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

Grid Modernization Plan
Annual Report 2018

D.P.U. 15-120

May 1, 2019

Submitted to:
Massachusetts Department of
Public Utilities

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I. Introduction

On May 10, 2018, the Department of Public Utilities (the "Department") issued a decision (the "Order") approving in part the grid modernization plans ("GMPs") for Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid" or "Company"), Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), and NSTAR Electric Company d/b/a Eversource Energy ("Eversource") (together the "Electric Distribution Companies" or "EDCs"), in dockets D.P.U. 15-120, 15-121 and 15-122. In the Order, the Department pre-authorized grid-facing investments over three-years (2018-2020) for Eversource, National Grid and Unitil, respectively, and adopted a three-year (2018-2020) regulatory review construct for preauthorized Grid Modernization investments. Order at 106-115. The Order provided that the Companies will submit GMPs every three years, which will be addressed in separate proceedings, and that the Companies must submit "Grid Modernization Term Reports" at the end of each three-year term, which document performance during the term. Id. at 111-112. The Order also provided that the Companies must submit "Grid Modernization Annual Reports" to document performance during the applicable year and that these will be docketed for informational purposes only, but the DPU may formally investigate a company's performance during the term of the plan if the Department determines this is warranted. Id. These Grid Modernization Annual Reports were to be due on April 1 of the year following the first and second plan years. Id. at 114.

On January 10, 2019, the Department requested comments on the appropriate form and content of the annual report to be submitted by the Companies. Additionally, the Department requested comments on four reporting templates. The Companies and the Cape Light Compact JPE ("Compact") submitted initial comments on February 6, 2019. The Compact and the Department of Energy Resources ("DOER") submitted reply comments on February 20, 2019. On March 13, 2019, the Department held a technical conference regarding the Grid Modernization Annual Reports. At the technical conference, the Department presented a proposed outline and table of contents for discussion. Additionally, the Companies responded to DOER's February 20, 2019 reply comments.

In a Hearing Officer Memorandum dated March 29, 2019, the Department stated that because the form and content of the annual reports had not been finalized, the Department was extending the April 1, 2019 deadline for submission of the Grid Modernization Annual Reports for plan year 2018. The Department extended the deadline for the narrative section of the Grid Modernization Annual Reports, in accordance with an attached Grid Modernization Annual Report Outline/Table, to May 1, 2019. The Department stated it would establish the filing date for the remainder of the 2018 Grid Modernization Annual Reports in a subsequent procedural memorandum.

This filing is National Grid's first Grid Modernization Annual Report, which contains the narrative documenting the Company's performance on its Grid Modernization Plan for the time period May 10, 2018 through December 31, 2018 ("Report").

Key elements of the Department's Order approving in part the GMPs, and which are reflected in this Report, include:

- Objectives: The Department refined their grid modernization objectives to place additional focus on improved access to the distribution system planning process, to ensure a cleaner, more efficient and reliable grid.
- Grid-Facing Investments: The Department approved National Grid's proposed grid-facing investments and preauthorized $82 million in spending for these investments over three years from January 1, 2018 through December 31, 2020. The Department held that these investments may be treated as incremental to current investments if a "primary purpose" of the proposed investment is to accelerate progress in achieving the grid modernization objectives.
- Customer-Facing Investments: The Department did not pre-authorize: smart meters and Advanced Metering Infrastructure ("AMI") back office infrastructure; customer load management; communications and information/operational technologies related to AMI; cybersecurity related to customer-side investments; workforce training and asset management; marketing, education and outreach; and project management office.
- Cost Recovery: The Department approved a short-term targeted cost recovery mechanism, the Grid Modernization Factor ("GMF"), for pre-authorized grid modernization investments. This is a reconciling mechanism that: (1) includes both capital and operations and maintenance ("O&M") costs; (2) include incremental grid modernization costs that are prudently incurred, in service, and used and useful to customers; and (3) applies to investments made in the first six years of the GMPs only.

A. Progress Toward Grid Modernization Objectives

In the Order the Department refined its objectives for grid modernization, based on developments in the electric industry and its review of the Companies' GMPs, and described the objectives as follows:

1. Optimize system performance by attaining optimal levels of grid visibility, command and control, and self-healing;
2. Optimize system demand by facilitating consumer price responsiveness; and
3. Interconnect and integrate distributed energy resources.[1]

National Grid's GMP contained a comprehensive suite of investments and initiatives that will modernize the Company's infrastructure and deliver significant customer benefits, including

[1] Previously the Department had included a fourth objective, "improve workforce and asset management," as a stand-alone objective. In the Order the Department determined that this would be eliminated as a stand-alone objective and would be considered within the context of the other three objectives.

energy supply savings, reduced outage duration, reduced numbers of customers impacted by outages and improved system operations and system planning. Upon receiving the Order, National Grid reviewed the approved elements of the GMP in the context of the revised objectives, and aligned and revisited the plan elements in order to ensure progress towards the revised grid modernization objectives. With respect to optimizing system performance, the Company has progressed planning and engineering efforts for the selection of locations for both feeder monitors and advanced distribution automation. This also included a strategic assessment of the telecommunications information technology/operational technology ("IT/OT") approach for connecting, communicating and operating grid devices. The Company has also undertaken planning, analysis and identification of circuits to deploy Volt/VAR Optimization ("VVO"), which will help to optimize system demand. Lastly, the Company has progressed planning and design of the Advanced Distribution Management System ("ADMS")/Distribution Supervisory Control and Data Acquisition ("DSCADA") platform, which supports all three Grid Modernization objectives.

B. Summary of Grid Modernization Deployment (Actual v. Planned)

The Company's GMP organized its grid modernization investments into three primary groupings: (1) field deployments, (2) enabling infrastructure/initiatives and (3) other required components. Field deployments consist of devices and technology which are interconnected to the distribution system within the Company's service territory. These devices and technology provide benefits directly to the system and to customers, and are the GMP components with significant visibility. Enabling infrastructure is the required back office systems and field devices which enable these field deployed devices to operate, and enabling initiatives would include the project management office which will help with implementation. The other required components grouping included metrics and research, development and deployment ("RD&D").

The initial GMP timeline identified the installation of field equipment as beginning in year three of the GMP. During the first two years, National Grid will be installing the back-office IT infrastructure required to support the deployment, including the ADMS/DSCADA platform.

The original GMP was designed in the years 2014-2015. Due to the passage of time, the partial approval of the Company's proposed GMP investments, and the Department's revised objectives for Grid Modernization, during the time period May 10, 2018 through December 31, 2018 the Company focused on revisiting its GMP planning assumptions, timelines and enabling infrastructure requirements. This was necessary given that the customer-facing investments and enabling infrastructure/initiatives were not approved, and given that the Department approved a budget of up to $82 million for the grid-facing investments and provided the flexibility for the Company to shift spending among the preauthorized categories to respond to evolving conditions.

The Company has provided the summary of planned versus actual deployment of devices as of December 31, 2018 in Section IV.D.

National Grid laid out a five-year deployment effort to implement an ADMS and DSCADA system to support the increased number of distribution devices (including Fault Location, Isolation, and Servicer Restoration, or "FLISR"; Conservation Voltage Reduction ("CVR")/ VVO, telecommunications and feeder monitors) in the GMP (as well as Distributed Energy Resources, or "DERs") to meet the requirements for grid modernization. Laying out this deployment effort has been actively in the planning stages through the end of 2018.

C. Summary of Spending (Actual v. Planned)

The Department approved a budget of up to $82 million in incremental spending for grid-facing investments over three years. The investments' primary purpose must be to accelerate progress in achieving grid modernization objectives and they must be either (1) new types of technology or (2) an increase in the level of investment a company proposes relative to its current investment practices.[2] Incremental O&M expenses must be (1) incremental to the representative level of expenses recovered through rates, and (2) solely attributable to preauthorized grid modernization expenses.[3]

The Company filed its documentation for its incremental operations and maintenance ("O&M") costs for its GMP in CY 2018 of $98,935, in Docket D.P.U. 19-36. Due to the small amount of these costs, the costs did not generate a Grid Modernization Factor to bill to customers. The Company will not be seeking to begin recovery of these costs from customers until it makes its next Grid Modernization Factor filing on March 15, 2020. The Company will include these costs with the costs for CY 2019 for recovery through the Grid Modernization Factor that will go into effect beginning May 1, 2020.

The CY 2018 actual spending represents initial expenditures in the communications and information/operational technologies cost category. This category includes investments for additional backhaul networks, substation fiber installations, a multi-tiered field based wireless communication network, and radios for devices without embedded communications. This also includes integrating computer systems with communications infrastructure necessary to support the exponential increase in data and control.

The incremental CY 2018 spending was for a contractor who conducted a reassessment of the communications and IT/OT strategy and assumptions in the original GMP in light of the approvals granted (and not granted) and the passage of time since the initial GMP development. This reassessment will inform the planning and engineering effort to define the necessary network, computer and communications investments, and to develop the detailed plans to deliver these investments and capabilities to progress the Grid Modernization investments and objectives.

[2] Order at 221-222.

[3] Id.

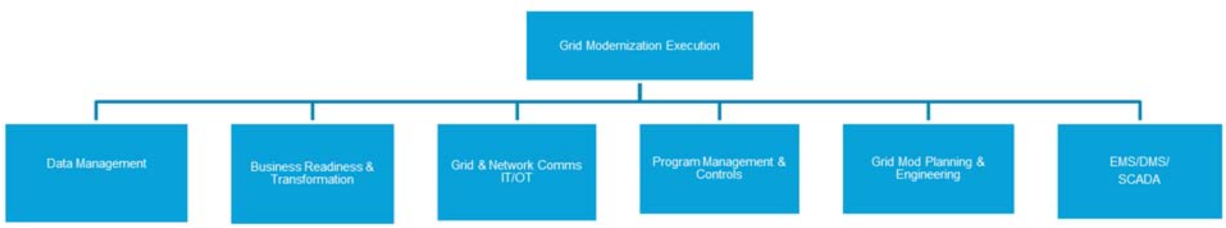
The Company has provided the summary of planned versus actual spending as of December 31, 2018 in Section IV.E.

II. Program Implementation Overview

A. Organizational Changes to Support Program Implementation

The Company has established a new organization to drive the delivery of the Grid Modernization program. The new organization is defined as Grid Modernization Execution. The Company then identified initial roles and capabilities to drive the delivery of grid modernization investments. The Company has been actively pursuing the right candidates to fill the organizational needs since August 2018. This activity will continue into calendar year 2019.

The Company has defined the organization to deliver on the core grid modernization investments, initiatives and capabilities, divided into the following areas listed below.



B. Cost and Performance Tracking Measures Adopted

The Company has developed protocols and measures for identifying and tracking incremental capital and O&M expenses. The Company will generate and manage grid modernization-specific work orders to distinguish the preauthorized grid modernization investments within the accounting system. The charges will be reviewed on a monthly basis for verification and any charges that are deemed unrelated to the eligible grid modernization investments will be reclassified to the appropriate organization.

The Department's Order provides that the Companies must demonstrate that all O&M expenses proposed for recovery through the GMF are: (1) incremental to the representative level of O&M expenses recovered through rates; and (2) solely attributable to preauthorized grid modernization expenses.[4]

[4] Order at 222.

This overarching two-prong test will be applied to all O&M expenses sought for recovery, including the two broad categories of: (a) internal O&M labor expenses; and (b) third-party/contractor costs. The Company also has established its own formal Project Management Office (PMO) and will drive GMP cost, performance and controls through the PMO.

The Company has actively engaged with Eversource and Unitil to develop, define and baseline both infrastructure and performance metrics described later in this Report. The joint utilities have also progressed the Evaluation Plan which will be formally filed on May 1, 2019.

C. Project Approval Process: Description and how it is different from process for standard capital investments

The Company recognized the requirement to maintain grid modernization investments separate from other capital investments, as described in the prior section. The Company also sought to maintain process efficiencies and alignment with core controls for progressing project approvals. The Company leveraged its existing sanctioning and approval process for capital investments, and applied this process to grid modernization investments as well. This ensures alignment with core controls and visibility of grid modernization investments for proper prioritization. The Company created separation and identification of these investments through separate but similar frameworks.

III. Implementation by Investment Category

A. System Level Narrative by Investment Category

The Department preauthorized the following categories of grid-facing investments for a combined three-year budget of $82 million: (1) VVO; (2) ADA; (3) feeder monitors; (4) communications and IT/OT; and (5) ADMS/SCADA.[5] National Grid's cost estimates for the proposed enabling infrastructure include: (1) a proposed budget of $48.4 million for three years for advanced distribution management systems/SCADA; and (2) a proposed budget of $1.8 million over three years for communications and information/operational technologies. Id. at 29, 35. National Grid's cost estimates for the proposed field deployments include: (1) $10.6 million over three years for deployment of VVO; (2) $13.4 million over three years for deployment of advanced distribution automation; and (3) $8 million over three years for feeder monitors.[6]

These investments and initiatives make progress on the Department's objectives for grid modernization in the following ways:

(i) They will optimize system performance by providing automated outage and restoration notifications, assisting with determining 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.

(ii) They will optimize system demand by creating a more efficient electric system with more real-time monitoring and control, better-managed system voltage and fewer losses. 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 interconnect and integrate DERs by providing more real-time information about the distribution system. The increased operational system awareness from the deployment of feeder monitors, ADA and CVR/VVO will collectively allow for much more data to be used when determining distributed generation ("DG") impact studies. The ADMS/DSCADA solution will enable advanced applications and distribution load flow to help manage circuit performance and the optimization of DERs.

[5] D.P.U. 15-120, Grid Modernization Plan (filed June 14, 2016) at 29, 32, 35, Atts. 3, 5; Order at 154-155.
[6] D.P.U. 15-120, Grid Modernization Plan (filed June 14, 2016) at 29, 32, 35, Atts. 3, 5; Order at 155, n. 81.

(1) Volt Var Optimization (VVO)

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.

(a) Description of Work Completed

The Company revisited the initial planning assumptions for VVO provided in the original GMP. The Company undertook an assessment and analysis to identify potential feeders to be selected using a data model containing the following information:

- Physical characteristics
- Number of customers and benefit potential
- Historic and projected loading and capacity
- 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. 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 VVO on those feeders and expected higher MWh savings. The timing of deployment of VVO has been reviewed within the context of other elements of the GMP, including the enabling communications infrastructure and ADMS/DSCADA efforts.

The GMP proposed 16 feeders within the first three years of the plan. The Company is performing a review of the highest value feeders from the assessment, and once target feeders are selected, will initiate an engineering effort. The Company has identified two substations with a total of eight feeders that it will initially pursue in 2019. Upon completion of the engineering, a formal sanction will be progressed. This is expected to occur in May 2019.

(b) Lessons learned/challenges and successes.

While the Company has not initiated deployment in 2018, the Company has leveraged the Volt Var Optimization Program conducted by the Company's affiliate in Rhode Island,[7] Narragansett Electric Company d/b/a National Grid, to inform the Company's GMP efforts in Massachusetts. Some of the key lessons learned include selecting reliable telecommunications solutions that

[7] R.I. P.U.C. Docket 4592 - FY 2017 Electric Infrastructure, Safety, and Reliability Plan Volt Var Optimization Pilot.

provide good quality of service for device level communications and coordination of the work, resources, and scheduling throughout execution and implementation across multiple departments.

(c) Actual vs. planned implementation and spending, with explanations for deviation and rationale.

During the time period of May 10, 2018 through December 31, 2018 the Company focused on revisiting its GMP planning assumptions, timelines and initial plans for deploying VVO and enabling infrastructure requirements. The Company did not plan for device implementation or spending in 2018.

(d) Performance on implementation/deployment.

The Company did not deploy VVO capabilities in 2018.

(e) Description of benefits realized as the result of implementation.

Since the Company did not deploy VVO during 2018, the Company has not realized any benefits during 2018. The benefits of the deployment of VVO are expected to include:

- Improved feeder power factor
- Flatter voltage profiles
- Reduced feeder losses
- Reduced peak demand and reduced energy consumption by customers
- Reduction in greenhouse gas (GHG) emissions
- Improved management of the distribution system which will assist in the integration of distributed resources
- Improve feeder voltage performance
- Improved system awareness into the daily operations and planning processes

(f) Description of capability improvement by capability/status category.

The Company has not actively installed or deployed VVO on circuits during 2018.

(g) Key milestones.

Milestone	Target Date
Complete Project Sanction	May 2019
Engineering Completed	Substation/feeder specific
Design Completed	Substation/feeder specific
Construction Completed	Substation/feeder specific
In service date	Substation/feeder specific

(h) Updated projections for remainder of the three-year term.

The Company is forecasting completion of 16 feeders during the three-year plan period. Device specific projections can be found in Section IV.D.

(2) Advanced Distribution Automation

ADA is a Fault Location, Isolation and Service Restoration ("FLISR")-based advanced distribution automation program where sectionalizing protection equipment is automated and controlled in a coordinated manner, to minimize the effects of outages. 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. The Company also has limited FLISR capabilities still active within the Worcester Smart Energy Solutions Pilot area. The ADA scheme will replace manual tie points between adjacent feeders, to provide for downstream restoration. It also will integrate enhanced telecommunications and additional control on existing protective switches, and potentially add switch locations as necessary to optimize system reliability.

(a) Description of work completed.

The GMP proposed 16 feeders within the first three years of the plan. The Company is performing a review of the candidate feeders, and once they are selected, will initiate an engineering effort.

(b) Lessons learned/challenges and successes.

Although the Company has not initiated deployment, it intends to leverage the lessons learned from its Worcester Smart Energy Solutions Pilot ("Pilot") which deployed ADA. The key learnings from the grid-facing portions of the Pilot include:

- The importance of ensuring the communications network required to support grid devices is installed, tested and enabled to provide for an efficient deployment and commissioning of distribution automation;

- The need for a broader set of employee roles and capabilities than exists in the current utility workforce, in order to deliver and manage this new, enhanced equipment and technologies;

- Supporting a hybrid grid communications strategy where a combination of WiMax, cellular, 900Mhz and other solutions can coexist to provide options for connecting to devices when circumstances require it; and

- The need to establish an independent data analytics solution and information repository for the engineering data required to support the evaluation plan and perform advanced engineering analysis.

(c) Actual vs. planned implementation and spending, with explanations for deviation and rationale.

The Company did not plan for installation of ADA in 2018 and has not actively installed or deployed ADA on circuits during 2018. The Company did not progress specific spending for the 2018 annual report period.

(d) Performance on implementation/deployment.

The Company did not plan for deployment of ADA in 2018 and has not actively installed or deployed ADA on circuits during 2018.

(e) Description of benefits realized as the result of implementation.

There are no benefits realized for this annual reporting period. The benefits of ADA are expected to include:

- Optimizing system performance – 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 system demand – The additional operational data collected by the automated switches will support the improved management of the distribution system, assisting in demand optimization.

- Interconnecting and integrating distributed energy 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.

(f) Description of capability improvement by capability/status category (e.g., VVO-enabled, Fully Automated, ADMS Load Flow Modelling, Control Functions, Reduced Zone Size).

The Company has not actively installed or deployed ADA on circuits during 2018.

(g) Key milestones.

Milestone	**Target Date**
Complete Project Sanction	April 30, 2019
Engineering Completed	Feeder/Device specific
Design Completed	Feeder/Device specific
Construction Completed	Feeder/Device specific
In service date	Feeder/Device specific

(h) Updated projections for the remainder of the three-year term.

The Company is forecasting deployment of 70 advanced reclosers during the three-year plan period. Device specific projections can be found in Section IV.D.

<u>(3) Feeder Monitors</u>

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.

National Grid has over 1,100 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 Department's objectives for gird modernization.

(a) Description of work completed.

The Company has reviewed the population of feeders, with a focus on overhead feeders, 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 will 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. The Company has undertaken a planning assessment to prioritize the deployment of feeder monitors through the three-year period.

(b) Lessons learned/challenges and successes.

The Company has not actively installed or deployed feeder monitors on circuits during 2018. Therefore, there are not yet immediate lessons learned.

(c) Actual vs. planned implementation and spending, with explanations for deviation and rationale.

The Company did not plan for deployment of feeder monitors during 2018 and has not actively installed or deployed feeder monitors on circuits during 2018. The Company did not progress specific spending for the 2018 annual report period.

(d) Performance on implementation/deployment.

The Company did not plan for deployment of feeder monitors during 2018 and has not actively installed or deployed feeder monitors on circuits during 2018.

(e) Description of benefits realized as the result of implementation.

The Company has not actively installed or deployed feeder monitors on circuits during 2018. Installing feeder monitors will provide real-time data while building historic data on the Company's distribution system and will assist in more efficient operation and maintenance, planning and storm recovery, in furtherance of the Department's objectives for grid modernization.

(f) Description of capability improvement by capability/status category (e.g., VVO-enabled, Fully Automated, ADMS Load Flow Modelling, Control Functions, Reduced Zone Size).

This information will be provided in future reports after deployment.

(g) Key milestones.

Milestone	**Target Date**
Complete Project Sanction	April 30, 2019
Engineering Completed	Device dependent
Design Completed	Device dependent
Construction Completed	Device dependent
In service date	Device dependent

(h) Updated projections for remainder of the three-year term.

The Company is still targeting completion of 180 feeder monitors during the three-year plan period. Device specific projections can be found in Section IV.D.

(4) Communications and Information/Operational technologies

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 grid automation controls, field sensors, and substations.
- 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 telecommunications network will be comprised of two main layers. The Field Area Network ("FAN") will provide "last mile" communications to the end devices. Field-installed grid controls are the endpoints on this network layer. The Wide Area Network ("WAN") provides the backbone and ties the end devices to major field communications nodes and ultimately the ADMS and back end data systems. Substations and other Company facilities make up the major nodes of the WAN.

(a) Description of work completed.

In anticipation of Grid Modernization, the Company undertook a strategic assessment of the operational telecommunications during 2017. This initial assessment identified technologies and opportunities for progressing grid modernization investments. During 2018, the Company leveraged that strategic assessment to identify specific elements were critical investments for progressing the GMP.

(b) Lessons learned/challenges and successes.

The Company has not actively installed or deployed communications or OT/IT on circuits during 2018. Therefore, there are no immediate lessons learned.

(c) Actual vs. planned implementation and spending, with explanations for deviation and rationale.

The Company had limited spending for the 2018 annual report period. It initially estimated an early start for specific resources when proposing the spend. The Company had not planned for implementation and deployment during 2018.

(d) Performance on implementation/deployment.

The Company had not planned for implementation and deployment in 2018.

(e) Description of benefits realized as the result of implementation.

The Company had not planned for implementation in 2018. Communications and OT/IT are enabling technologies that will enable the benefits to be realized through the other technologies to be installed as part of the GMP.

(f) Description of capability improvement by capability/status category (e.g., VVO-enabled, Fully Automated, ADMS Load Flow Modelling, Control Functions, Reduced Zone Size).

The Company has not actively installed or deployed communications or OT/IT on circuits during 2018. Therefore, there is no capability improvement to report on yet.

(g) Key milestones.

Milestone	**Target Date**
Complete Project Sanction	January 24, 2019
Engineering Completed	Location/device dependent
Design Completed	Location/device dependent
Construction Completed	Location/device dependent
In service date	Location/device dependent

(h) Updated projections for remainder of the three-year term.

The Company is still targeting completion of telecommunications enablement for all installed grid devices identified during the three-year plan period.

<u>(5) ADMS/DSCADA</u>

Currently, National Grid operates an Energy Management System ("EMS") and a SCADA system. SCADA is a database where information is acquired from remote devices and stored in a centralized location. An ADMS will work with a distribution SCADA ("DSCADA") system just like an EMS works with a SCADA system. The ADMS will be dedicated to the distribution network, whereas the EMS will be devoted to the transmission system. The overall project is expected to take up to five years before fully implemented.

This project will implement a phased approach for rolling out an ADMS which includes implementing distribution management system applications ("DMS") and a future upgrade to the existing Outage Management System ("OMS") production system into one common platform and network model. The project will implement a DSCADA system by splitting the present SCADA system into separate transmission and distribution platforms. The resulting DSCADA system will be fully integrated with the DMS/OMS, creating one common model integrated ADMS.

The ADMS/DSCADA will consist of a set of advanced distribution network applications and integrated outage management functionality. This will be a multi-phased initiative guided by the following steps:

- Providing system infrastructure, baseline monitoring and functionality, sizing and scalability to provide operational benefits.

- 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

(a) Description of work completed.

The Company has completed an analysis and scoping effort for the development of the ADMS and DSCADA effort. The Company is progressing formal sanctioning and has issued RFPs for both a business integration and system integration partner.

(b) Lessons learned/challenges and successes.

In 2016, a National Grid Control Centers Roadmap effort was undertaken with a third-party consultancy to develop a framework and roadmap to enable the implementation of platforms and tools to satisfy the needs of today and support the operations vision of the future.

In 2016, a DMS pilot project was carried out to help understand the Company's present vendor's capabilities as well as internal changes required to support a full-scale rollout of ADMS functionality.

The two efforts summarized above helped to define our approach to implement a common vendor platform for ADMS as well as validate product roadmaps and define supporting systems and resource requirements for this full ADMS implementation.

(c) Actual vs. planned implementation and spending, with explanations for deviation and rationale.

The Company did not progress specific spending on the ADMS/DSCADA investment category for the 2018 annual report period. The Company had not planned to install ADMS/DSCADA in 2018.

(d) Performance on implementation/deployment.

The Company has not actively installed or deployed ADMS/DSCADA investments during 2018. Therefore, there is no performance on implementation and deployment for this annual reporting period. The Company had not planned to install ADMS/DSCADA in 2018.

(e) Description of benefits realized as the result of implementation.

The Company has not actively installed or deployed ADMS during 2018. The Company had not planned to install ADMS/DSCADA in 2018. Therefore, there are no benefits realized for this annual reporting period.

(f) Description of capability improvement by capability/status category (e.g., VVO-enabled, Fully Automated, ADMS Load Flow Modelling, Control Functions, Reduced Zone Size).

The capability improvements expected to accrue during the initial phase of the ADMS/DSCADA solution include:

- Expanded situational awareness and visibility of future predicted states with respect to system operations

- ADMS will create a platform to enable utilization of exponential growth of remote monitoring, control and distribution automation

- Enable system operations to maintain or improve reliability under the growing system complexities associated with the integration of DER

- Provide Control Center Operations advanced monitoring visualization capabilities to assist in operating the system in real time and contingent conditions

- Assist in creating efficient system operations and the potential to defer capital investments where possible

- Enable advanced applications and distribution load flow to help manage circuit performance and the optimization of DERs.

(g) Key Milestones.

Milestone	**Target Date**
Complete Project Sanction	April 22, 2018
Begin Requirements and Design	May 2019
Begin Development and Implementation	January 2020
Begin User Acceptance Testing	September 2020
Move to Production / Go Live	December 2020

(h) Updated projections for remainder of the three-year term.

Specific projections are provided in section IV.D and IV.E. The Company is targeting roll out of the initial phase of capabilities of ADMS for December 2020.

B. Feeder Level Narrative by Investment Category

1. For each investment category:

a. Highlights of feeder level implementation

b. Feeder level lessons learned/challenges and successes

During calendar year 2018, the Company has undertaken a distribution planning effort to identify the feeders and locations to pursue investments in grid modernization looking to balance the overall objectives and the benefits. In future year's reports, a feeder level narrative on progress in implementation along with lessons learned, challenges and successes will be available. National Grid does not have additional feeder-level detail, by investment category, to provide at this time.

Independent of the GMP, the Company has had experience in installing and operating the core distribution devices that also are part of the GMP. Specifically, the Worcester Smart Energy Solutions Pilot[8] in Massachusetts and the Volt Var Optimization Program conducted by the Company's affiliate in Rhode Island,[9] Narragansett Electric Company d/b/a National Grid, have informed the Company's GMP efforts in Massachusetts.

[8] See Docket D.P.U. 10-82, National Grid Smart Energy Solutions Pilot Final Grid Evaluation Report (June 28, 2017).

[9] R.I. P.U.C. Docket 4592 - FY 2017 Electric Infrastructure, Safety, and Reliability Plan Volt Var Optimization Pilot.

IV. Description and Report on Each Infrastructure Metric

A. Grid-Connected Distributed Generation Facilities

One of the primary objectives of grid modernization is to facilitate the interconnection of distributed energy resources ("DER") and to integrate these resources into National Grid's planning and operations processes. This infrastructure metric quantifies the DER units connected to the Company's system on a circuit level and substation level. It is important to note that DER developers' decisions regarding DER interconnection may be influenced by tax incentives, subsidies, and costs and availability of the technology, which, in turn, will influence these metrics.

The table below lists the number of DERs connected to the Company's distribution system as of December 31, 2018.

Fuel Type	Total Units	Nameplate AC Rating(kW)	Capacity Factor	Est Annual Output
Biogas	6	2,730	73.3%	17,529,548
Diesel	5	1,675	40.0%	5,869,200
Electricity	1	1,200	-	-
Fuel Oil	2	5,350	40.0%	18,746,400
Hydro	10	5,087	37.4%	16,666,233
Landfill Gas	7	17,230	73.3%	110,635,208
Methane	1	280	57.6%	1,412,813
Natural Gas	148	76,582	57.6%	386,412,879
Propane	2	10	57.6%	50,458
Solar	47,403	1,038,829	13.4%	1,215,141,967
Solar and Battery Storage	126	1,888	13.4%	2,207,707
Energy Storage	1	500	-	-
Wind	56	21,813	37.4%	71,464,623
Grand Total	47,768	1,173,174		1,846,137,035

The nameplate rating as a percent of the Massachusetts National Grid summer adjusted peak load is 24.2%. The Company is actively validating the substation and circuit level details.

B. System Automation Saturation

This infrastructure metric for system automation saturation measures customers served by fully automated or partially automated device. The terms "fully automated" and "partially automated" refer to feeders for which National Grid has attained optimal or partial, respectively, levels of visibility, command and control, and self-healing capability through the use of automation.

National Grid has initially calculated the system automation saturation to be 505. The Company is actively validating circuit level details and will provide feeder specific levels with the performance metrics.

C. Number/ Percentage of Circuits With Installed Sensors

This metric measures the total number of electric distribution circuits with installed sensors which will provide information useful for proactive planning and intervention. The installation of sensors provides the means to enable proactive planning and to measure a number of grid modernization initiatives such as VVO and asset management. A sensor analytics development program is an essential part of grid modernization and provides the visibility into network operations needed to move toward an effective grid modernization program.

National Grid has initially calculated the percentage of circuits with installed sensors at 66%. The Company is actively validating circuit level details and will provide feeder specific levels with the performance metrics.

D. Number of Devices or Other Technologies Deployed

These metric measures how National Grid is progressing with its GMP from an equipment and/or device standpoint. The number of devices installed will be compared to the total number of devices planned by circuit for each investment.

NUMBER OF DEVICES OR OTHER TECHNOLOGIES DEPLOYED

			Planned			Actual	Deviation
Category	**Investment**	**3-Year Quantity**	**2018**	**2019**	**2020**	**2018**	**2018**
VVO	Capacitor Banks	100	0	40	60	0	0
VVO	Line Sensors	32	0	12	20	0	0
VVO	Regulators	16	0	8	8	0	0
VVO	LTC Controls	12	0	6	6	0	0
Communications	Number of Nodes	410	0	204	206	0	0
Communications	Miles of Fiber	5	0	0	5	0	0
Distribution Automation	Reclosers	70	0	20	50	0	0
Sensors	Feeder Monitors	180	0	80	100	0	0
ADMS/DSCADA	RTU	95	0	40	55	0	0

E. Associated Cost for Deployment

This metric measures the associated costs for the number of devices or technologies installed and is designed to measure how National Grid is progressing under its GMP. The cost of devices installed will be compared to the total cost of devices planned by circuit for each investment.

ASSOCIATED COST FOR DEPLOYMENT ($m)

			Planned			Actual	Deviation
Category	**Investment**	**3-Year Quantity**	**2018**	**2019**	**2020**	**2018**	**2018**
VVO	Capacitor Banks	$ 5.00	$ -	$ 2.00	$ 3.00	$ -	$ -
VVO	Line Sensors	$ 0.64	$ -	$ 0.24	$ 0.40	$ -	$ -
VVO	Regulators	$ 3.20	$ -	$ 1.60	$ 1.60	$ -	$ -
VVO	LTC Controls	$ 2.72	$ -	$ 1.36	$ 1.36	$ -	$ -
Communications	Number of Nodes	$ 4.60	$ 0.50	$ 2.04	$ 2.06	$ 0.10	$ 0.40
Communications	Miles of Fiber	$ 5.00	$ -	$ -	$ 5.00	$ -	$ -
Distribution Automation	Reclosers	$ 6.89	$ -	$ 2.54	$ 4.35	$ -	$ -
Sensors	Feeder Monitors	$ 3.96	$ -	$ 1.76	$ 2.20	$ -	$ -
ADMS/DSCADA	RTU	$ 7.38	$ -	$ 4.10	$ 3.28	$ -	$ -
ADMS/DSCADA	DMS	$ 30.30	$ -	$ 10.10	$ 20.20	$ -	$ -
ADMS/DSCADA	GIS	$ 5.00	$ -	$ 2.50	$ 2.50	$ -	$ -

F. Reasons for Deviation Between Actual and Planned Deployment for the Plan Year

This metric is designed to measure how National Grid is progressing under its GMP on a year-by-year basis. The quantity and cost of devices or technology installed in a given GMP investment year will be compared on a year-by-year basis and any variations will be quantified and addressed.

The Company did not plan for deployment of any devices during the plan year 2018. The Company intended to progress expenditures in telecommunications to validate and update the study performed in 2017.

G. Projected Deployment for the Remainder of the Three-Year (2018-2020) Term

This metric is designed to show National Grid's projected deployment for the three-year term under its GMP on a year-by-year basis. The year-by-year investment plan is subject to change based upon the quantity of work completed, the availability of the technology, material lead times, contractor availability, etc. The revised investment plan each year will be used as the basis for projecting the following year's GMP work. The table below presents National Grid's projected deployment for 2019 and 2020.

NUMBER OF DEVICES OR OTHER TECHNOLOGIES DEPLOYED

			Planned	
Category	**Investment**	**3-Year Quantity**	**2019**	**2020**
VVO	Capacitor Banks	100	40	60
VVO	Line Sensors	32	12	20
VVO	Regulators	16	8	8
VVO	LTC Controls	12	6	6
Communications	Number of Nodes	410	204	206
Communications	Miles of Fiber	5	0	5
Distribution Automation	Reclosers	70	20	50
Sensors	Feeder Monitors	180	80	100
ADMS/DSCADA	RTU	95	40	55

V. Distributed Energy Resources ("DERs")

A. Overview of DERs on Distribution System

The Company currently has over 47,000 interconnected DER's on its system with a total nameplate capacity of 1,713 MW. The drivers of DERs continue to be state and federal incentives to promote renewable energy, utility tariffs that authorize net metering and virtual net metering, overall market developments, and reductions in cost of solar PV technology, among other factors. Many of the programs initiated to progress the market for DERs continue to incent the pursuit of DER interconnection requests. The Company currently has over 4,800 active applications representing an incremental 1.3 GW. Over 3,500 of the active applications were driven through the new SMART Program representing over 678 MW in the application process.

B. Lessons Learned Integrating DERs

The Company continues to progress and support requests for interconnections. While the Company continues to evolve its understanding of the dynamics and impacts of DERs on the distribution system, the following areas represent learnings that are being incorporated into the Grid Modernization Plan.

LESSON: Planning and operating with intermittent loads requires upgraded modeling tools and systems.

Planning of the electric distribution system has traditionally focused on the long-term delivery of electricity to meet the high reliability expectations of a utility's customers. Forecasts are applied to system models to predict system concerns. However, with widespread distributed generation, electric vehicles, and heat electrification, these forecasts become more complicated and have more complex variables. As a result, existing planning tools and approaches are insufficient to incorporate the necessary forecast details. For example, the current tools and approaches consider distributed generation as a load adjustment as there is no current method for forecasting. Operating the distribution system becomes similarly complicated. For example, operators must become proficient in short-term predictions for distributed generation and vehicle charging. National Grid does not have the tools, programs, or information necessary to complete such tasks today. Furthermore, the traditional one-way power flow and sequential protection scheme made efficient operation possible with limited sensors and information. Under future load scenarios that result in two-way power flow and a reversal of protection schemes, the existing operating tools and technologies become insufficient.

The planning and operational complexities associated with DER integration can be linked to near term and far term grid modernization concepts. Some planning tools are being researched and obtained to facilitate the interconnection analysis. These same tools would be useful for grid modernization analysis. For example, tools that can properly model DER voltage performance could also be used to model Volt-VAR optimization algorithms. Operational improvement is more complicated and perhaps far term due to the significant back-office and communications requirements. However, the sensing provided by many grid modernization technologies, such as advanced reclosers, capacitors, and feeder monitors, is a step towards providing the control centers information for improved DER management.

LESSON: Thermal and voltage management becomes more complex.

Proper thermal and voltage performance is necessary to ensure the reliability of the electric distribution system. Thermal performance ensures that the utility's equipment does not degrade or fail during normal or contingency situations. Voltage performance ensures that the utility is delivering energy within a range suitable for the safe and efficient operation of customers' end use equipment. Proper thermal and voltage performance could traditionally be accomplished by focusing on the peak loading period, which has the highest loading and greatest voltage drop. Historically, planning the distribution system to accommodate annual peak loads would ensure reliable operation throughout the year. Therefore, system models were created, and tools developed to focus on peak loading analysis. However, with widespread distributed generation and electric vehicle charging, loading and voltage becomes more dynamic over the course of a year. For example, controlling or preventing overvoltage during high generation/light load periods such as in the Spring and Fall daylight hours is becoming increasingly difficult. Some fixed assets need to be replaced with switchable equipment and certain controls need to be replaced with more sophisticated versions.

The technologies included in the Grid Modernization Plan link directly to this DER integration issue. Assets such as capacitors will be switched from a fixed to a switched configuration as part of a Volt-VAR optimization program. In addition, the sensing provided by a number of grid modernization assets will be an important part of thermal and voltage management.

LESSON: Reverse power flow requires upgraded controls.

Reverse power flow has a significant impact on distribution and transmission electrical systems. For example, voltage regulators and transformer load tap changers undercorrect voltage levels under reverse power flow conditions. The controls for these devices must be upgraded to allow for bidirectional power flow. Similarly, protection devices have settings to isolate portions of the system during fault conditions. These setting are carefully selected to avoid mis-operation for high load levels yet maximize protection speed. Reserve power flow can impact this balance and require devices that can accommodate reverse power flow settings. Additional impacts are described in the fault current section below.

The advancements in the Grid Modernization Plan link directly to this DER integration issue. Regulator and transformer load tap changer control upgrades might be required as part of a Volt-VAR optimization program. The upgraded controls would include reverse power functionality. Similarly, advanced reclosers would include primary and alternate settings capabilities. However, there is significant protection procedure analysis to be done before such functionality is enabled. Again, the sensing provided by a number of grid modernization assets will play an important role in identifying and managing the power flow direction at any given point in time.

LESSON: DER intermittency can lead to power quality/flicker issues.

A sudden drop in solar or wind resources due to changing weather characteristics can create power quality issues such as voltage flicker. As these resources become more concentrated the same cloud cover or wind drop can affect multiple generators compounding the impact. National Grid has created long-term dynamic analysis methods to best evaluate this problem but has limited options to mitigate the voltage flicker.

The current Grid Modernization Plan does little to mitigate this DER integration issue. The planned sensor response times are intended to address and inform on steady state system characteristics. Sub-second sensing for dynamic issues such as flicker would be a far term grid modernization concept. However, the current Grid Modernization Plan does provide a basis to integrate future technologies that could mitigate flicker such as smart inverters and paired energy storage.

LESSON: DER can affect fault current levels and fault current direction requiring complex analysis and complex protection systems.

Fault current is the level of current or power associated with a fault on the electric system. The amount of fault current plays an important role in protection system coordination and arc flash analysis. Protective device operating characteristics have an inverse relationship between time and fault current levels. The higher the fault current, the less time the protective devices takes to open. This timing must be carefully coordinated so that for a given fault the closest protective device operates keeping the isolated area as small as possible. DER can change the fault levels and direction such that certain devices operate slower than intended which could lead to mis-operation or mis-coordination. These existing protective devices must be changed or reset to reestablish proper coordination. It is anticipated that these devices will require multiple setting capabilities or adaptive setting capabilities.

Arc flash is a related phenomenon influenced by fault current levels and protection timing. Arc flash levels are assessed to evaluate the potential worker safety risks and are a key consideration in the development of personal protection equipment requirements and operating standards for utility and customer owned equipment. High current levels and long protection times can result in increased energy levels for nearby workers. Each distributed generator acts as a new source of fault current increasing the fault energy. However, the distributed generator can also change or split the direction of fault flow slowing down existing protection schemes. Cases where fault energy is increased and protection systems are desensitized or slowed present the greatest arc flash concerns. Furthermore, reanalysis may be necessary when certain size generators are interconnected or disconnected.

DER can also impacts transmission ground fault detection. In certain system configurations, DER can remain energized following a transmission fault. This can lead to equipment damage and presents a safety concern. Zero sequence voltage protection (commonly referred to as “3V0”) is required in order to detect and isolate this issue.

Similar to the reverse power flow discussion, the advancements in the Grid Modernization Plan link directly to the DER integration issues described above. The advanced recloser controls would include primary/alternate settings and remotely programmable setting capabilities. Remotely programmable settings tied to an advanced control center management system is a step towards adaptive protection settings. However, there is significant protection procedure analysis to be done before such functionality is enabled. Lastly, grid modernization sensing which would inform the control center systems on connected DERs, and thereby inform on possible fault current levels will play an important role in developing the adaptive settings to send to the reclosers.

VI. Metrics

A. Description and Report on each Performance Metric

The proposed performance metrics are under review by the Department, and pursuant to the March 29, 2019 Hearing Officer Memorandum in dockets D.P.U. 15-120, 15-121 and 15-122, the Department has not yet established a filing deadline for reporting on performance metrics.

B. Lessons Learned/Challenges and Successes

Please see Section VI.A above.

C. Hosting Capacity Analysis Update

In their filed initial GMPs, the Company described investments that would support the development of hosting capacity maps. The Department, in limiting its approved GMP investments to grid-facing investments, did not authorize the inclusion of hosting capacity map-related investments in the GMPs.[10] Instead, the Department noted that it would open a separate proceeding into the investigation of cost-effective deployment of customer-facing grid modernization investments.[11] Accordingly, the Companies, following the issuance of the order, shifted their attention and resources to implementing their approved grid modernization investments.

In addition, the Act to Advance Clean Energy, St. 2018, c. 227, §18, requires the Companies to file an annual electric distribution system resiliency report with the Department, which shall include heat maps that: (i) show the electric load on the electric distribution system, including electric loads during peak electricity demand time periods; (ii) highlight the most congested or constrained areas of the electric distribution system; and (iii) identify areas of the electric distribution system most vulnerable to outages due to high electricity demand, lack of local electric generating resources and extreme weather events.

Following the March 14, 2019 technical session on the proposed Grid Modernization Annual Report templates, the Department issued a Memorandum on March 19, 2019 requiring the Companies to make certain revisions to the grid modernization performance metrics as originally filed on August 15, 2018. As part of the performance metric reporting in the Annual Grid Modernization Reports, the Department also required the Companies to provide details of their hosting capacity analyses, including the feeder hosting capacity data, for each feeder and substation within their service territories in 2018, 2019, and 2020. Memorandum at 6.

Given that the Companies' proposed hosting capacity investments were not approved as part of the 2018-2020 GMPs, the Companies have not progressed hosting capacity analyses as part of

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[10] Order at 134, n. 70.

[11] Id. at 135.

their GMPs. As described in the GMP, investments planned over the course of the 2018-2020 GMPs in system visibility and load flow model capabilities are required in order for the Companies to calculate detailed hosting capacity values. In addition, the Companies need to work collaboratively with the stakeholders to communicate assumptions and hosting capacity calculation methodologies. This is required so stakeholders that are using the hosting capacity calculations have a common understanding of the approach as they interpret the information provided by the Companies.

The Companies proposed to provide the Department and stakeholders with an update on the status of hosting capacity within their respective Grid Modernization Annual Reports. The narrative status update would be supported with a schedule of when each substation and feeder is projected to be ready for a hosting capacity analysis. The Distribution Companies proposed to include the hosting capacity value for those feeders where the models and data is available. The Distribution Companies would also submit a schedule of when they would be able to provide a hosting capacity value for those feeders where the models and data to calculate hosting capacity does not currently exist.

The Company is actively reviewing the requirements for developing hosting capacity along with the recent requirements to file an electric distribution system resiliency report to define and develop a plan and schedule for providing both hosting capacity and heat maps. The Company has undertaken similar efforts in other jurisdictions and will seek to leverage that experience. Once a possible solution and tool is developed, the Company will be able to provide a schedule for every substation and feeder.

As was clear from the discussion at the March 19, 2019 technical session, the Distribution Companies, the Department, the DOER and other stakeholders are interested in developing robust, comprehensive and useful hosting capacity maps to assist in the interconnection of DG facilities

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 and interconnection of new DG. The Company anticipates the need to invest in advanced analysis for the investigation of DG hosting capacity.

National Grid proposed 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. The Company has developed similar tools for their New York and Rhode Island service areas. Tools will also require data collection and clean-up and possibly integration with internal systems to provide the most up-to-date distribution system information possible. The Company anticipates this may take as long as a year to develop for all substations and feeders.

VII. Research, Development and Deployment

An effective research and development ("R&D") program is a critical element supporting the development of a modern grid that progresses the Department's grid modernization objectives. While the Company's Research, Development and Deployment ("RD&D") proposals included in its filed GMP were not approved, the Company has continued to engage in research activities at similar levels as it has in the past outside of its GMP.

The R&D program at National Grid focuses its activities in areas where opportunity exists for enhanced performance or where disruptive factors may influence the operation of the grid. R&D activities are managed in a collaborative fashion among the various functions across National Grid USA's operating companies in Massachusetts, New York and Rhode Island. Distribution efforts are managed by the Grid Modernization Solutions team within the Electric Business Unit and Transmission efforts are managed by the Asset Development team within the Transmission Business Unit. Direct cost to fund dedicated R&D project efforts are allocated to multiple operating companies within National Grid USA that benefit from these research efforts.

The Company works with collaborative technical entities such as the Electric Power Research Institute ("EPRI") and Centre for Energy Advancement through Technological Innovation ("CEATI") to leverage investment from other like-minded utilities thus spreading the cost of the research across multiple companies. This approach is one of the Company's key means of maximizing its R&D investments.

The current areas of R&D focus include: Asset Management, Distributed Energy Resource Integration, and Cyber Security as illustrated in the list of R&D projects the Company is currently engaged in:

Through EPRI:

P40 - Transmission Planning: The Company's focus in this project set is on model development and validation and advanced power flow control.

P39 - Transmission Operations: The Company's area of focus in this project set concern System Voltage and Reactive Power Management and Decision Support Tools for System Restoration and Emergencies.

P37 – Substations: The Company's primary focus in this project set is on substation batteries, CCVT, arresters, disconnect switches and ratings.

P180 - Distribution Systems: The Company's key area of focus in this program are asset management practices and resiliency.

P174 - Integration of Distributed Energy Resources: Project sets address advances in feeder integration tools, hosting capacity analysis, performance and use of smart inverters (and other controllers), application of interconnection standards, learning with DER data analytics, monitoring and control via DERMS and microgrids. New interconnection standards such as IEEE 1547 are addressed. DER business strategy and cost-benefit analysis are key elements of the program such as research to optimize PV operation with storage and controllable loads.

P200 - Distribution Operations and Planning: Grid Modernization and advanced tools for planners, operators, and analysis experts are central to these efforts. The Company is engaging in all areas of this program which focus on modeling and simulation, planning, operations, system protection.

P94 - Energy Storage and Distributed Generation: The Company is participating in all aspects of this program involving energy storage, distributed generation, and microgrids integrated directly with transmission or distribution grids or behind the meter.

P183- Cyber Security: The Company is participating in all aspects of this program which focuses on addressing the emerging threats to an interconnected electric sector through multidisciplinary, collaborative research on cyber security technologies, standards, and business processes.

P34 - Transmission Asset Management Analytics: The Company is participating in three projects in this area; Principles, Practices and Technologies; Substation Asset Analytics and Overhead Transmission Analytics.

PP1 - Power Quality: The Company's focus in this project set is on achieving cost effective edge of grid compatibility.

Through CEATI:

Station Equipment Asset Management Program: Topics and issues include condition monitoring, prediction of remaining asset life, maintenance practices and life extension strategies and innovations and developing trends.

Transmission Overhead Design & Extreme Event Mitigation Program: The objective of this interest group is to develop and share strategies to deal with overhead transmission line design issues and to mitigate the impact of extreme events, develop benchmarks for increased utilization of existing lines as well as the design of new lines, address corrosion of transmission components, develop containment strategy against line cascade and develop technologies to reduce life cycle costs.

Grounding and Lightning Program: The Grounding and Lightning Interest Group focuses on improving the lightning performance of transmission and distribution systems.

Smart Grid Program: The key focuses of this Task Force will include deployment strategies, enabling technologies, quantified cost-benefit analyses, integration issues and lessons learned.

Vegetation Management Program: The Vegetation Management Task Force promotes the exchange of innovations and best practices with respect to utility vegetation management programs.

Distribution Line Asset Management Program: The goal of the program is to realize value from distribution assets by balancing costs, opportunities and risks against the desired performance of assets to achieve near and long-term utility objectives.