Plan Provision ("STIP Provision"); the Research Development and Deployment Provision ("RD&D Provision"); and the Advanced Metering Infrastructure Opt-Out Provision ("AMI Opt-Out Provision").[156]

In the STIP Provision, the Company is proposing to implement a tariff that will allow recovery of the costs incurred from implementing its GMP upon approval by the Department. The proposed STIP Provision allows for the concurrent recovery of capital investment of both plant placed into service as well as capital costs recorded to Constructions Work in Progress ("CWIP") along with incremental O&M expense also included in the Company's STIP and incurred as a direct result of implementing its GMP, as well as the Company's incremental GMP development costs.[157] The recovery of capital and O&M is proposed to take place on a revenue requirement based on estimated costs and will be reconciled to actual costs and revenue after each year of the STIP.

The Company is also proposing the RD&D Provision which will allow recovery of the costs incurred from carrying out its RD&D Program upon approval by the Department. The proposed RD&D Provision allows for the concurrent recovery of capital investment of both plant placed

[155] Exhibits AST/SMM-5 through AST/SMM-9, filed with the McCabe/Tabor Testimony.

[156] Exhibits AST/SMM-1 through AST/SMM-3.

[157] See Section 1.4.5.

into service as well as capital costs recorded to CWIP, along with incremental O&M expense also included in the Company's RD&D Program and incurred as a direct result of implementing its RD&D Program. The recovery of capital and O&M is proposed to take place on a revenue requirement based on estimated costs and will be reconciled to actual costs and revenue after each year of the RD&D Program.

As required by the Department,[158] the Company is proposing the AMI Opt-Out Provision for those customers who do not wish to receive an AMI meter. For this purpose, the Company proposes to expand its current Residential Automatic Meter Reading Opt-Out Provision[159] to include AMI metering. Since the AMR Opt-Out Provision is relatively new, the Company is not proposing to revise the fees it contains at this time.

12.5 Typical Bill Impact of Proposed STIP and RDD

The Company calculated illustrative Short Term Investment Factors ("STIFs") pursuant to the terms of its proposed STIP Provision and illustrative RD&D Factors ("RDDFs")[160] pursuant to the terms of its proposed RD&D Provision, in order to illustrate typical bill impacts of the Company's proposed GMP scenarios and of the proposed RD&D Program. The Company is presenting five years of illustrative bill impacts for all rate classes.[161] In these bill impact analyses, the Company kept constant all rates and only varied the analysis by the illustrative grid modernization cost recovery factors.

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[158] D.P.U. 12-76-B at 48-49.

[159] M.D.P.U. No. 1215.

[160] Exhibits AST/SMM-10 through AST/SMM-14, filed with the McCabe/Tabor Testimony.

[161] Exhibits AST/SMM-15 through AST/SMM-19, filed with the McCabe/Tabor Testimony.

13. Attachments

GMP Supporting Documents Attachment Listing

Table 24 below lists the various attachments referred to throughout the GMP.

Table 27: Attachment List

Attachment No.	Attachment Name
1	CVR/VVO and ADA - High value feeders per area for the field deployment of both ADA and CVR/VVO
2	CVR/VVO – Prioritization Ranking List
3	CVR/VVO – CVR/VVO pricing quote (Redacted)
4	ADA – Prioritization Ranking List (Redacted)
5	ADA – ADA pricing quote (Redacted)
6	CLM – CLM Services
7	CLM – Devices and Equipment
8	CLM - DRMS description
9	Billing – CSS upgrades quotation (Redacted)
10 (a,b,c,d,e)	BC – BCA Templates
11	BC – Tabors Caramanis Rudkevich (“TCR”) Study
12	BC – Avoided Energy Supply Costs in New England (“AESC”) 2015 Report
13	BC – TVR Concentric Energy Advisors Report
14	BC – TVR Analysis
15	DG – High level estimates (Redacted)
16	RD&D - Project Filtering and Scoring Methodology
17	RD&D – Project Sheets
18	RD&D – Business Investment Plan
19	MEO – Budget (Redacted)
20 (a,b,c,d)	MEO - Pricing quotations (Redacted)
21	Stakeholder Engagement –Attendee list for summits
22	Stakeholder Engagement – Themes from Stakeholder Engagement events
23	Customer Knowledge – Additional Information
24 (a,b)	RFP / RFI: - AMF/Comms/CLM RFP quotation (Redacted)
25 (a,b)	RFP / RFI: DSCADA/ADMS RFI quotation (Redacted)
26 (a,b,c,d)	RFP / RFI: Enterprise Architecture RFP quotation (Redacted)
27 (a,b,c,d,e)	RFP / RFI: GMP Implementation Partner Services RFP quotation (Redacted)
28	RFP / RFI: Opt-In scenario pricing quotation (Redacted)
29	Cybersecurity Budget (Redacted)

13.1 Glossary of Terms

AMF Advanced Metering Functionality - As defined in D.P.U. 12-76-B to include: (1) the collection of customers' interval usage data, in near real time, usable for settlement in the ISO-NE energy and ancillary services markets; (2) automated outage restoration and notification; (3) two-way communication between customers and the electric distribution company; and (4) with a customer's permission, communication with and control of appliances.

AMR Automated meter reading - Specially equipped metering devices that allows utilities to remotely collect kilowatt-hour use (and in some cases demand) information and transfer it to a central database for billing and/or analyzing purposes. Data, which flows just one way, can be gathered and sent via drive-by or walk-by readings as well as radio frequency, power line (note one word) carrier, telephone lines, or wireless systems.

AMI Advanced metering infrastructure - A comprehensive set of technologies and software applications that combine two-way communications with smart meters to provide electric utilities— using frequent meter reads—with near real-time oversight of system operations. Adding "ing" to "metering" has become the industry standard.

Benefit-cost ratio - Is an indicator, used in the formal discipline of cost-benefit analysis, that attempts to summarize the overall value for money of a project or proposal.

CAPEX Capital expenditures - Expenditures altering the future of the business. A capital expenditure is incurred when a business spends money either to buy fixed assets or to add to the value of an existing fixed asset with a useful life extending beyond the taxable year.

CGNMS The Cisco® Connected Grid Network Management System - (CG-NMS) is a software platform that will manage a multi-service network and security infrastructure for smart grid applications, including advanced metering infrastructure (AMI), distribution automation, distributed intelligence, and substation automation. CG-NMS is a scalable, highly secure, modular, and open-platform with an extensible architecture. CG-NMS is a multi-vendor, multi-service, communications network management platform that helps enable network connectivity to an open ecosystem of power grid devices.

CIS Comprehensive Integration Services - The integration services to enable the exchange of information between systems, services and devices.

CVR Conservation voltage reduction - A practice used by utilities to curtail load during periods of high electricity consumption, especially in emergencies where failure to take action could lead to cascading blackouts. Since watts equals volts times amps, CVR functions on the principle that by trimming volts a certain percentage you can also snip off watts. The preferred range for electric service is set at between 114 V and 126 V. Electric cooperatives, which often maintain long feeder lines, put a major focus on maintaining acceptable voltage levels. As a result, dropping voltage at a substation to perform CVR makes some cooperative engineers nervous. Now with the ability of advanced metering infrastructure systems to accurately monitor end-of-line voltage, CVR may become a more accepted way to ramp up demand-side management/load shaving efforts for very little added expense.

Cybersecurity - The process of protecting data and information systems from unauthorized access, use, disclosure, disruption, modification, or destruction. Critical infrastructure protection standards issued by the North American Electric Reliability Corporation are designed to defend bulk power systems from “cyber-tage.” Use as two words.

Direct Transfer Trip - Are initiated from station relays when a serious event occurs in the substation. Some of these events are breaker failure, bus faults, transformer failure, etc. A lockout relay (86 device) is assigned to each event.

EA Enterprise Analytics - The big data analytics capabilities to allow for the analysis of the data gathered from grid modernization investments combined with existing and third party data sources, providing valuable output reflecting current state as well as predictive and prescriptive outcomes.

FTE Full-time equivalent - Full-time equivalent (FTE) or whole time equivalent (WTE) is a unit that indicates the workload of an employed person (or student) in a way that makes workloads or class loads comparable across various contexts.

PI Database - the industry standard in enterprise infrastructure for management of real-time data and events.

PMO Project management office - a group or department within a business, agency or enterprise that defines and maintains standards for project management within the organization. The PMO strives to standardize and introduce economies of repetition in the execution of projects. The PMO is the source of documentation, guidance and metrics on the practice of project management and execution.

IT Information technology - the application of computers and telecommunications equipment to store, retrieve, transmit and manipulate data, often in the context of a business or other enterprise.

INOC Integrated Network Operations Center - To actively monitor, manage and maintain the integrated set of services and infrastructure and provide a single point of contact for support and operations through a cross functional set of people, processes and technologies.

ISO-NE ISO New England Inc. - an independent, non-profit Regional Transmission Organization (RTO), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

LAN Local area network - a computer network that interconnects computers within a limited area such as a residence, school, laboratory, or office building.[1] A local area network is contrasted in principle to a wide area network (WAN), which covers a larger geographic distance and may involve leased telecommunication circuits, while the media for LANs are locally managed.

MITRE The MITRE Corporation - An American not-for-profit organization based in Bedford, Massachusetts, and McLean, Virginia. It manages Federally Funded Research and Development Centers (FFRDCs) supporting the Department of Defense (DOD), the Federal Aviation Administration (FAA), the Internal Revenue Service (IRS), the Department of Veterans Affairs (VA), the Department of Homeland Security (DHS), the Administrative Office of the U.S. Courts on behalf of the Federal Judiciary, the Centers for Medicare and Medicaid Services (CMS), and the National Institute of Standards and Technology (NIST).

NPV net present value - calculation that compares the amount invested today to the present value of the future cash receipts from the investment. In other words, the amount invested is compared to the future cash amounts after they are discounted by a specified rate of return.

Recloser - A device that protects electric lines by momentarily interrupting service when a fault occurs, then restoring power automatically after the fault clears. This keeps outages from occurring when temporary problems arise, such as tree branches touching a line.

RFID Radio-frequency identification - the wireless use of electromagnetic fields to transfer data, for the purposes of automatically identifying and tracking tags attached to objects. The tags contain electronically stored information. Some tags are powered by electromagnetic induction from magnetic fields produced near the reader.

RF Mesh - a communications network made up of radio nodes organized in a mesh topology. It is also a form of wireless ad hoc network. Wireless mesh networks often consist of mesh clients, mesh routers and gateways.

RFP Request for Proposals - a solicitation, often made through a bidding process, by an agency or company interested in procurement of a commodity, service or valuable asset, to potential suppliers to submit business proposals.

SAP Accounting/ payment systems - SAP SE is a German multinational software corporation that makes enterprise software to manage business operations and customer relations.

SCADA Supervisory control and data acquisition - a system operating with coded signals over communication channels so as to provide control of remote equipment (using typically one communication channel per remote station).

SCCM **System Center Configuration Manager -** a systems-management software product developed by Microsoft for managing large groups of computers running Windows, Windows Embedded, Mac OS X, Linux or UNIX, as well as various mobile operating systems such as Windows Phone, Symbian, iOS and Android. Configuration Manager provides remote control, patch management, software distribution, operating system deployment, network access protection and hardware and software inventory.

SDLC **Systems development life cycle -** conceptual model used in project management that describes the stages involved in an information system development project, from an initial feasibility study through maintenance of the completed application.

WiMAX **Worldwide Interoperability for Microwave Access -** a wireless communications standard designed to provide 30 to 40 megabit-per-second data rates, with the 2011 update providing up to 1 Gbit/s for fixed stations.

ZigBee - a specification for a suite of high-level communication protocols used to create personal area networks built from small, low-power digital radios. ZigBee is based on an IEEE 802.15.4 standard. Its low power consumption limits transmission distances to 10–100 meters line-of-sight, depending on power output and environmental characteristics, ZigBee devices can transmit data over long distances by passing data through a mesh network of intermediate devices to reach more distant ones.

13.2 Glossary of Abbreviations Used in GMP

Abbreviation	Term
ADA	Advanced Distribution Automation
ADMS	Advanced Distribution Management System
AGA	American Gas Association
AMF	Advanced Metering Functionality
ANSI	American National Standards Institute
BCA	Benefit Cost Analysis
CAIDI	Customer Average Interruption Duration Index
CEATI	Centre for Energy Advancement through Technological Innovation
CES	Community Energy Storage
Cigre	The International Council on Large Electric Systems
CIP	Critical Infrastructure Protection
CLM	Customer load management
CMDB	Configuration Management Database
CMI	Customer Minutes of Interruption
CMS	Customer Meter Services

Company	Massachusetts Electric Company and Nantucket Electric Company d/b/a/ National Grid
CNI	Critical National Infrastructure
COTS	Commercial off the Shelf
CPNI	Center for Protection of National Infrastructure
CVR/VVO	Conservation Voltage Reduction/Volt-VAR Optimization
C&I	Commercial and Industrial Customers
DER	Distributed Energy Resource
DERMS	Distribution Energy Resource Management System
DES	Renewable-Integrated Distribution Energy Storage
DG	Distributed Generation
DHS	Department of Homeland Security
DLP	Data Leak Prevention
DOE	Department of Energy
D.P.U. 12-76-B	D.P.U. 12-76-B (June 12, 2014)
D.P.U. 12-76-C	D.P.U. 12-76-C (November 5, 2014)
D.P.U. 14-04-C	D.P.U. 14-04-C (November 5, 2014)
DPF	Distribution Power Flow
DRMS	Demand Response Management System
DR&S	Digital Risk and Security
DRIPE	Demand Reduction Induced Price Effects
DSCADA	Distribution Supervisory Control and Data Acquisition System
DTT	Direct transfer trip
EEI	Edison Electric Institute
EOPs	Electronic Standards and Electric Operating Procedures
EMS	Energy Management System
EPRI	Electric Power Research Institute
ESB	Enterprise Service Bus
ESRI	Environmental System Research Institute
ETR	Estimated Time of Restoration
FAN	Field Area Network
FLISR	Fault Location, Isolation and Service Restoration
GAPP	Generally Accepted Privacy Principles
GIS	Geographic Information System
GMP	Grid Modernization Plan
GWSP	Global Warming Solutions Act
HAN	Home Area Network
HIPPA	Health Insurance Portability and Accountability Act
IAM	Identity and Access Management
IaaS	Infrastructure as a Service

ICCP	Inter-Control Center Communications Protocol
ICE	Interruption Cost Estimate
IDS	Intrusion Detection Systems
IEEE	Institute of Electrical and Electronics Engineers
INOC	Integrated Network Operations Center
IS	Information Services
ISO-NE	Independent System Operator – New England
IT/OT	Information Technology/Operational Technology
Interconnection Tariff	The Company's Standards for Interconnection of Distributed Generation, M.D.P.U. No. 1248
LBNL	Lawrence Berkeley National Laboratory
MDMS	Meter Data Management System
MDS	Meter Data Services
MEO	Marketing, education and outreach
MITS	Meter Issues Tracking System
MPLS	Multi-Protocol Label Switching
National Grid	Massachusetts Electric Company and Nantucket Electric Company d/b/a/ National Grid
NAC	Network Access Control
NDA	Non-Disclosure Agreement
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NPCC	North Power Coordinating Council
Objectives	The Department's four objectives for grid modernization laid out in D.P.U. 12-76-B: (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.
OT	Operational Technology
O&M	Operations and Maintenance
Order	D.P.U. 12-76-B (June 12, 2014)
PaaS	Platform as a service
PCTs	Programmable Controlled Thermostats
Plan	Grid Modernization Plan
P2MP DTT	Point-to-Multi-Point Direct Transfer Trip
PMO	Project Management Office
RD&D	Research, development and deployment/pilot
RGGI	Regional Greenhouse Gas Initiative
SaaS	Software as a Service

SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency
SES	Smart Energy Solutions
SGAM	Smart Grid Architectural Model
SIEM	Security Information and Event Management
SOC	Secured Operations Centre
STIP	Short Term Investment Plan
TCR	Tabors, Caramanis and Rudkevich
TSCADA	Transmission SCADA system
TOU	Time of Use
T&D	Transmission and distribution
TSCADA	Transmission Supervisory Control and Data Acquisition System
TVR	Time varying rates
V2G	Vehicle-to-Grid
VVO	Volt/VAR Optimization
WACC	Weighted Average Cost of Capital
WAN	Wide Area Network
WTAM	Workforce, training and asset management