New Hampshire Public Utilities Commission

Staff Recommendation on Grid Modernization

IR 15-296 Investigation into Grid Modernization

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Table of Contents

Tables and Figures

Executive Summary

The electric grid modernization (grid mod) initiative provides a venue for broad stakeholder input regarding the integration of distributed energy resources (DERs) into the existing electric grid, with direct customer and developer engagement in the process while ensuring that the electric utilities continue to provide safe and reliable service at just and reasonable rates. The New Hampshire legislature directed the New Hampshire Public Utilities Commission (Commission or PUC) to open a docket on electric grid modernization, which resulted in the formation of a stakeholder Working Group and issuance of a report (Grid Mod Working Group Report, or Grid Mod Report). Subsequent to the issuance of the Grid Mod Report, PUC Staff conducted additional research and received training from the United States Department of Energy (DOE) on a methodological approach for the development of a grid mod framework that aligns utility investment plans with grid mod objectives.

Based on the Grid Mod Report, further Staff research, and discussions with DOE grid mod experts, Staff proposes a recommended approach for utilities to assess their respective electric distribution systems and devise plans for least-cost distribution planning strategies that incorporate grid mod initiatives. Staff proposes that utilities be required to submit integrated distribution plans (IDP), which will integrate grid mod initiatives and supporting documentation into their existing least cost integrated resource plans (LCIRPs). Staff's approach first defines recommended objectives for electric distribution utilities, including capabilities and functionalities required by the distribution system to meet those objectives. Staff's proposed approach does not dictate specific solutions or technologies, but, instead, allows for a structured evaluation of potential alternatives to achieve customer benefits that can be traced back to the grid mod objectives. Staff's recommendation in this report (Staff Report) provides a structure that uses a holistic framework for consideration by the Commission, utilities, and stakeholders.

REGULATORY OVERVIEW

The grid mod process started with the passing of House Bill 614 on July 8, 2015 requiring the opening of an investigative docket to implement the goals of the *New Hampshire 10-Year State Energy Strategy*[1] (2014 NH Energy Strategy). After opening an investigative docket and receiving comments on the scope of the proceedings, the Commission hired consultants to provide expertise and assist in facilitating a Working Group comprised of stakeholders interested in grid modernization. The Working Group met a number of times during the course of approximately one year and issued the Grid Mod Working Group Report, entitled *Grid Modernization in New Hampshire*,[2] with associated appendices,[3] on March 20, 2017. The Grid

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[1] New Hampshire Office of Energy and Planning, *New Hampshire 10-Year State Energy Strategy,* September 2014. https://www.nh.gov/oep/energy/programs/documents/energy-strategy.pdf

[2] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

[3] Grid Modernization Working Group, *Appendices, Grid Modernization in New Hampshire,* March 20, 2017. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_APP_FINAL_RPT.PDF

Mod Working Group Report presented consensus recommendations on many issues, where possible, but provided limited direction on next steps in grid modernization for the Commission.

Since the issuance of the Grid Mod Working Group Report, Staff has researched other grid mod dockets and attended training organized by NECPUC and provided by the DOE, based on DOE's Office of Electricity Delivery & Energy Reliability's Modern Distribution Grid report[4] (DOE Modern Grid Report). DOE's approach for distribution planning and grid operation links investments to stated objectives and goals while building a platform for the distribution system that will facilitate the integration of DERs.

One of the recommendations of the Grid Mod Working Group Report was to identify related dockets and determine how to integrate them in the grid mod initiative. Staff identified related dockets as listed in Table ES-1.

Table ES- 1 Dockets Related to Grid Mod

Docket Topic	Docket Number
Distributed Generation Net Metering Tariff (and Time-of-Use Rates, Value of DER, and Locational Value Analysis)	DE 16-576
Interconnection Process	DE 15-271
Energy Efficiency Programs	DE 15-137, DE 14-216, DE 17-136
Peak Demand Reduction Goals	DE 16-714, DE 17-101
Utility DER Ownership/Time of Use Rate Design	DE 09-137, DE 17-189
Least Cost Integrated Resource Plans	DE 15-248, DE 16-097, DE 16-463
Distribution Service Rate Cases	DE 16-383, DE 16-384, DE 09-035
Utility Reliability Enhancement Programs (REPs)/Vegetation Management Programs (VMPs)	DE 16-383, DE 16-384, DE 17-196, DG 06-107, DE 10-055, DE 06-028

PROPOSED APPROACH FOR INTEGRATED DISTRIBUTION PLANS

As noted above in the related docket list, utilities are required to submit an LCIRP on a periodic basis. RSA 378:38 lists certain elements that must be included in the LCIRP, including a demand forecast and assessments of demand-side energy management programs and supply options. The LCIRP must also assess distribution and transmission requirements, as well as the benefits and costs of smart grid technologies. In addition, the LCIRP must include an assessment of plan integration and impacts on state compliance with environmental requirements, assessments of the plan's long- and short-term environmental, economic, and energy price and supply impacts, and consistency with the state energy strategy.

The Grid Mod Working Group proposed to combine the existing LCIRP requirements with a grid mod plan. Staff agrees with this approach and proposes that the utilities be required to submit more comprehensive IDP's which integrate grid mod initiatives and supporting documentation into the LCIRP. The IDP would include a 5- and 10-year roadmap for each utility and determine the least cost options for operating distribution and sub-transmission

[4] US Department of Energy, Office of Electricity Delivery & Energy Reliability, *Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, Version 1.1,* March 27, 2017; *Volume II: Advanced Technology Maturity Assessment, Version 1.1,* March 27, 2017; *Volume III: Decision Guide,* June 28, 2017. https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

systems by analyzing both traditional utility investments and non-utility owned resources. The IDP must review technologies and processes that will enable the integration of DERs at varying levels of penetration while ensuring reliability, resiliency, and safety.

The proposed approach for the IDP focuses on the functionalities and related technologies and process changes required within five years: 1) to support the grid mod objectives; (2) to maintain a technology-neutral approach; and (3) to stay neutral on roles, industry structures, and business models. This approach allows for the grid to evolve over time, starting with the planning stage and moving to the grid operations stage and then to the grid services/markets stage. This requires a disciplined approach that requires the utilities to look beyond the five year investments and utilize a system level model approach to assess the overall grid health.

Grid architecture provides the framework to manage the complexity and the risk associated with making grid changes and helps to identify hidden interactions and technical gaps so as to reduce the likelihood of unintended consequences and stranded investments.[5] This approach increases the likelihood of future proofing investments in various platforms within the electric grid structure.

To develop the grid architecture, the objectives must first be determined, followed by the associated capabilities and the associated functionalities, as shown in Figure ES-1. Once the objectives, capabilities, and functionalities are understood, the appropriate solution, technology, or process change can be determined while taking into account any legacy constraints and the current environment. This mapping methodology allows for traceability and accountability so that a given solution ties back to a specific objective. Note that each objective will match to multiple capabilities and functionalities as shown in Figure ES-2.

[5] https://gridarchitecture.pnnl.gov/media/The%20Need%20for%20Grid%20Architecture.pdf

Figure ES- 1 High Level Schematic View of the Relationship of Various Aspects of Grid Architecture

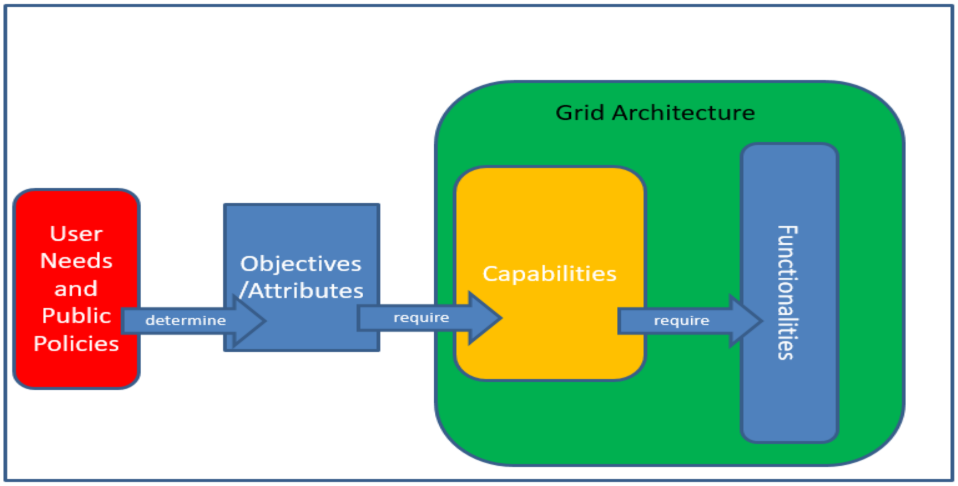
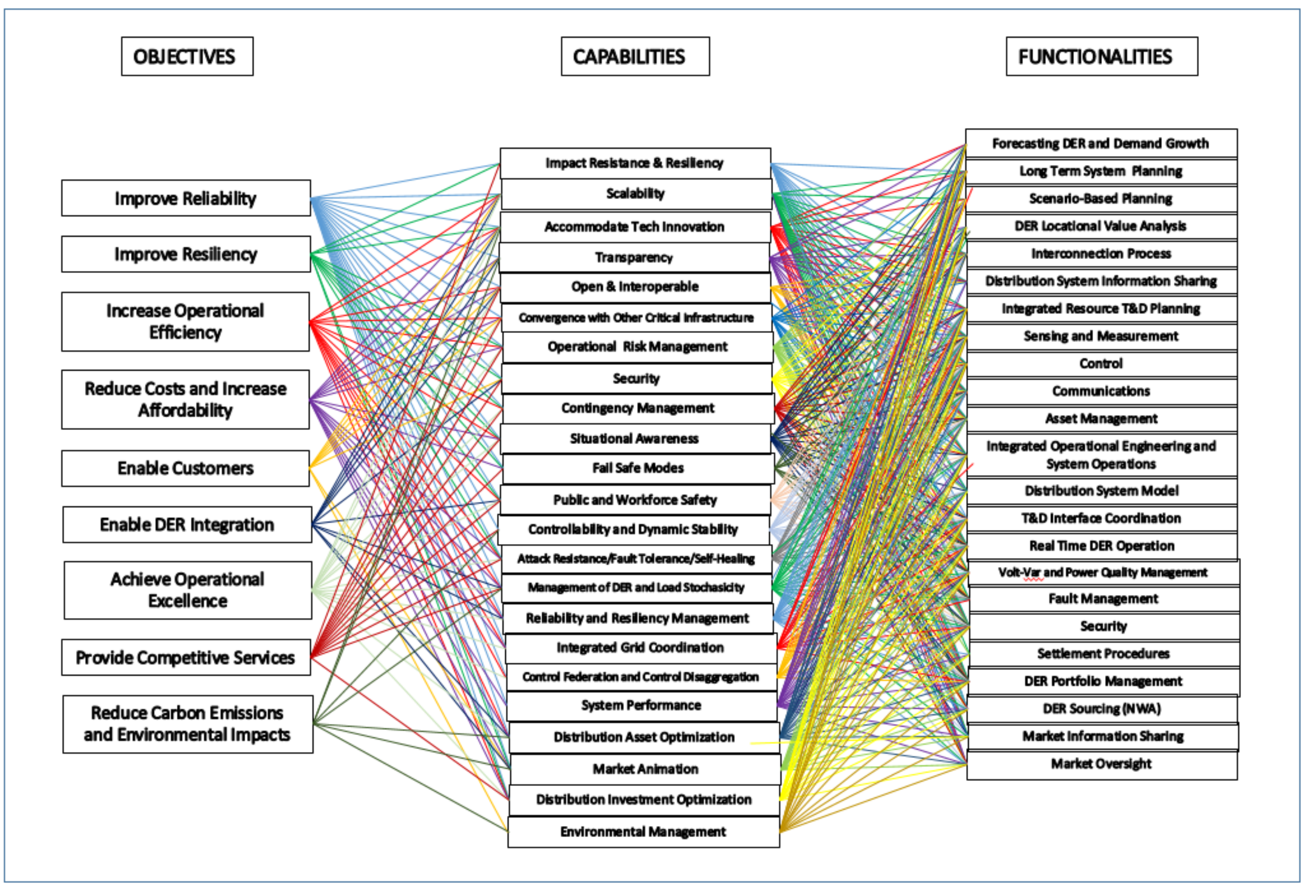
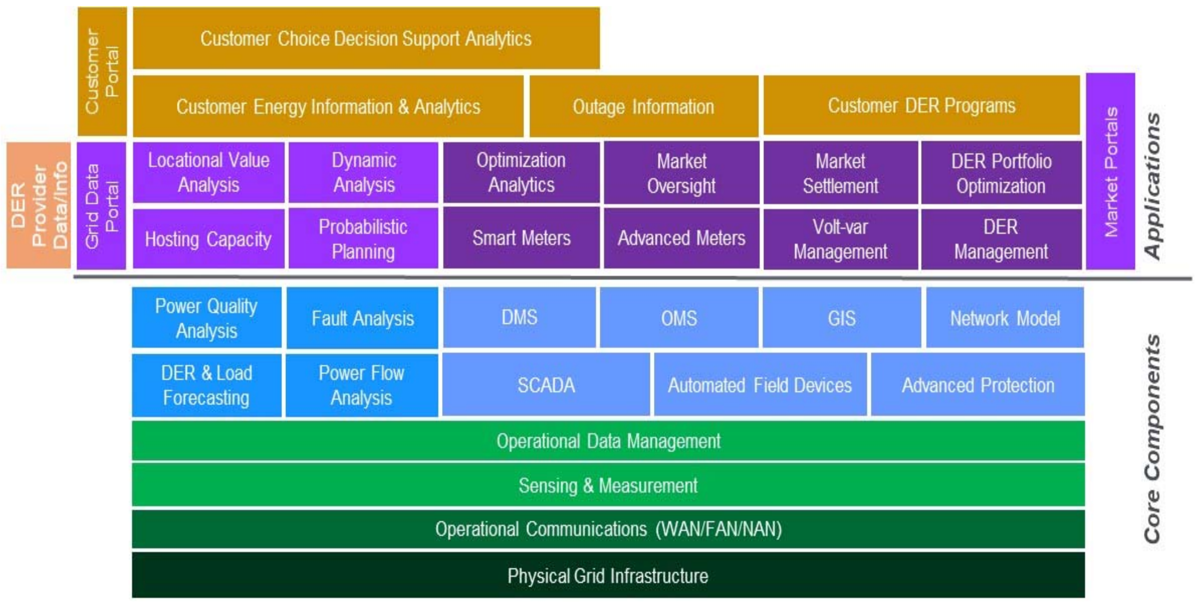


Figure ES- 2 Complex Mapping of Objectives, Capabilities, and Functionalities



To verify that the grid architecture meets the required objectives, Staff suggests that each utility assess its current system functionalities and perform a gap analysis between the existing and required functionalities. Next the utilities will determine what additional functionalities are necessary to meet the desired grid capabilities. Then the utilities will ensure that the grid capabilities will meet all applicable objectives. After each utility has assessed its system, it can select the appropriate solutions and build the distribution system platform to meet the objectives. Figure ES-3 illustrates the distribution system platform and the core technology components and applications. Each distribution system may have different needs or solutions.

Figure ES- 3 *Distribution System Platform with Core Technology Components and Applications*[6]



Green - Core Cyber-Physical Layer (including poles and wires)
Blue - Core Planning & Operational Systems
Purple - Applications for Planning, Grid & Market Operations
Gold - Applications for Customer Engagement with Grid Technologies
Orange - DER Provider Application

PROPOSED IDP OBJECTIVES, CAPABILITIES, AND FUNCTIONALITIES FOR NEW HAMPSHIRE

To provide utilities with the basis from which to assess their electric distribution systems, Staff identified applicable objectives, capabilities, and functionalities. Building upon the objectives originally outlined by the Commission and expanded upon in the Grid Mod Working Group Report, Staff identified the following objectives:

- Improve reliability, resiliency, and operational efficiency
- Reduce generation, transmission, and distribution costs and increase affordability
- Empower customers to use electricity more efficiently, lower electricity bills, and ensure access to usage data in readily accessible form, which can be made available to third parties while retaining privacy
- Facilitate integration of DERs
- Better align interests of energy consumers and producers to optimize system performance, while enabling strategic electrification of buildings, homes, and vehicles
- Keep New Hampshire technologically innovative, economically competitive, and in step with the region
- Reduce environmental impacts and carbon emissions in New Hampshire

[6] US Department of Energy, Office of Electricity & Energy Reliability, *Modern Distribution Grid Report, Volume III*, 2017.

Staff identified the capabilities that would be necessary to meet these objectives for each of the evolutionary stages--planning, grid operations, and grid services/markets--as shown in Table ES-2.

Table ES-2 *Capabilities*

Planning
• Impact resistance and resilience • Scalability • Accommodate tech innovation • Transparency • Open and interoperable • Convergence with other critical infrastructure
Operations
• Operational risk management • Security • Contingency management • Situational awareness • Fail safe modes • Public and workforce safety • Controllability and dynamic stability • Attack resistance/Fault tolerance/Self-healing • Management of DER and load variability • Reliability and resiliency management • Integrated grid coordination • Control federation and control disaggregation
Grid Services/Markets
• System performance • Distribution asset optimization • Market animation • Distribution investment optimization • Environmental management

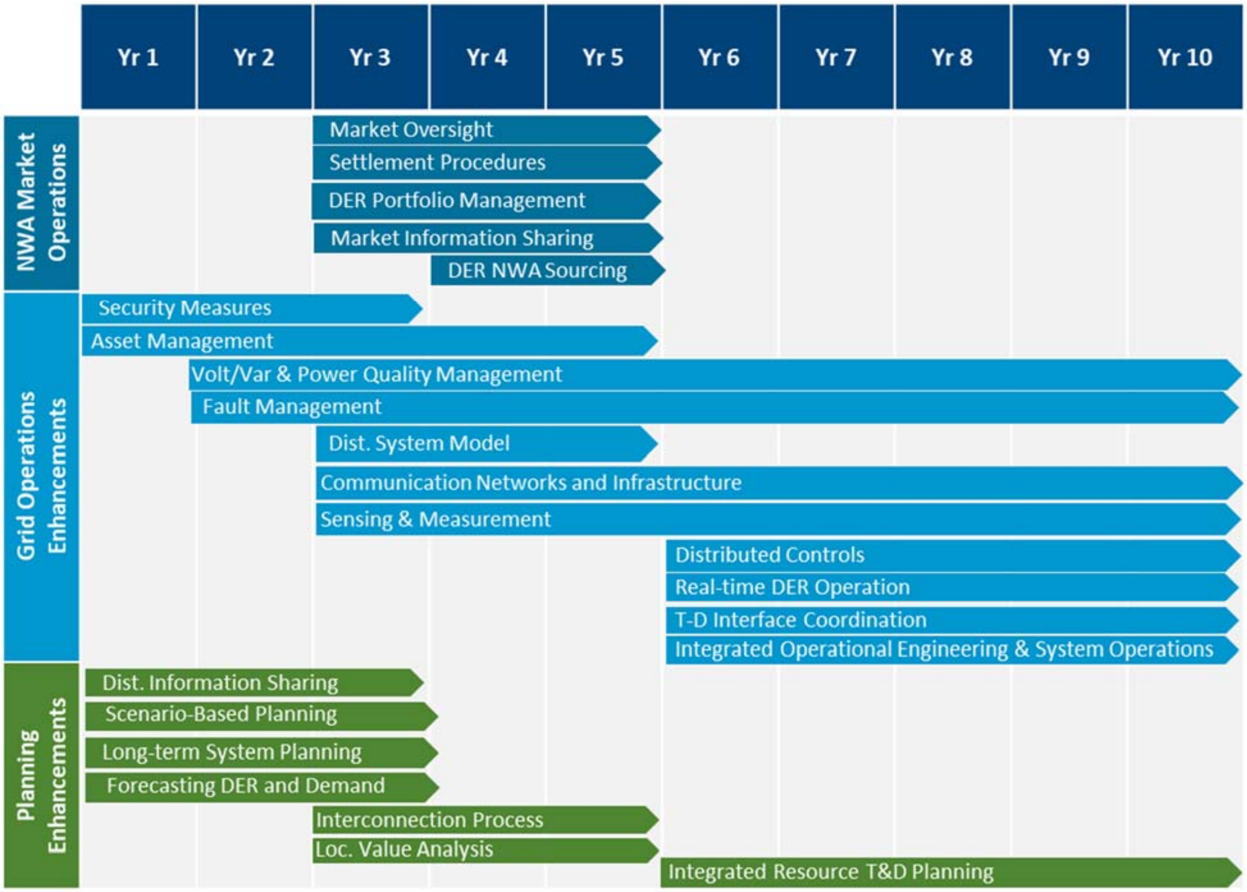
As shown in Table ES-3, Staff then identified the functionalities that will be necessary to meet the identified capabilities and objectives.

Table ES- 3. Functionalities

Planning	
➢ **Forecasting DER and Demand Growth** • Short- and Long-Term Demand & DER Forecasting ➢ **Long-term System Planning** • Load Flow Analysis Process • Hosting Capacity Analysis (long-term planning use case) ➢ **Scenario-Based Planning**	➢ **DER Locational Value Analysis** ➢ **Interconnection Process** • Interconnection Studies Enhancements • DER Interconnection Process Streamline • Interconnection Portal ➢ **Distribution System Information Sharing** • Planning Data Sharing (portal/mapping) ➢ **Integrated Resource T&D Planning**
Grid Operations	
➢ **Sensing and Measurement** • Power State Measurement • Advanced Customer Metering • Meter Data Management • Environmental Sensing ➢ **Control** • Grid Configuration and Connectivity • Flow Control ➢ **Communications** • Communication Infrastructure • Communication Network Management ➢ **Asset Management** • Asset Monitoring (substation) ➢ **Integrated Operational Engineering and System Operations** ➢ **Distribution System Model**	➢ **T-D Interface Coordination** ➢ **Real Time DER Operation** • Automated Islanding and Reconnection • State Estimation & Optimal Power Flow ➢ **Volt/VAR and Power Quality Management** • Volt VAR Control • PQ Measurement and Stabilization ➢ **Fault Management** • Advanced Protection & Relay Management • FLISR • Outage Management ➢ **Security** • Cyber Security Measures ➢ **Physical Security Measures**
Grid Services/Market Operations	
➢ **Settlement Procedures** • Measurement & Verification • Confirmation, Clearing • Settlement • Billing ➢ **DER Portfolio Management** • Optimization • Dynamic Notifications	➢ **DER Sourcing (NWA)** • Advanced Pricing • Programs • Procurement • Market Participant Rules ➢ **Market Information Sharing** • Market Information Sharing Portal ➢ **Market Oversight** • Market Surveillance • Market Security, Cybersecurity

Each of the functionalities will be addressed over a short term (1-3 years), mid-term (4-5 years), and long term (6-10 years), as shown in Figure ES-4.

Table ES- 4 Conceptual Functionalities Roadmap



GRID MOD WORKING GROUP REPORT

The Grid Mod Working Group Report addressed possible objectives, capabilities, functionalities, and desired solutions; however, these elements were not all linked in the systematic approach outlined above. Most of the items discussed in the Grid Mod Report will need to be addressed in the IDPs.

The Grid Mod Working Group Report included discussion of the stakeholder engagement process and cost-effectiveness framework as part of grid mod planning. Customer engagement discussions included recommendations for rate design (including customer charges; demand charges; time vary rates for generation, transmission, and distribution; and low income protection), advanced meter functionality, customer and utility data (including hosting capacity analysis, locational net benefit analysis, and electronic data access system), and customer education (including customer engagement platforms and consolidated billing by suppliers). The Grid Mod Working Group Report also discussed performance metrics and cost recovery and reconciliation.

Staff used the goals discussed in the Grid Mod Working Group Report to form the basis for the resulting objectives outlined above. Staff further examined many of the topics and provided a recommended approach in the Staff Report. The Staff Report provides further details and recommendations regarding these topics and how to address them in the utility IDPs.

IDP PROCESS AND CONTENT REQUIREMENTS

Staff recommends that each utility submit an IDP within 12 months of a Commission Order requesting the submittal. First, Staff recommends that stakeholders provide feedback on this recommended approach for the IDP. If a topic still needs further definition, Staff suggests that the Commission form working groups for additional discussion and stakeholder input prior to the submission of individual utility IDPs. Working Group topics under consideration include the following:

1. Rate design
2. Cost-effectiveness analysis methodology
3. Utility cost recovery
4. Utility and customer data access
5. Hosting capacity analysis
6. Locational value analysis
7. Metering
8. Customer education
9. Strategic electrification
10. DER pricing structure
11. Consolidated billing
12. Cybersecurity
13. Annual reporting requirements

Each IDP will include a 10-year roadmap of how the utility plans to meet grid objectives and a detailed 5-year implementation plan (capital investment/operational expense plan). Even though IDPs will vary from utility to utility, the core content will include the cost-effectiveness framework and associated assumptions to assess the feasibility of proposed solutions. The IDP will also describe current system capabilities and processes plus the 5-year capital investment plan and 5-year operational expense plan.

The IDP will discuss distribution planning, including load and DER forecasting, hosting capacity analysis, locational value analysis, DER interconnection process, and strategic electrification. Before choosing specific technological solutions, the utilities must assess architectural strategies and considerations that will allow for adaptability, scalability, efficiencies, and resilience. For distribution operations, the IDP will assess the various functionalities and the best solution(s) to achieve the given objective as well as how to provide transparency for customer engagement. The IDP will determine a deployment plan for cost-effective advanced meter functionality. The utilities will also include a proposed rate design, taking into consideration time varying distribution rates at a minimum. The IDP will also address cyber security and privacy issues which are required in both customer facing and distribution system investments. Finally, the IDP will propose grid mod and business-as-usual performance metrics, as well as a methodology for cost recovery.

1.0 Regulatory Overview

This section provides the regulatory background of the grid modernization initiative and outlines a list of related dockets.

1.1. Background to the Grid Modernization Initiative

On July 8, 2015, the Governor signed House Bill 614,[7] implementing goals of the *New Hampshire 10-Year State Energy Strategy*[8] (2014 NH Energy Strategy) developed by the New Hampshire Office of Energy and Planning. Pursuant to House Bill 614, the Commission "shall open a docket on electric grid modernization on or before August 1, 2015." The 2014 NH Energy Strategy states that "Grid modernization refers to a wide range of actions aimed at ensuring that the electric grid is more resilient and flexible, better able to integrate variable energy sources and demand side management, and capable of providing real time information to help customers manage this energy use and reduce energy cost." The 2014 NH Energy Strategy built upon other documents that had previously been issued, including *NH Climate Change Action Plan,*[9] *Additional Opportunities for Energy Efficiency in New Hampshire,*[10] *Independent Study of Energy Policy Issues,*[11] *Increasing Energy Efficiency in New Hampshire: Realizing Our Potential,*[12] and *2002 NH State Energy Plan.*[13] Even though these documents focus on energy efficiency or climate change, the goals of these programs are integral to the grid mod initiative.

On July 30, 2015, the Commission issued an Order of Notice[14] requesting comments on the scope of the grid mod proceedings. After reviewing the numerous comments received, Staff determined that a grid mod expert and a facilitator/moderator would be necessary. The Commission hired Raab Associates Ltd as facilitator/moderator and Synapse Energy Economics

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[7] New Hampshire House, An Act implementing goals of the state 10-year energy strategy, 2015, HB 614. http://www.gencourt.state.nh.us/legislation/2015/HB0614.pdf

[8] New Hampshire Office of Energy and Planning, *New Hampshire 10-Year State Energy Strategy,* September 2014. https://www.nh.gov/oep/energy/programs/documents/energy-strategy.pdf

[9]New Hampshire Department of Environmental Services, *The New Hampshire Climate Action Plan,* March 2009. https://www.des.nh.gov/organization/divisions/air/tsb/tps/climate/action_plan/nh_climate_action_plan.htm

[10] GDS Associates, Inc., RLW Analytics and Research into Action, and RKM Research and Communication, *Additional Opportunities for Energy Efficiency in New Hampshire,* January 2009. https://www.puc.nh.gov/Electric/GDS%20Report/NH%20Additional%20EE%20Opportunities%20Study%202-19-09%20-%20Final.pdf

[11] Vermont Energy Investment Corporation, Jeffrey H. Taylor & Associates, Inc., and Optimal Energy, Inc., *Independent Study of Energy Policy Issues*, September 9, 2011. https://www.puc.nh.gov/EESE%20Board/VEIC%20NH%20Independent%20Study%20Key%20Findings%20and%20Recommendations.pdf

[12] Vermont Energy Investment Corporation, GDS Associates, Inc., and Jeffrey H. Taylor & Associates, Inc., *Increasing Energy Efficiency in New Hampshire: Realizing Our Potential*, November 15, 2013. https://www.nh.gov/oep/resource-library/energy/documents/nh_eers_study2013-11-13.pdf

[13] New Hampshire Governor's Office of Energy and Community Services, *New Hampshire Energy Plan*, November 2002. https://www.nh.gov/oep/resource-library/documents/nh-energy-plan-2002.pdf

[14] Order of Notice, IR 15-296, *Investigation into Grid Modernization*, July 30, 2015. http://puc.nh.gov/Regulatory/Docketbk/2015/15-296/INITIAL%20FILING%20-%20PETITION/15-296%202015-07-30%20ORDER%20OF%20NOTICE.PDF

as an expert consultant. On April 1, 2016, the Commission issued Order No. 25,877[15] establishing a Working Group and scheduling an initial meeting for April 29, 2016. The Working Group met over the course of a year and issued a report, *Grid Modernization in New Hampshire*[16] with associated appendices[17] (Grid Mod Working Group Report or Grid Mod Report), on March 20, 2017. The Grid Mod Working Group Report discussed the key elements outlined by the Commission in its order of notice. On April 20, 2017, a secretarial letter[18] was issued soliciting comments on the final report.

Since the issuance of the Grid Mod Working Group Report, the New Hampshire Office of Strategic Initiatives (formerly the New Hampshire Office of Energy and Planning) updated the 10-year state energy strategy in April 2018[19] (2018 State Energy Strategy). Although the 2018 State Energy Strategy did not specifically mention grid mod, the policy goals reflect many of the same goals as outlined by the Working Group.

Staff reviewed the Grid Mod Working Group Report and comments, reviewed the 2018 State Energy Strategy, conducted additional research on grid mod, and participated in training provided by the DOE, coordinated by the New England Conference of Public Utilities Commissioners (NECPUC). The basis for the DOE training was the DOE's Office of Electricity Delivery & Energy Reliability's Modern Distribution Grid report[20] (DOE Modern Grid Report) including *Volume I: Customer and State Policy Driven Functionality*; 2) *Volume II: Advanced Technology Maturity Assessment;* and 3) *Volume III: Decision Guide.*

Based on the Grid Mod Working Group Report, the additional research conducted by Staff, and the DOE training and reports, Staff has developed this report to summarize Staff's recommended approach for combining least cost integrated resource plans and grid mod plans into one document, the IDP. Staff's recommendation is based primarily on the DOE methodology, outlined in Volume I: Customer and State Policy Driven Functionality, which correlates distribution planning and distribution grid operation enhancements in a grid mod plan to stated objectives and goals. This approach enables development of a platform for the distribution system that facilitates the integration of distributed energy resources (DERs).[21] This report also identifies PUC dockets that are related or overlapping with grid mod and distribution planning,

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[15] Order No. 25, 877, Order on Scope and Process, IR 15-296, *Investigation into Grid Modernization*, April 1, 2016. http://puc.nh.gov/Regulatory/Orders/2016orders/25877e.pdf

[16] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

[17] Grid Modernization Working Group, Appendices, Grid Modernization in New Hampshire, March 20, 2017. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_APP_FINAL_RPT.PDF

[18] Debra A. Howland, Letter RE: Public Comment, April 20, 2017. http://puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-04-20_SEC_LTR_OPPORTUNITY_PUBLIC_COMMENT.PDF

[19] New Hampshire Office of Strategic Initiatives, *New Hampshire 10-Year State Energy Strategy*, April 2018. https://www.nh.gov/osi/energy/programs/documents/2018-10-year-state-energy-strategy.pdf

[20] US Department of Energy, Office of Electricity Delivery & Energy Reliability, *Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, Version 1.1,* March 27, 2017; *Volume II: Advanced Technology Maturity Assessment, Version 1.1,* March 27, 2017; *Volume III: Decision Guide,* June 28, 2017. https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

[21] DERs are electricity-producing **assets** or controllable loads that are directly connected to a local distribution system or to a host facility within a local distribution system, usually behind the meter, which can be used individually or in aggregate to provide value to the grid, individual customers, or both.

provides a staff recommendation for the key elements of the IDP, and proposes the recommended next steps for advancing grid modernization in New Hampshire.

1.2. Related PUC Dockets

One of the recommendations of the Grid Mod Working Group Report was to identify related dockets and determine whether and how to integrate them in the grid mod initiative. Grid mod and an IDP encompass various interconnected pieces, including distribution system planning and integration of distributed generation, energy efficiency, and peak load reduction. Other dockets that are related to grid mod and an integrated distribution plan include the following:

Distributed Generation Net Metering Tariff (and Time-of-Use Rates, Value of DER, and Locational Value Analysis)

- DE 16-576 – Alternative Net Metering Tariffs/Mechanisms for Customer-Generators
  - Time of Use Pilot Working Group
  - Value of DER Study Scope Working Group
  - Locational Value Analysis (formerly Non-Wires Alternative Pilot) Working Group
  - Low-Moderate Income Pilot Working Group

Interconnection Process

- DE 15-271 – Examination of Interconnection and Queue Management Processes for Net-Metered Customer-Generators

Energy Efficiency Programs

- DE 15-137 – Energy Efficiency Resource Standard (EERS)
- DE 14-216 – CORE Energy Efficiency Plan
- DE 17-136 – EERS Plan for 2018-2020

Peak Demand Reduction Goals

- DE 16-714 – Investigation into Electric Peak Load Reduction
- DE 17-101 – Peak Load Reduction Goals

Utility DER Ownership/Time of Use Rate Design

- DE 09-137 Unitil Energy Systems' Petition for Approval of Investment in and Rate Recovery for DERs
- DE 17-189 Liberty Utilities' Petition for Approval of Battery Storage Pilot Program (and TOU)

Least Cost Integrated Resource Plans

- DE 15-248 – Eversource Energy's 2015 Least Cost Integrated Resource Plan
- DE 16-097 – Liberty Utilities' 2016 Least Cost Integrated Resource Plan
- DE 16-463 – Unitil Energy Systems' 2016 Least Cost Integrated Resource Plan

Distribution Service Rate Cases (DE 09-035, DE 16-383, and DE 16-384)

- DE 16-383 – Liberty Utilities' Distribution Service Rate Case
- DE 16-384 – Unitil Energy System's Distribution Service Rate Case
- DE 09-035 – Eversource Energy's Distribution Service Rate Case

Utility Reliability Enhancement Programs (REPs)/Vegetation Management Programs (VMPs) [22]

- DE 16-383 – Liberty Utilities' Distribution Service Rate Case
- DE 16-384 – Unitil Energy System's Distribution Service Rate Case
- DE 17-196 – Eversource Energy's Petition for the Continuation of REP

As noted, the utilities and stakeholders must keep current of developments and subsequent orders in these related dockets when considering the IDP. Staff recommends the utilities monitor the progress of the related dockets and take note of any new Orders which may affect their IDP recommendations.

[22] Dockets shown superseded previous dockets where REPs/VMPs were handled. The original dockets establishing REPs/VMPs for Liberty Utilities, Unitil Energy System, and Eversource Energy were DG 06-107 (Granite State Electric), DE 10-055, and DE 06-028 (Public Service of NH), respectively.

2.0 Proposed Approach for Integrated Distribution Plans (IDP)

This section explains the current LCIRP process and provides a description of the proposed IDP process, including how to look at the process holistically while taking into account modernized grid objectives. This section also explains the rationale for the integrated approach and provides an overview of the proposed approach.

2.1 Current Least Cost Integrated Plan (LCIRP) Process

Pursuant to RSA 378:38,[23] electric utilities are required to file a LCIRP with the Commission within two years of the Commission's orders regarding each utility's prior plan, and in all cases within five years of the filing date of the prior plan. The plan must include the following elements, pursuant to RSA 378:38:

- *A forecast of future demand for the utility's service area.*
- *An assessment of demand-side energy management programs, including conservation, efficiency, and load management programs.*
- *An assessment of supply options, including owned capacity, market procurements, renewable energy and distributed energy resources.*
- *An assessment of distribution and transmission requirements, including an assessment of the benefits and costs of "smart grid" technologies, and the institution or extension of electric utility programs designed to ensure a more reliable and resilient grid to prevent or minimize power outages, including but not limited to, infrastructure automation and technologies.*
- *An assessment of plan integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers.*
- *An assessment of the plan's long- and short-term environmental, economic, and energy price and supply impact on the state.*
- *An assessment of plan integration and consistency with the state energy strategy under RSA 4-E:1.*

Eversource Energy, Unitil Energy Systems, and Liberty Utilities filed their plans in 2015, 2016, and 2016, respectively. The existing statute does not account for a grid mod initiative which would include asset, technology, and architecture investments that are required for each utility to accommodate DER integration into its distribution system. "Smart grid" technologies are the predecessor to grid mod and refer to a modern electric system that incorporates communications and information technologies into the existing electric grid.

The existing LCIRP requirement for smart grid technologies is based on the premise that a utility's planning process should include a myriad of assessments that take into account the overall system and circuit loading as well as associated distribution investment for future or existing system planning requirements. Load forecasting utilizes linear regression to determine future system loading based on past actual load growth figures. Distribution circuits and supply

[23] New Hampshire Administrative Law, Chapter 378, Rates and Charges, Least Cost Energy Planning, Section 378:38, Submission of Plans to the Commission, August 4, 2015. http://www.gencourt.state.nh.us/rsa/html/XXXIV/378/378-38.htm.

lines, which do not utilize real time monitoring, are allocated load based on historical peak loading of that supply or distribution circuit. The utility initially forecasts the system's load requirements 10 to 15 years out by employing established forecasting tools that either are rooted in econometric models or based on historic load data and weather records to forecast various loading scenarios.

Existing DERs that are in service during peak loading are considered part of the overall circuit loading and are not removed from the base load calculation. DER impacts on future projected load is constructed based on known DER installations. Currently, the size of the DERs generally will need to be significant to be used for projected load calculations by the distribution planning engineer.

Demand reduction and energy efficiency assessment measures are reported in current LCIRPs as a requirement of the state energy policy. The kilowatt-hour (kWh) savings and projected reduced loads are presented in the filed LCIRPs as an overall system benefit with little to no targeted distribution capacity deficiency solution or strategic quantifiable deferment of future distribution investments. Grid automation and data retrieval through customer metering and distribution assets are a part of the smart grid initiative and assessment criteria for the LCIRP; however, the technology used is typically for a traditional grid reliability focus with little to no targeted application for DER integration.

Utilities prepare LCIRPs to outline their 5- to 10-year distribution system investment solutions for ensuring reliability and meeting design criteria requirements based on planning forecasts. The grid mod objective to further strengthen reliability, resiliency, and safety while enabling forecasting and facilitating DER integration and forecasting probabilistic DER penetration throughout the distribution planning process, is absent in the present LCIRP requirements.

2.2 Combining the LCIRP and Grid Mod into the Integrated Distribution Plan

The current LCIRPs take into consideration multiple factors that ultimately determine a 5- to 10-year roadmap for each utility. This roadmap is based on each utility's business goals, reliability requirements, energy efficiency initiatives, identified distribution capacity constraints, power quality requirements, and other state-mandated energy programs. The purpose of the LCIRP is to determine the least cost option for operating utility distribution and sub-transmission systems by analyzing both traditional distribution investments and non-utility owned resources. The fundamental drivers in this assessment are the load forecasts and design criteria that are applied to the system loading, which in turn spurs future circuit and equipment upgrades or replacements. Each of these elements are incorporated into each LCIRP.

The grid mod initiative requires the review of technologies and processes that will enable the grid to integrate varying levels of DER penetration while ensuring reliability, resiliency, and safety. To evaluate the impact of DER integration, the distribution planning methodology will need to incorporate more probability-based analyses for the utilities to assess various scenarios of system load growth, including increased load from strategic electrification, with low, medium, or high penetrations of DERs.

The current LCIRP process has two required assessments that relate to the grid mod initiative. The first is the smart grid assessment (RSA 378:38, IV); the second is the assessment of supply options including distributed energy resources (RSA 378:38, III). Thus, the grid mod concept is already an element of the overall LCIRP. Planning for grid mod should not be separate from the LCIRP, nor should a separate "Grid Mod Plan" be required to highlight assessments that should be considered business-as-usual grid operations and planning.

In order to capture the various capital investments in a holistic planning document where "business as usual" and grid mod investments will tend to be interrelated, the utilities should incorporate and include in each five-year capital investment plan both the business as usual and grid mod driven investments. Items that are "business as usual" would include typical utility mandated items, such as new business, street lighting, public requirements, damage/failure, condemned poles, and facility upgrades or purchases. A complete and comprehensive capital plan will provide the necessary transparency for stakeholders to evaluate the utility's overall capital expenditures for the five-year period. The utility will review and modify the overall capital investment plan annually as future information and investment conditions change.

The Grid Mod Working Group Report recognized the interrelationship of the grid mod initiative and least cost planning process and recommended eventually replacing the existing LCIRP with a Grid Modernization Plan, which would encompass all of the existing LCIRP's assessment requirements. The Working Group recommended that the Grid Modernization Plan have a 10-year roadmap, a five-year detailed investment plan, and a three-year filing requirement. Since the Grid Mod Working Group Report was issued, additional guidance from the DOE and various DOE consultants has furthered Staff's understanding of the grid mod initiative. Staff agrees with the Grid Mod Working Group Report's recommendation to combine the two and proposes that this integrated plan be called the Integrated Distribution Plan (IDP); however, Staff recommends that the integration occur with the initial plan submitted following an Order addressing the grid mod initiative.

2.3 Rationale for the Proposed IDP Process

The rationale for the proposed IDP process is based on the DOE Modern Grid Report, a guidance document developed as part of DOE's grid mod initiative and distribution planning analyses. The DOE Modern Grid Report was developed at the request of and with guidance from the Public Utility Commissions of California, New York, the District of Columbia, Hawaii, and Minnesota. Beyond a core of technical advisors, the project was supported by DOE Laboratories, DOE consultants, including Newport Consulting, and numerous electric utility and industry experts. Currently, elements of the DOE report are being applied in over 20 states.

The primary aim of this proposed approach is to facilitate the identification of functional requirements for a modern distribution grid that are needed to enhance reliability, resiliency, and operational efficiency, and to integrate and efficiently utilize distributed energy resources. Staff's proposed approach is to develop a consistent understanding of the underlying requirements that inform investments in grid modernization to support grid planning, operations, and utilization of DERs. Furthermore, this methodological approach is adaptable in view of the fact that the distribution grid will continue to evolve over time to address changing customer needs and uses of the system.

Staff's approach employs a taxonomy framework to logically organize required capabilities and functionalities based on an individual state's grid modernization policy and distribution planning objectives and related system attributes. Staff examined a wealth of literature based on the experiences of a number of states in order to identify a paradigm that was logical in nature, derived from sound engineering practice, and, above all, would allow scrutiny of the process. Staff sought to identify the functional requirements for a modern distribution grid that would enhance reliability, resiliency and operational efficiency, and integrate and utilize DERs.

Key assumptions in the approach include the following:

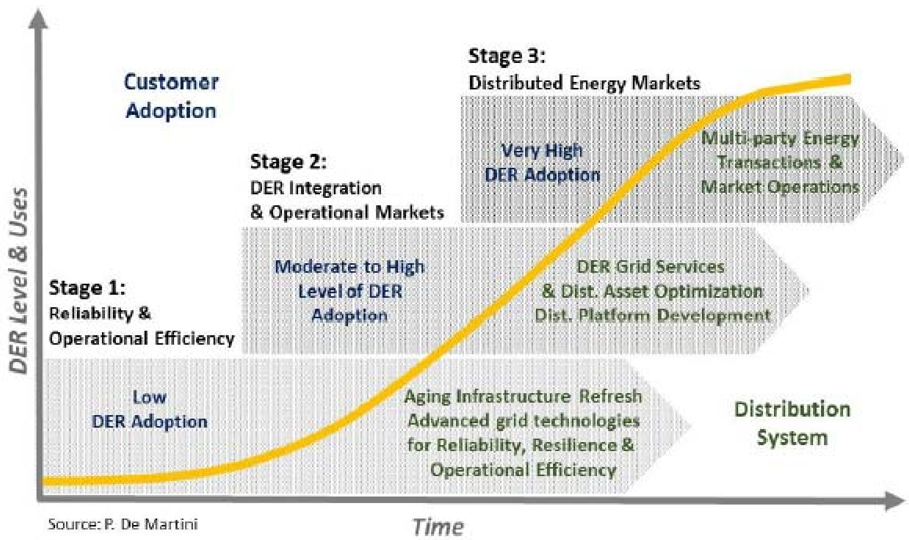
- Focusing on the initial set of functions and related technologies and process changes needed to begin implementation within five years to support the Commission's objectives.
- Avoiding preference of any one type of technology over another, that is, a technology-neutral approach that leaves design level solutions to the marketplace.
- Neutrality on roles, industry structures, and business models.

This approach recognizes that the distribution grid and planning process need to evolve over time to be able to integrate DERs. Under the old paradigm, distribution planning was done using traditional tools with different objectives. The grid was designed mainly for reliability with electricity flowing in one direction from a dispatchable generation facility and following load; as a result, the grid comprises a complex network of legacy structures. Now the grid is changing and becoming more complex, consumers and stakeholders have changing needs and expectations, new technologies and services are now available, existing infrastructure is aging, and the resiliency and reliability of the grid will be subject to greater stress.[24]

The proposed approach recognizes that the modern grid will evolve over time. According to analysis by DOE, the grid will evolve in three stages, from both the customer adoption perspective and from the distribution system development perspective. Each stage requires numerous levels of additional functionalities needed to modernize the grid and support an increasing penetration of DERs. The staged (or incremental) approach developed by Paul De Martini of the Newport Consulting Group, LLC, recognizes that all of the complex features of the grid do not need to be addressed initially, while utilities and stakeholders must take a global view of the grid and keep in mind future features that will be required, but are not needed at this time. See Figure 2-1 below.

[24] Dr. Jeffrey D. Taft, PNNL, Dr. Ron Melton, PNNL, Mr. Dave Hardin, SEPA, *Grid Architecture, An Overview,* PNNL-SA-128082, Grid Evolution Summit, SEPA, A National Town Meeting, July 2017. https://gridarchitecture.pnnl.gov/media/methods/SEPA_Grid_Architecture_Overview.pdf

Figure 2- 1. Stages of Grid Evolution[25]



[25] US Department of Energy, Office of Electricity & Energy Reliability, *Modern Distribution Grid Report, Volume III*, 2017.

In general, grid evolution to-date has been driven by customer expectations and choice and the need for greater reliability and resilience as well as technology advancement. This evolution can be considered in three conceptual stages as adapted from the descriptions in the DOE Modern Grid Report:[26]

> Stage 1: Planning–Reliability & Operational Efficiency– *In this stage, the focus of grid modernization is on enhancing reliability, resilience and operational efficiency while addressing aging infrastructure replacement. The level of customer DER adoption is relatively low and DER market participation at wholesale levels is nonexistent or limited. This level of DER integration can be accommodated within the existing distribution system without material changes to infrastructure or operations. Proactive development of integrated distribution planning is introduced to assess continued distribution grid enhancements to meet customer expectations, address technological advancements and policy objectives in Stage 2 and beyond. A significant part of this stage contains "business as usual" distribution investments due to aging infrastructure refresh requirements. Most distribution systems in the U.S. are currently at Stage 1.*[27]
>
> *Stage 2:* Grid Operations–*DER Integration– This stage is characterized by substantial integration of DERs into power system operations, either through significant levels of customers' DER adoption or public policies creating market opportunities for DER in wholesale and/or distribution grid services. At higher levels of DER uptake on the distribution grid (e.g., solar farms, behind-the-meter customer resources and microgrids), operational impacts may occur, including voltage variations and bi-directional power flows. The coordination of DER participation in wholesale markets with distribution operations becomes necessary to maintain reliability and service quality. This in turn creates the need in Stage 2 for enhanced functionality related to maintaining reliable operation of the grid and optimizing the use of DERs.*
>
> *Stage 3:* Grid Services–*Distributed Energy Markets*[28,29]*– Stage 3 involves the introduction and scaling of bilateral energy transactions between sellers and buyers across a distribution system. A prerequisite is a high penetration level of distributed resources, either behind the meter or grid connected, that can supply dispatchable energy and that are not encumbered by pre-existing net energy metering tariffs, or interconnection rules or regulations that effectively prevent the resale of the energy produced to another party across the distribution grid. It is important to note that the vast majority of energy producing DERs, such as rooftop solar, installed in the U.S. (exceptions include Texas and Hawaii) are similarly encumbered, and therefore it is*

[26] US Department of Energy, Office of Electricity & Energy Reliability, *Modern Distribution Grid Report, Volume III*, 2017.

[27] Note that even where average distribution system DER penetration rate is low, customer DER adoption tends to cluster or locate near one another. So, even at a low penetration, some circuits may exhibit very high levels, *necessitating* earlier consideration of DER integration issues.

[28] De Martini, P. and Kristov, L. Distribution Systems in a High Distributed Energy Resources Future – Planning, Market Design, Operation and Oversight. Lawrence Berkeley National Laboratory. October 2015. Available online: https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf

[29] De Martini, P., et al., Evolving Distribution Operational Markets, Caltech-ICF, 2016. Available online: http://resnick.caltech.edu/docs/EDOM.pdf

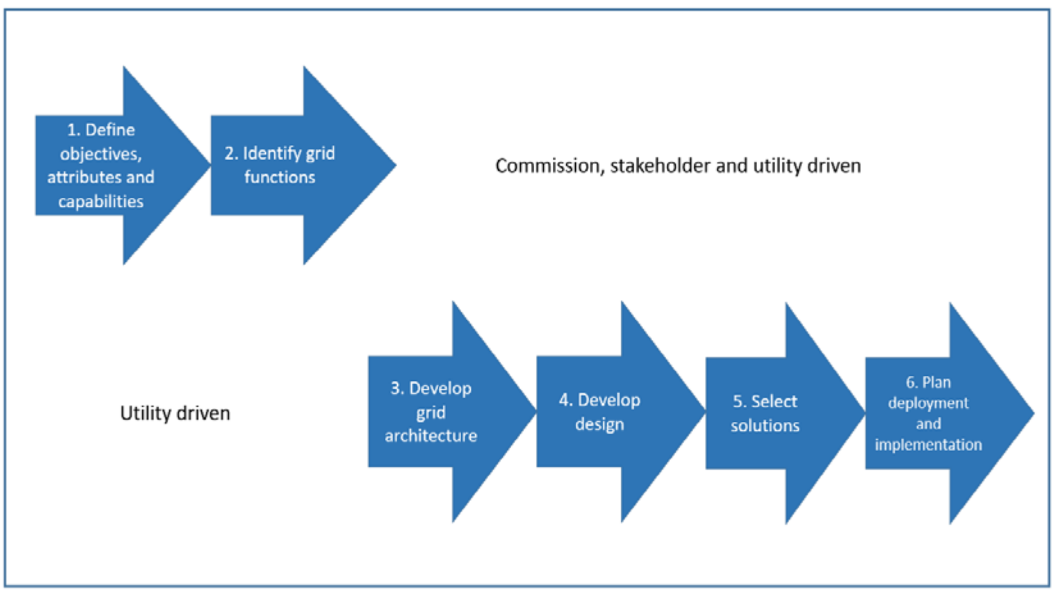
unlikely that Stage 3 markets will develop until after DER rate reform and current incentives expire. However, it is likely that some limited energy transactions may occur in Stage 2 related to multi-user microgrids as discussed in the Boston harbor project,[30] for example. Stage 3 will likely occur beyond the 5-year horizon of this effort and so will not be addressed in this guide.

The IDP will address grid modernization in a systematic way using suitable tools for Stages 1 and 2 while keeping in mind the future potential for Stage 3.

2.4 Overview of Proposed Approach

Staff's proposed approach takes a holistic view of grid modernization and distribution planning. The key drivers for the approach are the objectives for the modern grid on which the IDP will be based. Figure 2-2 summarizes at a high level the division of responsibilities among the parties. Accordingly, Staff first identifies the objectives after taking into consideration the Commission's Orders, the Grid Mod Working Group Report, and the 2018 State Energy Strategy. Staff then maps the objectives to capabilities, then capabilities to functionalities. Based on that input, the utilities will then determine the optimum grid architecture - that is, what technologies, software, and grid capabilities will serve to meet the required functionalities capabilities and overall objectives. Initially, the utilities will focus on the planning stage and the operations stage, but must keep in mind that features proposed now may also be necessary in the grid services/markets stage.

Figure 2- 2. Proposed Methodology and Division of Responsibilities



[30] South Boston Waterfront Multi-User Microgrid project. Available online: http://www.bostonplans.org/planning/planning-initiatives/community-energy-planning

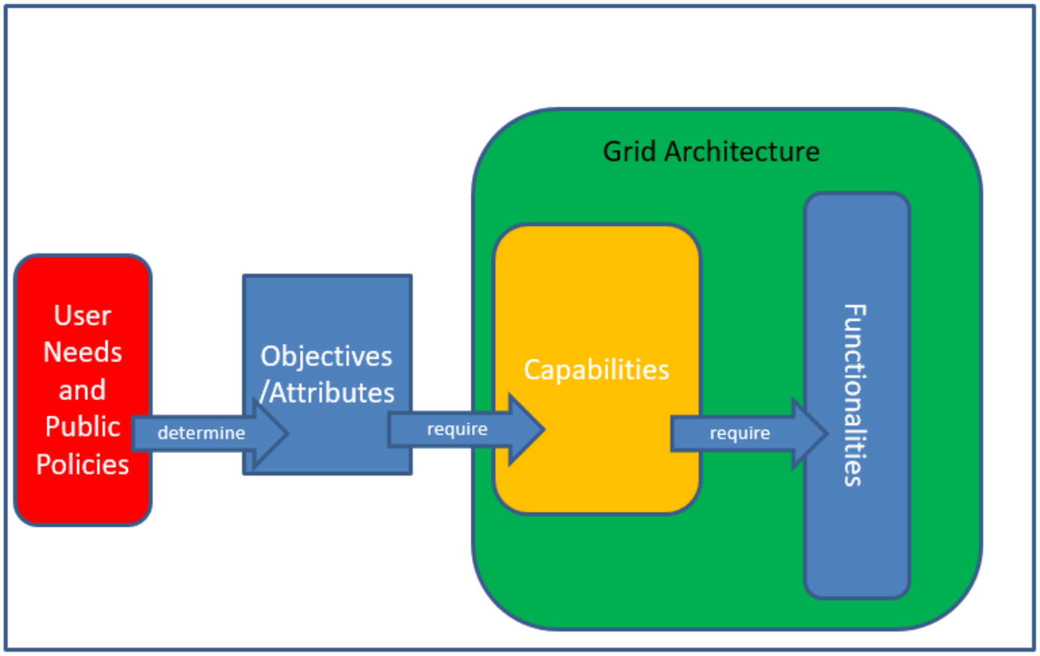
Grid architecture is the framework where the utilities must focus their initial analysis of existing systems and processes to determine the correct path or plan in which grid mod objectives will integrate with legacy or future proposed investments. Without architecture development, utility investments are patched into various platforms with limited functionality and integration with other various platforms and networks within the utility thereby creating additional legacy systems. These applications or processes become obsolete or standalone systems as industry and consumer processes, expectations, and technologies evolve. Grid architecture provides the framework to manage the complexity and the risk associated with making grid changes and helps to identify hidden interactions and technical gaps so as to reduce the likelihood of unintended consequences and stranded investments. This approach increases the likelihood of future proofing investments in various platforms within the electric grid structure.

The proposed methodology anticipates that grid architecture, design, and technical solutions will be the responsibility of the utilities to prepare within their IDPs. This methodology will enable New Hampshire utilities to define the objectives and drive the outcome of their IDPs, identify the capabilities that enable a certain objective to be achieved, and select the functionalities that need to be considered when developing their IDPs. Staff does not propose technological solutions since it believes that utilities are better positioned to offer innovative solutions. Staff anticipates that each utility will employ this methodology consistent with its current grid baseline and the timeframe with which it plans to modernize its grid.

In developing the grid architecture, the objectives, not the technologies, of the system must first be established, and the desired system capabilities must be defined. Then the necessary system functionalities must be determined, the problem environment understood, and issues and legacy constraints identified. Lastly, the grid technologies associated with each functionality can be selected. These all relate to one another as shown in Figure 2-3 in a synthesis view.[31]

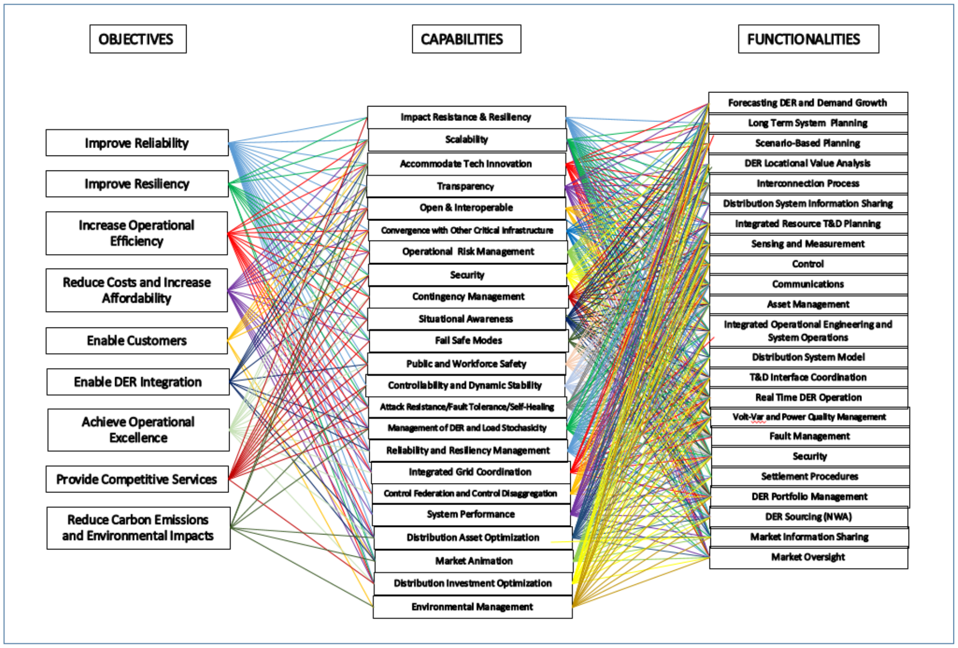
[31] Based on JD Taft, Pacific Norwest National Laboratory, *Grid Architecture 2*, PNL-24044 2, January 2016, Figure 2.17, pg. 2.25. https://gridarchitecture.pnnl.gov/media/white-papers/GridArchitecture2final.pdf

Figure 2- 3 High Level Schematic View of the Relationship of Various Aspects of Grid Architecture



Actual mapping of the distribution network involves multiple hierarchical layers of architecture and bi-directional interdependence of system objectives with functionalities. Figure 2-4 provides an example of the mapping of specific objectives, capabilities, and functionalities and demonstrates the complexity of these mapped relationships. Through this methodology, the IDPs will ensure that the distribution system and its components and structure and associated functionalities are tied back to specific system capabilities and objectives; thus, traceability and accountability will be safeguarded.

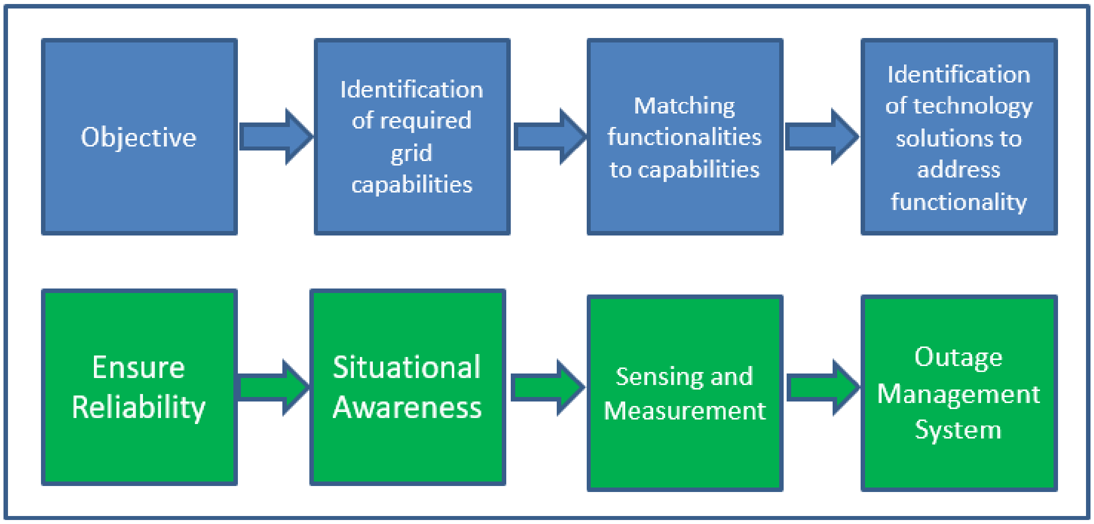
Figure 2- 4 Complex Mapping of Objectives, Capabilities, and Functionalities



In mapping grid architecture, first the priorities of public policy and user needs must be understood. Following identification of all required public policies and user needs, a primary list of grid objectives is determined. In the next step, objectives are mapped to the supporting grid capabilities. The combination of objectives and grid capabilities will vary depending on what stage on the continuum of grid evolution is under consideration at any given time – i.e., planning, operations, or grid services/market operations. The final steps require the mapping of grid functionalities that will enable the performance of each selected capability.

All of the mapping is shown in Work Papers 1-4 attached to this report culminating in a master list that indicates the combinations of functionalities associated with each capability required by each objective allocated by each stage of grid evolution. An example of such a mapping is in Figure 2-5 for one objective mapped to one capability and one functionality. Note however, that each objective will map to multiple capabilities and functionalities.

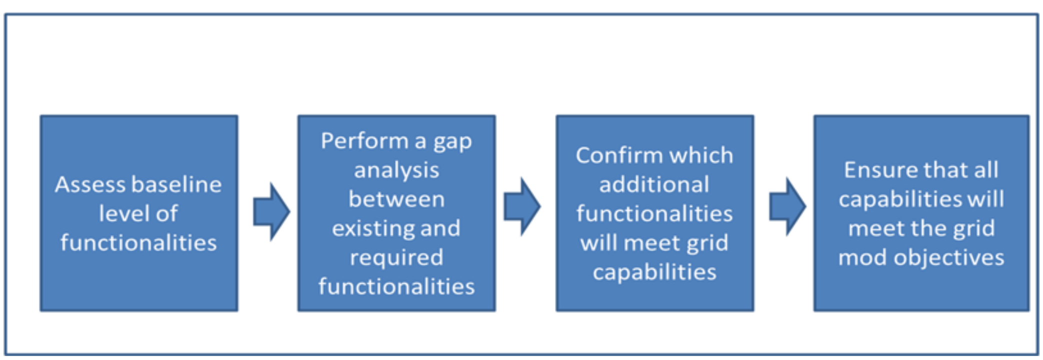
Figure 2- 5 Methodological Process and Sample Mapping.



In Section 3, Staff illustrates the application of this process for New Hampshire, from objectives to functionalities. Staff identifies grid modernizing objectives, selects the capabilities required to achieve them, and develops a list of functionalities associated with each capability to be considered by the utilities to ensure achievement of the objectives.

From the utilities' perspective, the mapping analysis shows how functionalities dictate architectural capabilities, and how the capabilities in turn support desired objectives. Utilities tasked with developing an IDP based on clear objectives can trace the logical path from objective to required functionality and evaluate further actions needed to meet the capabilities required. Alternatively, the utilities can assess current functionalities associated with their grids and perform a gap analysis between existing and required functionalities. They must then project forward on the grid evolution continuum and determine which additional functionalities they will require and how these additional functionalities will strengthen their capabilities all while keeping in mind the stated objectives. Figure 2-6 shows the suggested process for utilities to verify that the grid architecture is meeting the objectives.

Figure 2- 6 Suggested Process for Utilities for Traceability

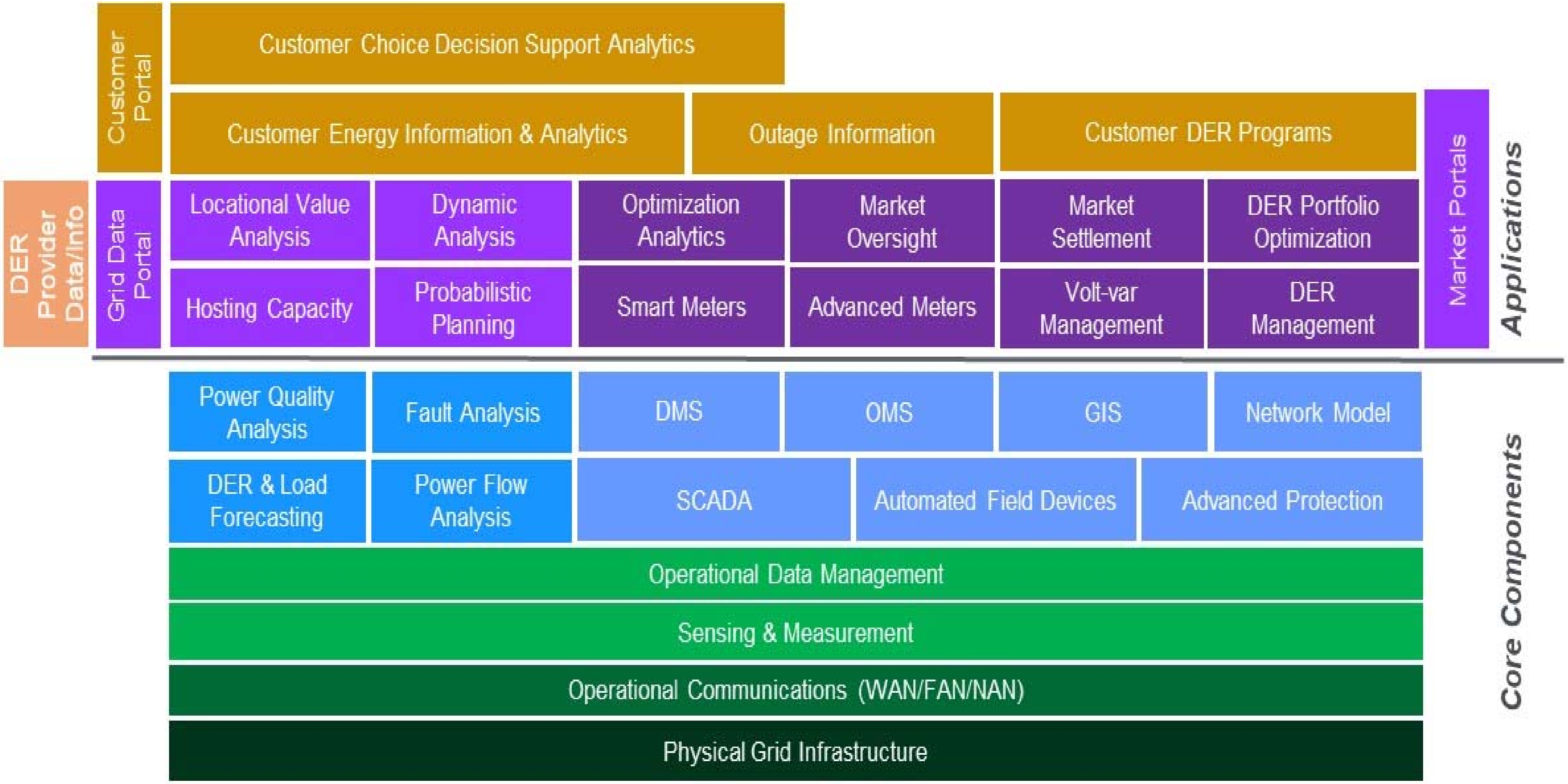


For the Commission and stakeholders, this mapping process will enable examination and verification that a utility's proposed plans are facilitating the desired grid modernizing objectives. With this approach, each utility will be required to justify its proposed investments by showing what functionalities that investment will facilitate, how that investment will strengthen required capabilities, and how that investment in turn will serve to promote the desired objectives.

These objectives, in turn, are focused on transforming the distribution system to a platform that will enable DER integration. The functionalities form the basis for the platform and its core components and applications, as shown in Figure 2.7. When the utilities develop and implement their plans, they must take into consideration not only what they require to meet these objectives, but also when the solution is needed, how fast and at what scale, who can provide the solution, and the cost-effectiveness of each solution.[32]

[32] US Department of Energy, Office of Electricity & Energy Reliability, *Modern Distribution Grid Report, Volume III*, 2017, p. 27.

Figure 2- 7 Distribution System Platform with Core Technology Components and Applications [33]



Green - Core Cyber-physical layer (including poles and wires)
Blue - Core Planning & Operational systems
Purple - Applications for Planning, Grid & Market Operations
Gold - Applications for Customer Engagement with Grid Technologies
Orange - DER Provider Application

[33] US Department of Energy, Office of Electricity & Energy Reliability, *Modern Distribution Grid Report, Volume III*, 2017.

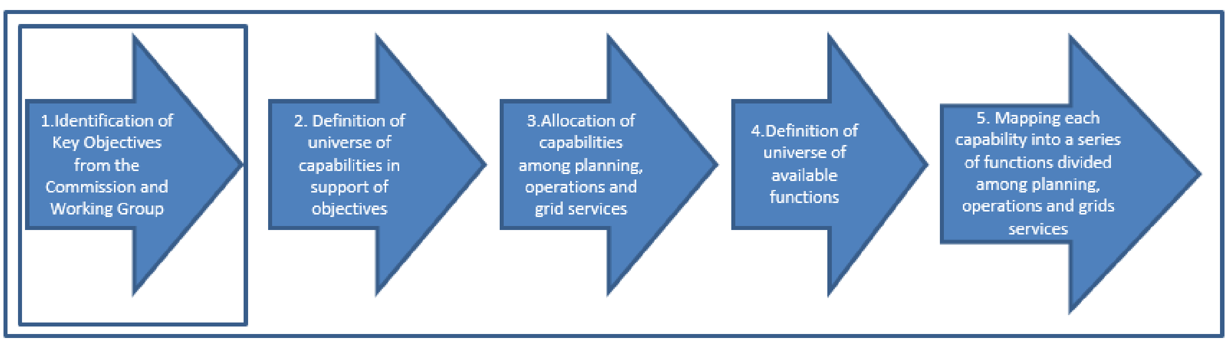
3.0 Proposed Integrated Distribution Plan Objectives, Capabilities, and Functionalities for New Hampshire

Building upon the approach outlined in Section 2, this section summarizes Staff's methodological approach for determining the objectives necessary to achieve a modernized grid. The detailed methodological analyses conducted to determine the associated capabilities and functionalities required of a modernized grid can be found in attached Work Papers 1, 2, 3, and 4. Staff proposes the resulting objectives, capabilities, and functionalities for New Hampshire in this section.

3.1 Objectives

Following a review of Commission orders related to grid mod,[34] the Grid Mod Working Group Report[35] and associated stakeholder feedback, and the 2018 State Energy Strategy,[36] Staff developed a list of general objectives and attributes of a desired modernized grid. These objectives were analyzed in order to identify areas of common ground from the various documents, and a final list of general objectives and attributes was developed. Staff further analyzed the objectives and attributes to develop definitions of each specific objective arising from the recommendations and best practices provided in this proceeding, as well as the guidance found in the DOE Modern Grid Report. The list of objectives was compared with a baseline list of objectives compiled from eleven state jurisdictions to ensure that no critical objective was overlooked. The resulting objectives Staff identified are shown in Table 3-1.

Figure 3- 1 Methodological Approach Highlighting Objectives



[34] Order of Notice, IR 15-296, Investigation into Grid Modernization, July 30, 2015. http://puc.nh.gov/Regulatory/Docketbk/2015/15-296/INITIAL%20FILING%20-%20PETITION/15-296%202015-07-30%20ORDER%20OF%20NOTICE.PDF
Order No. 25,877, Order on Scope and Process, IR 15-296, Investigation into Grid Modernization, April 1, 2016. http://puc.nh.gov/Regulatory/Orders/2016orders/25877e.pdf
[35] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF
[36] New Hampshire Office of Energy and Planning, *New Hampshire 10-Year State Energy Strategy*, September 2014. https://www.nh.gov/oep/energy/programs/documents/energy-strategy.pdf

Further detailed discussion of the process whereby Staff arrived at the objectives listed below may be found in Work Paper 1 attached to this report.

Table 3- 1. Comprehensive List of Objectives/Attributes

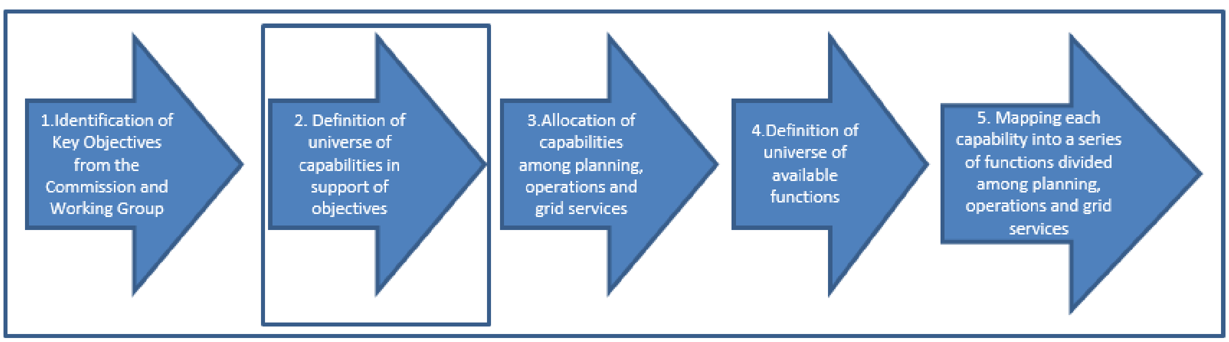
General Objectives & Attributes	Specific Objectives	Definition
1. Improve reliability, resiliency and operational efficiency	Improve reliability	Maintain and enhance the safety, security reliability of the electric grid at fair and reasonable costs, within acceptable standards and consistent with the state's energy policies.
	Improve resiliency	Maintain and enhance the resiliency of the electric grid at fair and reasonable costs, within acceptable standards and consistent with the state's energy policies.
	Increase operational efficiency	Increase operational efficiency of distribution facilities.
2. Reduce generation, transmission and distribution costs	Reduce costs and increase affordability	Reduce costs and increase affordability. Distribution investments may enable the reduction of generation and transmission costs.
3. Empower customers to use electricity more efficiently and lower electricity bills and have access to usage data in readily accessible form, which they can make available to third parties while retaining privacy	Enable customers	Support greater empowerment, engagement, technology options and information for customers to manage their energy bills, including related infrastructure investment to accommodate two way flows of energy and to enable all types of DER technologies to interconnect and participate in market opportunities.
4. Facilitate integration of DERs	Enable DER integration	Ensure that the grid can integrate or host DERs while facilitating value to the distribution grid and reducing interconnection costs. Enable all type of DERs by providing the necessary communication, information, and cyber and physical security protocols, while providing engineering and economic benefits.
5.Better align interests of energy consumers and producers to optimize system performance, while enabling strategic electrification of buildings, homes, and vehicles	Achieve operational excellence	Enhance customer service and optimize utilization of electricity grid assets and resources to minimize total system costs.
6. Keep NH technologically innovative, economically	Provide competitive services	Innovate while striving for most competitive pricing of services. Consider the possibility of multiple services for an investment to provide for more economic viability.

General Objectives & Attributes	Specific Objectives	Definition
competitive, and in step with the region		
7.Reduce environmental impacts and carbon emissions in NH	Reduce carbon emissions and environmental impacts	Reduce carbon dioxide emissions and other greenhouse gases and air pollutants emitted from the electricity sector by meeting new generation needs with renewable or other clean sources of energy; displace fossil fuel use in generation with renewable power or other clean sources of energy; increase building efficiency and implement other conservation or energy efficiency measures; and increase electrification of the transportation sector.

3.2 Capabilities

Step 2 of Staff's analysis required the translation of objectives and attributes into associated capabilities. Capabilities identified in this section provide a bridge from the policy objectives to the enabling set of platform technologies.

Figure 3- 2 Methodological Approach Highlighting Capabilities



A capability refers to the ability to execute a specific course of action or set of functions. The DOE Modern Grid Report[37] has derived a list of possible capabilities by distilling a series of key industry documents to guide the functionality of the next generation distribution system.

The specific capabilities identified in this report were drawn principally from Pacific Northwest National Laboratory's (PNNL's) 2015 "Grid Architecture" report and California's "More Than Smart" report based on stakeholder input and direct feedback from the industry through Distribution System Planning Initiative engagement.[38] Table 3-2 lists the capabilities for

[37] US Department of Energy, Office of Electricity Delivery & Energy Reliability, *Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, Version 1.1*, March 27, 2017.
[38] List derived from 2014 "More Than Smart" paper and 2015 PNNL *Grid Architecture* report: Greentech Leadership Group and Caltech Resnick Institute, *More Than Smart – A Framework to Make the Distribution Grid*

consideration. Each specific objective may require a combination of capabilities. For ease of reference, the universe of possible capabilities is disaggregated by system planning, grid operations, and grid services/market operations, in accordance with the DOE Modern Grid Report. Detailed definitions and analysis may be found in Work Paper 2 at the end of this report.

Table 3- 2 Capabilities*

Planning
• Impact resistance and resilience • Scalability • Accommodate tech innovation • Transparency • Open and interoperable • Convergence with other critical infrastructure
Operations
• Operational risk management • Security • Contingency management • Situational awareness • Fail safe modes • Public and workforce safety • Controllability and dynamic stability • Attack resistance/Fault tolerance/Self-healing • Management of DER and load variability • Reliability and resiliency management • Integrated grid coordination • Control federation and control disaggregation
Grid Services/Markets
• System performance • Distribution asset optimization • Market animation • Distribution investment optimization • Environmental management

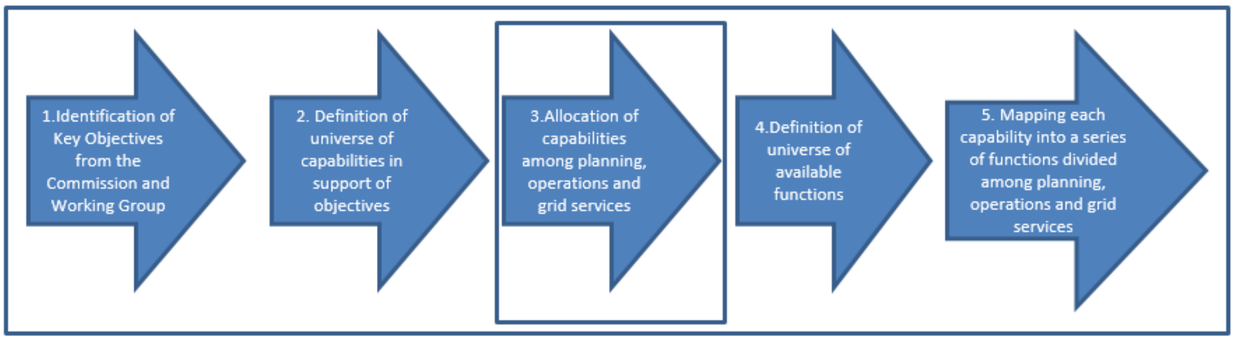
*See Work Paper 2, Table C-6 for definitions.

More Open, Efficient and Resilient, August 2014. https://authors.library.caltech.edu/48575/; and Taft, JD and Becker-Dippmann, A, *Grid Architecture*, January 2015. https://gridarchitecture.pnnl.gov/media/white-papers/Grid%20Architecture%20%20-%20DOE%20QER.pdf

3.3 Sample Mapping of Capabilities to Objectives

Next Staff matched capabilities to specific objectives identified earlier and to distribution planning, operations and grid services/market operations. By way of example, the objective, "reliability," has been selected, and the various capabilities are subdivided according to planning, operations and grid services/markets. The capabilities are not ranked in order of importance.

Figure 3- 3. Mapping Capabilities to Objectives



Staff reviewed the universe of possible capabilities and identified the capabilities associated with reliability as shown in Table 3-3. Out of the universe of possible capabilities associated with reliability identified by the DOE Modern Grid Report cited above,[39] Staff determined that, given the objectives established earlier, the capabilities highlighted below are applicable: six under planning, twelve under operations, and four under markets.

Table 3- 3. Mapping Capabilities to the Reliability Objective

Objective	**Required Capabilities**
Reliability: Distribution system planning	Impact resistance and resiliency
	Scalability
	Accommodate tech innovation
	Transparency
	Open and interoperable
	Convergence with other critical infrastructure
Reliability: Distribution system operations	Operational risk management
	Security
	Contingency management
	Situational awareness
	Fail safe modes
	Public and workforce safety

[39] US Department of Energy, Office of Electricity Delivery & Energy Reliability, *Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, Version 1.1,* March 27, 2017.

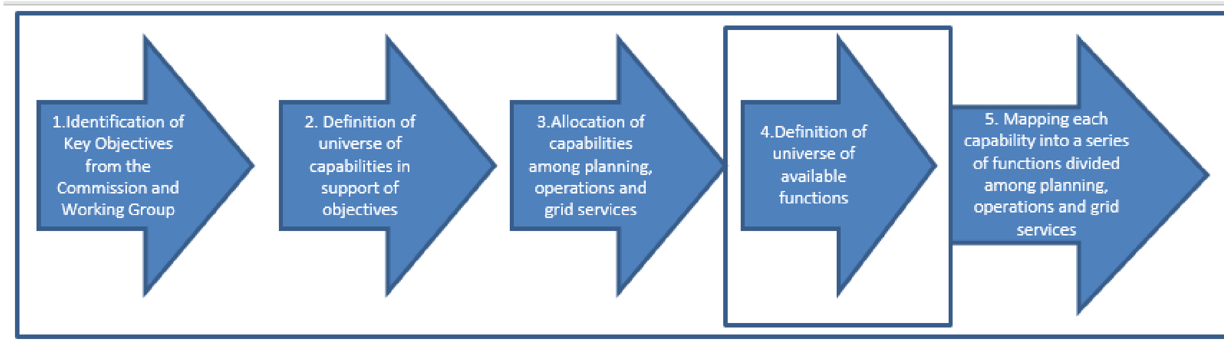
	Controllability and dynamic stability
	Attack resistance/Fault tolerance/Self-healing
	Management of DER and Load variability
	Reliability and resiliency management
	Integrated grid coordination
	Control federation and control disaggregation
Reliability: Distribution grid services/market operations	System performance
	Distribution asset optimization
	Market animation
	Distribution investment optimization

Staff then replicated the same analysis for all remaining objectives. These mappings can be found in Work Paper 2 at the end of this report.

3.4 Functionalities

After mapping all relevant capabilities associated with each objective/attribute, Staff identified and defined required functionalities. Each functionality defines a process, behavior or operational result of a process that facilitates a capability linked to one or more policy objectives. The functional descriptions and definitions are drawn from existing regulatory standards or industry references and compiled in the DOE Modern Grid Report.[40]

Figure 3- 4. Defining Functionalities



Functionalities were first subdivided under the categories of planning, grid operations, and grid services/market operations, as shown in Table 3-4. This table also suggests the timeframe for completion of each functionality.

[40] US Department of Energy, Office of Electricity Delivery & Energy Reliability, *Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, Version 1.1,* March 27, 2017, at page 27 *et seq.*

Table 3- 4. Functionalities*

Functionality	Timeframe for Completion		
	Short-Term (1-3 years)	Mid-Term (4-5 years)	Longer-Term (6-10 years)
Planning			
Forecasting DER and Demand Growth			
Short- and Long-Term Demand & DER Forecasting	X		
Long-term System Planning			
Load Flow Analysis Process	X		
Hosting Capacity Analysis (long-term planning use case)	X		
Scenario-Based Planning	X		
DER Locational Value Analysis		X	
Interconnection Process			
Interconnection Studies Enhancements		X	
DER Interconnection Process Streamline		X	
Interconnection Portal		X	
Distribution System Information Sharing			
Planning Data Sharing (portal/ mapping)	X		
Integrated Resource T&D Planning			X
Grid Operations			
Sensing and Measurement			
Power State Measurement			X
Advanced Customer Metering			X
Meter Data Management			X
Environmental Sensing			X
Control			
Grid Configuration and Connectivity			X
Flow Control			X
Communications			
Communication Infrastructure			X
Communication Network Management			X
Asset Management			
Asset Monitoring (substation)		X	
Integrated Operational Engineering and System Operations			X
Distribution System Model		X	
T-D Interface Coordination			X
Real Time DER Operation			

Functionality	Timeframe for Completion		
	Short-Term (1-3 years)	Mid-Term (4-5 years)	Longer-Term (6-10 years)
Automated Islanding and Reconnection			X
State Estimation & Optimal Power Flow			X
Volt/VAR and Power Quality Management			
Volt VAR Control		X	
PQ Measurement and Stabilization			X
Fault Management			
Advanced Protection & Relay Management			X
FLISR		X	
Outage Management		X	
Security			
Cyber Security Measures	X		
Physical Security Measures	X		
Grid Services/Market Operations			
Settlement Procedures			
Measurement & Verification		X	
Confirmation, Clearing		X	
Settlement		X	
Billing		X	
DER Portfolio Management			
Optimization		X	
Dynamic Notifications		X	
DER Sourcing (NWA)			
Advanced Pricing		X	
Programs		X	
Procurement		X	
Market Participant Rules		X	
Market Information Sharing			
Market Information Sharing Portal		X	
Market Oversight			
Market Surveillance		X	
Market Security, Cybersecurity		X	

*Definitions may be found in Work Paper 3 at the end of this report.

In Work Paper 4, Staff created a master list mapping all applicable capabilities to functionalities. For any given capability, the combinations of functionalities associated with that capability can be examined. The universe of functionalities available and applicable to a given capability varies by planning, operations, and grid service/distribution markets. Although functionalities have been furnished for planning, operations, and grid services/markets at each stage of grid modernization, a different combination of capabilities and functionalities may take precedence. All functionalities have been included out of recognition that since planning, operations, and grid services/market operations are in some instances interdependent, effective action in one segment requires an understanding of the activities in remaining segments.

Staff anticipates that, following Commission approval, utilities will examine each of the recommended required functionalities and address them when preparing their individual IDPs. The master list found in Work Paper 4 attached to this report maps the capabilities to the various functionalities under each stage—planning, operations, and grid services/market operations. Staff expects that utilities will evaluate which of these functionalities they currently perform, which they will need to perform as part of the grid modernization process, and which they will discard due to redundancy or an alternative approach. In each instance, Staff expects that the IDP submitted by each utility will contain a discussion of which functionalities already exist, which will be required and why, and which will be redundant in achieving the objectives outlined earlier.

3.5 Proposed Timeframe for IDP

As indicated above in Table 3-4, Staff proposes a timeframe for completing the implementation of each functionality. Figure 3-5 provides a conceptual roadmap of the functionalities, indicating a starting and ending point. Figure 3-6 shows a schematic diagram that depicts the conceptual technology roadmap aligning the timeframe with the functionality roadmap.

Figure 3- 5. Conceptual Functional Roadmap

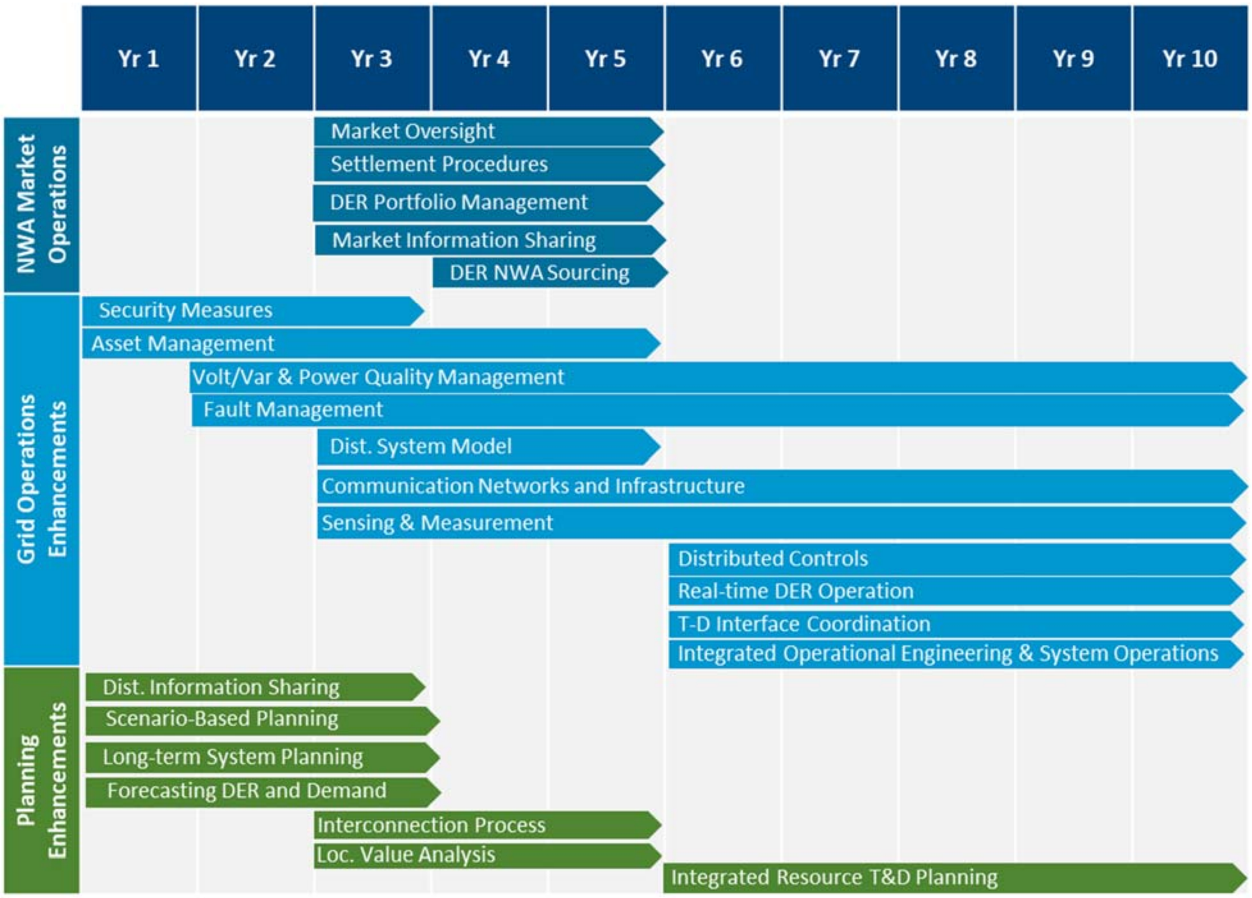
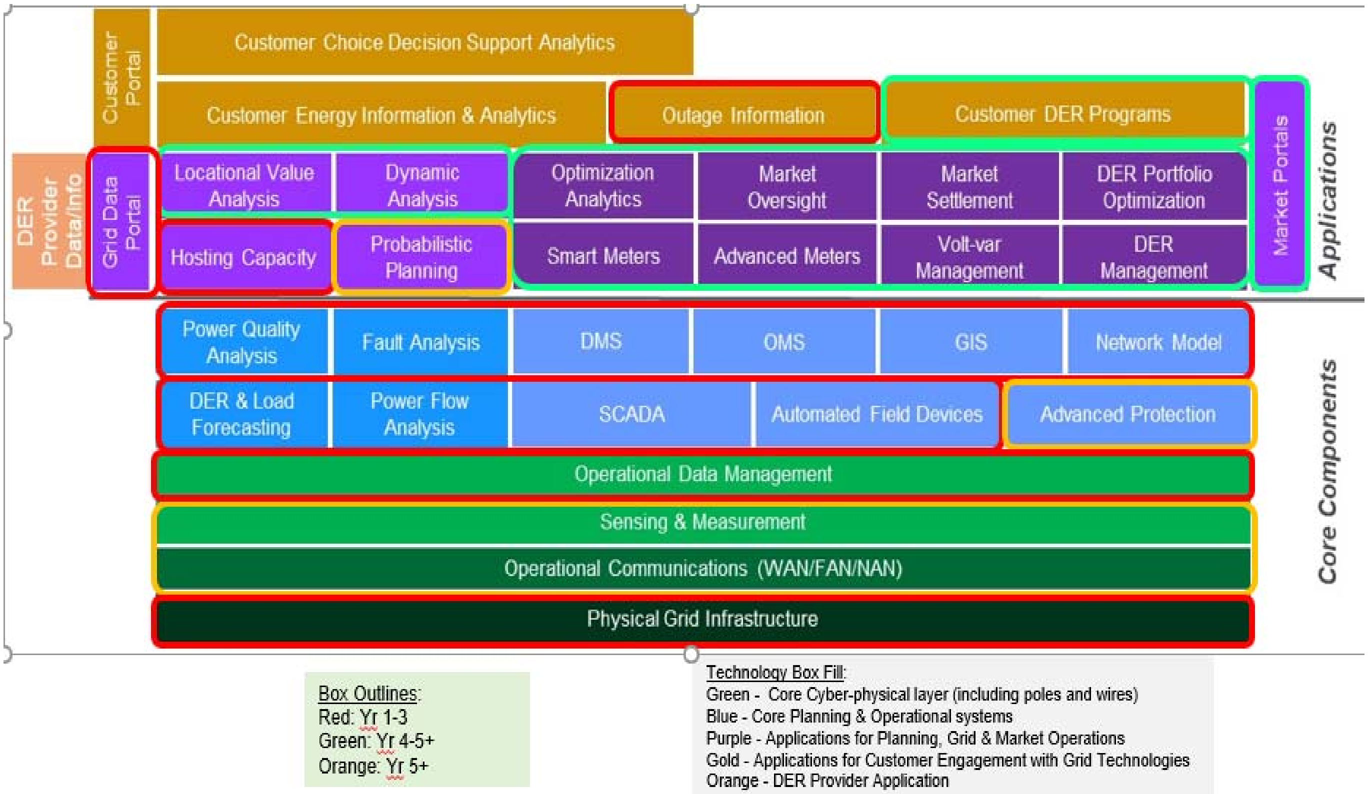


Figure 3- 6. Conceptual Technology Roadmap Aligned to Functional Roadmap



Source: U.S. Department of Energy-Office of Electricity Delivery and Energy Reliability, 2017. *Modern Distribution Grid, Volume III: Decision Guide*. Available online at: https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf

4.0 Grid Mod Working Group Report

In Section 3, Staff proposed a methodical approach for developing the IDP by leveraging the work of the DOE and other states and tying all technical decisions back to the defined objectives. This section summarizes the recommendations of the Grid Mod Working Group Report and links the recommendations to the proposed objectives. The Working Group discussed six main topics:

1. Goals
2. Outcomes and Capabilities
3. Grid Mod Planning
4. Customer Engagement
5. Cost Recovery
6. Recommended Next Steps

4.1 Goals

The goals and further benefits of modernizing the grid as proposed by the Working Group have been captured in Section 2, above. The Working Group further identified four overarching goals and four additional perceived benefits of modernizing the grid. In the Work Papers associated with Section 2, Staff demonstrated close congruence between the objectives and attributes documented in eleven selected states and the objectives and benefits derived through the Working Group process. This enabled Staff to embrace these objectives when developing their capability and functionality mapping exercise. Beyond "business as usual," Staff recognizes that the momentum for the grid modernization process relies on facilitating opportunities for DERs to provide services through the grid. This, in turn, will require new infrastructure, enhancement of existing networks, and adoption of new analytical tools to enable customers to become active managers of their electricity use through the adoption of DERs. The grid capabilities outlined in Section 3 will serve to advance these goals while ensuring a safe, reliable, resilient, and secure distribution grid.

4.2 Outcomes and Capabilities

In the Scoping Order initiating the Working Group process, the Commission specifically asked the Working Group to review and revise the "Grid Modernization Outcomes, Capabilities, and Enablers" matrix that was submitted in Massachusetts by the stakeholder Working Group several years ago. After careful consideration, the Working Group made numerous changes to the overall categorizations within the matrix, as well as to the specific outcomes, capabilities, and proposed solutions, and reached a consensus as to the final content of the matrix.

The matrix uses the terms "outcomes," "capabilities," and "enablers." Comparing the matrix to the terminology used in this report, the outcomes are considered to be objectives of grid modernization. The capabilities/activities in the matrix most closely resemble the functionalities in Staff's analysis. The enablers also resemble the functionalities, but at a more disaggregated level. Staff believes that the elements included in the Grid Mod Working Group Report matrix have been covered by the objectives, capabilities, functionalities described in this report.

4.3 Grid Modernization Planning

The Working Group examined a number of issues associated with grid modernization planning. Citing the Commission's Scoping Order, the Working Group 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."[41] The Commission further noted that it expects grid modernization planning to build off electric utilities' existing practices for making investment decisions, and that it should fit naturally within the utilities' existing integrated resource planning framework. Staff believes that to achieve optimum technologies and practices will require a fully open and transparent process; that conclusion is reflected in the Section 5 recommendations. Further, Staff concurs with the incremental and gradual approach for modernizing the grid implied by the Commission's Scoping Order, as well as the need to leverage existing utility best practices. The Grid Mod Working Group Report addressed various questions raised in this proceeding regarding the plan content and submittal requirements. In addition, the Grid Mod Working Group Report briefly discussed the stakeholder engagement process and the framework for assessing cost-effectiveness. Each of these issues are discussed in more detail in this section.

4.3.1 Stakeholder Engagement Process

Non-utility stakeholders have suggested that the stakeholder engagement process could include the formation of a consumer advisory committee to ensure that stakeholders have a meaningful role. The utilities believe that the envisaged stakeholder process provides ample opportunity for stakeholder input at key junctions and that a consumer advisory committee is unnecessary. In post report comments, Unitil stated that the planning function of the distribution system must remain in the control of the utilities and non-utility stakeholders will have ample opportunity to participate in the development of the plan, but the planning, design, and operation of the distribution system is the responsibility of the utilities and needs to remain as such. Staff concurs with the utilities that the envisaged stakeholder process adequately safeguards stakeholder input. Therefore, no additional consumer advisory council is recommended. Stakeholder input will be provided through the docket process. As the Working Group agreed, stakeholders will be involved in pre-planning, project identification and consideration, and project prioritization.

4.3.2 Cost-Effectiveness Framework

The Working Group agreed that evaluation of cost effectiveness should include both a quantitative and a qualitative evaluation of each program or type of investment. While the quantitative evaluation would include monetized values, the qualitative evaluation might embrace other factors that cannot be readily monetized, such as customer equity, environmental impacts, and the degree to which the evaluation process facilitates customer and third party engagement.

[41] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017, pg.9. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

Cost effectiveness refers to a business case framework comprising both qualitative and quantitative evaluations. It should include a detailed description of the project, including scope and schedule, the rationale and business drivers (capabilities) for the investment, the expected costs, the anticipated benefits, any assumptions underpinning the evaluation of expected benefits, options considered, and expected risks.

Staff recognizes that before the utilities file their IDPs, they must first establish a common framework for evaluating the costs and benefits of each proposed investment because each investment may have a variety of uses and implementation may require various approaches. For example, how should existing grid investments in aging infrastructure be assessed? What methods might be better to assess benefits in relation to certain investment costs, especially where benefits may be construed as either traditional utility benefits or incremental benefits that are attributed specifically to grid mod investments, and may including societal or qualitative values? Significant discussion and progress on this issue may be found in the California Public Utilities Commission decision issued on March 26, 2018.[42]

Staff suggests categorizing IDP expenditures using the four categories listed in the table below and adapted from Dr. Orans' testimony found in Appendix C of the Hawaiian Electric Companies Grid Modernization Strategy document dated August 29, 2017.[43]

Table 4- 1. Four Categories of IDP Expenditures

	Objectives	Expenditure Category	Clarification	Methodology
A	**Improve reliability, resiliency, and operational efficiency**	**Standards and Safety Compliance** Grid expenditures required to ensure reliable operations or to comply with service quality and safety standards. Includes both ongoing asset management (replacement of aging and failing infrastructure) and	Expenditures that are needed primarily to ensure reliable operations or to comply with service quality and safety standards in a grid with much higher levels of renewable resources connected behind and in front of the customer meter.	Least-cost, best-fit method

[42] California Public Utilities Commission Decision 18-03-023, Issued on March 26, 2018. Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M212/K432/212432689.PDF

[43] Orans, R. et al, *Proposed Grid Modernization Net Benefits Assessment*, Summary of Methodology, Energy and Environmental Economics, Inc., San Francisco, 2017. Included in Appendix C to the report: Modernizing Hawai'i's Grid for Our Customers, Prepared by the Hawaiian Electric Companies.
https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/final_august_2017_grid_modernization_strategy.pdf

	Objectives	Expenditure Category	Clarification	Methodology
		relevant grid modernization technologies.		
B	**Facilitate integration of DERs**	**Policy Compliance** Expenditures that are needed to comply with state policy goals.	Expenditures that are needed to comply with state policy goals such as the renewable portfolio standard, or interconnect requirements to enable customer adoption of DERs.	Least-cost, best-fit method
C	**Reduce generation, transmission, and distribution costs and Empower customers to use electricity more efficiently and lower electricity bills**	**Net Benefits** Expenditures that are not required for standards and safety compliance or policy compliance but that would provide positive net benefits for customers.	Expenditures that utilities identify as needed primarily because they would provide direct net benefits to customers or enable renewables or DER to lower the costs of electricity service. Renewables or DER may lower costs by displacing grid services that would have otherwise been offered by a more expensive source.	Total Resource Cost Test and/or another cost/benefit test such as the Utility Cost Test or Participant Cost Test.
D		**Self-Supporting** Expenditures incurred for a specific customer (e.g., for interconnection) with costs directly assigned to that specific customer(s).	Expenditures that would be paid for directly by customers participating in DER programs, and programs, including demand response and others that could be developed in the future, such as real time pricing, that require advanced	Only for projects that do not shift a cost burden to non-participants. This category does not require cost/benefit justification.

	Objectives	Expenditure Category	Clarification	Methodology
			metering capabilities, for example.	

Under this approach, the utilities must first develop an appropriate evaluation methodology for the proposed expenditures in each of the four categories, including the common assumptions used to estimate benefits by category. The methodology and assumptions should be similar for all utilities unless a utility has a unique characteristic that justifies a difference. Utilities and stakeholders should propose specific methodologies, which can be further discussed in working groups, if necessary. After the methodologies are established, each utility must identify each of the proposed expenditures in its IDP according to one of four main categories. Finally, utilities will apply the appropriate methodology, assumptions, and cost estimates to the proposed expenditures to develop transparent estimates of net costs and benefits for each part of the proposed plan. According to this approach, different screening and evaluation approaches would be required based on the purpose of the expenditure.

Not all expenditure categories would require a positive net benefit. Only in the Net Benefit category would benefits be required to exceed costs. Proposed expenditures in the Standards and Safety and the Policy Compliance categories would be evaluated based on lowest reasonable cost criteria with the best fit, and, while a cost/benefit assessment should be made, the expenditure would not need to result in a positive net benefit.

The potential benefits of such an approach include making the grid modernization strategy and its potential cost impacts more transparent. Disaggregation of grid mod expenditures into component parts will facilitate better matching of methodologies with specific evaluation methods. Finally, this approach permits evaluation of those applications that are required for the integration and utilization of DERs that will ultimately enable customer-facing programs, as well as those that provide net benefits to all customers and support energy policy in a resource planning context. Staff encourages further examination of this approach, including determining how to handle investments that would fall into one or more of the cost-effectiveness categories.

4.4 Customer Engagement

The Customer Engagement section of the Grid Mod Working Group Report included discussion and recommendations regarding the following:

- Rate design;
- Advanced metering functionality (AMF);
- Customer and utility data; and
- Customer education.

4.4.1 Rate Design

As electric utilities look to make their systems more efficient and meet public policy goals, efforts to send price signals that both reflect the true cost of energy and reduce stress on the grid are becoming increasingly important. One of the challenges of rate design under conditions of grid modernization is to balance numerous and varying interests. In a number of states, potential entrants to the market want to ensure that valuations and rate design align DERs with system needs while supporting financially feasible projects. In other states, for example, participants are working to ensure that distribution system planning harnesses the full value of distributed solar through the identification of locational values to incorporate in rate design as an option.

Recent recommendations on rate design from other jurisdictions included the following:

- Indemnify low income customers;
- Use an opt-out approach to enrollment;
- Provide rates that accurately reflect the costs of energy;
- Balance precision and practicality for all parties involved; and
- Give customers adequate tools to assess their energy usage.

Staff supports the rate design principles embraced by the Working Group:[44]

- Rates should include fair compensation to utilities and consumers;
- Rates should provide appropriate and efficient price signals;
- Rates should incentivize consumers to use electricity wisely and to invest in cost-effective DERs;
- Rates should maximize consumer choice and control and protect vulnerable customers; and
- Rates should reflect cost causation principles.

When developing the distribution system plan, utilities should consider rate design when trying to achieve two of the distribution planning objectives outlined in this report: reducing costs and enabling/empowering customers, and, more specifically, strengthening openness, interoperability, scalability, and transparency.

The utilities should look to time varying rates (TVR) pilots in New Hampshire and other states to help determine the best approach for rate design. As part of the net metering docket (DE 16-576), the Commission directed Eversource and Unitil to propose and conduct a time-of-use (TOU) pilot and Liberty Utilities to work with the City of Lebanon on a real-time pricing pilot. In addition, Liberty Utilities has proposed TVR for generation, distribution, and transmission as part of its battery pilot. Various components of rates are addressed below and further discussed in the Grid Mod Working Group Report, including customer charges; demand charges; TVR for generation, transmission and distribution; location-based pricing; and low-income protection.

Customer Charges

Staff recommends that, as a goal, utilities should recover only customer-related costs through customer charges, which should be based on a cost of service study. Any significant increases in customer charges should be phased in gradually, in keeping with the ratemaking principle of moderation.

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[44] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017, pg.13. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

Demand Charges

Staff agrees with the Working Group's recommendation that demand charges should depend on customer class:[45]

- Large Commercial and Industrial (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.
- Residential customers: Utilities should not assess demand charges to residential customers for the present.
- All customers: The utilities and the Commission should consider whether demand charges should be more aligned with times when marginal costs are highest, for example, at periods of system peak demand.

Staff suggests consideration of aligning demand charges with coincident system peak demand periods. To evaluate the impact of coincident system peak demand charges, Staff recommends reviewing other states, if any, that have piloted or implemented such an option, with a view toward proposing a similar pilot in New Hampshire or including this aspect in other pilots.

Time Varying Rates for Generation

The Working Group discussed an opt-in and an opt-out approach for TVR for generation and the associated technology and information requirements, as well as a technology opt-in approach. Currently, not all customers in New Hampshire have the metering capability for TVR rates; therefore, the utilities may need to install new meters and update billing systems before rolling out TVR.

Time Varying Rates for Generation: Opt-In

Utilities may consider an opt-in TVR for generation. Any suppliers interested in offering TVR options to default service customers should make this clear to utilities during the supply request-for-proposal process. Staff supports the inclusion of TOU pricing with critical peak pricing where possible, where there is a compelling cost-effective case for customers, whether in this or another docket, and where it does not create a barrier to an eventual opt-out. In addition, Staff recommends the implementation of TVR for generation as part of a TVR pilot, similar to that being proposed by Liberty in DE 17-189 for its battery storage pilot program. For an opt-in rate, Staff supports that customers pay the incremental cost of the meter or other rate-specific costs. Staff concurs that for system-wide changes, utilities should recover costs from all customers. Customer data needs are dependent upon the applicable rate design. If a customer needs timely info to be able to react to a TVR, then that customer should have access to such data. If the utility has that data, then a mechanism for providing it to the customer should be implemented, unless an alternative, more cost-effective approach is available. Pilots could provide valuable information regarding TVR and the requisite data needs and technology requirements.

[45] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017, pg.14. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

Time Varying Rates for Generation: Opt-Out

Opt-out TVR for generation is not an option available 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 should be recovered from all customers. TVR 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). Any customer who opted out would shift to a competitive energy provider (CEP) or absent Commission approval, a flat rate default service option could be provided. Generally, the TVR should be as sophisticated as possible, utilizing the most current technologies deployed. Staff recommends that opt-out TVR represents a longer term goal for all customers. In addition, utilities could review other states, if any, that have piloted or implemented opt-out TVR for generation.

Alternative TVR Approach for Competitive Suppliers (Technology Opt-In)

An opt-in or opt-out for default service may not be practical to implement in the short term. In addition, there is concern that opt-in or opt-out TVR for default service may undermine competitive retail markets for energy service because of the uncertainty of load migration that could occur between a fixed rate and a TVR default service rate or competitive supply. Staff encourages the utilities to consider enabling competitive providers of energy services to offer TVR to small residential and small business customers through affordable opt-in interval meters and meter data systems. Consideration should also be given to the desirable features of the interval meters, including bi-directional metering, data storage capability, and level of granularity of data.

TVR for Transmission

Staff supports the eventual roll out of TVR for transmission services for distribution utilities. In the near term, a TVR for transmission based on simple grid capabilities and interval meters could be considered.

TVR for Distribution

Staff recognizes that TVR for distribution using simple on-peak and off-peak periods are already available for some customer groups in Eversource and Liberty service territories. Staff understands that most Unitil meters can accommodate TVR. Staff supports the gradual roll out of TVR capabilities in step with the ability to capture and provide the required data. In the near term, interval meters could be used with simple on-peak and off-peak periods and possibly a critical peak period.

Low Income Protection

Staff recommends maintaining existing protections and programs for low-income customers (e.g., Electric Assistance Program, targeted energy efficiency programs, and disconnection protections) and considering whether additional protections and opportunities related to grid mod are needed.

4.4.2 Advanced Meter Functionality

The Working Group discussed Advanced Meter Functionality (AMF) and available meter options. Given the statutory limitations on smart meter gateway devices, the Working Group proposed a technology opt-in. When developing distribution system plans, utilities must consider the goals, capabilities and functionalities to which AMF can contribute. Staff suggests that AMF can be used to meet the following goals and objectives: reduce costs and increase affordability, enable customers, enable DER integration, operational excellence, and flexibility.

Metering Options and Functionality

Table 4-2 shows the meter functionality of Automatic Meter Reading (AMR), enhanced AMR with Home Area Network (HAN), enhanced AMR with fixed network, and full Advanced Metering Infrastructure (AMI), as proposed in the Grid Mod Working Group Report. For AMF to be fully operational, appropriate utility back office infrastructure (i.e., compatible billing system) is necessary. The long-term goal is to enhance functionality and to ensure TVR opportunities for all customers. AMF could initially be deployed strategically (e.g., by geographical target areas, to large customers, through old meter retirement, through pilots, and to early adopters). Since technologies are rapidly changing and grid capabilities are evolving, Staff recommends that a cost/benefit analysis be conducted to determine the appropriate level of AMF before deployment of a certain type of meter at full scale. A customer can opt to install a specific type of meter, but the customer should be responsible for the incremental costs associated with such a meter, including costs associated with back office requirements. Staff recommends that stakeholders and utilities provide specific comments regarding AMF and then possibly discuss AMF further during working groups.

Table 4- 2. Metering Options and Functionality

Technology Option	Customer Facing									Grid Facing				
	Drive-by Reading	TOU Register	Interval Data	Remote Meter Read	Daily Read	Real Time Meter Read	One Way Communication	Two Way	Communication to	Remote Connect/	Power Quality Reading	Voltage Reading	Outage ID & Restoration Notification	Planning Data
AMR														
Enhanced AMR (w/HAN)														
Enhanced AMR (w/ fixed network)														
Full AMI														

Adapted from Table 5.2 of the Grid Mod Working Group Report.[46]

No Capability	
May/Limited Capability	
Full Capability	

Technology Opt-In

While Staff supports the notion of metering that ensures a full range of available competitive services, Staff believes, however, that since grid mod will be rolled out gradually, the desire for full metering capability needs to be tempered by considerations of cost-effectiveness. In contrast to New York where AMI functionality is considered a foundational technology, Staff believes that in the short term, interval metering will meet the needs of an evolving grid in many situations and is responsive to the Commission's recommendation for a gradual introduction of additional technologies. During the docket process, customer and utility data needs should be defined, and then the most cost-effective metering or technology options should be chosen to provide such data. The rate design must be taken into consideration. In addition, behind-the-meter technologies should be considered as a viable option for providing customer interval load data and power quality characteristics, such as voltage, in the absence of an advanced metering infrastructure. For customers who wish to install more advanced meters, including smart meters,

[46] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017, pg.16. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

they can opt for such technology, and pay the incremental cost of such meters. If those meters are deployed widely, however, then the cost recovery should be covered by all customers, or at least by the associated customer class opting to use them. The back office requirements and associated costs should be considered as part of an analysis of cost-effectiveness. Currently, smart meters that communicate with devices in a residence or business require the customer's written consent for installation in accordance with RSA 374:62.

The Working Group agreed to work together to provide time interval data, including time interval data to the customer, and proposed three possible approaches for an opt-in interval meter for exploration:[47]

- Option 1. Replace 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 third 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 by the customer requesting the upgrade.

- Option 2. Replace the existing utility meter with an interval meter that allows both the customer and the utility access to interval data in near real-time (using communication 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 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 to upgrade the meter would be paid for by the customer requesting the upgrade.

- Option 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, another 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 options 1 or 2. The Working Group recognizes that utilities cannot use this data for billing and reporting purposes under current rules and tariffs, and that this option this would require changes approved by the Commission.

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[47] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017, pp. 20 and 21. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

Staff concurs with these approaches but cautions that shared data points between the utility and the customer could pose a security risk; therefore, utilities must ensure that protections are in place. Customers should be able to opt-in to an interval meter option, if desired. The customer should pay the incremental costs unless the meter option is required for rate design or if the meters are deployed to a majority of customers, then all customers or the applicable customer class should pay the meter costs and associated expenses. During working group sessions, these options could be further explored to ensure that the chosen option provides the data necessary in a timely fashion, and that the back-office systems and other necessary systems are economically available.

Technology and Information Considerations

Desirable Features: Staff agrees with the Working Group[48] regarding the several desirable features of meters and technologies related to the specific data to read and log, access to an application programming interface for standardized data retrieval, cybersecurity features, accurate date and time stamping of data intervals close to ISO intervals, ability to collect and store data on a secure site, and a low cost option for collecting and accessing data in near real time. During working group sessions, the data needs and best options for providing such data should be evaluated further.

Metering Concerns: Staff agrees that public concerns with metering options (e.g., load control of individual circuits or devices and radio frequency communications) must be taken into consideration; however, customers can opt in to install smart meter gateway devices. In addition, cybersecurity issues must be considered.

Remote Disconnect Functionality: Staff recommends maintaining remote disconnect functionality, given that some utilities already employ that functionality, and that there are concerns about non-payment as well as security and reliability of the system.

Interval Data Granularity: Staff endorses the position that customers should be free to opt in and pay the incremental cost for the installation of fifteen-minute interval meters. Meters with five-minute intervals may require significant investments by the utilities for new meters, larger databases, and increased communication bandwidth. Because the utilities would be required to make significant changes, a five-minute interval meter option is not practical on an opt-in basis. Before requiring meters with fewer than hourly intervals, a cost feasibility analysis should be conducted.

4.4.3 Customer and Utility Data

This section discusses Staff's recommendation regarding customer and utility data, based on the Grid Mod Working Group Report discussions.[49]

[48] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017, pgs. 21-23. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

[49] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017, pgs. 23-26. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

Principles

Staff concurs with the principles of customer and utility data developed by the Working Group:

- Sharing of data with the market (including third-party providers) can encourage market competition for the provision of advanced energy technologies.
- In general, use of standards and protocols for data sharing can facilitate interoperability, empower third 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.)
- Security is an inherent risk related to the sharing of customer data and must be addressed.
- Interval data enables time varying rates, demand response, and 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.
- Aggregated customer information can be made available if certain protocols to protect individual customer usage and identity are adopted.
- Individual customer data should be made available consistent with the requirements and protections set forth in RSA 363:38.
- An individual customer is always free to share his or her own 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

Staff agrees with the Working Group regarding third party access to 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.

During working group sessions, issues related to customer data must be discussed further to determine customer data needs and the best approach for gathering and providing access to such data.

Hosting Capacity Analysis

Hosting Capacity Analysis (HCA) depicts the amount of DER that can be accommodated without adversely affecting power quality or reliability under existing control configurations and without requiring infrastructure upgrades.[50] Utilities that have implemented grid mod initiatives have utilized HCA in a phased approached[51] coincident with the planning and operational implementations of the grid modernization process. The initial function of the HCA is to provide a development guide to promote a more efficient process in the DER developer's decision-making approach. Staff recommends that the HCA be discussed in detail during working group sessions to determine a consistent approach, methodology, assumptions, and modeling tools. Staff supports the Grid Mod Working Group Report that at a minimum, the hosting capacity maps should provide the red, yellow, green portions of circuits to depict various levels of infrastructure upgrades required in order to accommodate a utility defined limit of DER output to minimize the impact in the existing grid power quality levels (i.e., voltage, current flow, asset loading, etc.).[52]

Prior to beginning those discussions, the utilities should provide information related to the availability of necessary data to conduct this analysis, such as location of all DG facilities, the granularity of data (e.g., by substation, feeder, line), specific monitoring data (voltage, thermal loading, protection, power quality, and control) and the basis for such data, and load profiles. In addition, the utilities should provide information related to their GIS systems, indicate how up-to-date their systems are, the method and frequency for updating the data, and how the data will be represented in their proposed HCA models. The progression of third party functionality and usability of the HCA maps should also be considered, incorporating increased sub-circuit granular real-time data as well as asset capacity status due to thermal or design limits. Early stages in the progression may require separate customer facing portal maps (e.g., heat maps) that indicate capacity constrained locations where DERs can help address problems and reduce, defer, or avoid conventional utility infrastructure projects.[53] Figure 4-1 is an example from NY REV that depicts a typical staged approach to HCA of functionality and effectiveness.

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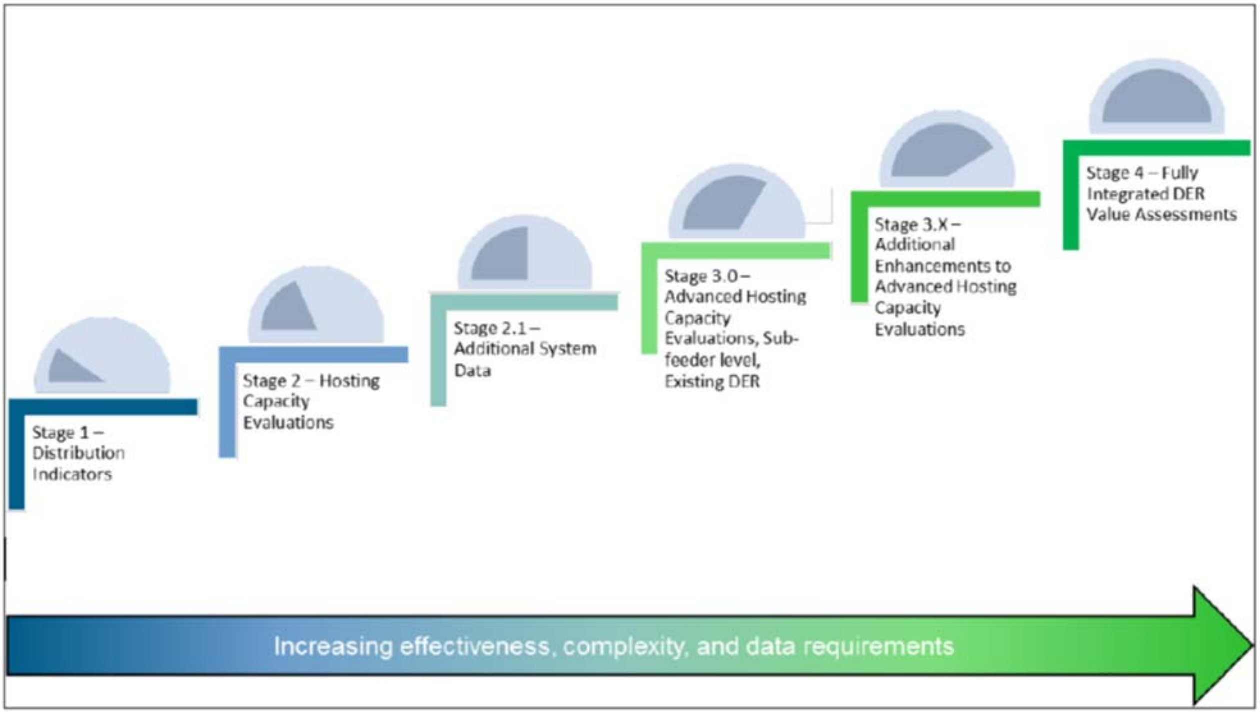
[50] EPRI, *Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity,* February 2018, pg.1-1, https://www.epri.com/#/pages/product/000000003002011009/

[51] ICF, *Integrated Distribution Planning, Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*, July 2018, pg. 9.

[52] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017, pgs. 24 and 25. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

[53] GridLab, *Integrated Distribution Planning: A Path Forward*, 2018, pg.14. https://static1.squarespace.com/static/598e2b896b8f5bf3ae8669ed/t/5b15ae6470a6ad59dcb92048/1528147563737/IDP+Whitepaper_GridLab.pdf

Figure 4- 1. Staged Approach from NY REV of HCA Functionality and Effectiveness[54]

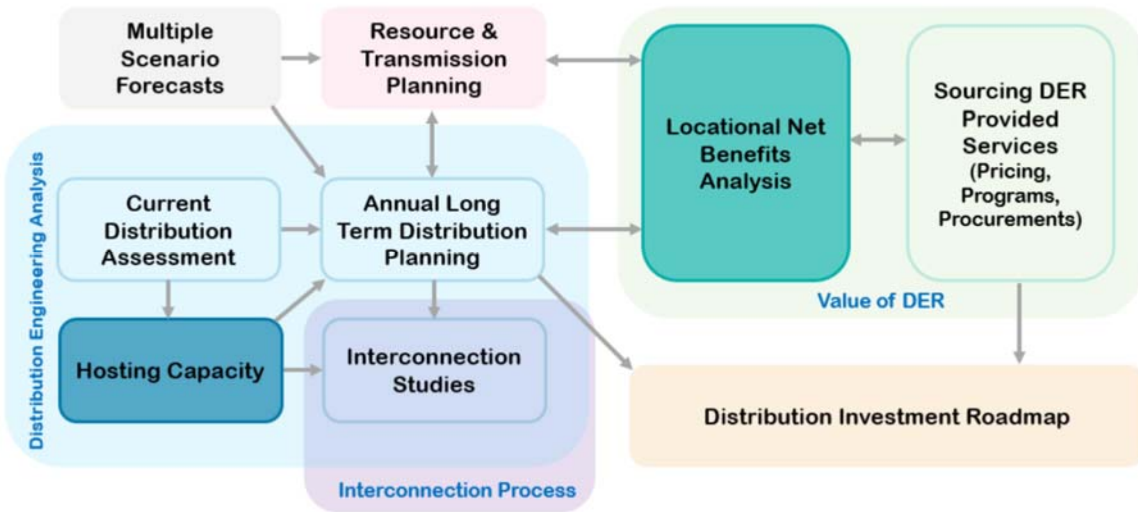


Initially, the utilities' HCA portals/maps will be limited in terms of data granularity and data refresh rates, but as more grid data is available and existing DER characteristics are included in the analysis, Staff expects that the HCA will become a more accurate representation of the grid. This will provide the utility and DER developers more functionality of the HCA model. Utilities in other states that have embarked on the grid mod initiative and developed HCA portals and their maps have incorporated more interactive tools to provide third party developers detailed data of circuit segments furnishing an added value in siting locations. A more robust analysis process including increased DER penetration analysis and reverse load flow may allow the utility to leverage the HCA as a key input into the interconnection process. Ultimately, as technology progresses, utility planning tools mature, and various non-utility factors are considered, such as DER long term behavior, economic trends, and policy changes, the functional benefit of the HCA process will significantly shape the forecasting element of the model and will provide an additional input into the utility's long term planning model.

The figure below depicts the various assessments and tools of the integrated distribution planning process. The level of impact that the HCA provides in the distribution engineering analysis will be reflected by the stage to which the HCA process has evolved.

[54] Consolidated Edison Distribution System Implementation Plan, April 2018, pg.179. https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/distributed-system-implementation-plan.pdf

Figure 4- 2. Relationship of the component parts of the distribution planning process[55]



Locational Net Benefit Analysis

Similar to HCA, locational net benefit analysis is a key component of the integrated distribution planning process. Locational value assessments (referred to as constraint relief analysis in the Grid Mod Working Group Report[56]) establish locations on the distribution system where non-utility solutions to capacity requirements due to substation or distribution asset loading or reliability requirements could be utilized. Location values also could feed into the pricing mechanisms of DERs. This pricing mechanism and value is presently being evaluated in the net metering docket (DE 16-576), but only for net metered distributed generation, not for other types of DERs. Depending on the resource capability required in a specific location, the pricing mechanism may differ from the aforementioned net-metered value stack. Staff believes that more detailed data for load, load shape by time of day and month, circuit capacity, and reliability deficiencies due to capacity needs will be critical for assessing innovative solutions to traditional investments. Therefore, this data should be made available to customers and third parties when and where the technical capability exists. At a minimum, the red, yellow, and green indicators mentioned above as part of the HCA could be provided for specific data elements initially. Additional data regarding distribution constraints will allow non-wire alternatives (NWAs) to be considered as an alternative relief mechanism or an option for deferring costlier investments. Procurement of an NWA solution relies on the utility specifying the required need and forecasting capability to allow appropriate time (i.e., 2 to 3 years) for the NWA solution to be

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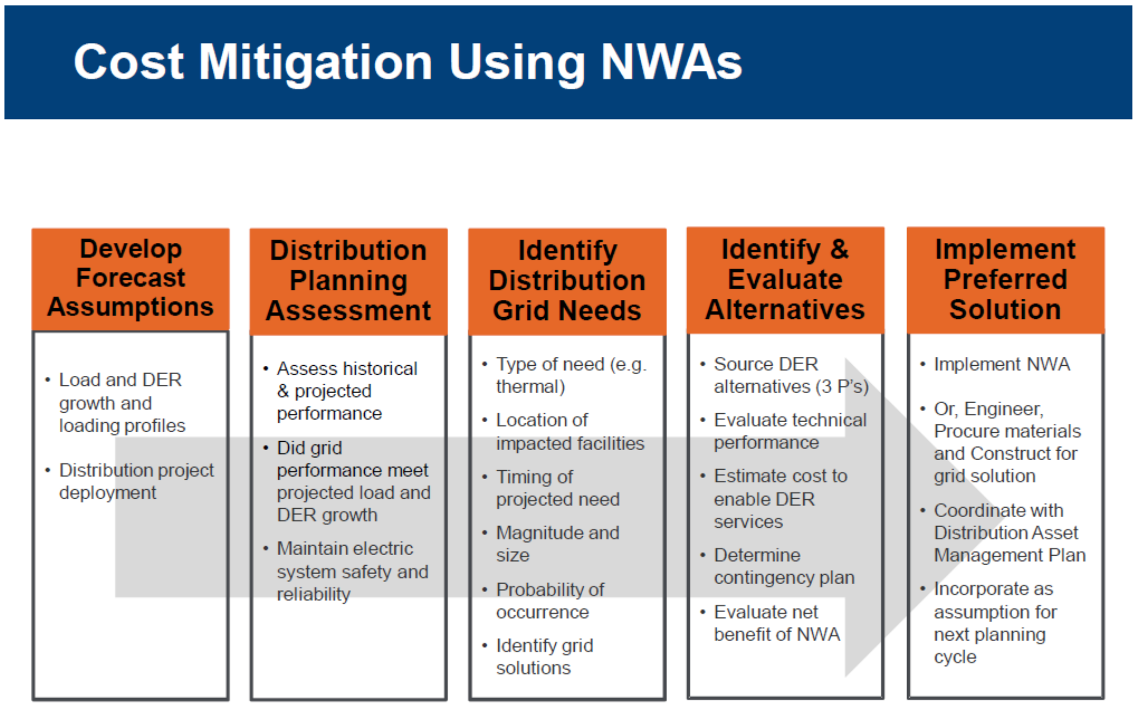
[55] ICF, *Integrated Distribution Planning, Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*, July 2018, p. 3.
[56] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017, p. 25.
http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

procured and evaluated for meeting the required distribution deferral need and timeframe, while providing equal levels of reliability, safety, and resiliency as a traditional distribution investment.

Figure 4- 3. Process for Reviewing NWA Locational Candidates[57]



The procurement process timeframe and complexity is based on the identified solution and resource timing requirements. Staff recommends that utilities follow the approach outlined in Figures 4-3 and 4-4 for reviewing NWA locational candidates and proposed resource solutions that fulfill the constraints of the capacity or reliability needs. Figure 4-4 depicts a typical procurement approach for an NWA project under the IDP.

[57] US Department of Energy, *Planning for a Modern Distribution Grid, NECPUC Practicum Report*, June 2018, pg.10.

Figure 4- 4. NWA Procurement Best Practices from ICF NWA Document[58]

Emerging Procurement Best Practices
• Provide useful customer and system data
• Provide anticipated device trigger/ dispatch and notification requirements
• Use demonstration projects to explore subsequent commercial terms
• Give DER providers the right amount of lead time
• Coordinate with other programs and markets
• Offer a vendor pre-qualification process
• Use sample pro forma agreements to explore the optimal commercial standards

Electronic Data Access System

Staff supports customer usage data transparency and recommends that an electronic access data platform be further investigated to determine data needs, the best approach for providing the data, and under what technical conditions and at what cost such a system could be deployed. The Commission may wish to evaluate data access (with customer authorization) by a third party on behalf of a customer who possesses a meter configured to gather data. Stakeholders and utilities could determine whether existing platforms can provide data access, including by a third party on behalf of a customer. In some states, the data is held by a third party, not the utilities. For ease of use by third parties, the data and access portals should have similar characteristics and provide data in similar formats.

4.4.4 Customer Education

The Working Group discussed customer education, including customer engagement platforms and consolidated billing. Such customer education would serve to meet the same goals, capabilities, and functionalities as customer data. Staff agrees with the Working Group that the utilities should take the lead in educating customers on distribution planning and grid mod opportunities and activities. Staff recommends that the Commission provide distribution planning and grid modernization education through this docket, as well as through a separate web page related to distribution planning/grid modernization, if possible.

Customer Engagement Platforms

Staff acknowledges that the examination of customer data to recommend cost-saving measures to customers can be a very useful tool; however, Staff cautions that a number of tools, including off-the-shelf options, are available to provide such information. Therefore, Staff recommends that such customer engagement platforms be subject to a cost/benefit analysis or at least be evaluated to ensure no duplication in such tools and to ensure that such a platform can accomplish the objectives cost-effectively. Staff suggests that the utilities either discuss these

[58] Sam Hile, Dale Murdock, and Matt Robison, ICF, Inc. *Procuring Distribution Non-Wires Alternatives: Practical Lessons from the Bleeding Edge*, 2017, pg. 2. https://www.icf.com/resources/white-papers/2017/nwa-utility-procurement

platforms as part of their distribution system plans or their EERS plans in the EERS docket. While Staff recognizes the possible advantages of a statewide platform, it believes that each utility should be able to develop its own platform, if desired and deemed cost-effective and beneficial. Staff does not believe that a customer engagement platform alone serves to promote customer engagement and investment in both supply and demand options. Once markets and pricing structures are established for all types of DERs, then a more detailed customer education plan can be developed.

Consolidated Billing

Staff recommends that consolidated billing by suppliers be further investigated using the cost/benefit methodology, taking into account utility financial integrity and the fixed costs associated with being the billing provider of last resort. Then a determination can be made whether it would serve to promote greater competitive alternatives for customers. A third-party billing option separate from billing by the utility and competitive supplier could be explored, as well.

4.5 Performance Metrics

Performance metrics need to be evaluated and based on an individual utility's existing infrastructure and operational architecture, including processes that currently integrate distribution assets with the necessary control, as well as data availability. Traditional infrastructure metrics, such as SAIDI, SAIFI, and CAIDI,[59] are reliability driven and will continue to be part of a utility's "business as usual" operational investment. As IDPs are proposed, additional metrics that accurately represent incremental grid mod investments, as well as all distribution investments, will need to be developed and will vary from utility to utility.

The implementation of the IDP will require a different application of metrics for rate case recovery of traditional distribution investments, which historically have been on a three-year cycle, compared to the proposed five-year grid modernization investment recovery mechanism, which may operate over a shorter cycle -- that is, annually. The causal effect of grid mod investments on traditional infrastructure investment will need to be linked and tracked through existing utility metrics, as well as through additional metrics that provide greater transparency and tracking of the relationship between infrastructure investments and grid modernization investments. Baseline metrics will need to be established to determine all aspects of grid capabilities including, but not limited to reliability, customer engagement, data capabilities, DER deployment and interconnection, and resiliency.

Staff recommends that stakeholders and utilities provide detailed comments on performance metrics. Further discussions may occur as part of working group sessions. If no agreement is reached among the stakeholders, then the utilities should propose metrics in their IDPs and begin establishing a baseline. Metrics should be proposed in the utilities' IDPs, and reviewed and

[59] SAIDI: The System Average Interruption Duration Index is the average outage duration for each customer served;
SAIFI: The System Average Interruption Frequency Index is the average number of interruptions that a customer would experience; and
CAIDI: Customer Average Interruption Duration Index is calculated as the average outage duration for each customer interrupted.

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

The following are examples of the types of metrics that can measure both infrastructure and grid mod performance progress:[60]

- Total number of customer minutes avoided due to grid mod investments at the system or circuit level;
- Total number of customer interruptions avoided due to grid mod investments at the system or circuit level; and
- Reduction in peak demand due to grid mod investments.

4.6 Cost Recovery (including Reconciliation)

The cost recovery of distribution system investments is discussed during periodic rate case proceedings or on a more frequent basis for certain programs such as vegetation management. For purposes of this report, these types of expenditures are referred to as "business as usual." For grid mod specific expenditures, Staff proposes that a cost/benefit methodology be established to determine the most cost-effective approach for handling grid mod investments.

Staff believes that the Commission should be able to provide preliminary approval of grid mod investments based on cost recovery analysis and subject to subsequent verification for prudency. For the first 3-5 years of the IDP implementation, the majority of capital investment will be driven by infrastructure and software upgrades, some of which would have happened during the normal course of doing business, some of which may be specific to grid modernization efforts, and some of which are a combination of normal business and grid modernization investments.

In the initial IDP, performance-based regulation and performance metrics that align with grid modernization objectives should be proposed as a way to replace existing traditional regulatory measures. Stay-out provisions were part of the most recent electric distribution rate cases, for example; therefore, Staff recommends that these multi-year rate plans continue. Recovery of stranded costs will need to be considered, especially during the initial implementation phase, because existing plant might be replaced prematurely in order to accelerate the timeline for a more technology-driven grid. Staff also recommends revenue decoupling in the next rate case to remove potential disincentives in grid modernization investments. The utilities have agreed to revenue decoupling in the next rate case as part of the most recent Energy Efficiency Resource Standard (EERS), Docket DE 17-136. Issues that will need to be resolved between stakeholders to this docket will include the following:

- Does the degree of risk facing the utilities in implementing grid modernization merit the need for a targeted cost recovery mechanism?

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[60] Order of Notice, Massachusetts D.P.U. 12-76B, Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, June 12, 2014. https://eeaonline.eea.state.ma.us/EEA/FileService/FileService.Api/file/FileRoom/9235208

- Is adoption of a performance-based ratemaking mechanism adequate and appropriate to recover grid modernizing investments or should a cost recovery mechanism be established?
- Should operating and maintenance (O&M) cost recovery precipitated by grid modernization efforts be included along with capital expenditures?
- How frequently should cost recovery filings take place—annually or semi-annually?
- How will eligible pre-authorized grid mod capital investments be defined, and what standards will they be required to meet?
- How long should such a cost recovery mechanism remain in place—three years, five years or more?
- Will cost recovery take place through a customer and volumetric charge or only a volumetric charge?
- How will stranded costs that are precipitated through the grid modernization program be recovered?

Staff's recommendation is in favor of a targeted cost recovery mechanism enabling recovery of both grid modernization related O&M as well as capital investment. The frequency of such a mechanism should be limited to no more than once per year. This mechanism would remain in place for no more than five years. Cost recovery of grid modernization investments would take place only through volumetric charges and would be accompanied by a mechanism for recovery of stranded costs, as well.

Reconciliation

Following the first year of a 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. The utilities would be required to provide sufficient documentation of pre-construction cost estimations, actual project costs, and explanations of any variance between the two, as would typically be provided during the context of a rate proceeding to justify the approval of cost recovery for capital additions. Whether a project is approved for cost recovery will not be revisited in a reconciliation docket; however, the total costs of the project should be examined for prudency, especially when the costs are above the original estimate. In years that do not require reconciliation, utilities should submit a brief report updating the Commission on the status of the implementation of their respective IDPs.

4.7 Mapping the Grid Mod Working Group Report to System Capabilities

The following table seeks to better illustrate the relationships between the issues addressed above and in the Grid Mod Working Group Report, including their relationship to the system capabilities outlined in Section 3.

Table 4- 3. Key Working Group Issues Mapped to Capabilities

Capability	Rate Design	TVR Rates	Location Based Pricing	Meter Functionality	Customer Data	Hosting Capacity Analysis	Data Access	Customer Education	Conso Billing
Reliability and Resilience Management									
Operational Risk Management									
Impact Resistance and Resiliency									
Security									
Contingency Management									
Accommodate Tech Innovation									
Situational Awareness									
Scalability									
Fail Safe Modes									
Public and Workforce Safety									
Open and Interoperable									
Controllability and Dynamic Stability									
Transparency									
Attack Resistance/Fault Tolerance/Self-Healing									
Integrated Grid Coordination									
Management of DER and Load Stochasticity									
System Performance									
Distribution Asset Optimization									
Control Federation and Control Disaggregation									
Market Animation									
Environmental Management									
Distribution Investment Optimization									
Convergence with Other Critical Infrastructure									

5.0 Integrated Distribution Plan Process and Content Requirements

Once grid needs have been identified, the utilities will submit an IDP that describes their proposed investments to address specific needs, as well as any investments intended to enhance visibility of system conditions, enable generation by DERs, or facilitate coordination between the distribution and transmission systems. The guidance provided in the preceding sections will direct the utilities in the submission of their IDPs. This section first discusses the proposed process steps and subsequently provides an outline of all the information that should be included in the plans.

5.1 Process Recommendations

Staff recommends that the Commission receive input from utilities and stakeholders on this report prior to the submission of IDPs. This section describes the proposed process for feedback and the process for submittal of initial and subsequent IDPs, as well as associated updates.

5.1.1 Stakeholder and Utility Feedback on Proposed Approach

Staff recommends that stakeholders and the utilities provide general and specific feedback on this report and the proposed approach for modernizing the grid through the IDPs. If necessary, Staff may provide expanded or revised recommendations depending on the information provided in comments.

5.1.2 Potential Working Groups

Prior to the submittal of utility IDPs, the Commission may wish to determine what working groups or working group sessions will need to be established to address specific issues and to provide further guidance to the utilities. Staff would prefer that the working group sessions be limited in scope, with the preferred approach to include written input from the utilities and stakeholders prior to establishing working group sessions. Topic areas that might need to be discussed at working groups include the following:

1. Rate design
2. Cost-effectiveness analysis methodology
3. Utility cost recovery
4. Utility and customer data access
5. Hosting capacity analysis
6. Locational value analysis
7. Metering
8. Customer education
9. Strategic electrification
10. DER pricing structure
11. Consolidated billing
12. Cybersecurity
13. Annual reporting requirements.

Some of these issues might not require immediate consideration during the first five years of the IDP.

5.1.3 IDP Submittals

The IDP will require approximately 12 months to develop, using the comprehensive LCIRP template with the incorporation of the grid modernization initiatives plus an engaged stakeholder process. Eversource and Liberty Utilities are required to file their next LCIRP to the Commission by August 25, 2019, and July 1, 2019, respectively, and Unitil is required to file its LCIRP by January 9, 2020. Staff recommends that, if necessary, the utilities request that the LCIRP filing requirement be waived by the Commission, pursuant to RSA 378:38-a, in order to enable the utilities to submit the more robust, integrated, and transparent IDPs.

The IDPs will include a 10-year roadmap outlining how the company proposes to make measurable progress towards the following modernizing grid objectives:

- Improve reliability
- Improve resiliency
- Increase operational efficiency
- Reduce costs and increase affordability
- Empower customers to use electricity more efficiently and lower electricity bills
- Enable DER integration
- Achieve operational excellence
- Provide competitive services
- Reduce carbon emissions and environmental impacts

The IDPs will also include a five-year detailed implementation plan. Utilities will file annual status reports on all IDP implementation activities, including deployment progress, actual-to-planned cost comparisons, and performance metric achievements. The IDP should propose metrics for consideration. For the initial IDP, the Commission may want to stagger the filings by at least three months, or at least consider staggering the review of each plan, to allow for adequate time for initial reviews. Staff proposes that subsequent filings, as well, have staggered due dates to facilitate review.

5.1.4 Stakeholder Input of IDP

Prior to plan submission, a series of working group sessions will facilitate contributions from all stakeholders to ensure that the proposed utility plans will comport with the proposed goals and directives for a modernizing grid. Once the plans have been submitted, the Commission will initiate a stakeholder review process to solicit input as to whether the IDP, as proposed, meets the objectives outlined in this report. Stakeholders may submit testimony commenting on the plans and proposing any changes.

5.1.5 Commission Approval

The Commission would take all viewpoints under advisement and, based on the plan and associated submissions, will issue an Order approving/disapproving, in whole or in part, the implementation of each individual utility plan.

5.2 Content of IDP

The utilities will file detailed IDPs with a 10-year roadmap and a 5-year detailed implementation plan. The structure of each IDP will vary slightly from utility to utility; however, the core content of each IDP shall be as follows:

1) **Executive Summary**
    a. Company Vision and Guiding Principles
    b. 10-Year Roadmap
    c. Discussion and Comparisons to Previous LCIRP Submittals
    d. Commission Objectives and Plan Alignment
2) **Introduction**
    a. Purpose of the Filing
    b. IDP Overall Objectives
    c. Traceability of IDP Investments
    d. Compliance with the Filing Requirements
    e. Stakeholder Involvement in Developing IDP
    f. Role(s) of Third Parties
3) **Common Cost-Effectiveness/Business Case Assumptions:**
    a. Future DER Integration
    b. Energy Forecast (kWh)
    c. Demand Forecast (kW)
    d. Forecast Capacity Prices
    e. Forecast Energy Prices.
    f. Forecast Renewable Energy Certificates
    g. Common Societal Assumptions (e.g., carbon savings, etc.)
    h. Rate of Inflation
    i. Methodology for Determining Discount Rate
    j. Time Horizon for Evaluating Investments
    k. Sensitivity Analysis
4) **Current System Capabilities and Processes**
    a. Overall 5-year Capital Investment Spending Plan
        i. "Business as Usual" Plan
        ii. Grid Mod Plan
    b. Overall 5-year Operational Expense Plan
        i. "Business as Usual" Plan
        ii. Grid Mod Plan
    c. Distribution System
        i. Distribution Substations and Distribution Supply Substations
        ii. Distribution, Sub-Transmission, and Distribution Supply Circuits
        iii. Metering

d. DER Integration
    i. Residential-Scale
    ii. Commercial-Scale
e. Business Applications
    i. Customer Information System (CIS) & Customer Relationship Management (CRM) System
    ii. Meter Data Management Systems
    iii. Distribution Operational Systems
        1. Distribution Management System (DMS)
        2. Supervisory Control and Data Acquisition System (SCADA)
        3. Outage Management System (OMS)
        4. Volt-Var Controls
        5. Geographic Information System (GIS)
    iv. Workforce Management Systems
    v. Demand Response Management System
    vi. Distributed Energy Resource Management System
    vii. Planning and Analysis Software
f. Communications Network for Distribution System
    i. Substation Communications
    ii. Field Area Network Communications
g. Information Management Systems
    i. Data Management Systems (Data Warehouse/Data Lake/Data Historian)
    ii. Enterprise Service Bus
    iii. Enterprise Resource Planning (ERP) Systems

5) Distribution System Planning

a. Distribution System Planning Process
b. Design Criteria
c. Load and DER Forecast
    i. Existing Forecast Methodology
    ii. Gap Analysis of Existing Forecast with Future Required Probabilistic Forecast
    iii. Enhanced Load Forecasting - Probabilistic Load Forecasting including DER Penetration:
        1. Energy Efficiency
        2. Demand Reduction
        3. Demand Response
        4. Distributed Generation
        5. Other DERs (e.g., Storage)
d. Hosting Capacity Analysis
    i. Hosting Capacity Maps
    ii. Heat (Thermal Loading) Maps
e. Locational Value Analysis
    i. NWA Analysis
    ii. Capacity Deficiency
    iii. Reliability
    iv. Resiliency
f. DER Interconnection - Improve DER Interconnection process and turnaround time

for DER integration

g. Strategic Electrification
    i. Electric Vehicles
    ii. Efficient Electric Appliances (e.g., air source heat pumps, hot water heat pumps)

6) Architectural Strategies and Considerations

a. Architectural Strategies
    i. Protection and Controls
    ii. Field Automation
    iii. Sensing and Measurement
    iv. Data Management and Analytics
    v. Communications

b. Architectural Considerations
    i. Platform Component Integration (e.g., Layering and Interoperability)
    ii. Future Proofing (e.g., Scalability, Extensibility, Flexibility)
    iii. Resilience (including Business Continuity Plans for Critical Operational Systems)

7) Distribution Operations

a. Sensing and Measurement

b. Field Automation

c. Substation Automation

d. Volt/Var Optimization

e. Operational Analytics and Efficiencies
    i. Field Data Management
    ii. Electrical Network Connectivity Model
    iii. Distribution State Estimation
    iv. Outage Management System (OMS)
    v. Geographic Information System (GIS)
    vi. Meter Data Management system (MDMS)
    vii. Advanced Distribution Management System (ADMS)
    viii. Asset Management
    ix. Workforce Management

f. Customer Data Transparency
    i. Customer Data and Portal
    ii. Customer Engagement
    iii. System Data

g. Cost-Effectiveness Analysis

8) Advanced Meter Functionality

a. Deployment Plan (Phased, if applicable)

b. Cost-Effectiveness for each Deployment Stage (By Phase, if Applicable)

9) Rate Design

a. TVR Implementation Plan (Phased, if Applicable)

b. Rate Design Considerations
    i. Rate Design Structures and Composition of Rate Class
    ii. Decoupling
    iii. Data Availability and Associated System Benefits Through Implementation

10) Cyber Security and Privacy
    a. Customer and DER Portals
    b. System Data Portals
    c. Grid Operations
        i. Infrastructure Utility Assets and Networks
        ii. DER/Customer Assets and Networks
        iii. Communications Network
    d. NIST Compliant
    e. Consideration for Other International Standards (e.g., BEIS SMETS2,)[61]
    f. Platform integration, interoperability, and scalability

11) Performance Metrics
    a. "Business as Usual" Metrics
        i. Historically Used Reliability Metrics
        ii. Additional Metrics to Capture Power Quality and Indirect Effects from Grid Mod Investments
    b. Grid Mod Baseline Metrics Common to All Utilities
    c. Grid Mod Investment Specific Metrics

12) Rates and Regulatory
    a. Cost Recovery
    b. Rate Impact by Customer Class
    c. Revenue Requirement and Customer Bill Impact
    d. Decoupling

The IDP must be accompanied by a discussion as to the proposed selection of suitable technical solutions, assessment of the various technology options under consideration, including current technology status, maturity, and its remaining life, why replacement is being proposed, and how the utility proposes to transition to the new solution, as well as the form and content of the cost-effectiveness of the option adopted. In each instance, the utility must demonstrate how the proposed capital investment strengthens required functionalities and increases the capabilities required by the objectives. The utility must also detail any departures from this approach and why. Detailed contents of the IDP are further discussed in this section.

5.2.1 Traceability of IDP Investments

The IDP will be based on the objectives, methodology, and recommendations, as laid out in previous sections of this report, making full use of the taxonomy in order to enable the reader to trace the relationship between a given specific objective, the capabilities that the utilities adopted in relation to that objective, the functionalities that the utilities utilized in developing their grid architecture, the subsequent design, and the proposed solutions. Utilities should make clear in the IDP where they depart from the proposed capabilities and functionalities and why they do so.

[61] United Kingdom's Department of Business, Energy and Industrial Strategy's (BEIS) second version of the Smart Meter Equipment Technical Specification (SMETS2).

5.2.2 Cost-Effectiveness Framework

The cost-effectiveness framework (including common business case assumptions) will need to be developed collectively by the utilities before they file their first IDP. Guidelines and a Staff recommended approach may be found in Section 4.3 under Grid Modernization Planning. Utilities should consider both a quantitative and qualitative evaluation of each type of investment. The IDP should include a detailed description of the project, including scope and schedule, rationale and business drivers (objectives and capabilities) for the investment, expected costs, anticipated benefits, any assumptions underpinning the evaluation of expected benefits, options considered, and expected risks.

5.2.3 Current System Capabilities and Processes

The utilities shall furnish detailed field communication and data assessment, including capabilities of their current (baseline) circuit, substation, grid sensing devices, substation automation, circuit automation, DER control (both small and large scale), and DER utilization. The utilities shall also provide detailed assessment of their business and enterprise applications, including GIS indication of asset capability and locational accuracy; OMS functionality with grid assets; SCADA capability and connectivity with grid assets; and OMS, CIS, and MDMS systems interoperability with metering, customer load data, and billing. In addition, the utility shall provide the capabilities of the planning software to accurately depict the system dynamics with data provided using planning and operations models as well as connectivity to other business systems.

5.2.4 Capital and Operating Plans

In order to provide a comprehensive cost approach in the IDP that includes both "business as usual" and grid mod investments, a capital and operating 5-year spending plan encompassing the detailed 5-year implementation plan shall be provided by each utility.

5.2.5 Load and DER Forecast

The IDP should include a forecast of future demand for the utility service area. The forecast should be scenario driven and based on probabilistic methods applying varying levels of DER penetration. The DERs considered shall include targeted and EERS based energy efficiency, demand reduction, demand response, known future DER installations. The DER penetration common assumption values should be established through working groups as outlined in Section 5.1.2. The forecast should incorporate a 10-year minimum loading on both distribution and sub-transmission supply circuits.

5.2.6 Hosting Capacity Analysis

The IDP should discuss the hosting capacity analysis applying the color coding nomenclature for distribution circuits. The methodology, assumptions, and modelling tools should be described in detail. Utilities should take into consideration any feedback provided either in written comments or in a working group to describe their current distribution system analysis and data and indicate how they plan to migrate to a more sophisticated procedure as more data becomes available. In the early stages of the 5-year detailed implementation plan, where a utility's data is not available at a sub-circuit level, a basic hosting capacity map shall be developed. As sub-circuit data is available to accurately model the circuits, additional maps, such as heat maps, shall be developed. The interactive level of maps and data available to DER developers shall also evolve and be integrated with grid sensing components as the implementation plan matures.

5.2.7 Locational Value Analysis

The IDP should describe how the locational value will be assessed. This assessment can be in the form of a capacity deficiency tool that allows for third party access to circuit data -- a heat map, for example -- to maximize the DER proposition. In the IDP, utilities should evaluate NWA to procure or utilize non-utility DER resources for capacity deferral, reliability, and resiliency deficiencies.

5.2.8 DER Interconnection

Regarding the DER interconnection process, the utilities shall provide an existing detailed process description of each type of analysis (e.g., simplified, system impact study, supplemental review, feasibility study, etc.) conducted by the utility for each interconnection application or study request. The utilities' detailed explanations should include various aspects of the analysis, including the data inputs, the basis for the data, the granularity of the data, the modeling tool(s), and the criteria and associated metrics used to determine if system upgrades are necessary.

The grid mod investment in DER interconnection shall provide a significant and measured improvement in DER developer interaction, transparency of system data, and decreased time duration that occurs within the utility's decision matrix. The connectivity and data availability from other planning tools will advance as the grid mod components within the system are developed further.

5.2.9 Strategic Electrification

In their IDPs, utilities should propose a plan for strategic electrification including electric vehicles and efficient electric appliances, such as air source heat pumps and hot water heat pumps. An electrification strategy could be implemented in conjunction with the EERS program. Utilities must ensure that the appropriate tariffs and infrastructure exist, especially for electric vehicles. In addition, a load forecasting must include any increases in electric demand that would result from an electrification strategy.

5.2.10 Architecture Design and Considerations

Utilities should provide their architectural strategies for distribution field automation, protection and controls (including grid and DER devices), sensing and measurement, data management and analytics, and operational communications. Additionally, in each of these strategies, utilities should provide consideration of platform component integration issues, future-proofing and platform resilience. These considerations must be taken into account during the architecture development phase prior to selecting specific technologies and components. The various existing and planned platform components and integration plans must demonstrate interoperability, an ability to evolve over time, and adequate measures to achieve satisfactory levels of resilience.

5.2.11 Customer Data Transparency

The IDP must describe all data provisions that will be made available. Utilities should take into consideration any feedback provided either in written comments or in a working group to prioritize data needs and to make clear what kind of data it will make available to customers and third parties. The data plan should include a discussion of standards and protocols for data sharing, safeguarding of security, and a timeline for installing the appropriate technology and for providing the data. Access to individual customer data must be limited to be consistent with the requirements and protections set forth in RSA 363:38.

5.2.12 Customer Engagement/Education

The IDP should include a detailed market outreach strategy as part of a comprehensive customer engagement plan detailing how customers will be informed about the changes under way and the opportunities that will be afforded by modernization. The plan will detail how and when customers would gain access to DERs and how they would be able to optimize their energy usage. Staff recommends that the utilities investigate the establishment of a utility-specific or statewide engagement platform or platforms; however, they should consider off-the-shelf solutions, where possible, and first demonstrate that they will be cost-effective.

5.2.13 Advanced Meter Functionality

The IDP should discuss the utility's strategy with respect to advanced meter functionality. Staff recognizes that grid modernization will be rolled out gradually and believes that any metering functionalities should by supported by consideration of cost-effectiveness. Where utilities have advanced meter capability in some form in place, they should consider taking full advantage of its capabilities; where no such capability exists, the utilities should offer interval metering (at the customer's expense, if implemented on an opt-in basis) in the short term and only fully embrace advanced metering when a cost-effective case can be made. Utilities should take into consideration any feedback provided either in written comments or in a working group when evaluating the acceptability of various solutions and considering the case for behind-the-meter technologies.

5.2.14 Rate Design

The IDP should contain a proposal for rate design. The proposal should address treatment of demand charges by various customer groups, as well as the conditions under which time varying rates may be implemented for generation, transmission, and/or distribution, and, where applicable, on an opt-in or opt-out basis. Any such proposal should be accompanied by an explanation of the technology and information requirements. Where possible, utilities should at least consider the gradual roll out of TVR for distribution. All customer-related charges should recover customer-only related costs. Any proposed rate design should be supported by a cost of service study. Utilities should take into consideration any feedback provided either in written comments or in a working group when evaluating the possibilities outlined above.

5.2.15 *Cyber Security*

The IDP will contain the utility's cyber security strategy, privacy policies, and standards. These policies and standards shall inform the proposed system architectural design, system infrastructure, critical systems, and system and customer data management.

The IDP shall not contain specific measures that may compromise the utility's security plan; however, the utility must demonstrate in its implementation plan a high level approach in addressing cyber security and privacy in the various layers of the utility's system, especially relative to the interconnection of DERs.

Demand response, generation from wind and solar, energy storage, and energy control devices will require more intensive cybersecurity protection. Toward that end, the IDP should include:

(a) A list of all anticipated vulnerabilities in the system, and a proposed mitigation strategy; and
(b) Evidence that each utility is monitoring and implementing the latest National Institute of Standards and Technology (NIST) standards and cyber security framework[62] by addressing the following:

- Authentication and identity;
- Self-assessing cybersecurity risk;
- Managing cybersecurity within the supply chain; and
- Vulnerability disclosure.

In addition, the utilities and grid modernization stakeholders should convene a cybersecurity working group to develop state utility strategy, outlining the approach, goals, and timeframe for proceeding and setting expectations for utility cybersecurity performance.

Questions under consideration may include the following:

- What should be the scope of the strategy?
- What actions might the Commission need to initiate?
- What performance requirements will be required from the utilities and other energy service companies?
- What will be the reporting requirements?
- Should Commission interactions with the utilities be formal or informal?
- Should the Commission seek to actively encourage utilities to make cyber investments and treatment of cost-recovery for utility investments in cybersecurity?

[62] NIST, Framework for Improving Critical Infrastructure Cybersecurity, April 2018

In addition, the working group may consider drawing on the experience of neighboring states[63] in the establishment of a business-to-business collaborative requiring that all entities that interface with utility systems have adequate cyber protections in place, in addition to those already established by the utilities themselves. Such protections might require that all energy service entities (ESEs) complete a self-attestation of information security controls and execute a data security agreement with the utilities with whom the ESE does business.[64]

Finally, in its Primer on Cybersecurity for State Utility Regulators, completed in January 2017, NARUC developed a series of 108 questions for consideration by utilities. The questions encompass the development of proactive and strategic action by the utilities; compliance with a set of clear and enforceable standards; reporting processes; the existence of alliances across public and private sectors for information-sharing, planning, and situational awareness around cybersecurity; identification of critical utility staff and budgeting; any mechanisms for performing risk assessments, evaluation of strategy effectiveness, responsibilities for response and recovery; mapping of related processes; and cybersecurity and utility governance. The utilities should consider those questions when developing their detailed cybersecurity plan. A list of these questions, a sample Self Attestation form and Data Security Agreement, and further discussion of cybersecurity threats may be found in Annex 1.

More detailed security plans will continue to be filed with the New Hampshire Department of Homeland Security and Emergency Management using confidential treatment.

5.2.16 Performance Metrics

The IDP will define the baseline conditions that each utility faces and provide associated infrastructure and performance metrics to determine the effectiveness of the utility's grid mod investments. Additional "business as usual" metrics may be developed as a result of grid mod system enhancements. The grid mod investment metrics will vary among the utilities due to different levels of baseline infrastructure and capabilities; however, the IDP should clearly define metrics that delineate grid mod investments from "business as usual" utility investments. Some of the performance or infrastructure metrics that are societal or customer-experience based may be more qualitative in nature.

5.2.17 Cost Recovery

Based on Commission guidance with respect to cost recovery arising from any written comments or in a working group, the utility IDP will indicate which capital investments will be made during the first five-year IDP and subject to preliminary approval by the Commission. The proposed capital investments will remain subject to verification for prudency. Preliminary approval will involve a review of each utility's proposed investments and cost estimates, as supported by the cost-effectiveness business case.

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[63] Case 18-M-0376, Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place, Order Instituting Proceeding, p. 3 (issued June 14, 2018) (June Order), NY PSC.
[64] Case 98-M-1343, In the Matter of Retail Access Business Rules, (Issued February16, 2018). NY PSC.

6.0 Proposed Next Steps

Based on the Grid Mod Working Group Report, DOE guidance documents, other states' approaches, and the recommendations of this report, Staff recommends the following next steps:

1. Comments on Staff Report - Request feedback from utilities and stakeholders on this report. Staff recommends that the utilities and stakeholders provide specific comments and proposals on the report as a whole, as well as the suggested approach.

2. Detailed Comments/Proposals on Specific Areas - Request detailed proposals from the utilities and stakeholders on the following key aspects:

    a. Cost-Effectiveness Framework – For benefit/cost analyses, methodology, and associated assumptions to be used by all utilities to ensure a consistent approach for evaluating grid modernization investments and "business as usual" investments.
    b. Utility Cost Recovery and Performance Incentives - An appropriate cost recovery structure to use for grid modernization investments in the short term and the long term. Possible options may include modifications to cost recovery (e.g., decoupling, etc.) as well as the development of performance incentives.
    c. Utility and Customer Data and Data Access – Utility data needs and customer data needs to help prioritize data needs, determine technology requirements and data access options, and outline a timeline for installing appropriate technology and providing the data.
    d. Hosting Capacity Analysis - The level of hosting capacity data that should be available, the technologies required for such data, a timeline for providing the data, and how each utility plans to progress to a more detailed data input and output over time.
    e. Locational Value Analysis - The level of locational value data that can provide successful parameters for implementation of a third party DER solution through an NWA.
    f. Metering – Metering functionality requirements and best practices for the short term and long term. Possible behind-the-meter technologies that could be considered cost-effective alternatives, especially to provide information to the customer or a third party or to communicate within the home or business, at least in the short term.
    g. Customer Education – Alternative customer engagement platforms, including existing, off-the-shelf tools that could be considered. An analysis of the best platforms for educating customers, and a demonstration by the utilities that any platform proposed will achieve the desired outcomes.
    h. Strategic Electrification – A proposed approach for strategic electrification, such as the use of air source heat pumps and electric vehicles.
    i. Rate Design – Considering the TOU pilots being conducted in the net metering docket and proposed in the Liberty battery storage pilot, a suggested approach for rate design, will include TVR options for generation, transmission, and distribution, suggested interval periods and number of interval periods, whether

an opt-in or opt-out or some alternative offering, and the timeframe to begin implementing TVR rates.

j. DER Pricing Structure – Suggested DER pricing structures to take into consideration with the rate design. Suggestions of whether any additional pricing structures are necessary, and suggestions of the appropriate compensation structures. Ensure coordination with the net metering docket, where applicable.
k. Consolidated Billing – Suggested approach for offering consolidated billing by a competitive supplier or an independent third party, including details of potential hurdles and risks of such an approach, any necessary technology and data requirements, and how to ensure cybersecurity.
l. Cyber Security – Develop state utility strategy, outlining the approach, goals, and timeframe for proceeding and setting expectations for utility cybersecurity performance.
m. Annual Reporting Requirements – Develop a collective understanding of the form and content of the metrics that will best be able to capture progress with grid modernization from one year to the next.

3. Working Groups - Based on the stakeholders' and utilities' feedback on this report and the specific areas identified above, Staff may provide an expanded or revised recommended approach if new information provides more detail that would enhance or modify Staff's recommendation significantly. When necessary, the Commission may initiate working groups to further address these issues, if the Commission or Staff needs further input. Staff recommends that the working groups be limited with more emphasis placed on written feedback regarding specific areas. Potential topic areas include rate design, cost-effectiveness analysis methodology, utility cost recovery, utility and customer data access, hosting capacity analysis, locational value analysis, metering, customer education, strategic electrification, DER pricing structure, consolidated billing, cybersecurity, and annual reporting requirements.

4. Studies - Initiate studies to provide data necessary for furthering grid mod including the following:
    - Hosting Capacity Analysis by the utilities using the red, yellow, and green convention, indicating, initially, at a minimum the areas that will require minimal or no cost, some additional costs, and high costs to interconnect. Based on stakeholder feedback, Staff recommends that the Commission require more data inputs and outputs over time.
    - Heat maps by the utilities showing initially thermal loading, but adding more data elements over time.
    - Coordination with the net metering docket on the Value of DER Study to determine if other Value of DER studies should be conducted in addition to the Value of DER Study for distributed generation in the net metering docket.
    - Coordinate with the net metering docket on the locational analysis to determine if additional locational analysis should be conducted for DERs, and possibly require an NWA.

5. Coordination with Other Related Dockets - Coordinate with other related dockets, especially the net metering, EERS plan, LCIRP, and peak demand reduction goals dockets.

6. Plan Submissions - Require IDP submissions within 12 months of the Commission's approval of the Staff recommendations, with a possible staggering of the plan submittals (or at least in the review and approval) in three month intervals. The IDP should cover the next LCIRP submittal requirements, if possible, or the utilities could request a waiver from LCIRP filing timeframe requirements.

7. Adjudicatory Proceeding for Each Utility's Plan - Initiate an adjudicatory proceeding for each utility after submittal of its IDP. The adjudicatory process will entail discovery and technical sessions, with input from stakeholders, to assist the Commission in determining whether the plan meets the objective

Appendices

Appendix A

Glossary and Definitions

(Adapted from the DOE Modern Grid Report)

Reference Term	Acronym	Definition
Advanced Distribution Management System	ADMS	A software platform that integrates numerous operational systems, provides automated outage restoration, and optimize distribution grid performance. ADMS components and functions can include distribution management system (DMS); demand response management system (DRMS); automated fault location, isolation, and service restoration (FLISR); conservation voltage reduction (CVR); and Volt-var optimization (VVO).
Advanced Metering Functionality	AMF	Application neutral system comprised of smart meters, communications networks, and information-management systems. Features include two-way communications. The information can be used to support outage restoration efforts, voltage optimization, and application of time-varying rates.
Advanced Metering Infrastructure	AMI	Typically refers to the full measurement and collection system that includes meters at the customer site, communication networks between the customer and an electric service provider, and data reception and management systems that make the information available to the service provider.
Automated Meter Reading	AMR	Electric meters that collect simple time-of-use or non-interval kWh data for billing purposes only and transmit this data one way, usually from the customer to the distribution utility. AMR systems which rely on mobile or “drive-by” technology are generally unable to be modified to provide advanced metering capabilities, since these capabilities require a fixed network.
Conservation Voltage Reduction	CVR	An operating strategy of the equipment and control system used for Volt-Var Optimization (VVO) that reduces energy and peak demand by managing voltage at the lower part of the required range.
Critical Infrastructure		Customers whose services are vital to the community in that the incapacity or destruction of such systems and assets would have a debilitating impact on public health or safety.
Demand Response	DR	A voluntary program which compensates customers for reducing and/or changing the pattern of their electricity use (load) over a defined period of time, when requested or automatically instructed to do so during periods of high

Reference Term	Acronym	Definition
		power prices or when the reliability of the grid is threatened.
Customer Information System	CIS	Used to maintain customer data, which is available to a grid operator's or utility's customer service representatives so that they may answer inquiries from customers.
Demand Response Management System	DRMS	A software solution used to administer and operationalize demand response aggregations and programs. The system uses a one-way or two-way communication link to effect control over and gather information from enrolled systems, including some commercial and industrial loads, and residential devices.
Demand Side Management	DSM	Efforts by electric utilities and other entities to modify the level or pattern of consumer energy use. DSM includes energy efficiency improvements and demand response programs.
Distributed Energy Resource	DER	Resources that are deployed at the distribution level, including energy efficiency, demand response (including price-responsive loads), distribution-level energy storage, distributed generation, and electric vehicles.
Distributed Generation	DG	A generating source typically sited near customer loads or distribution and sub-transmission substations connected directly to the grid at distribution level voltage or on the customer side of the meter. These resources may be utility or customer owned.
Distribution Management System	DMS	A utility operating system capable of collecting, organizing, displaying and analyzing real-time or near real-time electric distribution system information, which will allow the operators to plan and execute complex operations to increase system efficiency and prevent overloads. The system can interface with other operation applications such as geographic information systems (GIS), outage management systems (OMS), and customer information systems (CIS) to create an integrated view of distribution operations.
Distribution Supply Circuits		Distribution circuits that connect lower voltage distribution substations with higher voltage substations. Generally, these circuits are dedicated to supply and do not have a high amount of residential or commercial customers e.g. 34kV supply circuits that initiate at a 115kV substation and terminate at a 4kV substation.
Distribution System		The portion of the electric system that is composed of medium voltage (4kV through 34kV) sub-transmission lines, substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high-voltage transmission system. The distribution system includes all the information, telecommunication and operational technologies needed to support reliable operation integrated with the physical infrastructure

Reference Term	Acronym	Definition
		comprised of transformers, wires, switches and other apparatus.
Energy Efficiency Resource Standard	EERS	A policy to establish specific targets or goals for energy savings that utilities must meet in New Hampshire.
Fault Localization Isolation Service Restoration	FLISR	Automatic sectionalizing and restoration, and automatic circuit reconfiguration of the distribution grid. Automatically determines the location of a fault, and rapidly reconfigures the flow of electricity so that some or all of the customers can avoid experiencing an outage.
Future-Proof		Describes a product, service or technological system that will not need to be significantly updated as technology advances.
Heat Maps		Maps that reveal where DERs can help address problems (e.g., by reducing congestion or peak loads on an overloaded feeder). They are intended to help direct third-party investment toward areas on the grid where DER can help reduce, defer, or avoid conventional utility infrastructure projects.
Hosting Capacity Analysis	HCA	Used to establish a baseline of the maximum amount of DER, an existing distribution grid can accommodate safely and reliably without requiring significant infrastructure upgrades.
Independent System Operator	ISO	An independent, Federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system.
Integrated Distribution Plan	IDP	The utility's distribution planning framework that encompasses existing LCIRP requirements, a utility's 10-year roadmap and strategy, and grid modernization investments that ensure a comprehensive and cohesive future planning document, creating a more transparent utility infrastructure through traceable and measurable capabilities.
Islanding		The condition in which a DER continues to power a location even though electrical grid power is no longer present. It may be intentionally isolated from the mainline distribution grid or automated through threshold parameters e.g. frequency, voltage, power quality.
Least Cost Integrated Resource Planning	LCIRP	The process of developing a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period.
Load Stochasticity		Random deviations in electric load due to weather, usage deviations, economic health, DER penetration, social energy policies, etc.
Meter Data Management		Meter data management consists of process and tools for securely storing, organizing, normalizing data from advanced meters integrating data from other meters, and

Reference Term	Acronym	Definition
		making the data available for multiple applications including customer billing, analysis for grid control, outage management and others.
Microgrid		A group of interconnected loads and DERs within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island modes.
Non Wires Alternatives	NWA	An electricity grid investment or project that uses non-traditional solutions, such as distributed generation, energy storage, energy efficiency demand response, and grid software and controls, to defer or replace the need for specific equipment upgrades, such as lines or transformers, by reducing load at a substation or circuit level.
Outage Management System	OMS	A computer-aided system used to better manage the response to power outages or other planned or unplanned power quality events. Generally uses predictive logic in area outages.
Time-of-Use rates	TOU	Electricity customer prices set in advance but varying over the day. Utilities can use time-of-use rate structures to shift electricity use from peak-load hours by offering lower rates during partial-peak and off-peak hours as a way to reduce strain on the electric grid.
Time Varying Rates	TVR	A general term that encompasses multiple types of rates such as Time-of-Use (TOU), Critical Peak Pricing (CPP), Peak Time Rebates (PTR), and Real Time Pricing (RTP).
Transmission-Distribution Interface		The physical point at which the transmission system and distribution system interconnect.
Volt Amp Reactive	VAR	Power that is delivered to an inductive load such as a motor (lagging) or is delivered by a synchronous generator, smart inverter, or capacitor bank (leading).
Volt-Var Optimization	VVO	A process undertaken to maintain an optimal voltage at all points along a distribution feeder under all loading and DER conditions.

Appendix B

Work Paper 1

Proposed Methodology for Grid Modernization

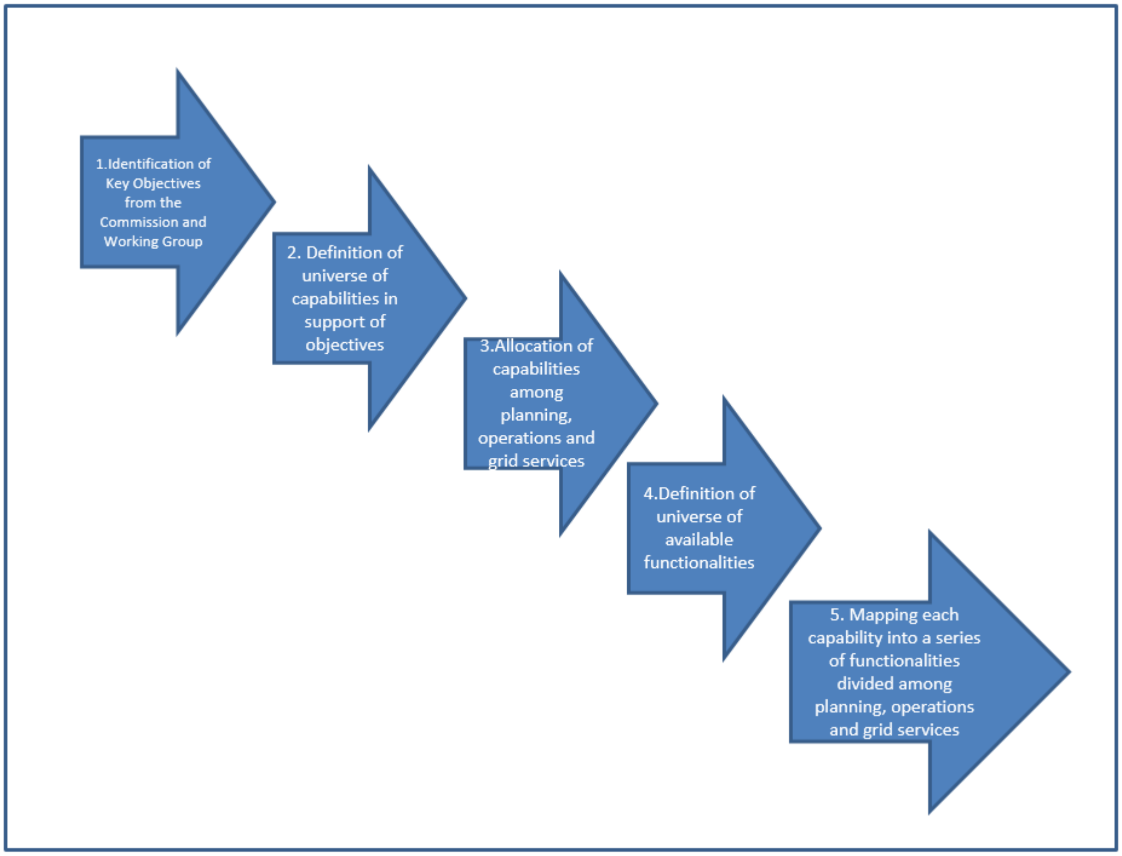
1.0 The Five Step Process

The five proposed methodological steps to ensure traceability of investments in the grid modernization process are as follows:

- Step 1. Define the objectives;
- Step 2. Develop a universe of capabilities from the DOE Modern Grid Report[65] and map specific capabilities to selected objectives;
- Step 3. Allocate capabilities among planning, operations and grid services/markets;
- Step 4. Define the universe of available functionalities; and
- Step 5. Translate each capability into a series of required functionalities, further allocated into system planning, grid operations and grid services/market operations (See Table E-5 in Work Paper 4, Master List of Capabilities and Related Functionalities.)

[65] US Department of Energy, Office of Electricity Delivery & Energy Reliability, *Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, Version 1.1,* March 27, 2017; *Volume II: Advanced Technology Maturity Assessment, Version 1.1,* March 27, 2017; *Volume III: Decision Guide,* June 28, 2017. https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

Figure B- 1. Schematic of the Five Step Process Mapping Objectives to Functionalities



Step 1. Defining the Objectives

Following a thorough review of Commission Orders,[66] the Grid Mod Working Group Report and associated stakeholder feedback, and the 2018 State Energy Strategy,[67] Staff developed a short list of seven general objectives and attributes of the desired modernized grid. The detail of this analysis may be found in Work Paper 2.

[66] Order of Notice, IR 15-296, Investigation into Grid Modernization, July 30, 2015. http://puc.nh.gov/Regulatory/Docketbk/2015/15-296/INITIAL%20FILING%20-%20PETITION/15-296%202015-07-30%20ORDER%20OF%20NOTICE.PDF and Order No. 25, 877, Order on Scope and Process, IR 15-296, *Investigation into Grid Modernization*, April 1, 2016. http://puc.nh.gov/Regulatory/Orders/2016orders/25877e.pdf

[67] New Hampshire Office of Strategic Initiatives, *New Hampshire 10-Year State Energy Strategy*, April 2018. https://www.nh.gov/osi/energy/programs/documents/2018-10-year-state-energy-strategy.pdf

Step 2. Development of a Universe of Capabilities from the DOE Modern Grid Report and Mapping of Specific Capabilities to Selected Objectives

Using the DOE Modern Grid Report, Staff examined each specific objective in turn and associated definitions in order to derive a series of targeted capabilities that would be required to support the specific objectives.

Step 3. Allocation of Capabilities between Planning, Operations, and Grid Services/Markets

From this step forward, further analysis was subdivided into three general categories of needs, as defined below. Combinations of capabilities were mapped for each objective at each stage of grid modernization evolution.

(a) Distribution system planning
Defined as an integrated planning approach that assesses physical and operational changes to the electric grid necessary to enable safe, reliable, and affordable service that meets customers' changing expectations, and the use of DERs, including the provision of DER services to operate the distribution system.

(b) Distribution grid operations
Defined as safe and reliable operation of a distribution system, including associated sub-transmission facilities. This would include regular reconfiguring or switching of circuits and substation loading for scheduled maintenance, isolating faults and restoring electric service, as well as active management of voltage and reactive power. It also includes physical coordination of DER and micro grid operation and interconnections to ensure safety and reliability as well as physical coordination of DER services and scheduled and real-time power flows between the distribution and transmission systems.

(c) Grid services/Distribution market operations.
Consideration of an operational market for DER-provided grid services (non-wire alternatives or NWAs), including understanding under what conditions such grid services will provide alternatives to distribution infrastructure upgrades, and supporting operational requirements to manage voltage and reliability.

Step 4. Definition of the Universe of Available Functionalities

Using the DOE Modern Grid Report,[68] Staff identified a series of targeted functionalities that would be required to facilitate each capability identified in Step 2, above.

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[68] US Department of Energy, Office of Electricity Delivery & Energy Reliability, *Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, Version 1.1,* March 27, 2017; *Version 1.1,* March 27, 2017.

Step 5. Mapping Capabilities to Required Functionalities Allocated among System Planning, Grid Operations, and Grid Services/Market Operations

Staff next developed a series of tables to identify the targeted functionalities that would be required of each capability and their allocation among grid planning, grid operations, and grid services/market operations.

Finally, Staff developed a master list for each of the capabilities outlined above and listed the functionalities associated with each capability, allocated by system planning, grid operations and grid services/market operations. The identification of the recommended functionalities will form the basis of the utilities' grid planning as each utility, based on its differentiated baseline, will develop an Integrated Distribution Plan (IDP) that will first evaluate and then encompass the functionalities that they consider relevant to their distribution network. Table E-5 in Work Paper 4, Master List of Capabilities and Related Functionalities, should form the point of departure for the development of an IDP by each state electric utility.

Further, given that the current stage of development of the modernized grid and its short-term growth will focus primarily on planning and operations, and that different utilities will be modernizing at different paces, Staff has provided an indication of grid services/market functionalities primarily as a placeholder and to aid in perspective planning. It is Staff's expectation that the utilities will utilize the objectives, capabilities, and functionalities outlined below in developing their technologies and practices, as discussed further in Section 5 of the memo.

Appendix C

Work Paper 2

Derivation of Objectives and Attributes

1.0 Identification and Definition of Grid Objectives.

By Order No. 25,877 dated April 1, 2016,[69] the New Hampshire Public Utilities Commission stated that it expects the benefits of grid modernization to include the following:

1. Improving the reliability, resiliency, and operational efficiency of the grid.
2. Reducing generation, transmission, and distribution costs.
3. Empowering customers to use electricity more efficiently and to lower their electricity bills.
4. Facilitating the integration of distributed energy resources.

The Commission further clarified its position by adding the following:

> "One of the Commission's goals in this investigation is to ensure that grid modernization results in net benefits for customers. This means (1) that the overall benefits of grid modernization initiatives must exceed the overall costs, (2) that all customers must have a meaningful opportunity to enjoy grid modernization benefits, and (3) that the costs of grid modernization are allocated fairly among all customers."

In Table C-1, Staff has listed each of the Commission's benefits and goals as general objectives and attributes, identified the specific objectives associated with each general objective, and developed an associated definition.

Table C- 1. Commission's Original Objectives

General Objectives	Specific Objectives	Definition
1. Improve reliability, resiliency, and operational efficiency	Improve reliability	Maintain and enhance the safety, security reliability, and resiliency of the electric grid at fair and reasonable costs, within acceptable standards and consistent with the state's energy policies
	Improve resiliency	Maintain and enhance the resiliency of the electric grid at fair and reasonable costs, within acceptable standards and consistent with the state's energy policies

[69] http://puc.nh.gov/Regulatory/Docketbk/2015/15-296/ORDERS/15-296_2016-04-01_ORDER_25877.PDF

General Objectives	Specific Objectives	Definition
	Increase operational efficiency	Increase operational efficiency of distribution facilities
2. Reduce generation, transmission, and distribution costs	Reduce costs and increase affordability	Reduce costs and increase affordability
3. Empower customers to use electricity more efficiently and lower their electricity bills	Enable customers	Support greater empowerment, engagement, technology options, and information for customers to manage their energy bills, including related infrastructure investment to accommodate two way flows of energy
4. Facilitate integration of DERs	Enable DER integration	Ensure that the grid can integrate or host DERs while facilitating value to the distribution grid and reducing interconnection costs. Enable all types of DERs by providing the necessary communication, information, and cyber and physical security protocols, while providing engineering and economic benefits

2.0 Additional Recommendations from the Grid Mod Working Group Report and 2018 State Energy Plan

The Commission hired Raab Associates, Ltd., as facilitator/moderator and Synapse Energy Economics as an expert consultant, and on April 1, 2016, the Commission issued Order No. 25,877, establishing a Working Group and scheduling the first meeting for April 29, 2016. The Working Group met over the course of approximately a year and issued the following report: *Grid Modernization in New Hampshire*[70] and associated appendices[71] (Grid Mod Working Group Report), on March 20, 2017. The Grid Mod Working Group Report discussed the key elements outlined by the Commission. On April 20, 2017, a secretarial letter was issued soliciting comments on the final report.

Staff extracted key objectives and attributes from the Grid Mod Working Group Report that were identified as additional benefits or goals of grid modernization. These additional objectives are listed in Table C-2 below.

[70] http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF
[71] http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_APP_FINAL_RPT.PDF

Table C- 2. Grid Mod Working Group Report Objectives and Recommendations

General Objectives	Specific Objectives	Definition
5. Better align interests of energy consumers and producers to optimize system performance, while enabling strategic electrification of buildings, homes, and vehicles	Achieve operational excellence	Enhance customer service and optimize utilization of electricity grid assets and resources to minimize total system costs
6. Ensure that all customers share in benefits of modern grid, have access to usage data in readily accessible form, which they can make available to third parties while retaining privacy safeguards	Enable customers/Flexibility	Operation and design of the electric grid to enable all types of DER technologies to interconnect and participate in market opportunities
7. Keep NH technologically innovative, economically competitive, in step with region	Provide competitive services	Innovate while striving for most competitive pricing of services, and consider the possibility of multiple services for investment to provide for more economic viability
8. Reduce environmental impacts and carbon emissions in NH	Reduce carbon emissions	Reduce carbon dioxide emissions and other greenhouse gases and air pollutants emitted from the electricity sector by meeting new generation needs with renewable or other clean sources of energy; displace fossil fuel use in generation with renewable power or other clean sources of energy; increase building efficiency and promote other conservation or energy efficiency measures; and increase electrification of the transportation sector

In addition, Staff identified additional goals in the Grid Mod Working Group Report in the Outcomes and Capabilities section, which overlaps with Tables C-1 and C-2.

Table C- 3. Grid Mod Working Group Report Objectives Derived from the Outcome and Capabilities Section

General Objective (Outcome)	Specific Objective
9. Customer Engagement and Empowerment	Enable Customers
10. Optimize Demand (through Utility Initiatives)	Enable DER integration
11. Integrate Distributed Generation, Storage, and Electric Vehicles (through Utility Initiatives)	Enable DER integration
12. Resiliency: Reduce Impact of Outages	Improve Resiliency
13. Reliability: Prevent Outages	Improve Reliability
14. Workforce and Asset Management	Increase operational excellence of distribution facilities

Staff further analyzed the 10-Year State Energy Strategy prepared by the Office of Strategic Initiatives and found overlapping recommendations.

Table C- 4. Objections and Recommendations from the 2018 New Hampshire 10-Year State Energy Strategy

General Objectives and Recommendations	Specific Objectives
15. Prioritize cost-effective energy policies	Reduce costs and increase affordability of energy options
16. Ensure a secure, reliable, and resilient energy system	Address cybersecurity and improve reliability/resiliency through grid modernization
17. Adopt all-resource energy strategies	Enable customer choice through market-based mechanisms to achieve cost-effective energy while avoiding preferential quotas and mandates
18. Maximize cost-effective energy savings	Reduce costs and increase affordability by encouraging energy efficiency as the cheapest and cleanest energy resource
19. Achieve environmental protection that is cost-effective and enables economic growth	Reduce carbon emissions through economically competitive low-emission resources
20. Govt. intervention in energy markets should be limited, justifiable, and technology neutral	Ensure competitive provision of services through minimization of subsidies and government policy preferences
21. Encourage market selection of cost-effective energy resources	Ensure competitive wholesale energy markets
22. Generate in-state economic activity	Ensure competitive provision of services without reliance on subsidization

General Objectives and Recommendations	Specific Objectives
23. Maximize the economic lifespan of existing resources while integrating new entrants on a levelized basis	Enable cost-competitive DER integration
24. Protect against neighboring states' policies that socialize costs	Ensure competitive provision of services through regional allocation of costs for higher-cost resources
25. Ensure that appropriate energy infrastructure is able to be sited while incorporating input and output from stakeholders	Ensure competitive provision of services through predictability, defined processes, good communication, and clear standards

Staff determined that each of the 10-Year State Energy Strategy recommendations is encompassed in the general objectives and recommendations outlined in Tables C-1 and C-2, and, thus, are captured by the Goals as defined both by the NHPUC and the Grid Mod Working Group Report.

3.0 Proposed Final Objectives

Table C-5 combines the goals, specific objectives and definitions of the Commission and Working Group into a single table comprising seven objectives/attributes. This table will be used as reference for the derivation of desired grid capabilities and functionalities.

Table C- 5. Goals, Specific Objectives, and Definitions.

General Objectives & Attributes	Specific Objectives	Definition
1. Improve reliability, resiliency, and operational efficiency	Improve reliability	Maintain and enhance the safety, security, and reliability of the electric grid at fair and reasonable costs, within acceptable standards and consistent with the State's energy policies.
	Improve resiliency	Maintain and enhance the resiliency of the electric grid at fair and reasonable costs, within acceptable standards and consistent with the State's energy policies.
	Increase operational efficiency	Increase operational efficiency of distribution facilities.
2. Reduce generation, transmission, and distribution costs	Reduce costs and increase affordability	Reduce costs and increase affordability. Distribution investments may enable the reduction of generation and transmission costs.
3. Empower customers to use electricity more efficiently and lower electricity bills and have access to usage data in readily accessible form, which	Enable customers	Support greater empowerment, engagement, technology options, and information for customers to manage their energy bills, including related infrastructure investment to accommodate two-way flows of energy and to enable all types of DER technologies to

General Objectives & Attributes	Specific Objectives	Definition
can be made available to third parties, while retaining privacy safeguards		interconnect and participate in market opportunities.
4. Facilitate integration of DERs	Enable DER integration	Ensure that the grid can integrate or host DERs while facilitating value to the distribution grid and reducing interconnection costs. Enable all types of DERs by providing the necessary communication, information, and cyber and physical security protocols, while providing engineering and economic benefits.
5.Better align interests of energy consumers and producers to optimize system performance, while enabling strategic electrification of buildings, homes, and vehicles	Achieve operational excellence	Enhance customer service and optimize utilization of electricity grid assets and resources to minimize total system costs.
6. Keep NH technologically innovative, economically competitive, and in step with region	Provide competitive services	Innovate while striving for most competitive pricing of services. Consider the possibility of multiple services for an investment to provide for more economic viability.
7.Reduce environmental impacts and carbon emissions in NH	Reduce carbon emissions and environmental impacts	Reduce carbon dioxide emissions and other greenhouse gases and air pollutants emitted from the electricity sector, by meeting new generation needs with renewable or other clean sources of energy; displace fossil fuel use in generation with renewable power or other clean sources of energy; increase building efficiency and implement other conservation or energy efficiency measures; and increase electrification of the transportation sector.

To ensure that the eight objectives/attributes list capture all the required needs of grid modernization, Staff compared the list in Table C-5 above with an analysis of objectives /attributes as identified by eleven states that contributed to the DOE Modern Grid Report. Table C-6 compares objectives/attributes and demonstrates that the lists overlap closely.

Table C- 6. Comparison of Eleven Selected States' and NH's Energy Objectives and Attributes

Objective/Attribute from 11 States	**New Hampshire**
Affordability	Increase affordability
Reliability	Improve reliability
Customer enablement	Enable customers
Flexibility	
Transparency	
System efficiency	Increase operational efficiency
Enable DER integration	Enable DER integration
Adopt clean technologies	Reduce carbon emissions
Reduce carbon emissions	
Operational market animation	Provide competitive services and enable customers
Safety	Enhance reliability
Cyber and Physical Security	Ensure Resiliency
Resiliency	
Operational excellence	Achieve operational excellence

A closer examination of the NH objectives led Staff to the conclusion that adoption of clean technologies can be subsumed under reduction of carbon emissions; operational market animation is captured by customer enablement and competitive provision of services; flexibility is part of customer enablement; and cyber physical security is captured by resiliency.

Appendix D

Work Paper 3

Derivation of Universe of Capabilities in Support of Objectives

1.0 Identification and Definition of Capabilities in Support of Objectives

The next stage of Staff's analysis required the translation of objectives and attributes into associated capabilities. In this section, the identification of capabilities provides a bridge from policy objectives to an enabling set of platform technologies.

A capability refers to the ability to execute a specific course of action or set of qualities. The DOE Modern Grid Report distills a series of key industry documents to derive a series of possible capabilities to guide the functionality of the next generation distribution system.

The specific capabilities identified in this report were principally drawn from DOE's Pacific Northwest National Laboratory's (PNNL's) 2015 Grid Architecture report, California's "More Than Smart" report based on stakeholder input, and direct feedback from the industry through DOE's distribution system planning initiative. Tables D-1 through D-3 lists the capabilities under consideration. Each specific objective may require a number of capabilities. The universe of possible capabilities, disaggregated into system planning, grid operations, and grid services/market operations in accordance with the DOE Modern Grid Report, follows below with associated definitions.

Table D- 1. Definition of Distribution System Planning Capabilities

Capability	Definition
Impact resistance and resilience	The ability to withstand environmental hazards or cyber-physical attacks over a period of time while maintaining a required expected level of service, which includes the ability to recover from disruptions and resume normal operations within an acceptable period of time.
Scalability	The capability of the distribution grid and related operational and market systems to increase capacity with additional resources rather than extensive modifications or replacement of the cyber/physical systems, while delivering the same quality of service with no impact to performance, reliability, and interoperability.
Accommodate tech innovation	Facilitate the integration of new grid and DER types that enable net positive benefits for all customers, with due consideration to privacy and security concerns, and provide access to system, customer, and third-party data (as needed) to animate market innovation.
Transparency	Timely and consistent access to relevant information by market actors, as well as public visibility into planning, market design, and operational performance without putting sensitive information at risk.

Capability	Definition
Open and interoperable	Enable active participation by customers and accommodate all forms of DER, new services, and markets. This is accomplished via transparent planning, operations, and market interactions that adhere to open standard architecture protocols when available, applicable and cost effective.
Convergence with other critical infrastructure	Integration with other networks such as natural gas, telecommunications, water, and transportation to create a more efficient and resilient infrastructure.

Table D- 2. Definition of Distributed System Operations Capabilities

Capability	Definition
Operational risk management	Examines core operations, including energy delivery and reliability as well as DER-provided operational services performance and related distributed platform systems. It encompasses current and future risks and mitigation strategies to manage tangible operational risks related to environmental factors, human interaction (including errors and public safety), and equipment/system failures.
Security	Activities that detect and respond to man-made and environmental threats and mitigate risks. These risks include cyber-attacks, storms, fire, earthquakes, terrorism, vandalism, and numerous other physical threats.
Contingency management	Understanding and mitigating potential failures in a distribution network through the assessment of potential impacts due to changes in system power flows due to real-time variations in net load resulting from DER operation and/or changes in gross load, and the assessment of potential impacts due to distribution component reliability and faults in specific system configurations.
Situational awareness	Operational visibility into physical variables, events, and forecasting for all grid conditions that may need to be addressed, normal operating states, criteria violations, equipment failures, customer outages, and cybersecurity events.
Fail safe modes	When a system fails, it will fail in a safe manner or be placed in a safe state.
Public and workforce safety	The design, construction, operation, and maintenance of the distribution system, including facilities that do not belong to electric utilities, to ensure adequate service and secure safety to workers and the general public.
Controllability and dynamic stability	Controllability describes the ability of an external input (the vector of control variables) to move the internal state of a system from any initial state to any other final state in a finite time interval. For the grid, this means the ability to make the grid behave as desired within the bounds of grid capability. Dynamic stability is the property of a system by which it returns to an equilibrium state after a small perturbation. For the grid, this means the ability to tolerate and compensate for small disturbances to maintain proper settings of quantities like voltage and power flow.
Attack resistance/Fault tolerance /Self-healing	The design, construction, operation, and maintenance of the distribution system, including facilities that do not belong to electric utilities, to ensure adequate service and secure safety to workers and the general public.
Management of DER and load variability	The ability to assess and respond to changes in load requirements at minimal cost and with environmental impact while maintaining reliability.

Capability	Definition
Reliability and resiliency management	The provision of adequate, efficient, safe, and reasonable service and facilities, and making repairs, changes, and improvements in or to the service and facilities necessary or proper for the accommodation, convenience, and safety of customers, employees, and the public.
Integrated grid coordination	The physical coordination of real and reactive power flows across the transmission/distribution system interface where the coordination is between the distribution operator and the transmission system operator
Control aggregation and disaggregation	Control aggregation is the ability to combine and resolve multiple competing and possibly conflicting control objectives. Control disaggregation is the ability to decompose broad control commands into forms suitable for local consumption and decision making while accounting for local constraints.

Table D- 3. Definition of Grid Services/Market Operations Capabilities

Capability	Definition
System performance	Performance is defined in terms of cost, quality of service, and applicable environmental and societal parameters through optimization of a portfolio of grid and DER-provided services, between the distribution and bulk power systems, and across various timescales.
Distribution asset optimization	The utilization of physical grid assets and DER-provided services to manage distribution operations in a safe, reliable, secure, and efficient manner through dynamic optimization.
Market animation	Establishment of transparent distribution markets to enable viable market development for grid services and to achieve a more efficient and secure electric system, including better utilization of the distribution system, as well as the transmission system and bulk generation.
Distribution investment optimization	Identification and sourcing of a mix of grid infrastructure and technology assets and DER provided services to enable efficient investment and expenditures for a safe, reliable distribution grid addressing needs identified in distribution planning. Investment optimization includes solving multiple problems with the same investment, such as DER, to simultaneously improve reliability and capacity.
Environmental management	The use and optimization of DER resources along with centralized clean resources to meet federal, state, and local environmental targets.

2.0 Allocation of Capabilities Among Planning, Grid Operations, and Grid Services/Market Operations

In this step, capabilities are matched to specific objectives identified earlier and to distribution planning and operations and grid services/market operations. By way of example, the objective *reliability* has been selected and the various capabilities are identified according to planning, operations, and grid services/markets. The mapped capabilities are not ranked in order of importance.

Staff reviewed the universe of possible capabilities and identified the following capabilities associated with reliability. Out of the universe of possible capabilities associated with reliability identified by the DOE Modern Grid Report cited above, Staff determined that the capabilities listed below are applicable.

Table D- 4. Mapping Capabilities to Reliability

Objective	**Required Capabilities**
Reliability: Distribution system planning	Impact resistance and resiliency
	Scalability
	Accommodation of tech innovation
	Transparency
	Open and Interoperable
	Convergence with other critical infrastructure
Reliability: Distribution system operations	Operational risk management
	Security
	Contingency management
	Situational awareness
	Fail-safe modes
	Public and workforce safety
	Controllability and dynamic stability
	Attack resistance/Fault tolerance /Self-healing
	Management of DER and load stochasticity
	Reliability and resiliency management
	Integrated grid coordination
	Control aggregation and disaggregation

Reliability: Grid services/Distribution market operations	System Performance
	Distribution asset optimization
	Market animation
	Distribution investment optimization

Staff then replicated the same analysis for all the remaining objectives/attributes. They can be found below.

Definition of Required Capabilities Associated with Resiliency

Resiliency: Staff identified the following capabilities associated with resiliency. Out of the universe of possible capabilities associated with resiliency identified by the DOE Modern Grid Report, Staff determined that those outlined below are applicable. A definition of each capability selected may be found in Tables D-1 through D-3 above.

Table D- 5. Mapping Capabilities to Resiliency

Objective	Required Capabilities
Resiliency: Distribution system planning	Impact resistance and resilience
	Scalability
	Accommodate tech innovation
Resiliency: Distribution system operations	Situational awareness
	Operational risk management
	Attack resistance/Fault tolerance/Self-healing
	Contingency management
	Fail-safe modes
	Public and workforce safety
	Security
Resiliency: Grid services/Distribution market operations	Distribution investment optimization
	Market animation

Definition of Required Capabilities Associated with Operational Efficiency

Operational Efficiency: Staff identified the following capabilities associated with operational efficiency. Out of the universe of possible capabilities associated with resiliency identified by the DOE Modern Grid Report, Staff determined that those outlined below are applicable. A definition of each capability selected may be found in Tables D-1 through D-3 above.

Table D- 6. Mapping Capabilities to Operational Efficiency

Objective	**Required Capabilities**
Operational efficiency: Distribution system planning	Accommodate technology innovation
	Open and interoperable
	Scalability
	Convergence with other critical infrastructure
Operational efficiency: Distribution system operations	Situational awareness
	Operational risk management
	Management of DER and load stochasticity
	Attack resistance/Fault tolerance/Self-healing
	Integrated grid coordination
	Reliability and resiliency management
	Contingency management
	Control aggregation and disaggregation
	Public and Workforce Safety
Operational efficiency: Grid services/Distribution market operations	Distribution investment optimization
	Distribution asset optimization

Definition of Required Capabilities Associated with Cost Reduction/Affordability

Cost reduction/affordability: Staff identified the following capabilities associated with cost reduction/affordability. Out of the universe of possible capabilities associated with resiliency identified by the DOE Modern Grid Report, Staff determined that those outlined below are applicable. A definition of each capability selected may be found in Tables D-1 through D-3 above.

Table D- 7. Mapping Capabilities to Cost Reduction/Affordability.

Objective	Required Capabilities
Cost reduction/affordability: Distribution system planning	Accommodate tech innovation
	Open and interoperable
	Scalability
	Transparency
	Convergence with other critical infrastructure
Cost reduction/affordability: Distribution system operations	Situational awareness
	Operational risk management
	Management of DER and load variability
	Attack resistance/Fault tolerance/Self-healing
	Integrated grid coordination
	Reliability and resiliency management
	Fail-safe modes
Cost reduction/affordability: Grid services/Distribution market operations	Market animation
	Distribution investment optimization
	Distribution asset optimization
	System performance

Definition of Required Capabilities Associated with Customer Enablement

Customer Enablement: Staff identified the following capabilities associated with Customer enablement. Out of the universe of possible capabilities associated with resiliency identified by the DOE Modern Grid Report, Staff determined that those outlined below were applicable. A definition of each capability selected may be found in Tables D-1 through D-3 above.

Table D- 8. Mapping Capabilities to Customer Enablement

Objective	Required Capabilities
Customer enablement: Distribution system planning	Accommodate technology innovation
	Open and interoperable
	Scalability
	Transparency
	Convergence with other critical infrastructure
Customer enablement: Distribution system operations	Security
Customer enablement: Grid services/Distribution market operations	Market animation
	Environmental management

Definition of Required Capabilities Associated with Integration of DERs

Integration of DERs: Staff identified the following capabilities associated with integration of DERs. Out of the universe of possible capabilities associated with resiliency identified by the DOE Modern Grid Report, Staff determined that those outlined below were applicable. A definition of each capability selected may be found in Tables D-1 through D-3 above.

Table D- 9. Mapping Capabilities to Facilitation of Integration of DERs

Objective	Required Capabilities
Integration of DERs: Distribution system planning	Accommodate tech innovation
	Open and interoperable
	Scalability
	Transparency
Integration of DERs: Distribution system operations	Management of DER and load variability
	Reliability and resiliency management
	Public and workforce safety
	Security
Integration of DERs: Grid services/Distribution market operations	Market animation
	Distribution asset optimization

Definition of Required Capabilities Associated with Operational Excellence

Operational Excellence: Staff identified the following capabilities associated with operational excellence. Out of the universe of possible capabilities associated with resiliency identified by the DOE Modern Grid Report, Staff determined that those outlined below were applicable. A definition of each capability selected may be found in Tables D-1 through D-3 above.

Table D- 10. Mapping Capabilities to Operational Excellence

Objective	Required Capabilities
Operational excellence: Distribution system planning	Accommodate tech innovation
	Open and interoperable
	Scalability
	Convergence with other critical infrastructure
Operational excellence: Distribution system operations	Situational awareness
	Operational risk management
	Management of DER and load variability
	Attack resistance/Fault tolerance/Self-healing
	Integrated grid coordination
	Reliability and resiliency management
	Contingency analysis
	Control federation and control disaggregation
	Public and workforce safety
Operational excellence: Grid services/Distribution market operations	Distribution investment optimization
	Distribution asset optimization

Definition of Required Capabilities Associated with Competitive Provision of Services

Competitive Provision of Services: Staff identified the following capabilities associated with competitive provision of services. Out of the universe of possible capabilities associated with competitive provision of services identified by the DOE Modern Grid Report, Staff determined that those outlined below were applicable. A definition of each capability selected may be found in Tables D-1 through D-3 above.

Table D- 11. Mapping Capabilities to Competitive Provision of Services

Objective	Required Capabilities
Competitive provision of services: Distribution system planning	Open and interoperable
	Convergence with other critical infrastructure
	Impact resistance and resiliency
Competitive provision of services: Distribution system operations	Situational awareness
	Operational risk management
	Management of DER and load variability
	Attack resistance/Fault tolerance/Self-healing
	Contingency analysis
	Fail safe modes
	Controllability and dynamic stability
	Public and workforce safety
	Security
Competitive provision of services: Grid services/Distribution market operations	Distribution investment optimization

Definition of Required Capabilities Associated with Carbon Emission Reductions

Carbon Emissions Reduction: Staff identified the following capabilities associated with reduction of carbon emissions. Out of the universe of possible capabilities associated with resiliency identified by the DOE Modern Grid Report, Staff determined that those outlined below were applicable. A definition of each capability selected may be found in Tables D-1 through D-3 above.

Table D- 12. Mapping Capabilities to Reduction in Carbon Emissions

Objective	Required Capabilities
Reduce carbon emissions: Distribution system planning	Accommodate tech innovation
	Transparency
Reduce carbon emissions: Distribution system operations	Management of DER and load variability
	Controllability and dynamic stability
Reduce carbon emissions: Grid Services/Distribution market operations	Market animation
	Distribution asset optimization
	Environmental management

Appendix E

Work Paper 4

Derivation of Required Functionalities Associated with Given Capabilities

1.0 Identification and Definition of Functionalities Associated with Capabilities

After mapping all relevant capabilities associated with each objective/attribute, Staff identified and defined the required functionalities. Each functionality defines a process, behavior, or operational result of a process to enable a capability linked to one or more policy objectives. The functional descriptions are drawn from existing regulatory, standards or industry references and compiled in the DOE Modern Grid Report.[72]

Functionalities were first subdivided under the three categories of distribution system planning, distribution grid operations, and grid services/distribution market operations. Then for ease of reference, each of the required functionalities was defined, as set forth below.

Table E- 1. Definitions of Distribution System Planning Functionalities

Functionalities	Description
Growth Forecasts for DER and Demand	Planners forecast demand growth for various customers, class types, transformers, line sections, circuits, banks, transferrable loads, and other granular forecast groupings, based on historical seasonal, monthly, daily, hourly, and sub-hourly load data. The forecasts may reflect micro/local hourly weather, regional economics and local spatial influence, expected spot load additions, forecasted DER adoption, and the variability of these factors due to weather, the economy or other factors.
Long Term System Planning	Long term system planning involves load flow analysis process and hosting capacity analysis (for long-term planning use case).
Scenario-Based Analysis	As DER adoption grows, the distribution system will increasingly exhibit variability of loading, DER performance, voltage, and other power characteristics that affect the reliability and quality of power delivery. As such, the uncertainty of the types, amount and

[72] Grid Modernization Working Group, *Grid Modernization in New Hampshire*, March 20, 2017, p. 27 and following. http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/LETTERS-MEMOS-TARIFFS/15-296_2017-03-20_NH_GRID_MOD_GRP_FINAL_RPT.PDF

Functionalities	Description
	pace of DER expansion make singular deterministic forecasts ineffective for long-term distribution investment planning. Multiple DER forecast scenarios reflecting potential changes in DER and loads plus assessment of current system capabilities and incremental infrastructure requirements facilitating analysis of the locational value of DERs.
DER Locational Value Analysis	DERs have the potential to provide incremental value for all customers through improved system efficiency, capital deferral, and support for wholesale and distribution operations. The value of DER on the distribution system is generally locational and temporal in nature, i.e., the value may be associated with a distribution substation, an individual feeder, a section of a feeder, or a combination of these components and for a given time period. The avoided cost of infrastructure investments form the potential value that may be met by sourcing services from qualified DERs, as well as optimizing the location and timing of DER adoption on the distribution system to eliminate impacts and achieve least cost outcomes.
Interconnection Process	Provide a non-discriminatory, transparent, and timely evaluation of an interconnection request from a DER provider to determine the ability to safely and reliably integrate a new DER system into the grid. The interconnection process will include Interconnection study enhancements, DER interconnection process streamlining, and interconnection portal development.
Distribution System Information Sharing	Share distribution system data that support intended use cases for DER integration with mutual sharing between customers, third parties and utilities, complying with privacy and confidentially requirements, to promote customer choice and integration of DERs into planning and operations.
Integrated Resource Transmission & Distribution Planning	At high levels of DER adoption, the net load characteristics on the distribution system can have material impacts on the transmission system and bulk power system operation. To the extent DER is considered in resource and transmission planning, it is essential to align those DER growth patterns, timing and net load shape assumptions and plans with those used for distribution planning.

Table E- 2. Definitions of Distribution Grid Operation Functionalities

Functionalities	**Description**
Sensing and Measurement	Sensing and measurement includes power state measurement, customer metering, and environmental sensing.
Controls	Coordination and control at the distribution level refers to the signaling and mobilization of distribution physical assets and DER providing grid services (directly or through an aggregator) to meet system operational and reliability goals on a dynamic basis. Controls include operations to coordinate and control both conventional equipment and DERs to optimize distribution system performance, and maximizing DER benefits, while avoiding adverse impacts. The system's control of elements on the distribution system will evolve as the integration of DERs increases and will be affected by changes to market rules, economic signals, and technological advancements at the system, subsystem and device levels.
Communications	Communications include utility and services provider systems employing various private and public infrastructure networks to increasingly connect distribution intelligent devices, DERs, customers, and third parties through formalized communication protocols. Communications may involve wide area networks (WAN), local area networks (LAN) and neighborhood area networks (NAN) that are public common carrier, private enterprise or private operational in terms of service level quality and security.
Asset Management	Analytical functionality integrated with decision support systems for monitoring and operational control of distribution assets to optimize the performance of grid reliability, efficiency, and hosting capacity, as well as related work and resource management.
Integrated Operational Engineering and Systems Operations	Assessments of the impacts of planned maintenance outages, system reconfigurations and other changes to the distribution system, and associated operations for planned and unplanned work.
Distribution Systems Model	A distribution system model is a representation of the physical distribution system infrastructure (including the characteristics of system components and system topology) and adapts to the system state/configuration; it is usually contained in a software system.

Functionalities	Description
Transmission-Distribution Interface Coordination	Ensures reliability and assurance to the balancing authorities of the operational services of dispatched DERs, by efficiently coordinating, scheduling, and managing DERs in real-time, including prioritization rules. T-D interface coordination functions are carried out to avoid detrimental effects on local distribution systems.
Real Time DER Operation	Real time direct or indirect control or coordination of DERs through pricing and/or engineering signals, in order to optimize network operations and to maintain the reliability of the system. Real time DER operation includes automated islanding and reconnection, distribution system state estimation and optimal power flow.
Volt-Var Management and Power Quality Management	Management of steady-state voltage (generally >60 sec), including voltage limit violation relief, reduced voltage variability, compensating reactive power. Power quality management, includes mitigating voltage transients and waveform distortions, such as voltage sags, surges, and harmonic distortion as well as momentary outages.
Fault Management	Fault management includes advanced protection and relay management, fault location, isolation, and service restoration (FLISR), line sensing and measurement, and outage management.
Security	Physical security: Technologies or techniques that detect and address threats, breaches, unauthorized access, or physical incursion (that may or may not result in damage) and communicate that detection to authorized monitoring systems and personnel. In addition, physical security pertains to technologies that improve the security posture of transmission, and distribution components, as well as the monitoring, communication, and computation hardware that constitute grid control systems. Cybersecurity: The protection of computer systems from theft or damage to the hardware, software, data, as well as from disruption or misdirection of the services they provide. It includes controlling physical access to the hardware, as well as protecting against harm that may come via network access, data and code injection, and due to malpractice by operators, whether intentional, accidental, or due to deviation from secure procedures.
Cybersecurity	Cybersecurity is the protection of computer systems from theft or damage to the hardware, software, or the information on them, as well as from disruption or misdirection of the services they

Functionalities	Description
	provide. It includes controlling physical access to the hardware, as well as protecting against harm that may come via network access, data and code injection, or due to malpractice by operators, whether intentional, accidental, or due to deviation from secure procedures.
Physical Security	Technologies that detect threats, breaches, unauthorized access, or physical incursion (that may or may not result in damage) and communicate that detection to authorized monitoring systems and personnel. In addition, physical security pertains to technologies that improve the security posture of transmission, and distribution components, as well as the monitoring, communication, and computation hardware that constitute grid control systems.
Information Technology	Refers to the data management, data processing, and storage technologies, equipment, and systems that are used in support of both business enterprise functions and grid operations.
Reliability Management	A number of processes and systems that enable distribution operators to discover, locate, and resolve power outages in an informed, orderly, efficient, and timely manner. Related systems work in concert to automate the process of mitigating the scope of outages and, in power restoration, reducing both the impact and length of power interruptions.
Operational Forecasting	The use of a combination of measurement data and analytics to develop short-term (minutes, hours, days) projections of loads and resources for scheduling, management, and operational optimization.

Table E- 3. Definitions of Grid Services/Distribution Market Operation Functionalities

Functionalities	Description
Settlement Procedures	The guidelines that govern the settlement of market contractual, program, or tariff obligations by an enhanced distribution platform, will require comparison of actual performance to commitment in terms of quantity, quality, timing, tracking and reconciling discrepancies, managing disputes and escalations. The settlement process includes calculating credits and charges for DER services and other market activity.
DER Portfolio Management	DER portfolio management consists of managing a mix of DER sourced through various mechanisms involving prices, programs

Functionalities	Description
	and procurements, as well as grid infrastructure investments. This involves optimizing the utilization of these resources to achieve desired performance in terms of response time and duration, load profile impacts, market requirements and value (net of the costs to integrate DERs into grid operations), and dynamic notifications.
DER Sourcing (NWA)	Distribution markets would enable DER to provide services as an alternative to certain utility distribution capital investments and/or operational expenses. The potential types of services may include distribution capacity deferral, voltage and power quality management, reliability and resiliency, and distribution line loss reduction. The distribution grid operator is the buyer of these services. The distribution planning process defines the need for these grid operational services. The services provided by DER providers and customers may be sourced through a combination of three general types of mechanisms: • Prices – DER response through time-varying rates, tariffs market-based prices, or cost-based distribution marginal values • Programs – DER services developed through programs operated by the utility or third parties with funding by utility customers through retail rates, incentives, locational vendor bounties, or other means by the state • Procurements – DER services sourced through competitive procurements such as requests for proposals/offers, auctions, etc.
Market Information Sharing	This functionality encompasses the communication and exchange of market information between the ISO, the distribution system, and participating DERs, including information on distribution area net demand, net interchanged supply, DER services scheduled by the distribution system, DER forecasts, aggregate output of DERs, and DER services that may be offered to the ISO for wholesale market participation.
Market Oversight	The market oversight process includes functions to monitor distribution market activity and assess potential market manipulation, and to ensure market security, legitimacy and performance.

2.0 Mapping Capabilities to Functionalities

Now we need to map capabilities to required functionalities. Assuming that our specific objective is reliability and that the capability supporting it is transparency, Table E-4 lists by example all the functionalities associated with transparency. Staff has replicated this mapping to determine the combination of functionalities associated with a given capability under conditions of distribution planning, distribution operations, and grid services/market operations. The collective road map can be found at the end of this Work Paper as Table E-5, the Master List.

Table E- 4. Required Functionalities Associated with Transparency Capability

Capability	Required Functionality
Transparency: Distribution system planning	Long-term system planning
	Growth forecast of DER and Demand
	DER Locational Value Analysis
	Integrated Resource Transmission & Distribution Planning
	Interconnection Process
	Distribution System Information Sharing
Transparency: Distribution system operations	Asset Management
	Fault Management
	Sensing and Measurement
	Real Time DER Operation
Transparency: Grid Services/Distribution market operations	DER Portfolio Management
	DER Sourcing
	Market Information Sharing
	Market Oversight

The Staff-derived Master List below allocates all the required functionalities by grid system planning, distributed grid operations, and grid services/distributed market operations, as well as groups functionalities by required capability.

Table E- 5. Master List of Capabilities and Related Functionalities

Capabilities	Functionalities: Distribution System Planning	Functionalities: Distribution Grid Operations	Functionalities: Grid Services/Distribution Market Operations
Reliability and resiliency management	Long Term System Planning; Growth Forecasts of DER and Demand; DER Locational Value Analysis; Integrated Resource T&D Planning; Scenario Based Planning; Interconnection Process; Distribution System Information Sharing	Control; Communications; Integrated Operational Engineering and System; Distribution System Model; T-D Interface Coordination; Volt-Var and Power Quality Management; Security; Sensing and Measurement; Asset Management; Real Time DER Operation; Fault Management	DER Portfolio Management; Settlement Procedures; DER Sourcing; Market Oversight
Operational risk management	Long Term System Planning; Growth forecasts of DER and Demand; DER Locational Value analysis; Integrated Resource T&D Planning; Scenario Based Planning; Interconnection Process	Control; Communications: Integrated Operational Engineering and System; Distribution System Model; T-D Interface Coordination; Security; Sensing and Measurement; Asset Management; Real Time DER Operation; Fault Management	DER Portfolio Management; Settlement Procedures; DER Sourcing; Market Oversight
Impact resistance and resiliency	Long Term System Planning; Interconnection Process; Distribution System Information Sharing	Control; Communications; Integrated Operational Engineering and System; Distribution System Model; T-D Interface Coordination; Security; Sensing and Measurement; Asset Management; Real Time DER Operation; Fault Management	DER Portfolio Management; DER Sourcing
Security	Long Term System Planning; Integrated Resource T&D Planning; Scenario Based Planning; Interconnection Process	Control; Communications; Integrated Operational Engineering and System; T-D Interface Coordination; Sensing and Measurement; Asset Management; Real Time DER Operation; Fault Management	DER Portfolio Management; DER Sourcing; Market Information Sharing; Market Oversight
Contingency management	Long Term System Planning; Integrated Resource T&D Planning; Scenario Based Planning; Interconnection Process	Control; Communications; Integrated Operational Engineering and System; T-D Interface Coordination; Sensing and Measurement; Volt-Var and Power Quality Management; Asset Management; Real Time DER Operation; Fault Management	DER Portfolio Management; DER Sourcing; Market Oversight
Accommodate tech innovation	Long Term System Planning; Growth Forecasts of DER and Demand; Integrated Resource T&D Planning;	Control; Communications; Integrated Operational Engineering and System; Volt-Var and Power Quality Management; Security;	DER Portfolio Management; Market Information Sharing; Market Oversight

Capabilities	Functionalities: Distribution System Planning	Functionalities: Distribution Grid Operations	Functionalities: Grid Services/Distribution Market Operations
	Scenario Based Planning; Interconnection Process; Distribution System Information Sharing	Sensing and Measurement; Asset Management; Real Time DER Operation	
Situational awareness	Long Term System Planning; Growth Forecasts of DER and Demand; DER Locational Value Analysis; Integrated Resource T&D Planning; Scenario Based Planning; Interconnection Process	Communications; Integrated Operational Engineering and System; Distribution System Model; T-D Interface Coordination; Volt-Var and Power Quality Management; Security; Sensing and Measurement; Asset Management; Real Time DER Operation; Fault Management	DER Portfolio Management; Market Information Sharing
Scalability	Long Term System Planning; Integrated Resource T&D Planning; Scenario Based Planning; Interconnection Process; Distribution System Information Sharing	Control; Communications; Integrated Operational Engineering and System; Distribution System Model; Volt-Var and Power Quality Management; Security; Sensing and Measurement; Asset Management; Real Time DER Operation; Fault Management	Settlement Procedures; DER Portfolio Management; DER Sourcing; Market Information Sharing; Market Oversight
Failsafe modes	Long Term System Planning; Scenario Based Planning	Control; Communications; Volt-Var and Power Quality Management; Security; Sensing and Measurement; Asset Management; Real Time DER Operation; Fault Management	DER Portfolio Management
Public and workforce safety	Long Term System Planning; Scenario Based Planning; Interconnection Process	Control; Communications; Integrated Operational Engineering and System; T-D Interface Coordination; Security; Sensing and Measurement; Asset Management; Real Time DER Operation; Fault Management	DER Portfolio Management
Open and interoperable	Interconnection Process; Distribution System Information Sharing	Control; Communications; T-D Interface Coordination; Volt-Var Power Quality Management; Sensing and Measurement; Asset Management; Real Time DER Operation	Settlement Procedures; DER Portfolio Management; DER Sourcing; Market Information Sharing; Market Oversight
Controllability and dynamic stability	DER Locational Value Analysis; Integrated Resource T&D Planning; Scenario Based Planning; Interconnection Process	Control; Communications; Distribution System Model; T-D Interface Coordination; Volt-Var and Power Quality Management; Security; Sensing and Measurement; Asset Management; Real Time DER Operation; Fault Management	DER Portfolio Management;DER Sourcing; Market Information Sharing; Market Oversight
Transparency	Long Term System Planning; Growth Forecast of DER and Demand; DER Locational Value Analysis; Integrated	Sensing and Measurement; Distribution System Model; Asset Management; Real Time DER Operation; Communications; Security	DER Portfolio Management; Market Information Sharing; Market Oversight

Capabilities	Functionalities: Distribution System Planning	Functionalities: Distribution Grid Operations	Functionalities: Grid Services/Distribution Market Operations
	Resource T&D Planning; Interconnection Process; Distribution System Information Sharing		
Attack resistance/Fault tolerance/Self-healing	Long Term System Planning; Integrated Resource T&D Planning; Scenario Based Planning; DER Locational Value Analysis	Control; Communications; Integrated Operational Engineering and System; Distribution System Model; T-D Interface Coordination; Security; Sensing and Measurement; Asset Management; Real Time DER Operation; Fault Management	DER Portfolio Management
Integrated grid coordination	Long Term System Planning; Growth Forecasts of DER and Demand; Integrated Resource T&D Planning; Scenario Based Planning	Control; Communications; T-D Interface Coordination; Volt-Var and Power Quality Management; Security; Sensing and Measurement; Asset Management; Real Time DER Operation; Fault Management	DER Portfolio Management
Management of DER and Load stochasticity	Long Term System Planning; Growth Forecast of DER and Demand; DER Locational Value Analysis; Integrated Resource T&D Planning; Scenario Based Planning	Control; Communications; Integrated Operational Engineering and System; Distribution System Model; T-D Interface Coordination; Volt-Var and Power Quality Management; Security; Sensing and Measurement; Asset Management; Real Time DER Operation; Fault Management	DER Portfolio Management; DER Sourcing; Market Information Sharing; Market Oversight
System performance	Long Term System Planning; Growth Forecast of DER and Demand; DER Locational Value Analysis; Integrated Resource T&D Planning; Scenario Based Planning; Distribution System Information Sharing	Control; Integrated Operational Engineering and System; Distribution System Model; T-D Interface Coordination; Volt-Var and Power Quality Management; Security; Sensing and Measurement; Asset Management; Real Time DER Operation	Settlement Procedures; DER Portfolio Management; DER Sourcing; Market Information Sharing; Market Oversight
Distribution asset optimization	Long Term System Planning; Growth Forecasts of DER and Demand; DER Locational Value Analysis; Integrated Resource T&D Planning; Interconnection Process	Control; Communications; Integrated Operational Engineering and System; Distribution System Model; Volt-Var and Power Quality Management; Security; Sensing and Measurement; Asset Management; Real Time DER Operation	DER Portfolio Management; DER Sourcing; Market Information Sharing; Market Oversight
Control federation and control disaggregation	Long Term System Planning; Integrated Resource T&D Planning; Interconnection Process; Growth Forecast of DER and Demand	Control; Communications; Distribution System Model; T-D Interface Coordination; Volt-Var and Power Quality Management; Security; Sensing and Measurement; Asset Management; Real Time DER Operation	DER Portfolio Management

Capabilities	Functionalities: Distribution System Planning	Functionalities: Distribution Grid Operations	Functionalities: Grid Services/Distribution Market Operations
Market animation	DER Locational Value Analysis; Integrated Resource T&D Planning	Control; Integrated Operational Engineering and System; Distribution System Model; T-D Interface Coordination; Volt-Var and Power Quality Management; Sensing and Measurement; Real Time DER Operation; Asset Management; Security	Settlement Procedures; DER Portfolio Management; DER Sourcing; Market Information Sharing; Market Oversight
Environmental management	Long Term System Planning; Growth Forecast of DER And Demand; DER Locational Value Analysis; Integrated Resource T&D Planning	Control; Integrated Operational Engineering and System; T-D Interface Coordination; Volt-Var and Power Quality Management; Security; Real Time DER Operation; Sensing and Measurement	DER Portfolio Management; DER Sourcing; Market Information Sharing; Market Oversight
Distribution investment optimization	Long Term System Planning; Growth Forecasts of DER and Demand; DER Locational Value Analysis; Integrated Resource T&D Planning; Scenario Based Planning	Control; Integrated Operational Engineering and System; Distribution System Model; T-D Interface Coordination; Volt-Var and Power Quality Management; Security; Real Time DER Operation; Sensing and Measurement	Settlement Procedures; DER Portfolio Management; DER Sourcing; Market Information Sharing; Market Oversight
Convergence with other critical infrastructure	Long Term System Planning; DER Locational Value Analysis; Integrated Resource T&D Planning; Interconnection Process; Distribution System Information Sharing	Control; Communications; Integrated Operational Engineering and System; Distribution System Model; T-D Interface Coordination; Security; Real Time DER Operation; Sensing and Measurement	DER Portfolio Management; DER Sourcing; Market Information Sharing; Market Oversight

Appendix F

Cybersecurity and the Threats from DERs

Introduction

Commissions around the country are expressing the need to adequately address increasingly common cyber security threats in order to mitigate the vulnerability of utility systems to cyber-attacks and to ensure that confidential and sensitive customer information remains safeguarded from potential data breaches.

Cyber and physical security threats pose a significant and growing challenge to electric utilities. Unlike traditional threats to electric grid reliability, such as extreme weather, cyber threats are less predictable and therefore more difficult to anticipate and address. The ways in which a cyber-attack can be conducted are numerous and the growing complexity and interconnectedness of electric grids is increasing the number of potential targets and vulnerabilities.

Cyber incidents can cause loss of grid control or damage to grid equipment due to deliberate tampering with data, firmware, algorithms, and communications; false data injection into pricing or demand systems; data exfiltration; and ransom demands to restore access to data.

Threats can be both external and internal to the power system. DER nodes can be compromised by strategically manipulating generation set points on a distribution feeder (Shelar and Amin 2016).[73] Software attacks can damage variable frequency drives in electro-mechanical equipment to control motor speed and torque. Traditional supervisory control and data acquisition (SCADA) systems, distributed control systems, and programmable logic controllers were designed as closed systems with limited control interfaces, but these technologies are now becoming digitized and are being designed to include more "intelligent" software and hardware components. This increase in digitization and complexity can create new opportunities for unauthorized outsiders to access, and potentially disrupt, these systems.

Mobile communications connected to utility systems may compound the cyber risks that utilities confront. The growth of the "Internet of Things" (IoT), which can improve efficiency and convenience, also expands vulnerabilities if sufficient cybersecurity and encryption have not been built in and vulnerable wireless protocols (such as ZigBee) are used.[74] Wirelessly connected IoT devices, including smart light bulbs and other electrical components in a "smart home" or sensors or cameras at an industrial facility, are vulnerable to cyber disruptions and attacks, and could spread malicious codes.

Although all utilities have cyber security programs, widespread connection of distributed energy resources (DERs) – for example, demand response, generation including from wind and solar,

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[73]Devendra Shelar, Saurabh Amin, *Security Assessment of Electricity Distribution Networks under DER Node Compromises*, Cornell University Library, Aug. 2016.
[74] Cyril W. Draffin, Jr., *Cybersecurity White Paper*, MIT Energy Initiative Utility of the Future, Dec. 2016.

energy storage, and energy control devices -- will increase digital complexity and attack surfaces, and therefore require more intensive cybersecurity protection.

The Challenge

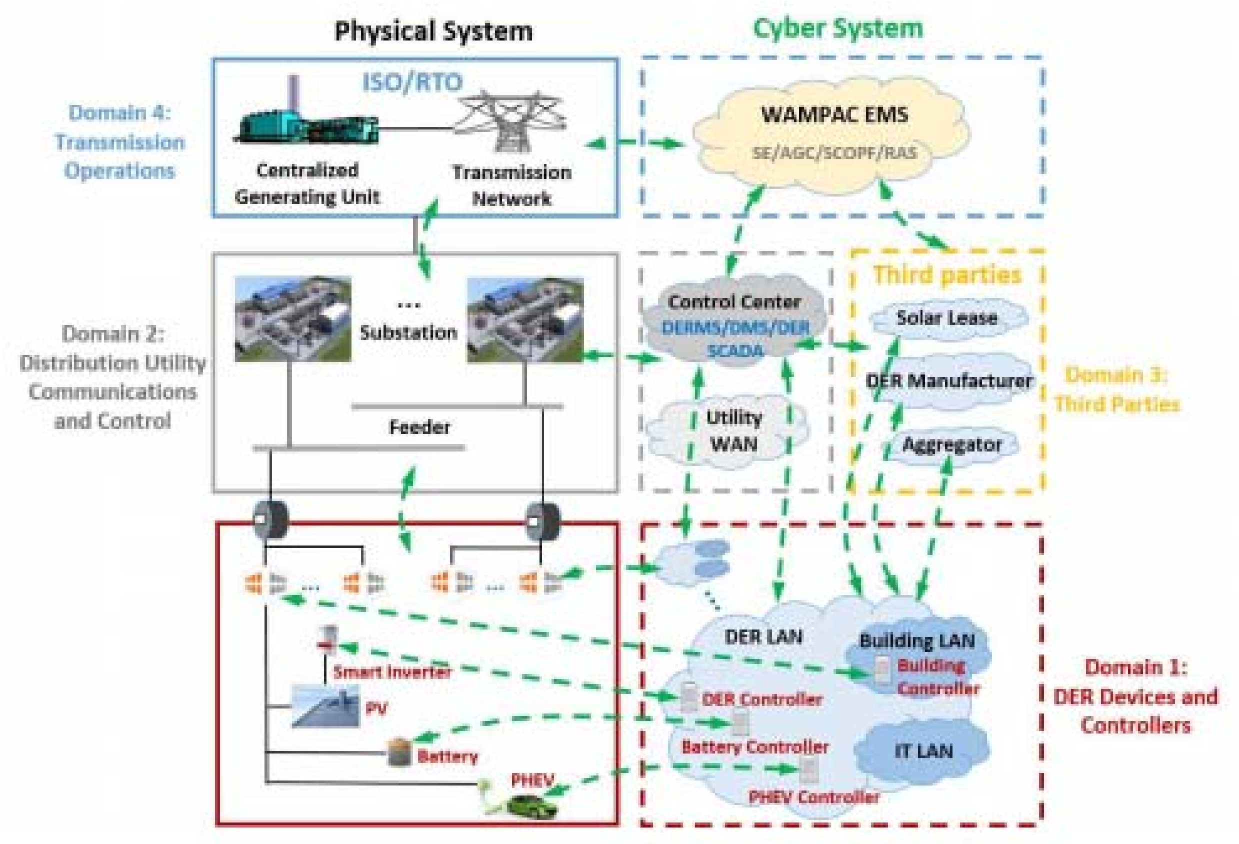
System operators must have the capacity to operate, maintain, and recover a system that will never be fully protected from cyber-attacks. Relevant issues that need to be addressed include cloud security, machine-to-machine information sharing, advanced cybersecurity technologies, and outcome-based regulation to avoid prolonged outages and increase system resilience.

With expanding connection of electric and telecommunications devices, vastly more information will become available. Data analytics and the opportunity for outside organizations to have access to large quantities of data will increase the amount of information held by electric utilities and their affiliated partners. If electric utility companies expand their services beyond just delivering electricity -- for example, by interacting with DER aggregators -- specific procedures to prevent data breaches and exfiltration of information will be needed.

On the one hand, utilities will need to be resilient and prepared to contain and minimize the consequences of cyber incidents. Future power systems with a high penetration of DERs are envisioned to have features that are favorable for resilient operation. For instance, with DERs, microgrids can be helpful for enhanced resilience, and with "islanding" operations can assist in "black-start" or continued operations if the broader grid goes down due to a cyber or physical incident. On the other hand, the increasing digital complexity and growing number of potential attack surfaces will require more intensive cybersecurity protection and will require electric utilities, vendors, law enforcement and government to develop the capability to share current cyber threat information quickly and effectively.

With the large-scale integration of DER, the power grid will evolve from a utility-centric structure to a distributed smart grid. In their study of future DER power grid architecture and the unique cybersecurity challenges that DER integration presents Messrs Qi, Hahn, Lu, Wang and Liu[75] have delineated four domains of DER grid architecture as follows in their paper, *Cybersecurity for Distributed Energy Resources and Smart Inverters*:

[75] Junjian Qi, Adam Hahn, Xiaonan Lu, Jianhui Wang and Chen-Ching Liu, *Cybersecurity for Distributed Energy Resources and Smart Inverters,* Energy Systems Division, Argonne National laboratory, Lemont, USA. Oct 2016.



Accordingly, the composition and vulnerabilities of each domain can be charted as follows:

Domain Name	Characteristics	Vulnerabilities
DER Devices and Controllers	• DERs are likely owned and controlled by consumers • Facilities DER energy management systems (FDEMS) act upon the DERs and their controllers for operations (using smart inverters). • Owners have complete authority over the devices and controllers, and the FDEMS may have access limited to management of the devices, modification of certain DER operations, and reading real-time data allowed by the DER owner. • Where present, AMIs collect data from the devices and send that data to the utilities • DER owners get information about their DERs by communicating with	• unauthorized access to DER controllers and smart inverters, • penetration through the facility network, • unauthorized access to smart meters, • unauthorized change in the settings in the FDEMS • novice owners who fail to adequately secure their devices

Domain Name	Characteristics	Vulnerabilities
	smart inverters through wireless technology, such as ZigBee.	
Distribution Utility Communications and Control	• The utility can send control commands to smart inverters to connect or disconnect the DER, regulate the voltage, and manage the amount of penetration allowed. • Utilities may also use a FDEMS to handle DER systems located at utility sites such as substations or physical plant sites. • The distribution management system ensures the stability of the grid after the addition of the DER. It is also responsible for shutting down the DER in case of an emergency. • Utility interacts with the smart inverters and controllers using communication protocols such as Smart Energy Profile (SEP) 2.0. • The distribution system uses the WAN/LAN of the utility.	• Penetration via the utility network and malicious commands sent to DER controllers and/or smart meters.
Third Parties	• Include: (i) aggregators, (ii) companies providing power purchase agreements (PPAs) or energy leases, and (iii) DER manufacturers • Most third-party entities have the ability to monitor the status of DERs; some may also have the ability to directly control DER operation. • Some entities may have connectivity to a very large number of DERs. • Many DER manufacturers provide additional online services that come with their device, such as automatic cloud storage of device data. • Many devices are configured to immediately connect back to a manufacturer-controlled cloud environment in order to provide consumers with easy access to data and to support maintenance operations.	• Where systems are used for third-party access they may directly interconnect with many more DERs. • The security of these connections is often outside the control of the utility and the DER owner.

Domain Name	Characteristics	Vulnerabilities
	• Companies that provide PPAs and energy leases also often remotely monitor the energy produced by the DER and may be responsible for performing maintenance on the devices remotely.	
Transmission Operations	• ISOs maintain a stable frequency by balancing systems based on operating reliability regulations. • In ISO emergency management systems (EMS) there are many advanced applications, such as state estimation (SE) and automatic generation control (AGC). • Going forward, ISOs and market operations will affect what the DER systems are requested or required to do, based on tariffs and other agreements • DER operations will need to be integrated with the large power grid operations. • Distribution utilities may interact with their ISO as a wholesale market participant. • DER aggregators may seek to bid into the electricity market for both energy and ancillary services.	• Many advanced applications in EMS are based on measurements from sensors, such as remote terminal units (RTUs) or phasor measurement units (PMUs). • Compromised measurements can negatively influence the functionalities of advanced applications and further influence power grid operation, which can lead to serious voltage or frequency violations.

Threat Scenarios

An attack against DER could target a number of devices and communication networks owned by either the utility or the DER owner. Furthermore, there may also be a variety of third-party services and entities that are interdependent with the operation of DER. The severity of attacks on the various system components and entities will be determined by the size of the DER and the number of available DER instances they are connected to.

Based after the work of Messrs. Qi, et al.,[76] the following diagram displays a high level schematic of potential cyberattacks targeting DERs.

The DER threats are listed as follows:

1. Malicious DER commands sent through utility wide area networks (WAN);

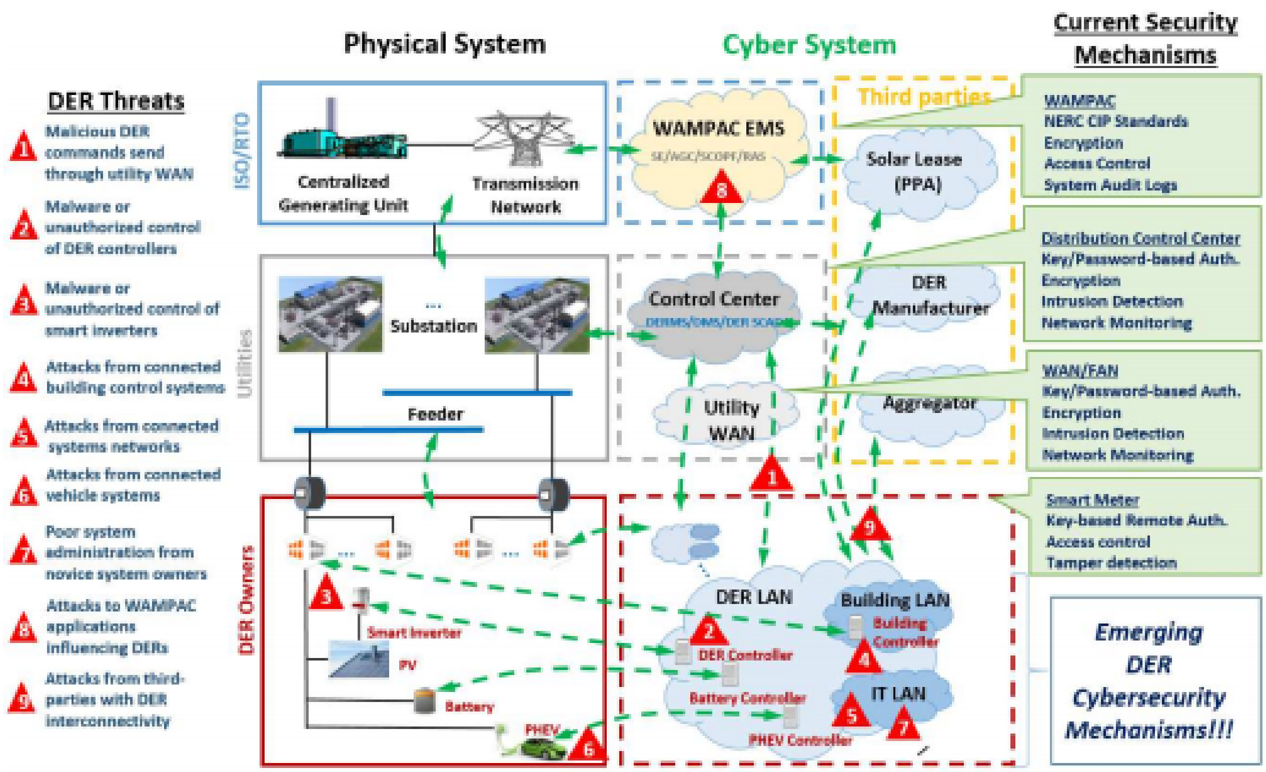
[76] Ibid

2-3. Malware or unauthorized control of smart inverters and DER controllers;

4-6. Attacks from connected building control systems, IT networks, and vehicle systems;

7. Poor system administration from novice system owners;

8. Attacks to wide area monitoring, protection, and control (WAMPAC) applications influencing DER.



Meeting the Challenge

Minimum cybersecurity regulatory standards are needed for all components of an interconnected network: the bulk power and transmission systems, distribution systems and distributed energy resources, metered points of connection with network users, and internet-enabled devices in residential, commercial, and industrial buildings. All entities that interact with and connect to the electric grid (e.g., DERs, micro grids) should adhere to minimum cybersecurity standards, not only those entities, such as utilities, that are registered with the North American Electric Reliability Corporation (NERC). Nontraditional energy providers and electricity service providers, including DER aggregators, should be obligated to address cyber risks because their actions (or inactions) could have a dramatic impact on the overall security of the electric grid.

Standards

To confront the new challenges faced by the increased exposure of power systems to cyberattacks within the United States, the following regulatory agencies, electric utility coordinating organizations and standards agencies are developing standards relevant for cybersecurity:

Organization	Institution
Regulatory Organizations	Federal Energy Regulatory Commission (FERC); North American Electric Reliability Corporation (NERC); state public utility commissions and public service commissions
Coordinating Organizations	Electricity Sector Information Sharing and Analysis Center (E-ISAC); Industrial Control Systems – Computer Emergency Readiness Team (ISC-CERT); Electricity Sector Coordinating Council (ESCC); North American Transmission Forum; Edison Electric Institute (EEI)
Supporting Organizations	Department of Energy (DOE); Department of Homeland Security (DHS)
Relevant Standards and Models	National Institute of Standards and Technology (NIST) standards and cybersecurity framework; SANS Institute CIS Critical Security Controls; DOE'S Cybersecurity Capability Maturity Model (C2M2) Program

Staff encourage all participants and stakeholders in the Grid Modernization proceeding to closely monitor the activities of the above-mentioned institutions to ensure that they have the latest understanding of applicable standards and models, and are conditioning their grid modernization plans accordingly. Please note that NIST's most recent version 1.1 of its popular Framework for Improving Critical Infrastructure Cybersecurity issued on April 16, 2018,[77] https://nvlpubs.nist.gov/nistpubs/CSWP/NIST.CSWP.04162018.pdf, includes sections addressing the following: authentication and identity, self-assessing cybersecurity risk, managing cybersecurity within the supply chain and vulnerability disclosure.

The Framework is accompanied by a Roadmap update which includes the following areas:

Confidence mechanisms, cyber-attack lifecycle, cybersecurity workforce, cyber supply chain risk management, federal agency cybersecurity alignment, governance and enterprise risk management, identity management, measuring cyber security, privacy engineering, referencing techniques, Internet of Things, and secure software development. Further information on DOE's Cybersecurity Capability Maturity Model (C2M2) Program is available at:

[77] NIST, *Framework for Improving Critical Infrastructure Cybersecurity*, April 2018

https://www.energy.gov/ceser/activities/cybersecurity-critical-energy-infrastructure/energy-sector-cybersecurity-0

Other Safeguarding Mechanisms

A number of other parallel strategies are under consideration within neighboring states. For example, Staff has been monitoring the progress of the Business to Business collaborative[78] currently underway in New York State that requires all entities that interface with utility systems have adequate cyber protections in place, in addition to those already established by the utilities themselves. Toward that end, the New York Joint Utilities have requested that all energy service entities (ESEs) complete a self-attestation of information security controls and execute a Data Security Agreement[79] with each utility with whom the ESE does business. Staff would urge the participants in the Grid Mod docket to consider the efficacy of moving forward with such a parallel strategy.

Working Group Recommendation

In view of the increasing incidence of cybersecurity threats, Staff recommends that the Grid Modernization participants convene a working group to develop a state utility strategy outlining the approach, goals, and timeframe for proceeding and setting expectations for utility performance. This working group should be on going and should revisit the strategy and ensurance steps on a regular cycle of continuous improvement.

Questions under consideration may include the following:

- What should be the scope of the strategy?
- What actions might the Commission need to initiate?
- What performance requirements will be required from the utilities and other energy service companies?
- What will be the reporting requirements?
- Should Commission interactions with the utilities be formal or informal?
- Should the Commission seek to actively encourage utilities to make cyber investments and treatment of cost-recovery for utility investments in cybersecurity?

Concurrently, Staff urges the utilities to consider including a section in their IDP that addresses critical cybersecurity questions. In its Primer on Cybersecurity for State Utility Regulators, completed in January of 2017,[80] NARUC developed a series of 108 questions for consideration by utilities. Staff recommends that, based upon utilities existing cybersecurity plans and the work group discussions, each utility develop its own DER driven cybersecurity strategy. The

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[78] Case 18-M-0376, Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place, Order Instituting Proceeding, p. 3 (issued June 14, 2018) (June Order), NY PSC.
[79] Found at end of annex.
[80] NARUC, *Primer on Cybersecurity for State Utility Regulators*, Jan 2017.

strategy should form part of the utility's IDP although it may need to be safeguarded by a confidentiality agreement.

Questions to be examined will include development of proactive and strategic action by the utilities, compliance with a set of clear and enforceable standards, reporting processes, existence of alliances across public and private sectors for information-sharing, planning, and situational awareness around cybersecurity, identification of critical utility staff and budget, any mechanisms for performing risk assessments, evaluation of strategy effectiveness, responsibilities for response and recovery, mapping of related processes, and cybersecurity and utility governance. A list of these questions may be found at the end of this document. The responses, apart from forming part of the IDP will also cause the utilities to question the adequacy of their existing strategy and whether to bolster existing internal policies.

Sample Attestation of Information Security Controls
(based on NY State templates)

SELF-ATTESTATION OF INFORMATION SECURITY CONTROLS This SELF-ATTESTATION OF INFORMATION SECURITY CONTROLS ("Attestation"), is made as of this _____ day of ________________, 20___ by ___________________________, a third party ("Third Party") to Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, National Fuel Gas Distribution Corporation, The Brooklyn Union Gas Company d/b/a National Grid NY, KeySpan Gas East Corporation d/b/a National Grid, and Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation (together, the New York State Joint Utilities or "JU").

WHEREAS, Third Party desires to retain access to certain Confidential Utility Information (as defined previously in this Data Security Agreement), Third Party must THEREFORE self-attest to Third Party's compliance with the Information Security Control Requirements ("Requirements") as listed herein. Third Party acknowledges that non-compliance with any of the Requirements may result in the termination of utility data access as per the discretion of any of the JU, individually as a Utility or collectively, in whole or part, for its or their system(s).

The Requirements are as follows (check all that apply to Third Party's computing environment):

- An Information Security Policy is implemented across the Third Party corporation which includes officer level approval.

- A risk-based Information Security Program exists to manage policy requirements.

- An Incident Response Procedure is implemented that includes notification within 24 hours of knowledge of a potential incident alerting utilities when Confidential Utility Information is potentially exposed, or of any other potential security breach.

- Role-based access controls are used to restrict system access to authorized users and limited on a need-to-know basis.

- Multi-factor authentication is used for all remote administrative access, including, but not limited to, access to production environments. All production systems are properly maintained and updated to include security patches on an at-least monthly basis. Where a critical alert is raised, time is of the essence, and patches will be applied as soon as practicable.

- Antivirus software is installed on all servers, workstations, and mobile devices and is maintained with up-to-date signatures.

- All Confidential Utility Information is encrypted in transit utilizing industry best practice encryption methods.

- All Confidential Utility Information is encrypted at rest utilizing industry best practice encryption methods, or is otherwise physically secured.

- All forms of mobile and removable storage media, including, but not limited to, laptop PCs, mobile phones, backup storage media, external hard drives, and USB drives must be encrypted.

- All Confidential Utility Information is stored in the United States only, including, but not limited to, cloud storage environments and data management services.

- Third Party monitors and alerts their network for anomalous cyber activity on a 24/7 basis.
- Security awareness training is provided to all personnel with access to Confidential Utility Information.

- Employee background screening occurs prior to the granting of access to Confidential Utility Information.

- Replication of Confidential Utility Information to non-company assets, systems, or locations is prohibited.

- Access to Confidential Utility Information is revoked when no longer required, or if employees separate from the Third Party.

- Additionally, the attestation of the following item is requested, but is NOT part of the

Requirements:

Third Party maintains an up-to-date SOC II Type 2 Audit Report, or other security controls audit report.

Upon reasonable notice to Third Party, Third Party shall permit Utility, its auditors, designated audit representatives, and regulators to audit and inspect facilities, including computerized and paper systems, where Confidential Utility Information is processed or stored, and relevant security practices, procedures, records, and technical controls. Such audit and inspection rights shall be, at a minimum, for the purpose of verifying Third Party's compliance with this Attestation. If Third Party provides an up-to-date SOC II Type 2 Audit Report, the respective Third Party will not be chosen for audit for one year after submission of the Report. If Third Party provides an alternative security controls audit report, it is at the JU's discretion, individually as a Utility or collectively, in whole or part, of if the respective Third Party is absolved of potential audit for one year.

IN WITNESS WHEREOF, Third Party has delivered accurate information for this Attestation as of the date first above written.

Signature: Name: Title: Date:

Sample Non-Disclosure Agreement
(based on a NY State template)

NON-DISCLOSURE AGREEMENT
This Non-Disclosure Agreement (“Non-Disclosure Agreement”) dated as of _____ __, 20__ (the “Effective Date”), between [_____________] (the “Supplier”), a [_______________] [corporation][limited liability company][limited liability partnership], having offices at [_________________________________] and [______________________________________] (“Company”), a [________________] [corporation], having offices at [____] (each, individually, a “Party” and, collectively, the “Parties”).

WHEREAS, the Parties and their respective Affiliates (as such term is defined below) possess certain confidential and proprietary Information (as such term is defined below);

and WHEREAS, each Party may elect, in its sole discretion, to disclose Information to the other Party, its Representatives (as such term is defined below) or its Affiliates in connection with entering a Data Security Agreement (“DSA”) and the Self Attestation Form/Vendor Risk Attestation (“VRA”) to govern the exchange of information between the Parties (the “Purpose”), subject to the terms and conditions of this Non-Disclosure Agreement.

NOW, THEREFORE, in consideration of the mutual covenants contained herein and for other good and valuable consideration, the sufficiency and receipt of which are hereby acknowledged, the Parties agree as follows:

§1. Certain Definitions.

(a) The term “Information” means (i) all financial, technical and other non-public or proprietary information which is furnished or disclosed orally, in writing, electronically or in other form or media by the Disclosing Party, its Representatives or its Affiliates to the Recipient, its Representatives or its Affiliates in connection with the Purpose and that is described or identified (at the time of disclosure) as being non-public, confidential or proprietary, or the non-public or proprietary nature of which is apparent from the context of the disclosure or the contents or nature of the information disclosed; and (ii) all memoranda, notes, reports, files, copies, extracts, inventions, discoveries, improvements or any other thing prepared or derived from the information described in §1(a)(i), above; and (iii) all Personal Data (as defined in the DSA); and

(b) The term “Recipient” means a Party to whom the other Party, its Representatives or its Affiliates discloses Information in its possession.

(c) The term “Disclosing Party” means the Party Disclosing Information in its possession, or on whose behalf Information is disclosed, to a Recipient.

(d) The term “Representative(s)” means the officers, directors, managers, partners, members, shareholders, employees, agents, attorneys, accountants, contractors and advisors of a Party or its Affiliates.

(e) The term "Affiliate" means any person controlling, controlled by, or under common control with, any other person; "control" shall mean the ownership of, with right to vote, 50% or more of the outstanding voting securities, equity, membership interests, or equivalent, of such person.

§2. Permitted Disclosure and Personal Data.

(a) Recipient shall receive all Information in strict confidence, shall exercise reasonable care to maintain the confidentiality and secrecy of the Information, and, except to the extent expressly permitted by this Non-Disclosure Agreement, shall not divulge Information to any third party without the prior written consent of the Disclosing Party. The foregoing notwithstanding, the Recipient may disclose Information to its Representatives and/or Affiliates to the extent each such Representative or Affiliate has a need to know such Information for the Purpose contemplated by this Non-Disclosure Agreement and agrees to observe and comply with the obligations of the Recipient under this Non-Disclosure Agreement with regard to such Information. The Recipient shall be responsible hereunder for any breach of the terms of this Non-Disclosure Agreement to the extent caused by any of its Representatives and/or Affiliates.

(b) The Parties acknowledge that Information and/or data disclosed under this Non-Disclosure Agreement may include Personal Data (as such term is defined in the DSA). To the extent Personal Data is disclosed under this Non-Disclosure Agreement, the Parties' obligations shall be governed by DSA, which is hereby incorporated by reference and made a part of this Non-Disclosure Agreement.

§3. Exclusions from Application. This Non-Disclosure Agreement shall not apply to Information that:

(i) at the time of disclosure by or on behalf of the Disclosing Party hereunder, is in the public domain, or thereafter enters the public domain without any breach of this Non-Disclosure Agreement by the Recipient or any of its Representatives or Affiliates;

(ii) is rightfully in the possession or knowledge of Recipient, its Representatives or its Affiliates prior to its disclosure by or on behalf of the Disclosing Party;

(iii) is rightfully acquired by Recipient, its Representatives or its Affiliates from a third party who is not under any obligation of confidence with respect to such Information, or

is developed by Recipient, its Representatives or its Affiliates independently of the Information disclosed hereunder by or on behalf of the Disclosing Party (as evidenced by written documentation).

§4. Production of Information. The Recipient agrees that if it, or any of its Representatives or Affiliates, is required by law, by a court or by other governmental or regulatory authorities (including, without limitation, by oral question, interrogatory, request for information or documents, subpoena, civil or criminal investigative demand or other process) to disclose any of the Disclosing Party's Information, the Recipient shall provide the Disclosing Party with prompt notice of any such request or requirement, to the extent permitted to do so by applicable law, so that the Disclosing Party may seek an appropriate protective order or waive compliance with the provisions of this Non-Disclosure Agreement; except in the instance where the Company is the Disclosing Party, in which case, the Company shall be permitted to disclose information to other utilities that are a signatory to this form agreement, or in the case of non-Personal Data, to governmental or regulatory authorities, subject, at the Company's sole discretion, to a request for confidential treatment made to the applicable governmental or regulatory authority's Records Access Officer.

If, failing the entry of a protective order or the receipt of a waiver hereunder, the Recipient (or any Representative or Affiliate of the Recipient) is, in the opinion of its counsel, legally compelled to disclose such Information, the Recipient may disclose, and may permit such Representative to disclose, that portion of the Information which its counsel advises must be disclosed and such disclosure shall not be deemed a breach of any term of this Non-Disclosure Agreement.

In any event, the Recipient shall use (and, to the extent applicable, shall cause its Representatives and Affiliates to) use reasonable efforts to seek confidential treatment for Information so disclosed if requested to do so by Disclosing Party, and shall not oppose any action by, and shall reasonably cooperate with, the Disclosing Party to obtain an appropriate protective order or other reliable assurance that confidential treatment will be accorded the Information.

§5. Scope of Use. Recipient shall, and shall cause its Representatives and Affiliates to, use Information disclosed by or on behalf of the Disclosing Party solely in connection with the Purpose and shall not, and shall cause its Representatives and Affiliates not to, use, directly or indirectly, any Information for any other purpose without the Disclosing Party's prior written consent.

§6. No Representations. No Rights Conferred. Disclosing Party makes no representations or warranties, express or implied, with respect to any Information disclosed hereunder, including, without limitation, any representations or warranties as to the quality, accuracy, completeness or reliability of any such Information; all such representations and warranties are hereby expressly disclaimed. Neither the Disclosing Party nor its Representatives or Affiliates shall have any liability whatsoever with respect to the use of, or reliance upon, the Information by the Recipient, its Representatives or its Affiliates. Neither Recipient, its Representatives nor its Affiliates shall acquire any rights in Information by virtue of its disclosure hereunder. No license to Recipient, its Representatives or its Affiliates under any trademark, patent, or other intellectual property right, is either granted or implied by the disclosure of Information under this Non-Disclosure Agreement.

§7. Return or Destruction of Information. Recipient shall return and deliver, or cause to be returned and delivered, to the Disclosing Party, or destroy or cause to be destroyed (with certification of destruction delivered to Disclosing Party), all tangible Information, including copies and abstracts thereof, within thirty (30) days of a written request by the Disclosing Party (a "Request"). The foregoing notwithstanding, Recipient may retain one copy of such Information for archival purposes only and subject to compliance with the terms of this Non-Disclosure Agreement. Notwithstanding the foregoing, each Party agrees that the Recipient shall not be required to return to the Disclosing Party, or destroy, copies of Disclosing Party's

Information that (A) reside on the Recipient's or its Affiliates' backup, disaster recovery or business continuity systems, or (B) that the Recipient or its Affiliates are obligated by applicable law and/or governmental regulations to retain. The Recipient agrees that, following its receipt of the Request, it shall neither retrieve nor use

§8. No Partnership, Etc. Nothing contained herein shall bind, require, or otherwise commit a Party (or any Affiliate thereof) to proceed with any project, sale, acquisition, or other transaction of or with the other Party or any other entity. No agency, partnership, joint venture, or other joint relationship is created by this Non-Disclosure Agreement. Neither this Non-Disclosure Agreement nor any discussions or disclosures hereunder shall prevent any Party from conducting similar discussions with other parties or performing work, so long as such discussions or work do not result in the disclosure or use of Information in violation of the terms of this No-Disclosure Agreement. The terms of this Non-Disclosure Agreement shall not be construed to limit any Party's right to independently engage in any transaction, or independently develop any information, without use of any other Party's Information.

§9. Term and Termination. Except with respect to any Information that is Personal Data, Recipient's obligations and duties under this Non-Disclosure Agreement shall have a term of two (2) years from the Effective Date (the "Term"). In the case of any Information that is Personal Data, Recipient's obligations and duties under this Non-Disclosure Agreement shall survive indefinitely (the "Special Information Term"). Either Party may terminate this NonDisclosure Agreement by written notice to the other Party. Notwithstanding any such termination, all rights and obligations hereunder shall survive (i) for the Special Information Term for all Personal Data disclosed prior to such termination, and (ii) for the Term for all other Information disclosed prior to such termination.

§10. Injunctive Relief. The Parties acknowledge that a breach of this Non-Disclosure Agreement by Recipient may cause irreparable harm to the Disclosing Party for which money damages would be inadequate and would entitle the Disclosing Party to injunctive relief and to such other remedies as may be provided by law.

§11. Governing Law; Consent to Jurisdiction. This Non-Disclosure Agreement shall be governed and construed in accordance with the laws of the State of New York without regard to the principles of the conflict of laws contained therein. Each Party hereby submits to the personal and subject matter jurisdiction of the courts of the State of New York for the purpose of interpretation and enforcement of this Non-Disclosure Agreement.

§12. Amendments. This Non-Disclosure Agreement may be amended or modified only by an instrument in writing signed by authorized representatives of all Parties.

§13. Assignment. This Non-Disclosure Agreement may not be assigned without the express written consent of all Parties hereto; provided, however, that Company may assign this Non-Disclosure Agreement to an Affiliate without further consent.

§14. Severability. Whenever possible, each provision of this Non-Disclosure Agreement shall be interpreted in such manner as to be effective and valid under applicable law, but if any provision hereof shall be prohibited by, or determined to be invalid under, applicable law, such provision shall be ineffective to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of this Non-Disclosure Agreement. All obligations and rights of the Parties expressed herein shall be in addition to, and not in limitation of, those provided by applicable law.

§15. Entire Agreement. This Non-Disclosure Agreement and the DSA constitute the entire agreement among the Parties with respect to the subject matter hereof, and any and all previous representations or agreements with respect to such subject matter, either oral or written, are hereby annulled and superseded.

§16. Consents and Waivers. Any consent or waiver of compliance with any provision of this Non-Disclosure Agreement shall be effective only if in writing and signed by an authorized representative of the Party purported to be bound thereby, and then such consent or waiver shall be effective only in the specific instance and for the specific purpose for which it is given. No failure or delay by any Party in exercising any right, power or privilege under this Non-Disclosure Agreement shall operate as a waiver thereof, nor shall any single or partial waiver thereof preclude any other exercise of any other right, power or privilege hereunder.

§17 Notices. Where written notice is required by this Non-Disclosure Agreement, such notice shall be deemed to be given when delivered personally, mailed by certified mail, postage prepaid and return receipt requested, or by facsimile or electronic mail, as follows: To Company:
[_____________] Attn: __________________________ _______________ _______________
To [_____________]: [_____________] Attn: __________________________
_______________ _______________

§18 Counterparts. This Non-Disclosure Agreement may be executed in one or more counterparts, each of which will be deemed to be an original copy of this Non-Disclosure Agreement and all of which, when taken together, will be deemed to constitute one and the same agreement. The exchange of copies of this Non-Disclosure Agreement and of signature pages by facsimile or other electronic transmission (including, without limitation, exchange of PDFs by electronic mail) shall constitute effective execution and delivery of this Non-Disclosure Agreement as to the Parties and may be used in lieu of the original Non-Disclosure Agreement for all purposes. Signatures of the Parties transmitted by facsimile or other electronic means shall be deemed to be their original signatures for all purposes. In proving this Non-Disclosure Agreement, it shall not be necessary to produce or account for more than one such counterpart signed by the Party against whom enforcement is sought. [Signatures are on following page.]

IN WITNESS WHEREOF, this Non-Disclosure Agreement has been executed by authorized representatives of the Parties as of the date first above written. [insert utility name]

By:_________________________________ Name: Title: [insert legal name of Supplier]
By:_________________________________ Name: Title.

NARUC suggested cybersecurity questions

(for consideration by utilities and other entrants into the Grid Modernizing marketplace)

Planning

1. Does your company have a cybersecurity policy, strategy, or governing document?
2. Is the cybersecurity policy reviewed or audited? Internally or by an outside party? What qualifications does the company consider relevant to this type of review?
3. Does your cybersecurity plan contain both cyber and physical security components, or does your physical security plan identify critical cyber assets.
4. Does your cybersecurity plan include recognition of critical facilities and/or cyber assets that are dependent upon IT or automated processing?
5. Are interdependent service providers (for example, fuel suppliers, telecommunications providers, meter data processors) included in risk assessments?
6. Does your cybersecurity plan include alternative methods for meeting critical functional responsibilities in the absence of IT or communication technology?
7. Has your organization conducted a cyber-risk or vulnerability assessment of its information systems, control systems, and other networked systems?
8. Has your company conducted a cybersecurity evaluation of key assets in concert with the National Cyber Security Division of the U.S. Department of Homeland Security (DHS)? Has your company had contact with the National Cyber Security Division of DHS or other elements of DHS that may be helpful in this arena?
9. Has your cybersecurity plan been reviewed in the last year and updated as needed?
10. Is your cybersecurity plan tested regularly? Is it tested internally or by or with a third party?
11. What is your process/plan for managing risk? (Example: DOE/NIST/NERC Risk RMP)
12. Has your company undergone a whole-system, comprehensive cybersecurity audit or assessment? When and by whom?

Standards

13. Is the company currently in compliance with NERC CIP-002 through CIP-014?
14. Does the company use the NIST Cybersecurity framework?
15. Does the company leverage resources like the ESC2M2 or DOE Risk Management Process for cybersecurity?
16. What collaborative organizations or efforts has your company interacted with or become involved with to improve its cybersecurity posture (such as NESCO, NESCOR, Fusion centers, Infragard, US-CERT, ICS-CERT, E-ISAC, SANS, HSIN, the Cross-Sector Cyber Security Working Group of the National Sector Partnership, etc.)?
17. Can your company identify any other mandatory cybersecurity standards that apply to its systems? What is your company's plan for certifying its compliance or identifying that it has a timetable for compliance? (Note: PUCs might also need to first establish standards for compliance they find suitable.)

18. Are there beyond-compliance activities? Absent cybersecurity standards specified by state regulatory authorities in regard to the distribution portion of the electrical grid, what are you doing to get in front of this?
19. How do you determine which systems, components and functions get priority in regard to implementation of new cybersecurity measures?
20. Is cybersecurity addressed differently for each major electrical component: distribution, transmission, generation, retail customers?

Reporting

21. How do you report cyberattacks? What is the threshold for notifying law enforcement?
22. Are you currently required to report any cyber incidents to any federal or state agencies?
23. Do you report cyberattacks or breaches to the PUC? What is the threshold for doing so?
24. Have you articulated reporting elements for the kinds of information you disclose in the event of an attack?
25. Do you currently report cyber incidents to the NCCIC?
26. Are you currently required to report any cyber incidents to any federal or state agencies?

Partnerships

27. Do you participate in a briefing process with other decision-makers (such as PUCs in neighboring states or other regions, governors, federal partnerships, etc.)?
28. Would the company be willing to provide a presentation to staff (as a closed, in-camera and non-disclosable setting with no documentation or materials coming into possession of the PUC)?
29. Discuss what the PUC can do to assist your company in the area of cybersecurity.
30. Identify whether the company has identified points of contact for cybersecurity:
    a. Emergency management/law enforcement?
    b. National security? DHS, including protective and cybersecurity advisors?
    c. Fellow utilities, ISO/RTO, NERC CIPC, others?
    d. NESCO, VirtualUSA, Einstein, Fusion centers, Infragard, US-CERT, ICS-CERT, ESISAC?
    e. Interdependent system service providers?

Procurement Practices

31. Has your organization conducted an evaluation of the cybersecurity risks for major systems at each stage of the system deployment lifecycle? What has been done with the results?
32. Are cybersecurity criteria used for vendor and device selection?
33. Have vendors documented and independently verified their cybersecurity controls? Who is the verifier and how are they qualified?
34. Are there third-party providers of services whose cybersecurity controls are beyond the ability of your organization to monitor, understand, or assure? Has your organization explored whether these may create cybersecurity vulnerabilities to your operations?

35. Does your organization perform vulnerability assessment activities as part of the acquisition cycle for products in each of the following areas: cybersecurity, SCADA, smart grid, internet connectivity, and website hosting?
36. Has the company managed cybersecurity in the replacement and upgrade cycle of its networked equipment? Does this include smart meters?
37. What kind of guidance do you follow to ensure that your procurement language is both specific and comprehensive enough to result in acquiring secure components and systems? (Note: Does your company include Cyber Security Procurement Language for Control Systems within its Procurement Language?

Personnel and Policies

38. Does your organization have a company-wide policy regarding best practices for cyber?
39. Does your company provide end-user training to all employees on cybersecurity, either as part of general staff training or specifically on the topic of computer security and company policy?
40. Does your company provide resources to improve end-user awareness of phishing, malware, indicators of compromise, and procedures in the event of a potential breach?
41.Is there a cybersecurity budget? What is the current budget for cybersecurity activities relative to the overall security spending?
42. Are individuals specifically assigned cybersecurity responsibility? Do you have a Chief Security Officer and does that person have explicit cybersecurity responsibilities?
43. Does your company use IT personnel directly, use outsourcing, or use both approaches to address IT issues? For companies that lack a full IT department, explain if one individual in your company is held responsible for IT security. (You may want to ask the same questions in regard to Operations Technology (OT) (i.e., energy operations) security; larger companies may have separate staffs.)
44. What training is provided to personnel that are involved with cybersecurity control, implementation, and policies?
45. What personnel surety/background checking is performed for those with access to key cyber components? Are vendors and other third parties that have access to key cyber systems screened?
46. For the most critical systems, are multiple operators required to implement changes that risk consequential events? Is a Change Management process in place, especially in regard to systems that could present a risk to electrical reliability?
47. Has business process cybersecurity has been included in continuity of operations plans for areas such as customer data, billing, etc.?
48. Describe the company's current practices that are used to protect proprietary information and customer privacy and personal information. Does the company have an information classification and handling policy?
49. Does the company collect personally identifiable information electronically? What type of information (name, address, social security number, etc.) is collected? Is there a policy for the protection of this information? How is your company ensuring that any third parties you deal with are also keeping this information secure?

Using Risk Management for Cybersecurity

50. Is there a person at your organization who assesses vulnerabilities, consequences, and threats?
51. How do you prioritize risks? With all the changes in the grid, how often do you update your priority list?
52. What criteria do you use to prioritize risks? What process do you go through? Which personnel are involved with this?
53. How do you assess vulnerabilities to your system and assets? (e.g. getting alerts from ICS SCERT; regularly applying patching programs; or with vulnerability scanning software)?
54. Do you have an internal or external company performing your vulnerability assessment? (e.g. a third party conducts these assessments)?
55. How do you assess threats to your system and assets? What are your information sources? (e.g., (ICS-CERT; IT/OT vendors; or communication channels such as ISACs)?
56. Do you use contingency-driven consequence analysis?
57. Do you have a process for looking at consequences of cyber incidents that informs your risk management process?

Implementation

58. How do you determine the effectiveness of your strategies?
59. Do you report on this effectiveness of strategies? Who do you report to? How often?
60. What needs to happen for improvement actions to take place? (What are hindrances and what can be done to overcome them?) What decision-making structures can authorize cybersecurity improvements?
61. How do you decide which activities to take action on regarding a detected cybersecurity threat? (such as by looking at case studies or deciding which activities to take action on based on conversations with other utilities about how they handled it)
62. How can you tell if the actions you plan to take will contain the impact of a potential cyber threat?

Response and Recovery

63. Is there a person at your organization who coordinates responding to threats and recovering from them?
64. Do you consider legacy alternatives (analog systems, manual mode, or "conservative operations") to provide redundancy to systems with cyber vulnerabilities?
65. Do you have a consumer communication plan or a way of dealing with customer perceptions and expectations?
66. Do you participate in sharing communication, analysis, and mitigation measures with other companies as part of a mutual network of defense?
67. Are response processes and procedures executable and are they being maintained?
68. Is the information shared consistent with the response plan? Is coordination with stakeholders consistent with the response plan?
69. Do your response plans include lessons learned and mechanisms for continual improvement?

70. Are your recovery strategies regularly updated?
71. Do your recovery plans incorporate lessons learned?
72. Do you have a plan in place for reputation management after an event?
73. Are recovery activities communicated to internal stakeholders and executive and management teams?

Process Questions

74. Are indicators of compromise shared with employee end-users and leadership?
75. Does your company communicate to employees the process for reporting and containing compromise?
76. Do you have a baseline configuration of IT/ICS that is used and regularly maintained?
77. Do you have a System Development Life Cycle plan that is implemented to manage systems?
78. Do you keep key information backed up, maintained, and tested periodically? Does your organization have a policy for storing hard copies of relevant essential documents for continuity of operations purposes?
79. Do you have policies and regulations in place regarding the physical and operating environment for organizational assets?
80. Does your organization destroy data according to policies in place?
81. Are protection processes being continuously improved?
82. Is maintenance and repair of organizational assets performed and logged in a timely manner, with approved and controlled tools?
83. Is remote maintenance of organizational assets approved, logged, and performed in a manner that prevents unauthorized access?
84. Are audit/log records determined, documented, implemented, and reviewed in accordance with your organization's policies?
85. Is removable media protected and its use restricted according to your organization's policies? 86. Is access to systems and assets controlled, incorporating the principle of least functionality?
87. Are communications and control networks jointly or separately protected?

Governance Questions

88. Are cybersecurity responsibilities assigned? Is this done separately from information technology responsibilities?
89. Is there a method of coordinating these responsibilities?
90. Is an organizational information security policy established?
91. Are information security roles and responsibilities coordinated and aligned with internal roles and external partners?
92. Does senior leadership have access to cybersecurity risk information?
93. Are legal and regulatory requirements regarding cybersecurity, including privacy and civil liberties obligations, understood and managed?
94. Do governance and risk management processes address cybersecurity risks?
95. Do you have an enterprise-wide risk management program that includes cybersecurity?

96. Have you had outside experts look at your cybersecurity plans? (such as law enforcement or a federal agency)
97. How do you monitor your cybersecurity posture on business IT systems and ICS systems and communicate status and needs to leadership

Systems and Operations

98. Is cybersecurity integrated between business systems and control systems? For the existing grid and for the smart grid?
99. Have logical and physical connections to key systems been evaluated and addressed?
100. Does the company maintain standards and expectations for downtime during the upgrade and replacement cycle?
101. Does the company have equipment dependent on remote upgrades to firmware or software, or have plans to implement such systems? Does the company have a plan in place to maintain system cybersecurity during statistically probable upgrade failures? Is there a schedule for required password updates from default vendor or manufacturer passwords?
102. Has cybersecurity been identified in the physical security plans for the assets, reflecting planning for a blended cyber/physical attack?
103. What network protocols (IP, proprietary, etc.) are used in remote communications? Is the potential vulnerability of each protocol considered in deployment?
104. Does the company have a log monitoring capability with analytics and alerting—also known as "continuous monitoring"?
105. Are records kept of cybersecurity access to key systems?
106. Are systems audited to detect cybersecurity intrusions?
107. Are records kept of successful cybersecurity intrusions?
108. What reporting occurs in the event of an attempted cybersecurity breach, successful or not? To whom is this report provided (internal and external)? What reporting is required and what is courtesy reporting?