Grid Modernization in New Hampshire

Report to the
New Hampshire Public Service Commission

From the
Grid Modernization Working Group

Final Report
Submitted March 17, 2017

Facilitator/Mediator: Dr. Jonathan Raab, Raab Associates, Ltd.
Technical Consultant: Tim Woolf, Synapse Energy Economics

Contents

1. Vision and Overarching Goals for Grid Modernization

The Working Group embraces the Commission's vision in the scoping order initiating this process that grid modernization policies, technologies, and practices should help fulfill its responsibility to ensure that electric utilities provide safe, reliable electric services at just and reasonable rates. This can be accomplished by enabling electric utilities to take advantage of new and emerging technological developments, providing customers with new service offerings, enabling and leveraging third-party products and services, and helping customers optimize their electricity consumption patterns. The Working Group believes that grid modernization can spur the development of cost-effective distributed energy resources, including energy efficiency, demand response, distributed generation, storage technologies, and more.

The Working Group's recommended overarching goals for grid modernization in New Hampshire begin by embracing the goals in the Commission's initial scoping order, and then highlight further benefits of modernizing the electric grid including the ways that grid modernization can help to achieve the goals of existing New Hampshire statutes. The Working Group process and findings lay the groundwork for future proceedings by the Commission and the eventual filing of Grid Modernization Plans by the distribution utilities.

Overarching Goals from the Commission's Grid Modernization Scoping Order

1. Improve reliability, resiliency and operational efficiency of the grid.
2. Reduce generation, transmission and distribution costs.
3. Empower customers to use electricity more efficiently and to lower their electricity bills.
4. Facilitate the integration of distributed energy resources (DERs).

Further Benefits of Modernizing the Electric Grid

Members of the Working Group believe that in addition to the goals outlined by the Commission, improvements to the technologies and policies related to the electric grid can:

- Better align the interests of energy consumers and energy producers so that system performance is optimized while enabling the strategic electrification of buildings, homes and vehicles.
- Ensure that all customers share in the benefits of a modern grid, have access to their usage data in a readily accessible form, which they can make available to 3rd parties, and retain privacy safeguards;
- Keep New Hampshire technologically innovative, economically competitive, and in step with the region; and,
- Reduce environmental impacts and carbon emissions in New Hampshire.

Reference and Support of Existing New Hampshire Statutes

The Working Group sees that Grid Modernization can be an important means for advancing the state's policy goals and statutory requirements inclusive of New Hampshire's Climate Action

Plan,[1] 10 Year Energy Strategy[2] and Electric Utility Restructuring Statute[3] among others.

Grid Modernization Technologies and Practices

Customer-centered technologies and practices enable and encourage customers to implement distributed energy resources, optimize their electricity consumption, and reduce their electricity bills, using for example: two-way communication systems; enhanced customer information delivery systems; in-home energy devices; programmable, communicating thermostats; and smart, communicating appliances.

Grid-centered technologies and practices allow utilities to optimize the delivery of electricity to homes and businesses by, for example: detecting, isolating and restoring faults and outages; automatically reconfiguring feeders; implementing voltage stabilization technology; regulating voltage; remotely monitoring and diagnosing grid operations; and better integrating distributed generation technologies.

[1] http://des.nh.gov/organization/divisions/air/tsb/tps/climate/action_plan/nh_climate_action_plan.htm, pg. 1

[2] https://www.nh.gov/oep/energy/programs/documents/energy-strategy.pdf

[3] http://www.gencourt.state.nh.us/rsa/html/NHTOC/NHTOC-XXXIV-374-F.htm

2. Background and Report Overview

On July 13, 2015, the Commission opened a docket to investigate grid modernization in New Hampshire (IR 15-296). This investigation or information-gathering proceeding is a first step to give stakeholders a chance to learn about grid modernization and to explore how and to what extent grid modernization can be advanced and made workable in New Hampshire. The Order of Notice invited comments by September 17, 2015, regarding "the definition, or elements, of grid modernization that should be included in this investigation. On April 1, 2016, the Commission issued Order No. 25,877 establishing a formal process to obtain additional input from interested parties, to create an open dialog on key grid modernization topics, and to reach as much agreement as possible on regulatory opportunities for advancing grid modernization in New Hampshire. This order also identified the key goals of grid modernization and defined the topics of inquiry the Commission expected to be most pertinent in this process, including:

- Distribution system planning
- Customer engagement with distributed energy resources
    - Advanced metering functionality
    - Rate design
    - Customer education
- Utility cost recovery and financial incentives

The Order posed numerous issues and questions under each of these topics. It also established a Working Group to provide input from distribution companies and other stakeholders. Finally, it requested that the distribution utilities provide information on current grid infrastructure in New Hampshire and its capabilities, as well as the status of the grid modernization activities in process or being planned.

To facilitate and mediate the Working Group process the Commission retained Raab Associates, Ltd. It also retained Synapse Energy Economics to provide consulting services to the Commission staff and to the Working Group as needed.

Working Group Process and Members

The Commission solicited stakeholder interest in participating in the Working Group by April 11 2016, and tasked Raab Associates and the Commission staff with establishing the Working Group. The Working Group shown in Table 2.1 initially included 17 Members, plus the New Hampshire Public Utilities Commission staff who attended the Working Group meetings and participated in an ex officio role (without weighing in on the Working Group recommendations). Only 14 Working Group Members participated in crafting the final recommendations in this

Report for a variety of reasons explained in the footnote below[4]. See Appendix A for the lead representative and alternate for each organization on the Working Group.

Table 2.1: NH Grid Mod Working Group Members

Acadia Center
City of Lebanon, NH
Conservation Law Foundation
Energy Freedom Coalition
Eversource Energy
Liberty Utilities
New Hampshire Department of Environmental Services
New Hampshire Legal Assistance
New Hampshire Office of Energy and Planning
New Hampshire Office of the Consumer Advocate
New Hampshire Public Utilities Commission Staff (ex officio)
New Hampshire Sustainable Energy Association/ Northeast Clean Energy Council
Northeast Energy Efficiency Partnerships
Patricia Martin, Retired Engineer
Retail Energy Supply Association
Revolution Energy
The Jordan Institute
Unitil Energy Systems Inc.

The Working Group held its first all day Working Group meeting on April 29, 2016 and met for eight day-long meetings over a ten-month period with the final meeting on February 3, 2017. In addition to the face-to-face full day Working Group meetings, the Working Group established a couple of Task Forces to work through issues and develop recommendations for the full Working Group's consideration (i.e., Customer and Utility Data Task Force and the Task Force on Integrating Existing Statutes with Grid Mod). There were also homework assignments between Working Group meetings for all the Members, which were usually completed in groups of Members, as well as specific requests for certain members to draft different proposals on issues for the full Working Group's consideration.

Overall, consensus was reached (defined as unanimous support by all 14 members of the Working Group) on most of the recommendations and work products in this Report. In those

4 Two Working Group members, the Jordan Institute and Northeast Energy Efficiency Partnerships actively participated in the first half of the stakeholder process but then dropped out as a result of staffing change. They did not participate in the recommendations made in this report. The Office of Energy Planning participated in the process, but abstained from participating in making recommendations due to the recent change in administration.

instances where one or more Working Group member did not agree, the report provides alternative options and identifies the supporters of each option.

There may be areas of relevant concern that lie outside this report due to 1) other ongoing proceedings, such as the net metering docket (DE 16-576) and the Energy Efficiency Resource Standard implementation process, and 2) limitations in the scope of the Working Group Report.

Overview of report

This Report includes five additional chapters. Chapter 3 explicates the Working Group's conceptualization of the outcomes and capabilities and the enablers related to grid modernization practices. In Chapter 4, the Working Group covers numerous recommendations related to distribution system planning. Chapter 5 covers recommendations in several areas related to improving customer engagement around distributed energy resource issues including rate design, advanced metering functionality, customer and utility data, and customer education. In the Chapter 6, the Working Group lays out its recommendations on utility cost recovery and financial incentives. In the last Chapter (7), the Working Group identifies a series of Next Steps and recommendations that will build on its work in 2016 and early 2017, before the PUC issues an order for the utilities to develop their first grid modernization plans.

Appendix A includes the lead representatives and alternates for each of the Working Group members. Appendix B includes some of the initial data filed in the Working Group process by the distribution companies with respect to their current grid infrastructure in New Hampshire and its capabilities, as well as the status of the grid modernization activities in process or being planned.

3. Outcomes and Capabilities

In the Scoping Order initiating this Working Group process, the Commission specifically asked the Working Group to review and revise as it saw fit the "Grid Modernization Outcomes, Capabilities, and Enablers" matrix that was submitted in Massachusetts by the stakeholder working group there several years ago. After careful consideration, this Working Group made numerous changes to the overall categorization as well as the specific outcomes, capabilities, and enablers. The Working Group members all agreed to these changes, and support the matrix as delineated in Table 3.1.

Table 3.1 Grid Modernization Outcomes, Capabilities, and Enablers

Outcomes	Capabilities/Activities*	Enablers
Customer Engagement and Empowerment	Energy Efficiency (end-use)	• Education and Technical Assistance • Smart Appliances • Energy Management Systems • Home Area Network Capability • Customer Communication System (e.g., web portals) • Information: Access, Transparency, Control, Privacy • Rate Design, including rates reflecting locational value of DER • Metering System (AMR/AMI[5]) • Other Innovative Technologies • Third-Party, Competitive Aggregators and Suppliers
	Demand Response	
	Distributed Generation	
	Storage	
	Electric Vehicles	
	Electric Heat Pumps	
Optimize Demand (Through Utility Initiatives)	Volt/VAR Control, Conservation Voltage Reduction	• Metering System (AMR/AMI) • Meter Data Management System • Billing System • Customer Information Management System • Real-Time Communication
	Load Control	
	Utility-Owned Energy Storage	
	Geo-Targeting of Distributed Energy	

[5] Advanced Meter Reading (AMR): AMR technology allows utilities to read customer meters via short-range radio-frequency signals. These systems typically capture meter readings from the street using specially equipped vehicles." Advanced Metering Infrastructure (AMI): "AMI systems combine meters with two-way communication capabilities. These systems are capable of recording near-real-time data on power consumption and typically report that consumption to the utility less frequently.

	Resources	System • SCADA • Distribution Automation • Distribution Management Systems • Rate Design
	Advanced Load Forecasting	
Integrate Distributed Generation, Storage and Electric Vehicles (Through Utility Initiatives)	Voltage Regulation	• Metering System (AMR/AMI) • Real-Time Communication System • SCADA • Distribution Automation • Distribution Management Systems • 3V0, voltage control, reverse power, direct transfer trips, frequency control • Geospatial Information System • System and circuit planning models • Rate Design
	Load Leveling and Shifting	
	System Protection	
	Energy Storage and EV Charging Infrastructure	
	Remote Connect/Disconnect	
Reliability: Reduce Impact of Outages	Fault Detection, Isolation and Restoration	• Metering System (AMR/AMI) • Real-Time Communication System • SCADA • Distribution Automation • Distribution Management Systems • System and circuit planning models • Outage Management System • Geospatial Information System • System Sensors • Voltage and Frequency Control, Protection • Mobile damage assessment
	Automated Feeder Reconfiguration	
	Intentional Islanding	
	Situational Awareness	
	Damage Assessment	
	Distributed Energy Resources (*i.e.* microgrids, demand response, storage and back-up generation resources)	
Reliability: Prevent Outages	System Hardening	• SCADA • Distribution Automation • Distribution Management Systems • Reliability database • Asset management system • Geospatial Information System • Outage Management System • Predictive Modeling Software
	Aging Infrastructure Replacement	
	Pre-Detection of Potential Outages	
	Vegetation Management	

Workforce and Asset Management	Mobile Workforce Management Mobile Geospatial Information System	• Real-Time Communication System • Distribution Management System • Outage Management System • Geospatial Information System • Mobile Data Systems
	Remote Monitoring and Diagnostics	

4. Grid Modernization Planning

The scoping order for this Working Group process noted that one of the "challenges of grid modernization will be to identify and assess emerging technologies and practices, and select those that are most appropriate and in the public interest, on an on-going basis." Grid modernization plans will assist the state, the Public Utilities Commission, electric utilities and private industry innovators in identifying and evaluating the necessary transformations and investments to achieve the goals and outcomes described above. In that order the Commission also noted that it expects grid modernization planning to build off electric utilities' existing practices for making investment decisions, and should fit naturally within the utilities' existing integrated resource planning framework.

The Working Group recommends by consensus the following distribution system planning related approaches and methodologies, except as noted:

<u>How should planning for grid modernization take place?</u>

Each utility should periodically develop, file and gain PUC approval of Grid Modernization Plans, with a stakeholder engagement process.

<u>How should stakeholders participate in the development of utility Grid Mod plans? (move to be the first section)</u>

The Commission should establish a stakeholder engagement process that allows all interested stakeholders to provide input to be considered at key junctures throughout the plan development process including:

- Pre-planning,
- Project identification and consideration, and
- Project prioritization.

Non-utility stakeholders:[6] The stakeholder engagement process could include the formation of a consumer advisory committee to ensure stakeholders have a meaningful role.

Utilities: Stakeholders process described above provides ample opportunities for stakeholder input at key junctures, and therefore a consumer advisory committee is unnecessary.

<u>What should be included in the Grid Mod Plans?</u>

Each Plan should include overall goals, guiding principles, a 10-year strategic Grid Mod Plan vision, delineated benefits to customers, a benefit-cost analysis of proposed projects, 5-Year Project Investment Plan (with proposed dollar amounts, priority investments, schedules for roll-

[6] Non-utility stakeholders include: Acadia Center, City of Lebanon, Conservation Law Foundation, Energy Freedom Coalition, Northeast Clean Energy Council/NH Sustainable Energy Association, NH Department of Environmental Services, NH Legal Services, NH Office of the Consumer Advocate, Patricia Martin, Retail Energy Supply Association, and Revolution Energy.

outs, metrics to measure progress), and customer education and stakeholder engagement plans, and identification of avenues for utility and third parties to develop new services.

Each utility's GMP should contain the following sections:

1. Grid Mod Vision and Strategy (where will we be in 10 years? How do we get there?);
2. Grid Mod Roadmap (including 10-year high-level plan, and a detailed project schedule, and project costs);
3. Business Case / Benefit Cost Analysis (Singular project analysis and/or combined project analysis) ;
4. Grid Security and Cyber Security Strategy; and
5. Metrics

See the illustrative detailed outline for NH Grid Mod Plan in Appendix C.

Specifically, what types of data should be included in the plans?

At a minimum, Grid Mod Plans should include any data that is required for the PUC to make a determination on the appropriateness of the Plan consistent with its traditional burden of proof. The Plan should also describe the types of data that a company will make available to customers and third parties, as described in Section 5.2.

How frequently should Utility Grid Mod plans be filed at the PUC?

Following the initial Plan filing, there should be an annual update (for example, for course corrections, cost recovery and reconciliations, and that subsequent Plans be filed at least every 3 years, following a Commission order on the most recent Plan.

What time period(s) should the Grid Mod plans cover?

The utilities' Grid Mod Plans should be a 10-year vision, with a more detailed 5-year plan updated every 3 years following a Commission order on the most recent Plan.

Should the Grid Mod plans filed at the PUC be separate from or integrated with the utilities' least cost integrated plan filings?

An initial Grid Mod plan should be filed in lieu of a utility's next Least Cost Integrated Resource Plan. To the extent that the purposes of RSA 378:38-satisfied by the Grid Mod plan, the Commission should consider issuing a waiver, to waive the IRP filing requirements in favor of a Grid Modernization Plan filing on a 3-year cycle following Commission's final order.

Should the Grid Mod plans filed at the PUC be separate from or integrated with the utilities internal distribution system planning processes?

The two should be coordinated and consistent with each other to the maximum extent feasible.

<u>How should utility planning process account for/facilitate role(s) of Third-Party vendors in providing Grid mod technologies and services?</u>

In meeting the goals of Grid Modernization outlined in this Report, the utilities should continue to engage third parties when relevant, while looking for and supporting opportunities where 3rd parties can be engaged and leveraged on a continuous basis (e.g., through open-source platforms) to achieve grid modernization outcomes.

<u>What is the appropriate cost-effectiveness framework for evaluating Grid Mod investments?</u>

Grid mod investments should be evaluated for cost-effectiveness using a business case framework that includes both a quantitative evaluation and qualitative evaluation of each program or type of investment. The quantitative evaluation would include monetized values. The qualitative evaluation might include other factors that cannot readily be monetized, such as customer equity, environmental impacts, degree that in enables customer and third-party engagement, interactive effects of DERs, short-term versus long-term impacts, and other strategic and policy factors including impact on metrics and achieving the Grid Mod goals.

A business case is a written document that captures the reasoning for initiating a project. A compelling business case adequately captures both the quantifiable and unquantifiable characteristics of a proposed project or investment. Information that may be included in a business case includes a detailed description of the project including scope and schedule, the rationale and business drivers for the investment, the expected costs, the expected benefits, any assumptions underpinning the evaluation of expected benefits, options considered, and expected risks, including sensitivities. From this information, the justification for the project is derived.[7]

Throughout this report the term "cost-effective" is used to refer to a business case framework, which includes both a quantitative and a qualitative evaluation. The parameters of a business case framework and how they will be evaluated remain to be fully developed. This must occur before utilities file their first grid modernization plans. This effort should include development of protocols and practices for conducting cost-benefit and business case analyses, informed by a range of best practices.

<u>How, if at all, should the cost-effectiveness framework account for the location and time issues?</u>

To the extent that time and/or location based information is available it should be included in cost-effectiveness analysis.

<u>How will the key assumptions used for evaluating Grid Mod investments be developed?</u>

Prior to the development of the first grid modernization plans, there would be an effort to coordinate common major assumptions among the utilities. Such assumptions could include, for example, the appropriate discount rate, the appropriate inflation rate, and electricity market

[7] This definition of a business case is taken word-for-word from the *Massachusetts Grid Modernization Working Group Report*: DPU 12-76 Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities from the Steering Committee, July 2, 2013.

price forecasts.

<u>How long should the Commission give the utilities to file the initial Grid Modernization plans?</u>

The initial Grid Modernization plan will take approximately 9-12 months, with the issuance of a final directive by the commission. This length of time is required to support the proposed Stakeholder Engagement process identified in this report and could vary with changes in the proposed stakeholder process. The Commission should require that the Grid mod filings be submitted in a staggered fashion.

5. Customer Engagement

The scoping order for the Working Group identified customer engagement with distributed energy resources as one of the key topics of inquiry. Customer engagement was defined as including four key subtopics: advanced metering functionality, rate design, customer data, and customer education. The advanced metering functionality is addressed both in Chapter 3 and in the Section 5.1 on rate design. The other three topics are addressed in turn below.

5.1 Rate Design

Rate Design Principles

The Working Group agrees that the following principles should guide rate design in New Hampshire, recognizing that there's a balancing of principles in setting rates:

- Utilities should be fairly compensated for the services they provide to consumers, and consumers should be fairly compensated for the services they provide to the grid.
- Electricity rates should provide appropriate and efficient price signals to customers.
- Electricity rates should incentivize consumers to use electricity wisely and invest in cost-effective DERS.
- Electricity rates should be designed in a way that maximizes consumer choice and control and also protects vulnerable consumers.
- Rates should reflect cost causation principles.
- Non-utility stakeholders: Advanced metering functionality should be deployed where cost-effective using the business case framework or, where not generally found to be cost-effective, individuals or groups of customers are willing to pay to upgrade their individual metering system.
- Utilities: Advanced metering functionality should be considered for deployment where cost-effective using business case framework. However, cost effectiveness is not the only consideration when evaluating projects. Utilities prioritize project spending by taking into account a range of other factors, such as customer bill impacts, potential impacts to customer satisfaction, potential impacts to reliability, and resource availability.

As this report was being developed, a separate net metering proceeding was pending in Docket No. DE 16-576, therefore we are not addressing specific net metering recommendations in this report. However, the rate design principles in this report should be generally applicable to distributed energy resource customers in the future.

Rate Design Recommendations

All Working Group members recommend the following rate design elements, except where noted otherwise. Because net metering customers are being dealt with currently in NH in a separate docket, these recommendations are not necessarily meant to cover net metering customers.

Customer Charge

Non-Utilities: Customer charges should be limited to customer-related costs (e.g., incremental costs to serve individual customers such as individual meters and service drops). Customer charges should recover customer-related costs based on a cost of service study in the most recent base rate case. Any significant increases in such fixed charges should be phased in gradually, consistent with generally-accepted ratemaking principles

Utilities: Customer charges should recover all customer-related costs based on a cost of service study in the most recent base rate case, and take in consideration generally-accepted rate design principles.

Demand Charge

Large C&I Customers: Utilities should continue to have demand charges for large C&I customers for distribution services.

Small C&I customers: Utilities should consider applying demand charges to small C&I customers for distribution services where not already offered. Utilities should apply demand charges for small C&I customers only if metering and information is available as an option to customers in a timely manner so that they can take action to reduce and manage their costs.

Residential customers: Utilities should not assess demand charges to residential customers for now.

All customers with demand charges: The utilities and the Commission should consider whether demand charges should be more aligned with times when marginal costs are highest, e.g., at periods of peak demand.

Time-Varying Rates for Generation

Recommendations on time-varying rates (TVR) for generation on an Opt-In basis and on an Opt-Out are described in detail below. A Technology Opt-in to support TVR by competitive electricity suppliers which can serve as an alternate or companion is also described below.

Time-Varying Rates for Transmission

Utilities: TVR for transmission services is not practical to implement at this time, but could be considered as grid capability is enhanced and billing modifications are considered to provide the information needed to support such rate design.

Non-utility stakeholders: TVR for transmission services for distribution utilities can be implemented in the near future, at least one based on simple peak and off peak periods.

Time-Varying Rates for Distribution

Utilities: TVR for distribution services is not practical to implement, because distribution costs do not vary with time of use.

Non-utility stakeholders: TVR using simple on-peak and off-peak TOU periods should be implemented for all customers in the near future. TVR using simple on-peak and off-peak periods is already in use for some rate classes of Liberty and Eversource, while most Unitil meters have this capability. While TVR for distribution services beyond use of simple on-peak and off-peak TOU periods for some meters and customers may not be practical to implement at this time, it should be considered as grid capability is enhanced to provide the information needed to support such rate design. Distribution system costs that correlate with peak demand, such as substation and feeder circuit capacities, could be primarily recovered during a defined peak period, aligned with a transmission charge peak period, while other costs that don't correlate with peak periods, such as vegetation management, could be recovered across all hours.

Location-Based Pricing

Location based distribution price signals should be, limited to DERs, bi-directional, and only implemented when practical to do so.

Role of Advanced Meter Functionality[8]

Advanced meter-related functionality both customer-and grid-facing are shown in Table 5.1. Appendix B presents information on the New Hampshire utilities' current metering capabilities.

Table 5.1 Meter-Related Functionality

Customer-Facing	Grid -Facing
1) Drive-By Meter Reading	8) Remote Service Connect/Disconnect Switch
2) TOU Register	9) Power Quality Reading
3) Interval Data	10) Outage Identification & Restoration Notification
4) Daily Read (at office)	11) Planning Data (snap-shot demand and system reads)
5) On-Demand/"Real-Time" Meter Reading	
6) Communication to Meter	
7) Communication Capability in Meter to Customer Equipment (appliances, thermostats, vehicles)	

As shown in Table 5.2, different metering types include different functionalities.

Table 5.2 Incremental Functionality of Metering Options

Technology Options:	Customer-Facing	Grid-Facing
AMR	Drive-By Meter Reading; One-Way Communication	

[8] Following two tables are copied from DPU 12-76: Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities from the Steering Committee July 2013, page 41

Enhanced AMR (w/HAN)	AMR PLUS Communication to Customer Equipment and MAY enable Remote Meter Read, TOU Register, Daily & Real-Time Meter Read	MAY enable Outage ID & Restoration Notification
Enhanced AMR (w/Fixed Network)	AMR PLUS Remote Meter Read, TOU Register, Interval Data, Daily Read, and MAY also enable Real-time Data Read, Communication to Customer Equipment	MAY/limited Outage ID & Restoration Notification, and Planning Data
Full AMI	AMR (w/Fixed Network) PLUS Real-time Data Read, Two-Way Communication to Meter, MAY also enable Communication to Customer Equipment9	AMR (w/Fixed Network) PLUS Remote Service Connect/Disconnect Switch, Voltage Reading, Power Quality Reading

For advanced metering functionality to be fully operational it also requires communication systems, as well as utility back-office infrastructure (e.g., compatible billing systems).

The long-term goal is to enhance functionality and ensure TVR opportunities for all customers where benefits exceed costs. Utilities should look for advanced metering functionalities that produce data availability and functionality where benefits exceed costs under a business case analysis, and at an affordable price. Advanced metering functionality should initially be deployed strategically (e.g., geographically, large customers, old meter retirement, pilots and early adopters).

Non-utilities: Furthermore, metering functionality should be installed that enables the full range of competitive energy products and services alternatives.

Utilities: Furthermore, metering functionality should be installed that achieves the level of rate complexity proposed by the utility. Having to install metering functionality to enable the full range of competitive alternatives, could be cost prohibitive.

Low-Income / Customer Protection

The Commission should maintain existing protections and programs for low-income customers (e.g., Electric Assistance Program, targeted Energy Efficiency programs, disconnection protections), and consider additional protections and opportunities to participate and share in the benefits of grid modernization.

Decoupling

Decoupling has been addressed in the EERS settlement, and utilities will submit proposals in their next distribution rate cases after the first triennium of the EERS (2020, if not earlier).

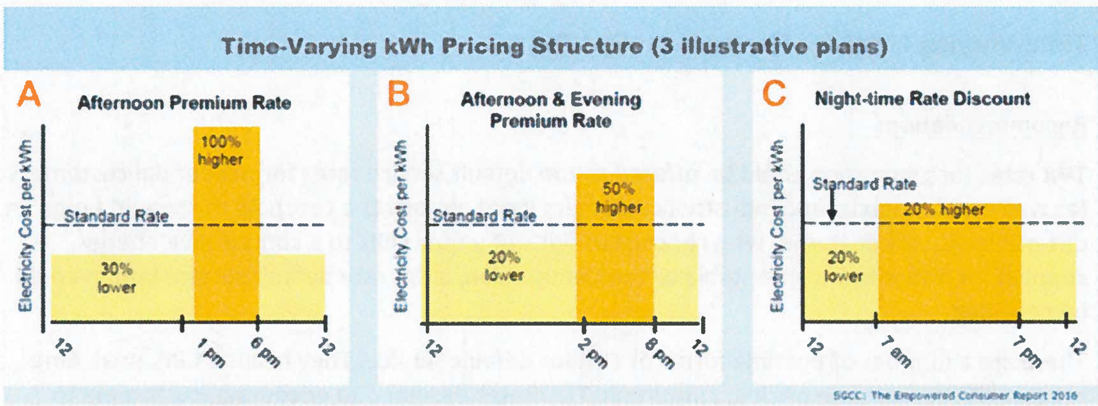
[9] A Zigbee chip or in home device may also be necessary.

Net Metering

Net metering is being addressed in a separate docket (DE 16-576).). As already noted, rate design decisions have impacts under net metering proposals in that docket and the two issues are intertwined.

Time-Varying Rates for Generation: Opt-In

The graphs below provide three examples of time-of-use (TOU) pricing structures. TOU pricing is one type of TVR, along with critical-peak pricing and real-time pricing.



Recommendations

If implemented, Opt-in TVR for generation should include time-of-use pricing with critical peak pricing.

Opt-In TVR for generation should be provided to customers if practical, considering the following:

- There is a compelling business case for customers, accounting for all costs and benefits. Utilities can use pilots to help ascertain the costs and benefits that would go into a business case.
- It does not create any barriers to an eventual opt-out approach.

Any suppliers interested in offering TVR options to default service customers should provide this feedback during the supply RFP process to the utilities.

Technology and Information Requirements for Opt-In TVR for Generation

Technology infrastructure upgrades (e.g., communications, billing, etc.) and meters with time-of-use (TOU) capability may be required for implementation of TOU. However, critical peak pricing (CPP) functionality will require TOU or other interval data and may also require a corresponding meter data management system to perform the analysis, depending on the design of the rate. These rates do not necessarily require a customer portal for sharing of timely customer usage data, but if desired, then the utilities will need to build or enhance their customer portals to provide this functionality as well.

Non-utility stakeholders: There must be timely information provided to customers so that they can act to reduce and manage their costs.

Utilities: Timely information would likely enhance the customer experience but is not necessary for TOU deployment.

Those customers opting for TOU/CPP should pay for their meter installation. However, if system-wide modifications to billing systems, default service plans, reporting, and related staffing levels are required under a TOU/CPP scenario, all costs of these requirements should be recovered from all customers. Such costs could potentially be recovered through volumetric rates, fixed charges, or demand charges as determined to be appropriate.

Time-Varying Rates for Generation: Opt-Out

Recommendations

TVR rates for generation could be offered as the default service rates for residential customers (as well as commercial and industrial customers if not already the case). As this would be on an opt-out basis, any customer who chooses to opt-out would shift to a competitive energy supplier, or if that is not acceptable to the Commission, a flat rate default service option could be provided.

There are a number of possible forms of TVR for default service. They include CPP, peak time rebates (PTR), real-time pricing, and simple TOU rates designed to encourage customers to lower their demand at peak times. Generally, the TVR rates should be as sophisticated as possible given the current technologies deployed. As grid modernization investments continue to provide increasingly advanced metering capabilities, TVR rates should be updated and implemented accordingly.

Non-Utility stakeholders: Opt-out TVR for generation for default services should be provided to all customers over the long-term.

Utilities: Opt-Out TVR may present opportunities for market development and customer savings. A comprehensive benefit/cost analysis and customer acceptance study should be performed in order to determine whether Opt-Out TVR should be a long-term goal for NH. The business case analysis should account for customers' interest in TVR and ability to respond, as well as third-party suppliers' willingness to provide TVR default service. The utilities do not support the premise that Opt-Out TVR should be recommended prior to performing the necessary benefit/cost analysis, nor before a customer acceptance study is performed. Unitil and Eversource's experience in Massachusetts indicated a poor benefit/cost ratio for Opt-Out TVR and does not recommend this approach until compelling evidence is presented to contradict the concurrent conclusion. A comprehensive benefit/cost analysis and customer acceptance study should be performed prior to recommending Opt-Out TVR as a long- term goal. In addition, any recommendation for Opt-Out TVR should take into account other factors such as customer bill impacts, potential impacts to customer satisfaction, potential impacts to reliability, and resource availability.

Technology and Information Requirements for Opt-Out TVR for Generation

Opt-out TVR for generation is not an available option in the short-term, given current metering and communications technologies and back-office technologies such as information and billing systems.

For Opt-Out to be possible, advanced metering infrastructure would need to be ubiquitous in addition to each utility having made the requisite back-office changes. Costs for such infrastructure, along with system-wide modifications to billing systems, default service plans, reporting, and related staffing levels are required under a TOU/CPP scenario, should be recovered from all customers. Such costs could potentially be recovered through volumetric rates, fixed charges, or demand charges as determined to be appropriate.

Alternative View on TVR for Default Service

Non-utility stakeholders: Given that an opt-in or opt-out for default service may not be practical to implement for some period of time,[10] a high priority should be placed in the near term on developing a Technology Opt-In to support a variety of TVR options for generation supply, as well as developing TVR for transmission and distribution services.

Technology Opt-In to Support TVR for Competitive Supply of Generation and More

Introduction

As an alternative or in addition to having the electric distribution utilities provide an opt-in or opt-out TVR for default generation service, the utilities could help enable affordable opt-in interval meters and meter data systems to facilitate third-party (competitive) providers of energy services offering a variety of time varying rates to smaller customers, including both residential and smaller C&I customers who typically don't currently have access to such alternatives, due at least in part to the current cost of interval meter data.

Rationale for Proposal

A fundamental purpose and goal of NH's Electric Utility Restructuring Statute (RSA 374-F) is to promote the development of competitive markets for electricity supply (generation services), including enabling customer choice of such options as "real-time pricing, and generation

[10] In addition to concerns about the possibility that an opt-in or opt-out TVR option for default service may undermine the development of competitive retail markets for energy service, we are concerned that such options may be difficult to implement in the context of competitively procured default service. For example, assuming load shapes for customers in a default service TVR option can be differentiated from each other and that of all other customers on fixed price default service, which is key to making TVR meaningful and will require interval metering functionality, then those customers with better than average (lower cost) load profiles may be attracted to a TVR default service rate by the savings, but not others who would pay more, leaving fixed price default service customers with an increasingly worse (higher cost) load profile on average. The uncertainty of load migration between fixed price and TVR default service, as well as competitive supply, plus the often seemingly random distribution of high and low price intervals in the wholesale market in recent years, compared to high and low demand periods that are fairly consistent and could logically be used for simple TOU or other TVR for transmission and distribution, may significantly increase the hedging costs of default service. The complexity of devising and responding to default service procurements (such as establishing meaningful peak and off peak rate periods) may also be increased by these factors and make such procurement of two default service rates, one fixed and the other TVR, impractical.

sources, including interconnected self-generation" and opening "markets for new and improved technologies" all with the aim of reducing "costs for all consumers of electricity by harnessing the power of competitive markets." So rather than use default service to deliver a limited choice of a single TVR option, competitive choices are more likely to develop by allowing customers to opt-in to metering systems that enable TVR, including, in particular, real-time pricing options, that might be procured from competitive providers or through municipal aggregations pursuant to RSA 53-E.

The larger C&I customers of utilities typically have interval meters and a variety of competitive supply choices, including real-time pricing and other TVRs. However current utility metering for residential and smaller C&I customers typically doesn't record or report interval data, except for monthly meter readings. Current tariffs to upgrade meters to interval meters for small customers may often be cost prohibitive due to recurring subscription costs and requirements to have a dedicated telephone land-line for the utility to dial into such meters to collect the data, which is not made available on a near real-time basis. The challenge is to find a modern metering solution that customers can opt into that can provide near real-time granular interval data at an affordable cost, without large up-front investment by utilities in new data collection and management systems that may not be cost-effective at this time with uncertain levels of customer participation.

<u>Three Possible Approaches</u>

The parties have agreed to continue to work together to investigate alternatives to provide interval data (including the time interval) to the customer.

There are 3 general possible approaches to providing an opt-in affordable interval metering system that should be explored:

1. Replace the existing utility meter with an interval meter that allows customer access to interval data in near real-time, including customer ability to grant access to 3rd parties, (using communications other than a dial-up land line phone modem) with the utility reading the data at least monthly using their existing meter data collection system (such as drive-by AMR). The meter would be owned by the utility, but the incremental costs would be paid for by the customer requesting the upgrade.

2. Replace the existing utility meter with an interval meter that allows both customer and utility access to interval data in near real-time (using communications other than a dial-up land line phone modem). Such a metering system may not allow the utility to read the data using their existing meter data collection system (such as drive-by AMR), but could provide access to the data collected through other means, if such means can be affordably integrated into the utility's existing meter data and billing systems. The meter would be owned by the utility, but the incremental costs would be paid for by the customer requesting the upgrade.

3. Supplement the existing utility meter with a secondary revenue grade meter, which provides near real-time interval data, accessible to both the customer and the utility. This meter, installed on the customer side of the utility service point, could be owned by the customer, a competitive supplier, other third-party, or the utility. While the utility should have access to the data generated

by such a meter, it would not require any modification to existing utility meter data or billing systems, as the utility could continue to use its existing meter and data collection systems for its billing and a competitive supplier could use the secondary meter data for its TVR energy supply billing if billed by the energy service supplier. This approach probably only makes sense if it is materially less expensive or more cost-effective than alternatives that might be proposed under option 1 or 2 above. The Working group recognizes that utilities cannot use this data for billing and reporting purposes under current rules and tariffs, and this would require changes approved by the Commission. The parties reserve their rights to express their positions on any such changes, based on specific proposals.

Technology and Information Considerations

Desirable Features

1. In addition to reading and logging kWh, both forward and reverse, by line, it would be desirable for an interval meter to be able to read (and report in near real-time) voltage and frequency (by line) as well as power factor, VARs, and total KVARh (Reactive) kilovolt ampere hours

2. An open application programming interface (API) with good user information and options for data retrieval or a standardized data approach such as Green Button, both with secured access, is desirable.

3. Additional cybersecurity features that help secure data privacy and control by the customer and that minimize the risk of and potential harm from hacking (such as with read only data output from a meter that is not otherwise addressable and subject to reprogramming by a hacker) will be desirable.

4. Accurate date and time stamping for data intervals that match ISO New England time stamps, or come close to it, is also a highly desirable feature.

5. Data could be collected and stored on a secure internet accessible website that both the utility and customer have access to. The customer should be able to give and revoke access to their meter data to 3rd parties approved by the customer (e.g. a competitive supplier or DER provider). This could be done through a utility specific or third-party hosted site or through a shared platform as is done in Texas, (https://www.smartmetertexas.com/CAP/public/home/home_about_us.html).

6. A low-cost method of collecting the interval data and allowing customer access to it in near real-time should be considered. Minimally this could be through a revenue grade optical port (true bidirectional optical ports for bidirectional meters).[11] Preferably this should allow LAN (local area network) access to read current or logged meter data, such as through a hardwired LAN connection to a customer router where the data is pushed to a cloud based data storage

[11] The problem with just using optical ports for real-time data logging and access it that in the event that the device reading the optical pulses losses power for any reason or duration, independent of the meter, the pulses will likely be undercounted and the resulting reported kWh will be incorrect.

site. At the customer's choice there should be an option for a wireless connection to a LAN, or a radio frequency (RF) connection to third-party cellular data service or WAN, when the customer doesn't have a secure LAN, or otherwise prefers to pay for a data service subscription.

Metering Concerns

1. Meters that control individual circuits or devices (on or off load control) should be avoided as this is also a significant cybersecurity concern and avoiding such minimizes issues with regard to RSA 374:62. It would be preferable for the customer or competitive supplier to procure their own load control gateway devices that could be part of a communication system for a secondary customer owned revenue grade meter.

2. Meters that require, as the only communication option, radio frequency (RF) pulse broadcasts should be avoided since potential RF radiation is a primary source of popular objection to smart meters. Opt-in advanced meters should have an option that allows RF communication to be turned off or not installed if the customer can provide a hardwired connection to an internet router for the meter or an accessory meter communication device.

3. Non-utility stakeholders: Meters with the ability to do remote disconnections should be avoided as an opt-in option. Remote service disconnections are a primary cybersecurity risk for advanced meters, since a security breach could cause considerable individual harm (including death) and system harm (such as sudden and damaging voltage surges with mass disconnects) by executing unauthorized disconnections (and power on when not expected). This point is only in reference to a technology opt-in that the individual customer or their energy service supplier would pay for. Customers should not be forced to include and pay for remote disconnect functionality, especially where such is not present in their current meter.

Utilities: The utilities do not agree to this restriction because there are times when utilities desire to remotely disconnect/reconnect customers for a variety of reasons (frequent customer changes (move-in/move-outs), seasonal customers, or for non-payment; and efficiency, security or safety reasons). Unitil and Eversource currently have remote disconnect functionality.

4. City of Lebanon, Revolution Energy, RESA, Acadia, NECEC, CLF, EFCA, DES??: Customers should have the ability to choose an opt-in interval meter, including bi-directional meters for distributed generation customers, capable of logging or compiling and storing kWh interval data down to a granularity of at least hourly intervals, and ideally five-minute, intervals to enable

retail access to real-time pricing, pursuant to RSA 374-F:3, II.[12]

Utilities, OCA, Pat Martin: If the customer chooses to install interval metering to pursue opportunities in the wholesale markets or for their own informational purposes, utilities cannot use this data for billing and reporting purposes under current rules and tariffs. Should customers decide to install meters for their own purposes and at their own cost, customer can choose whatever time interval makes sense for their own needs. However, five-minute interval data should not be required at this time nor should be identified as a requirement without first conducting a cost/benefit analysis. The difference in providing five-minute versus 15-minute interval data could prove to be costly and will likely require new meters, larger databases, increased communication bandwidth, etc. A cost/benefit analysis of requiring 5-minute interval data should be completed before it is included in the technology requirements.

5.2 Customer and Utility Data

Principles

The Working Group all agree to the following principles related to customer and utility data, except where noted:

1. Sharing of data with the market (including third-party providers) can encourage market competition for the provision of advanced energy technologies.
2. In general, use of standards and protocols for data sharing can facilitate interoperability, empower 3rd parties, and provide the opportunity for customers to reduce their costs or system costs. (Examples of data standards include: Standard Energy Services/Usage Data, Green Button, and "Connect My Data.")

[12] The reason for enabling five-minute interval data is to allow retail customers the choice of getting and responding to real-time prices as called for by RSA 374-F:3, II. Pursuant to Order No. 825 in Docket No. RM15-24-000, (also 18 CFR Part 35), FERC has required ISOs to settle "energy transactions in its real-time markets at the same time interval it dispatches energy," which is at a five-minute interval in New England. ISO-NE began settling its real-time energy market in five-minute intervals on March 1, 2017. While load in the real-time market is now technically settled at the same five-minute interval as generation and dispatchable-asset-related demand resources (DARDs), load is still be charged based on hourly interval meter reads that are flat profiled (by dividing those readings by 12 to create five-minute intervals, which assumes flat load shape for the hour). However, the new software deployed by ISO-NE for the real-time energy market is capable of accepting five-minute interval meter data. ISO-NE has indicated that some tariff changes will be needed before they will be able to settle load in actual five-minute intervals (versus hourly meter data divided by 12). So, it appears to be just a matter of time before load will be able to settle in real-time based on five-minute interval meter reads, and thus be enabled to alter demand, whether actual loads or BTM DG or storage, based on those real-time prices. Reasons that FERC and ISO-NE have stated for this five-minute settlement interval in the wholesale market in terms of improving price formation through better price signal resulting in improved market efficiency (savings) and reliability, also make sense for retail load that is enabled for RT pricing, which New Hampshire law calls for as a retail choice, hence the need and logic for five-minute interval capability for retail interval meters. At a minimum, customers who opt-in for new metering technology and pay for the new meters should have the option of this capability. The customer can do their own cost-benefit analysis if they are paying for it directly or through their energy service supplier. For more information on ISO-NE's subhourly settlement project, see: www.iso-ne.com/participate/support/customer-readiness-outlook/subhourly-settlements-project.

3. **Security is an inherent risk related to the sharing of customer data and must be addressed.**
4. **Interval data enables time varying rates, demand response, innovation, and can allow third-party service providers the opportunity to offer ways to reduce system costs, or for customers to reduce their own costs.**
5. **Aggregated customer information can be made available if certain protocols to protect individual customer usage and identity are adopted.**
6. **Individual customer data should be made available consistent with the requirements and protections set forth in RSA 363:38.**
7. **An individual customer is always free to share the customer's data with third parties, but utilities and third parties should take care to make customers aware of the risks created by such sharing.**

Customer Data

Third-party access to customer centered data, such as meter data, enables analysis of granular energy usage data. The analysis of historical granular energy usage data could enhance the Commission's and stakeholders' ability to evaluate diverse regulatory issues such as time and location based tariff designs, net metering, revenue decoupling, and energy efficiency program effectiveness. Third-party access to granular customer-centered energy data will enable new and innovative advanced technology solutions that educate and empower the consumer.

Utility Data: Hosting Capacity Analysis

The utilities and stakeholders should agree on assumptions for the hosting capacity analysis, including any assumptions on the DER system configurations. Those assumptions will influence how and what load data is analyzed, formatted, and published for publication, posting and/or sharing with market participants, and are a critical component to supporting development of a competitive energy services market in New Hampshire.[13]

Utilities should provide information about the hosting capacity for each circuit using a "bucket" approach such as coding distribution circuits green, yellow, or red to indicate how much room remains for incremental DG before relatively costly upgrades maybe needed

- Green – No upgrades necessary regardless of the DER location
- Yellow – Some upgrades and/or additional analyses may be necessary, depending upon the DER location
- RED - Upgrades necessary regardless of DER location

[13] By way of agreement on assumptions for hosting capacity analysis, the Working Group recommends adopting the Raab Associates' Final Report "Proposed Changed to the Uniform Standards for Interconnecting Distributed Generation," MA D.P.U. 11-75, Sept. 14, 2012, as a basis to continue interconnection analysis discussion in NH given the overlap of utilities and DER providers NH and MA.

Utility Data: Constraint Relief Analysis

Non-utility stakeholders: The utilities should also make available the more detailed data for load and load shape by time of day and month and circuit capacity (feeder and substation loads and capacity) which utilities have and use to make hosting capacity calculations and for planning purposes – by circuit.

Currently, consumer and third-party access to data is limited. Access to such data will require collaboration with utility partners. Data sharing is critical to grid modernization as it informs customer choice, spurs economic development, supports innovation, enables credible auditing of utility investment plans, supports public safety, and eventually will foster a robust transactive energy marketplace. Conversely, solely publishing outcomes of utility analyses rather than sharing the underlying data does not enable sufficient industry stakeholder engagement or competition. Data access and transparency is the foundation of current ratepayer advocacy efforts.

While data on specific utility-identified grid needs is critical to assessing innovative solutions in place of traditional investments, underlying grid data should also be made available to foster broader engagement in grid design and operations. Competitive least cost solutions require that third parties have access to information in the utilities Electrical System & Planning studies for the subtransmission and distribution, circuit-by -circuit subtransmission and distribution system constraints, projected violations and planning information, and cost for proposed solutions provided by the utilities. This information is critical to assessing innovative solutions as new alternatives to traditional investments, as well as in fostering broader engagement in grid design and operations.

The data in Table 5.3 should be made available and kept current by utilities in order to encourage broad engagement in grid design.

Table 5.3 Data to Encourage Broad Engagement in Grid Design

Data to Foster Engagement in General Grid Design and Optimization

DATA NEED	DESCRIPTION
Circuit Model	The information required to model the behavior of the grid at the location of grid need.
Circuit Loading	Annual loading and voltage data for feeder and SCADA line equipment (15 min or hourly), as well as forecasted growth
Circuit DER	Installed DER capacity and forecasted growth by circuit
Circuit Voltage	SCADA voltage profile data (e.g. representative voltage profiles)
Circuit Reliability	Reliability statistics by circuit (e.g. CAIDI, SAIFI, SAIDI, CEMI)
Circuit Resiliency	Number and configuration of circuit supply feeds (used as a proxy for resiliency)
Equipment Ratings, Settings, and Expected Life	The current and planned equipment ratings, relevant settings (e.g. protection, voltage regulation, etc.), and expected remaining life.
Area Served by Equipment	The geographic area that is served by the equipment in order to identify assets which could be used to address the grid need. This may take the form of a GIS polygon.

Utilities: The electric system is dynamic with constantly changing new customer loads, distributed generation interconnections, circuit configurations, planned upgrades, maintenance, outage restoration, power flows, protection system changes, etc. The posting and updating of electric system information would be a labor-intensive process and impossible for the utilities to keep the information up to date. The value of sharing this large amount of data is questionable since each utility is responsible for the safe and reliable operation of the electric system and will complete its own analysis for each DER regardless of what a third-party analysis demonstrates.

The utilities are responsible for the safe and reliable operation of the electric system that includes but is not limited to system planning. All proposed non-traditional solutions would need to be designed to the same level of capacity, reliability, power quality and availability as a traditional solution so the projects can be compared from a relative cost standpoint. Ownership, control and maintenance issues associated with non-traditional solutions pose a serious concern and will need to be addressed on a case by case basis. Any proposed system change will require the utility to conduct an evaluation to ensure there is not an adverse impact on the safety or reliability of the electric system.

The electric distribution system is dynamic with constantly changing new customer loads, distributed generation interconnections, circuit configurations, planned upgrades, maintenance, outage restoration, power flows, protection system changes, etc. The posting and update of electric system information would be a labor-intensive endeavor. The utilities have a concern that the dynamic nature of the electric system will make it impossible to keep any posted information updated to the current conditions. Utilizing selected elements of data, without the benefit of a holistic and comprehensive view of the system would easily lead to false conclusions. Most system enhancements take into account a combination of normal and contingency capacity ratings, reliability performance and improvement opportunities, asset condition and replacement opportunities, safety, and system operating performance in addition to solution economic and implementation risk.

Each utility may be starting from a different state of readiness with respect to the data being requested. The electric systems are complex with service territory consisting of multiple large planning areas with multiple substations and circuits of which each have varying designs, configurations, backup, protection, and control parameters. In some cases, the electric utility does not have the level of information that is being requested. For instance, the Working Group has discussed providing interval metering at the substation and circuit level. Not all of the utilities have this level of information and it becomes costly to install metering to get this information.

Electronic Data Access System

Non-utility stakeholders: An Electronic Data Access system or platform, containing both utility-centered data and customer-centered data[14], should be created. A study should be undertaken to determine the specific data to include and how to share it. Data in the Electronic Data Access system should be managed and shared using national standards, while enforcing security and privacy measures to protect all stakeholders and New Hampshire ratepayers.

---

14 The Berkeley Law January 2015 paper "Knowledge is Power" discusses energy data in terms of two buckets – Utility centered data and customer centered data. https://www.law.berkeley.edu/files/Knowledge_Is_Power.pdfhttps://www.law.berkeley.edu/files/Knowledge_Is_Power.pdf

Utilities: Do not agree with this electronic data access system recommendation for reasons described above under Utility Data: Constraint Relief Analysis

5.3 Customer Education

The Working Group recommends that the utilities will take the lead on educating their customers about grid modernization related activities and opportunities. In developing grid modernization-related customer education strategies, utilities should coordinate with each other and consult with stakeholders on common messaging and other aspects of an on-going education campaign. The Working Group further recommends that NH state government through the OCA, PUC, or both should also be engaged in customer education around grid modernization activities and opportunities in ways that complement, support, and re-enforce the utilities efforts (e.g., thru a state Grid Mod website).

Customer Engagement Platforms

The Working Group also recommends the development and use of customer engagement platforms by utilities that can examine various pieces of customer energy usage and other data and make cost-saving recommendations to customers. Utilities use customer engagement platforms to better educate customers as to how they use energy and encourage broader participation in energy efficiency programs that reduce system costs for all customers. The Working Group acknowledges that Eversource has recently developed a promising platform, and recommends that the other utilities also develop a customer engagement platform.

Non-utility stakeholders: A statewide platform should be developed for the following reasons: lower cost, risk mitigation, consistent Energy Efficiency policy, and a uniform customer engagement experience for all New Hampshire energy customers. Any statewide platform should be able to be tailored to each utility's customer and service offerings.

Utilities: All three utilities operate in multiple jurisdictions, and offer multiple services (i.e., gas, water, electric). Therefore, the utilities prefer to preserve the ability to develop customer engagement platforms tailored to their own customers and service offerings.

Consolidated Billing

Non-utility stakeholders: The Commission should investigate the merits, technical and operational capabilities as well as the related benefits & costs of expanding the current billing options in the state of New Hampshire to include a "Supplier Consolidated Billing" option where the retail supplier will be responsible for billing energy supply, transmission, distribution and all applicable distribution charges. A key overarching goal stated in the Commission's Grid Modernization Scoping Order is to *"empower customers to use electricity more efficiently and to lower their electricity bills"*. There is no more fundamental means to empower and educate customers than providing meaningful and actionable energy usage information on their bill. However, when we talk about energy consumption, most residential and small businesses consumers interact with their energy costs and consumption via a confusing, oftentimes arcane billing statement. Moreover, realizing cost savings from significant gains in energy efficiency will likely not come not from consumers interacting directly with their raw usage energy data, but rather from the value-added tools and products offered by competitive energy suppliers and other third parties. These innovative tools and products are largely enabled by smart meter technology deployed on a modern distribution grid. Leading retail suppliers are attempting to assist their customers to better understand their energy consumption and usage patterns by providing energy bills with detailed break-downs of their usage by end uses.

Utilities: The current billing option should not be expanded to allow a competitive supplier to bill not only energy supply, but also the utilities' delivery charges. Allowing this option would have several adverse effects on customers and the distribution companies. First, it would result in a weakening of the Commission's ability to enforce its consumer protection regulations because of the increased number of providers to whom the regulations would apply. This applies to collections, as well. The PUC 1200 rules provide a vehicle for the utilities to collect payment or disconnect if the customer is in arrears. The suppliers would need a set of rules that apply to them to deal with customers in arrears as the utilities would not be in the position to administer these rules when they do not have the billing data and they are no longer collecting. Second, it would weaken the relationship between distribution companies and their customers. Unless they call in, the bill is the only "touch point" for many of our customers. Also, it is not clear how distribution companies would communicate with, and distribute Commission mandated and other information to their customers. Third, this could create customer confusion on the part of customers as to which company is ultimately responsible for service and who to call in the event of an emergency.

The utilities are also concerned that their financial integrity could be affected. In such an environment, distribution companies would seek payment from suppliers, rather than their customers, for delivery service. The additional revenue risk from this arrangement could be substantial. To address this concern, distribution companies would need to ensure that suppliers providing billing services maintain adequate credit ratings or other financial instruments. The costs for the distribution companies to acquire, review, and maintain this information would likely be passed on to customers.

The utilities are the supplier of last resort which requires the utility to keep a billing system to bill those customers who do not take supplier service. Also, as the billing provider of last resort, distribution companies have fixed costs that would continue to be recovered from its customers. In addition, the incremental costs associated with developing communication and data exchange systems between the distribution companies and suppliers would be borne by customers.

6. Utility Cost Recovery/Incentives Framework

The Working Group recommends that the Commission adopt the utility cost recovery/incentives framework associated with grid modernization costs and investments described in this chapter.

A high-level process summary is as follows (detailed description to follow):

- Utilities develop grid modernization plans (GMPs) that describe incremental capital expenditures and O&M associated with Grid Mod investments
- Utilities file GMPs and corresponding testimony/exhibits for rate changes
- Commission reviews with opportunity for stakeholder intervention and discovery
- Commission pre-approves investments
- Expenditures are reconciled annually with Commission review, without re-examining the prudence of pre-approved investments
- Rates are reset annually
- GMPs are refreshed every three years following Commission's Order
- Performance-based and/or outcomes-based metrics could be implemented after tracking of grid modernization targets is in place for a long enough period of time to establish a baseline

Grid Modernization Plans

Each utility would submit a GMP to the New Hampshire Public Utilities Commission on a timeline established by the Commission. A utility's GMP would be designed to meet the established NH grid modernization objectives in a manner suitable for the unique characteristics of each system and rate plan. The high-level outline of a GMP can be found in Section 4, and the detailed outline for a GMP in Appendix C.

An individual utility approach would account for the unique service territory characteristics and various technologies currently deployed by each utility. A component of each GMP would be a business case justifying the expected costs and benefits of each utility's proposed portfolio of grid modernization investments.

A working proposal for an appropriate GMP outline, including general business case guidelines, is provided in Appendix C to this document.

Cost recovery

Utilities would be permitted to request targeted recovery of grid modernization plan development, support, and investments through cost recovery tracking mechanisms outside of base rates, with such mechanisms to be established by the Commission. For such mechanisms, the Utilities' requested revenue requirement associated with the grid modernization investments may include forecasted investments with return on and of the investments, grid modernization-specific O&M, property taxes, and other related costs.[15] The return on the investment would be based upon the utilities' most recently-approved cost of capital, as established in each of their most recently approved rate cases.[16]

Proceeding with proposed initiatives under the utilities' proposed GMPs would require pre-authorization by the Commission. Proposed grid modernization investments that are pre-authorized are presumed to be prudent, in terms of the decision to proceed with them. However, for reconciliation purposes, the utility still has to demonstrate that the actual costs incurred are reasonable.

GMP proceedings are expected to follow the normal course of Commission dockets that include requests for intervention, testimony, discovery, and hearings.

Upon approval, revenue requirements related to target investments in the GMP would be eligible for recovery across distribution customers based on cost causation.

Reconciliation

Following the first year of the rate change, and annually thereafter, utilities would be required to reconcile rates within an adjudicated Commission docket, conducted in a manner similar to other reconciling rate dockets (e.g., utilities' Reliability Enhancement Programs). The utilities would be required to provide sufficient documentation of pre-construction estimated costs, actual project costs, and explanation of any variance between the two, as would typically be provided during the context of a rate proceeding to justify the approval of the cost recovery for the capital additions. Whether a project is approved for recovery will not be revisited in a reconciliation docket.

Future GMPs and rate-setting proceedings

GMPs should be refreshed every three years from the last approval. Regardless of whether a GMP is refreshed in a given year, utilities may submit an annual rate filing reflecting changes to expected revenue requirements corresponding to pre-approved grid modernization projects, subject to reconciliation. In years that do not require a GMP refresh, utilities should submit a brief report updating the Commission on the progress of the GMP.

Performance metrics

Performance metrics will be addressed in the context of the Commission Grid Mod proceedings, and would be specific to the nature of the investment. Metrics would be proposed in the

15 Eversource, Liberty, and Unitil believe that this should also include any stranded costs that could occur as a result of the grid mod investment while the remaining Working Group members believe that this is not an appropriate element of capital trackers.

16 Any consideration of the effect such recovery mechanism on the cost of capital should be raised in the context of the next rate case proceeding.

utilities' Grid Mod Plan, and reviewed and approved by the Commission. Data will then be collected to inform establishment of performance-based and/or outcomes-based mechanisms, which could be implemented after tracking grid modernization targets for a long enough period of time to establish a baseline.

7. Recommended Next Steps for Commission

The Working Group's eight day-long meetings yielded many useful insights, and resulted in substantial progress toward shared understandings about how New Hampshire should move decisively toward a fully modernized grid that will meet the needs of its citizens and businesses in the decades to come. However, it is clear that key uncertainties and disagreements remain to be resolved. The Working Group therefore recommends the following potential next steps regarding reviewing this Report and furthering Grid Modernization in New Hampshire, before the utilities file Grid Mod plans.

1. Allow 30-60 days for any public comment on the Report
2. Hold one or more technical sessions or hearings on the Report following the 60-day comment period
3. The Commission to open a docket with testimony and discovery to fully adjudicate the non-consensus and other relevant items.
4. Issue a Commission Order that would include at least the following:
    a. Resolution of any WG non-consensus issues in the Report
    b. Address any gaps identified and issues not addressed in the Report.
    c. Any additional guidance on the Commission's grid mod related goals and priorities
    d. Any guidance on integration of grid mod w/other related dockets (e.g., net metering, energy efficiency)
    e. Address subsequent IRP filing requirements in relation to the Grid Mod filings, as described in Section 4.
    f. Schedule for utilities to file initial Grid Mod plans
    g. Delineate a stakeholder input process to develop common assumptions for the Grid Mod Plan filing, as described in Section 4.

Appendix A: Lead Representatives and Alternates

Table A.1 Lead Representatives and Alternatives

Organization	Representative	Alternate	Second Alternate
Acadia Center	Ellen Hawes		
City of Lebanon, New Hampshire	Clifton Below		
Conservation Law Foundation-New Hampshire	Melissa Birchard	Tom Irwin	
Energy Freedom Coalition of America	Todd Griset	Peter Brown	
Eversource Energy	Eric Chung	Matthew Fossum	
Liberty Utilities	Heather Tebbetts	Chris Brouillard	Michael Sheehan
New Hampshire Department of Environmental Services	Chris Skoglund	Joseph Fontaine	Rebecca Ohler
New Hampshire Legal Assistance	Dennis Labbe.	Stephen Tower	
New Hampshire Office of Energy and Planning	Rick Minard	Kerry Holmes	Deandra Perruccio
New Hampshire Office of Consumer Advocate	Donald Kreis	James Brennan	
New Hampshire Public Utilities Commission Staff (ex officio)	Tom Frantz	Les Stachow	Jim Cunnningham
NH Sustainable Energy Assn./Northeast Clean Energy Council/	Kate Epsen	Janet Gail Besser	Brianna Brand
Northeast Energy Efficiency Partnerships	Natalie Treat	Brian Buckley	
Patricia Martin, Retired Engineer	Patricia Martin		
RESA (Direct Energy/Exelon)	Marc Hanks	Dan Allegretti	
Revolution Energy	Clay Mitchell	Henry Herndon	
The Jordan Institute	Laura Richardson		
Unitil Energy Systems Inc.	Justin Eisfeller	Kevin Sprague	Gary Epler

Appendix B: Discovery Responses

The information presented in the tables below was provided by Eversource, Unitil, and Liberty in response to discovery requests that were included as Attachment B in the Commission's Order on Scope and Process in this Investigation into Grid Modernization, IR 15-296, April 1, 2016.

Table B.1 T&D Components That Are Automated

	Feeders			Substations			Capacitors		
	Total	Automated	Percent	Total	Automated	Percent	Total	Automated	Percent
Eversource	464	170	**37%**	173	102	**59%**	983	628	**64%**
Unitil	100	97	**97%**	30	28	**94%**	129	51	**40%**
Liberty	41	17	**17%**	15	10	**67%**	128	6	**5%**

Table B.2 T&D Components That Measure Minimum Load

	Feeders			Substations			Line section		
	Total	Min load	Percent	Total	Min load	Percent	Total	Min load	Percent
Eversource	464	252*	54%	173	102	59%	Not reported		
Unitil	System not configured to record			System not configured to record			System not configured to record		
Liberty	41	28	68%	15	5	33%	15	0	0%

*Number of fully automated feeders (170) and Source Automation only (82). Source automation can only be measured at source.

Table B.3 Substations That Are Capable Of Reverse Power Flow

	Substation transformers	Substation regulation	Feeder regulation
Eversource	8 known locations have reverse power flows due to larger Non-Utility Generator coming on line. Ultimately, each site could be made to accept reverse power, but scope of upgrades unknown till interconnection study is done.		For pole top regulators 48%
Unitil	No substation transformers designed for reverse power flow	No substation regulators designed for reverse power flow	No feeder/circuit regulators capable of reverse power flow. Sub-transmission systems designed for reverse power flow.
Liberty	No substation transformers capable of reverse power flow	27%	75%

Table B.4 Type & Location Of Network System Enablers - Eversource

Eversource		
Capability	**System Location**	**Notes**
Fault Detection, Isolation, Restoration (FDIR)	Distribution System and Substations	329 SCADA controlled substation breakers and 550 SCADA controlled pole top units capable of detecting faults. Some designed to trip while all others can be manually switched through SCADA to pick up load. A Distribution Management System (DMS) pilot installed in 2010 will be upgraded later in 2016. Expansion to the rest of the ESNH system is planned in future years to allow full automation for all existing SCADA controlled breaker and pole top units and any new units.
Automated Feeder Reconfiguration	Distribution System and Substations	FDIR devices continuously monitor the system, alerting operators of loading concerns and faults. A DMS pilot installed in 2010 will be upgraded later in 2016. Expansion to the rest of the ESNH system is planned in future years. to allow full automation for all existing SCADA controlled breaker and pole top units and any new units installed.
Integrated Volt/VAR Control, Conservation Voltage Reduction	Transmission, Distribution and Substations	65 substation capacitor banks controlled via SCADA. 14 pole top distribution capacitors controlled via SCADA. 563 distribution pole mounted capacitors that are controlled remotely via time, voltage, temperature or VAR controls. No CVR.
Remote Monitoring & Diagnostics (equipment conditions)	Transmission, Distribution and Substations	At major Transmission and Distribution Substations, alarms alert operators for various abnormal conditions.
Remote Monitoring & Diagnostics (system conditions)	Transmission, Distribution and Substations	All remotely controlled pole mounted reclosers and switches monitor the system providing voltage, current, power factor and fault indication.

Table B.5 Type & Location Of Network System Enablers - Unitil

Unitil		
Capability	**System Location**	**Notes**
Fault Detection, Isolation, Restoration (FDIR)	None	
Automated Feeder Reconfiguration	Distribution/Substation	2 locations
Integrated Volt/VAR Control, Conservation Voltage Reduction	None	
Remote Monitoring & Diagnostics (equipment conditions)	Substation	4 substations with GE and Weidman transformer hydrogen monitoring systems; SCADA system monitors e.g. communications, pressure, oil temps. Etc.
Remote Monitoring & Diagnostics (system conditions)	Distribution/Substation	AMI system provides system voltage, loads, outage and health information. SCADA sustem monitors e.g. communications, pressure, frequency, oil temps. Etc.

Table B.6 Type & Location Of Network System Enablers - Liberty

Liberty		
Capability	**System Location**	**Notes**
Fault Detection, Isolation, Restoration (FDIR)	Distribution Line Sections	Fault Indicators and Grid Sentry Line Sensors
Automated Feeder Reconfiguration	Distribution Line Sections	5 Loop Schemes
Integrated Volt/VAR Control, Conservation Voltage Reduction	None	None
Remote Monitoring & Diagnostics (equipment conditions)	None	None
Remote Monitoring & Diagnostics (system conditions)	Substation	Remote monitoring in 68% of breakers

Table B.7 Number Of Customers For Each Rate Offering

	Eversource			Unitil			Liberty		
	Residential	Gen. Service	Outdoor lighting	Residential	Gen. Service	Outdoor lighting	Residential	Gen. Service	Outdoor lighting
Flat energy rates	426,576	-	953	-	724	-	-	7,239	
Inclining block rates	-	-	-	65,237	-	-	35,435	-	-
Declining block rates	-	75,517	-	-	-	-	-	-	-
Seasonal Rate	-	-	-	-	-	-	-	-	-
Time-of-use rates	38	159	-	-	-	-	1,420		-
Critical peak pricing	-	-	-	-	-	-	-	-	-
Peak-time rebates	-	-	-	-	-	-	-	-	-
Total no. of customers:	426,614	75,676	953	65,237	11,181	1,706	35,877	6,436	685

Table B.8 Customer Options For Each Rate Offering

	Eversource			Unitil			Liberty		
	Residential	Gen. Service	Outdoor lighting	Residential	Gen. Service	Outdoor lighting	Residential	Gen. Service	Outdoor lighting
Flat energy rates	May opt-out to take service under Residential Time-of-day (TOD) or GS. Residential TOD opt-in.	Mandatory for Primary, Large GS. Opt-in for GS TOD. GS with approved applications may opt-out to take service under GS TOD	Mandatory	Mandatory for inclining block rates; n/a for others	Mandatory for flat energy rates; n/a for others	-	Mandatory except TOU opt-in rate for residential customers	Mandatory	
Inclining block rates									
Declining block rates									
Seasonal Rate									
Time-of-use rates									
Critical peak pricing									
Peak-time rebates									

Table B.9 Customer Participation In EE Programs, 2006 To 2015

No. of customers	Eversource		Unitil		Liberty	
	Residential	C&I	Residential	Gen. Service	Residential	Non-residential
2006	61,490	1,042	11,295	93	4,297	144
2007	77,143	972	10,883	110	5,194	87
2008	87,328	917	11,819	80	22,537	112
2009	71,216	1,187	9,456	100	14,064	83
2010	94,020	944	11,196	26	17,465	85
2011	79,194	862	9,887	77	19,386	118
2012	83,489	1,017	10,180	54	7,464	131
2013	80,714	1,252	10,498	81	20,622	47
2014	100,827	1,512	6,611	95	18,201	275
2015	94,840	987	8,295	95	22,317	176

Table B.10 Customer Participation In DR Programs, 2006 To 2015

No. of customers	Eversource		Unitil		Liberty	
	Residential	C&I	Residential	Gen. Service	Residential	Non-residential
2006	3,279	157	-	-	-	-
2007	3,319	136	-	-	-	-
2008	3,166	231	-	-	-	-
2009	3,303	251	-	-	-	-
2010	3,554	269	-	-	-	-
2011	3,614	229	-	-	-	-
2012	3,659	220	-	-	-	-
2013	3,675	219	-	-	-	-
2014	3,669	217	-	-	-	-
2015	3,620	211	-	-	-	-

Table B.11 Behind-The-Meter Technologies Installed

No. of customers	Eversource			Unitil			Liberty		
	Residential	Gen. Service	Total	Residential	Gen. Service	Total	Residential	Non-residential	Total
Photovoltaics	2,407	266	2,673	389*	39*	428*	272	24	296
CHP	1	14	15	0	1	1	0	2	2
Other DR	34	33	67	2**	7**	9**	N/A	N/A	N/A
Plug-in electric vehicles	Unable to determine	Unable to determine	Unable to determine	N/A	N/A	N/A	N/A	N/A	N/A
Batteries or other storage devices	Unable to determine	Unable to determine	Unable to determine	N/A	N/A	N/A	N/A	N/A	N/A
Total no. of customers:	426,614	75,676	502,290	65,237	11,181	76,418	35,877	6,436	42,313

** Data response by Unitil gives installations by fuel type. Unitil's "Solar" category is assumed to be PV.*
*** Other DR is the summation of Wind, Hydro, Gas, Wood and Biomass installations provided by Unitil*

Table B.12.a Annual Installation Schedule Of Current Meters - Liberty

The table below provides an annual schedule of the installation date of all of our current meters. Liberty Utilities converted the majority of the meter population to AMR in 2002. Of the approximately 43,000 meters, 3,000 are manually read and approximately 385 are interval meters probed monthly for hourly reads. Since 2002, the Company has introduced an AMR meter for customers with a demand of 20 KW – 200 KW. These meters are read using a probe wireless technology, or analog phone line.

Year	No. meters installed in year	No. AMR meters installed	No. of AMI meter
2002		Conversion year - majority of meters	0
Total current meters	43,333	40,254	0

Table B12.b Annual Installation Schedule Of Current Meters - Unitil

Year	UES Total	Notes
2005	158	Decision to AMI System was made, we started purchasing AMI meters even though the system wasn't in place.
2006	2,953	AMI project started in 3rd quarter of 2006
2007	49,786	AMI project replaced whole system
2008	3,116	These meter sets reflect URV replacement problem, not all new meter sets.
2009	1,782	These meter sets reflect URV replacement problem, not all new meter sets.
2010	3,983	These meter sets reflect URV replacement problem, not all new meter sets.
2011	2,188	These meter sets reflect URV replacement problem, not all new meter sets.
2012	2,268	These meter sets reflect URV replacement problem, not all new meter sets.
2013	3,178	These meter sets reflect URV replacement problem, not all new meter sets.
2014	2,567	These meter sets reflect URV replacement problem, not all new meter sets.
2015	4,013	These meter sets reflect URV replacement problem, not all new meter sets and PLX meter additions in Seacoast.
2016	1,029	These meter sets reflect URV replacement problem, not all new meter sets and PLX meter additions in Seacoast.
Total	77,021	

Table B12.c Annual Installation Schedule Of Current Meters - Eversource

	Eversource						
	AMR meters		Remotely read meters		Manually read meters		Total
Purchase years	C&I	Residential	C&I	Residential	C&I	Residential	
2016	5,646	4,220	1	0	0	0	9,867
2015	45,090	238,967	28	0	25	0	284,110
2014	23,460	219,928	8	0	107	0	243,503
2013	875	8,128	10	0	83	9	9,105
2012	458	3,494	6	0	208	14	4,180
2011	468	3,242	58	0	714	1	4,483
2010	292	1,768	43	0	261	2	2,366
2009	19	106	34	0	291	15	465
2008	30	445	10	0	337	6	828
2007	104	392	1	0	141	10	648
2006	13	75	2	0	320	10	420
2005	77	413	5	0	148	4	647
2004	228	1,356	7	0	339	20	1,950
2003	314	2,473	4	0	138	3	2,932
2002	227	1,173	2	0	148	114	1,664
2001	123	700	11	0	58	8	900
2000	130	731	5	0	458	9	1,333
1999 and earlier	9	105	0	0	363	339	816
TOTALS	77,563	487,716	235	0	4,139	564	570,217

Table B.13 Utility Metering Age And Cost Recovery Assumptions

	Eversource	Unitil	Liberty
Average meter age (years)	2	All meters: 20 Electronic endpoint meters: 7.5	Does not have data on meter life of the meters retrofitted to accomodate the AMR technology
Average book life (years)	35	20	19
Average assumed operating life (years)	20 to 25	Avg meter: 40 Endpoint: 20	19
Average expected life remaining (years)	18 to 23	12.5 (based on age of endpoints)	6 to 18

Table B.14 Current Practice For Meter Replacement

	Current practice for replacing meters	Replacement schedule?
Eversource	Meters that fail and under warranty: returned to manufacturer for correction/replacement. Replacement meters are replaced with like meters (AMR meters)	When warranty period expires, testing programs used to determing replacement schedule that may be needed.
Unitil	Replace meters with like meters.	Upgrading or installing ~500/year in one division with PLX enabled meters
Liberty	Failed AMR replaced with another AMR meter. Non-AMR meters replaced with AMR meter only when an AMR is available, otherwise a Non-AMR meter. AMR meters are replaced/exchanged for following reasons: Failed equipment, Access issues (Non-AMR to AMR), Regulated Sample Program.	-

Table B.15 Options When Meter Fails Or Requires Replacement

	Options available & selected	Reason
Eversource	Meter exchange, thereby replacing the entire meter	Lowest cost option; quickest resolution for any potential billing issues with the least service interruption for customers
Unitil	If AMI endpoint fails on a mechanical meter, Company replaces the endpoint; if mechanical meter fails, meter replaced with an electronic meter with built-in endpoint; if electronic meter fails, replaced with meter with and electronic meter with a built in endpoint. Purchasing separate endpoints will not be available after 2017.	
Liberty	Failed AMR meters replaced w/ another AMR meter; Non-AMR meters replaced w/ AMR meter if AMR meter is available, otherwise replaced with Non-AMR meter.	Company's policy is to replace entire meter when any part of the meter fails

Table B.16 Meter Replacements

	Type of meter chosen and why	Functions the replacement meter offers
Eversource	Two primary decision points in deciding what type of meter replacement: (a) Does it meet requirements for billing the specific customer where it is to be installed; (b) Does it comply with the requirements of the reading system used to collect billing data	None provided
Unitil	If AMI endpoint fails on a mechanical meter, endpoint replaced; if mechanical meter fails, meter replaced w/ an electronic meter w/ built-in endpoint; if electronic meter fails, replaced w/ meter with an electronic meter w/ a built in endpoint. Purchasing separate endpoints will not be available after 2017.	New meters can measure voltage by default; if a PLX meter is installed it also offers interval metering capability.
Liberty	If a meter fails, it is replaced with an AMR meter unless interval data is required.	None provided

Table B. 17 Number Of Customers With Following Meter Capabilities

			Eversource*			
			AMR & remotely read meters		Manually read meters	
	Liberty	Unitil	Residential	C&I	Residential	C&I
a. Drive-by meter reading	40,254	All AMI	487,716	77,563	0	0
b. Time-of-use register	1178	All	40	0	1	345
c. Reading of interval data	358	2170, currently expanding capabilities	1	234	112	1,815
d. Daily reading at the Company's office	8	All	1	234	0	0
e. On-demand / real-time meter reading	8	All	1	234	0	0
f. Communication to meter from the Company	0	All	0	0	0	0
g. Communication from meter to customer end-use equipment	0	None, but system capable	0	8	16	1,537
h. Remote switch for service connection / disconnection.	0	451, but system capable	11,799	1,011	0	0
i. Power quality reading	0	1903, but system capable	0	0	0	0
j. Outage identification and restoration notification	0	All	0	0	0	0
k. Planning data (snap-shot demand and system reads).	0	All	0	0	0	0

Appendix C: Illustrative Outline for NH Grid Modernization Plans

1) **List of Acronyms used in the plan**
2) **Executive Summary**
   a) Grid Mod Vision /Strategy (where will we be in 10 years, how will the Company get there
   b) Recovery window aligned with the plan
   c) 10 Year plan updated at similar interval to LCIRP (3 years)
   d) Envision GMP will take over LCIRP over time – Combine LCIRP/GMP
   e) Cost Causation Principles
3) **Introduction**
   a) Purpose of the Filing
   b) Regulatory Requirements
      i) *GMP and Cost Recovery Requirements*
      ii) *The Business Case Analysis*
   c) Grid Modernization Objectives
   d) Compliance with the Filing Requirements
4) **Grid Modernization Plan**
   a) Approach
   b) Overview of the Plan
      i) Grid Mod Roadmap (10 year High-level project sequence and dependencies
      ii) 5 years spending "pre-approved"
   c) Stakeholder Engagement
      i) Customer education component prior to engaging the customers
      ii) Involvement in the pre-planning and prioritization and project consideration (input to the plan, not review of the plan)
      iii) Prior to plan submittal, solicit comments on the proposed plan
   d) Role(s) of 3rd Parties
   e) Investment Plan
   f) *Key Factors for Projects*
      i) First 5 years of plan
      ii) "Pre-approved" spending portion of the plan
      iii) Annual cost recovery filing
   g) Rate Recovery Assumptions
   h) Project Portfolio and Business Case Analysis
      i) *Project descriptions*
      ii) *Projected project costs and benefits; (singular project analysis and/or combined project analysis)*
      iii) *Impact on metrics and state policy goals*
      iv) *Alternatives analysis/discussion*
      v) *Portfolio benefit to cost ratio*
      vi) Grid Security and Cyber Security Considerations
      vii) *Based upon a combination of utility, vendor, and RFP/RFQ estimates*
      viii) *Common Business Case Assumptions:*
         (1) *Common societal assumptions – carbon savings, etc.*
         (2) *Customer avoided cost of reliability*
         (3) *Rate of inflation - Moody's Analytics*
         (4) *Energy forecast (kWh) - Analyses conducted by the ISO-NE. More granular forecasts will be Distribution Company-specific.*
         (5) *Demand forecast (kW) - Analyses conducted by the ISO-NE. More granular forecasts will be Distribution Company-specific.*
         (6) *Forecast capacity prices - Third-party consultant to perform this analysis.*

Analysis conducted will be comparable to the analyses conducted for long-term renewable energy contracts.

(7) Forecast energy prices - Third-party consultant to perform this analysis. Analysis conducted will be comparable to the analyses conducted for long-term renewable energy contracts.

(8) Forecast Renewable Energy Certificates ("RECs") - Third-party consultant to perform this analysis. Analysis conducted will be comparable to the analyses conducted for long-term

(9) Recovery of Stranded Costs as part of the business case

(10) Methodology for determining discount rate

(11) Time horizon for evaluating investments

(12) Sensitivity Analysis - Variables that are best suited for a sensitivity analysis are those for which a small change in an assumption can lead to a large change in the resulting output of a calculation.

ix) Implementation Roadmap

i) Additional Plan Components
- *i) Marketing, Education and Outreach for Customers*
- *ii) Research Development &Deployment (RD&D)*
- *iii) Privacy and Customer Data Access*
- *iv) Program Build Metrics*

j) Financial Summary

5) Rates and Regulatory

a) Regulatory/Ratemaking Framework
- *i)* Proposed rate mechanism
- *ii)* Rate impact by customer class

b) Cost Recovery
- *i)* Study Costs
- *ii)* Stakeholder engagement costs
- iii) Marketing and Research Costs
- iv) Incremental O&M and Capital Costs

6) Appendix

a) Projects Considered
b) Benefit/Cost Models
c) Revenue Requirement and Customer Bill Impact
d) Supplemental Studies