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Debra A. Howland
Executive Director
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, NH 03301-2429

RE: Docket No. IR 15-296, Electric Distribution Utilities
Investigation into Grid Modernization

Joint Utility Comments

Dear Director Howland:

On February 12, 2019, the Staff of the Commission submitted its "Staff Recommendation on Grid Modernization" ("Staff Report") in the above-captioned proceeding. Following that report, and some additional processes, the Commission issued Order No. 26,254 on May 29, 2019 which, among other things, required that Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities, Public Service Company of New Hampshire d/b/a Eversource Energy, and Unitil Energy Systems, Inc. (collectively the "Utilities") would file proposals on a variety of topics enumerated in the Order. In response to the Commission's expectations in Order No. 26,254, the Utilities herein provide their comments and proposals the items enumerated in the Order.

If you have any questions, please do not hesitate to contact me. Thank you for your assistance with this matter.

Very truly yours,

Matthew J. Fossum
Senior Regulatory Counsel

Enclosures
CC: Service List

THE STATE OF NEW HAMPSHIRE
before the
PUBLIC UTILITIES COMMISSION

ELECTRIC DISTRIBUTION UTILITIES

Investigation into Grid Modernization

Docket No. IR 15-296

JOINT COMMENTS OF LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP. D/B/A LIBERTY UTILITIES, PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY, AND UNITIL ENERGY SYSTEMS, INC.
RE: ORDER NO. 26,254

I. Introduction

On February 12, 2019, the Staff of the New Hampshire Public Utilities Commission ("Commission") submitted its "Staff Recommendation on Grid Modernization" ("Staff Report") in Docket No. IR 15-296. The Staff Report set out the extensive review by the Staff of issues relating to grid modernization following on earlier work that had been undertaken by a large stakeholder group, and which had resulted in a report from the Staff's consultant, Raab Associates, Ltd., on March 20, 2017. The Staff Report set out numerous recommendations for changes to developing, planning, understanding, and communicating about activities aimed at modernizing the electric delivery grid in New Hampshire to make it more resilient, dynamic, and useful for utilities and customers alike. In response to this report various parties submitted comments in April 2019 and a technical session relating to those comments was held in May 2019.

Following on the Staff Report and the comments, on May 29, 2019, the Commission issued Order No. 26,254 to establish "the next steps in a stakeholder process for developing the framework for electric distribution utility integrated distribution system plans." Order No. 26,254 at 1. As part of that Order, the Commission noted that the Staff's report of the May 2019 technical session outlined 11 issues that the stakeholders agreed would merit proposals from the group, specifically:

1. Cost Effectiveness Methodology
2. Utility Cost Recovery
3. Utility and Customer Data and Third-Party Access
4. Hosting Capacity/Locational Value Analysis/Interconnection
5. Annual Reporting Requirements
6. Rate Design Policy

7. Strategic Electrification Policy
8. Consolidated Billing/General Billing
9. Consumer Advisory Council/Stakeholder Engagement
10. Capital Budgeting Process
11. LCIRP/IDP Integration

Order No. 26,254 at 4. Relative to these 11 issues, it was agreed that Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities, Public Service Company of New Hampshire d/b/a Eversource Energy, and Unitil Energy Systems, Inc. (collectively the "Utilities") "would file a joint proposal on the first five topics, that non-utility stakeholders would file separate proposals on the first five topics, and that all stakeholders might file proposals on any of the remaining six topics." Order No. 26,254 at 4. In response to the Commission's expectations in Order No. 26, 254, the Utilities herein provide their comments on each of the items enumerated in the order.

II. Utility Proposals

1. Cost Effectiveness Methodology

A well-designed cost effectiveness framework is the cornerstone of a successful Integrated Distribution Plan ("IDP") process that will ensure investments made in grid modernization will provide substantial benefits to customers. At the same time, the framework needs to facilitate building a distribution system that ensures safe and reliable service while taking advantage of the opportunities associated with clean and distributed energy technologies.

In developing a proposed cost effectiveness framework, the Utilities adhered to the principle that New Hampshire electric distribution customers will be well-served by a methodology that leverages best practices demonstrated in other states while ensuring a fit with the specific policy objectives and demographic characteristics of our state. For example, the framework builds upon the work by the US Department of Energy (DOE) through its DSPx framework, and various states, including New York, Hawaii and California in developing cost effectiveness methodologies used to evaluate grid modernization investments.

Another principle supported by the Utilities is the consistent application of the New Hampshire grid modernization cost effectiveness framework by each utility in their IDP development process. The Utilities recognize the importance of establishing a well-defined state-wide framework in advance of filing each company's IDP.

In support of an efficient process to finalize the framework and its guidelines, the Utilities have drafted the following comprehensive proposal that is largely consistent with the recommendations set forth in the Staff Report, including recognition of the Hawaii framework as the current standard for best practice cost effectiveness methodology. The Utilities welcome the opportunity to provide additional details and case studies on the use of the methodology at upcoming technical sessions.

A. Application of Cost Effectiveness Framework

A foundational premise of cost effectiveness frameworks is that individual investments should be evaluated using a standard that is consistent with the principle objective of the investment. This approach is consistent with the concept of "traceability" outlined in the Staff Report which recognizes the importance of clearly outlining how grid modernization functions and capabilities trace back to their intended objectives which are driven by user needs and public policies.

Utility investments made to run the business and provide safe and reliable electric delivery service can be characterized as "business as usual" investments. This category of investments includes items such as metering, facilities, like-for-like replacement of aging infrastructure, capital repairs and traditional reliability and load growth driven projects. As outlined in the proposed IDP content outline included on Pages 21-22 of these comments, these types of business as usual investments would be described in the IDP document. New Hampshire customers will continue to be well-served by maintaining the current "just and reasonable" review standard for inclusion of business as usual investments in rate base as a part of each company's general rate review proceeding.

The proposed cost effectiveness framework discussed herein is applicable to investments made in whole or in part to support New Hampshire's grid modernization objectives. These objectives expand the role of the utility to include investments made to develop people, process and technology capabilities required to support policy goals over and above the current standard of safe and reliable electric delivery service.

Some investments subject to review under this framework will be undertaken primarily to achieve a grid modernization objective such as integration of Distributed Energy Resources ("DER"). Some investments will provide multiple benefits related to the traditional safe and reliable service mandate as well as support one or more grid modernization objectives.

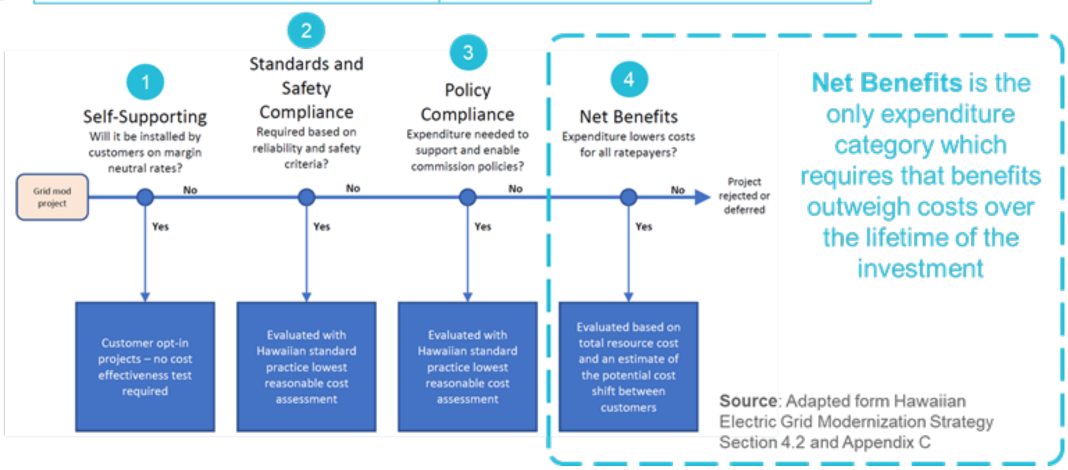
Many platform investments will need to be considered in a portfolio context recognizing that enabling investments are required to support multiple grid modernization benefit streams. The challenges associated with evaluating the cost effectiveness of grid modernization investments that provide multiple benefits to customers was recognized by the California Public Utility Commission in its 2018 order, "Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769." The California Commission's order (page 24) finds that it is infeasible to isolate the benefit of an investment solely towards the objective of enabling DER growth given the multiple interrelated functions of grid modernization investments.

B. Description of Cost Effectiveness Framework

In 2017, the DOE released its three-volume DSPx Modern Distribution Grid report. The report includes a grid modernization cost effectiveness framework that classifies expenditures into four categories based on the primary purpose of the expenditure. The framework identifies a cost effectiveness methodology for each of the four categories. Building upon the DOE framework, the Hawaiian Electric Companies refined the DSPx methodology in the cost effectiveness framework proposed in their report, "Modernizing Hawai'i's Grid for Our Customers" released in 2017. The Utilities support application of the Hawaii framework for all New Hampshire grid modernization investments included in each company's IDP as depicted in Figure 1 below.

Figure 1

	Expenditure Categories	Cost Methodology
1	Self-Supporting	Incremental cost borne by customer
2	Standards and Safety Compliance	Lowest Reasonable Cost (Least Cost, Best Fit)
3	Policy Compliance	
4	Net Benefits	Total Resource Cost Test



For all grid modernization investments, the first test is whether the expenditure is "self-supporting" - meaning that incremental costs are borne by the specific customer that benefits from the investment such that there is no impact to other ratepayers. For investments in this category no cost-effectiveness test is required.

For investments that will have a rate impact to customers, the second test is whether the expenditure is required for "standards and safety compliance" - meaning that the investment will support established criteria for providing safe and reliable service to customers. These investments would be evaluated based on the "lowest reasonable cost" or "least cost, best fit" cost effectiveness test. This test requires utilities to assess "fit" against "need" based on the utility's specific grid architecture and identify the lowest cost option, typically utilizing competitive procurement.

The third test is whether the expenditure is required to support and enable State and Commission policies and regulations. This category is especially important with respect to grid modernization investments that are focused on lowering the cost and maximizing the benefit associated with DER integration. In many cases, these types of investments are tied to the increasing importance of utility efforts to move beyond its traditional role to provide incremental value to customers. Investments in the "policy compliance" category will be evaluated based on a lowest reasonable cost standard. The approach is consistent with the current standards for such investments. Ideally, system and infrastructure investment costs to enable the benefits and value associated with DER integration would be considered when evaluating the benefits associated with DER policies and programs. For example, with increasing DER adoption there will be a need for hosting capacity analysis in areas with a high penetration of DER and the utilities may need to invest in a distributed energy resource management system (DERMS) to keep track of customer DER, help model DER on the distribution grid, and potentially dispatch DER if customers participate in specific DER programs.

There are grid modernization investments that will not fall in any of these three categories that nevertheless can be demonstrated to provide net benefit to customers. These investments fall in the "net benefit" category - meaning that utilities must demonstrate a net benefit over the lifetime of the investment, i.e., total benefits exceed total costs.

A great deal of work has taken place in states like Hawaii and New York to develop guidelines for net benefits analysis. There are various methods to calculate net benefits that generally vary in how certain factors are addressed such as societal benefits and participant costs. Hawaii, for example, has endorsed use of the Total Resource Cost Test which includes benefits tied to generation, transmission and distribution systems, operational benefits, customer benefits and avoided emissions and costs tied to the program investment and ongoing administration. This methodology omits quantification of societal benefits that are difficult to quantify. New York has established use of the Societal Cost Test as well as the Utility Cost Test and the Ratepayer Impact Measure. These tests incorporate important costs and benefits not included within the Total Resource Cost test, and provide additional information used to evaluate investments.

The Staff Report remains open to multiple methodologies including Total Resource Cost Test and/or another cost/benefit test such as the Utility Cost Test or Participant Cost Test. The Utilities agree that at this early stage in application of the grid modernization cost effectiveness framework it is premature to establish a one-size fits all net benefits test. The Utilities also recognize that there is an ongoing "Value of DER" proceeding that has the potential to add insight into the calculation of grid modernization benefits.

The Utilities recommend a two-phase approach to application of the net benefit test. In the first phase, prior to submission of each utility's first IDP, the Utilities would develop a common assumptions proposal. The common assumptions proposal would address benefits that could reasonably be calculated using similar values. These benefit categories include bulk system impact, avoided emissions values and customer benefits. The common assumptions proposal would also address inclusion of qualitative benefits and calculation methodological assumptions such as discount rate and term of net present value analysis. The common assumptions proposal would be made available prior to a technical session on common assumptions.

In each utility's first IDP, net benefits tests would be applied using established common assumptions as well as utility-specific costs and benefits. Utility-specific benefits would include transmission and distribution system benefits and operational benefits. Utility-specific costs would include initial and ongoing program costs. The Utilities propose to use as a net benefit tests the Total Resource Cost and the Utilities Cost Test given that both tests have been used and approved in New Hampshire and it is unclear at this time whether a single test is uniformly correct for all investments and portfolio of investments. At a minimum, both tests will help inform applicable investment decisions.

In the second phase, prior to submission of any subsequent IDP, a working group would be established to review use of net benefits tests in New Hampshire and evaluate the need for more specific guidance with respect to the use of net benefits tests.

The Utilities welcome the opportunity to provide more details and case studies on the use and application of the proposed cost effectiveness framework at upcoming technical sessions.

2. Utility Cost Recovery

Staff's report makes the following recommendation with respect to cost recovery:

> 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.

Staff Report at 64. In concurrence with Staff's recommendation, the Utilities also propose a targeted cost recovery mechanism, colloquially referred to as a "tracker". A tracker is appropriate for grid modernization for a number of reasons, including: a statewide desire to accelerate the investment of incremental grid technology over and above "business as usual" investments; the avoidance of frequent rate cases to support advancing such acceleration; the desire for near-term cost reconciliation to avoid the over- or under-recovery balances that can occur with new and uncertain technology investments; and because the types of technology investments that might be made to support grid modernization are uncertain, projects could be added or canceled and a tracker would match the inclusion or exclusion of those projects.

The Utilities do not agree that volumetric charges should be the only mechanism for recovery of grid modernization investments. Ensuring the equitable recovery of costs from all customers should also be a priority. The Utilities recommend costs be recovered through non-bypassable charges and that other types of charges be considered if equitable cost recovery could be challenging through volumetric charges.

More specifically, the Utilities propose the following features of a tracking mechanism:

- Utilities would be permitted to request targeted recovery of IDP development, support, and investments through cost recovery tracking mechanisms outside of base rates
- The mechanism would occur with an annual planning, forecasting, rate setting, and reconciliation cycle
- The mechanism will include return on and of the investments and related O&M, property taxes, and other related costs. To the extent a grid modernization investment creates a "stranded cost", the mechanism will allow for recovery of such costs, consistent with Staff's recommendation.
- Return on the investment would be based upon the Utilities' most recently approved cost of capital, as established in each of their most recently approved rate cases.
- Proceeding with proposed initiatives will require preauthorization by the Commission, either in the context of the IDP docket but potentially in standalone dockets.
- Proposed grid modernization investments that are preauthorized are presumed to be prudent, in terms of the decision to proceed with them. The investments would be subject to reconciliation based on actual costs and appropriate supporting documentation, but the decisions to proceed would not be revisited in a reconciliation docket.
- The mechanism will allow for recovery of incremental payroll and payroll-related costs associated with full-time equivalents ("FTE") hired in support of the grid modernization programs.
    - All employees hired to support programs such as grid modernization are considered incremental, as the Utilities would not be filling these positions but for the requirement to do so in support of these programs and these costs are not otherwise included in base rates.
- With regard to Staff's recommendation that the recovery mechanism would remain in place for no more than five years, the Utilities acknowledge and agree that a separate cost recovery mechanism will not be necessary or appropriate to maintain indefinitely; that we may reach a point where the activities currently considered "grid modernization" are the new normal, and therefore no longer require special ratemaking treatment. However, it is not possible to know at this point when in the future that will happen, and whether five years is too long or too short of a timeframe. Moreover, even if the Commission were to limit the time period whereby investments could be authorized for recovery under the grid modernization mechanism, the mechanism itself would need to remain in place until such time as those costs are reflected in base rates. As a result, to the extent the establishment of new base rates for a company does not align with the five year termination recommended by Staff, the mechanism would need to remain in place until the ongoing costs of previously authorized grid modernization investments are reflected in base rates.

3. Utility and Consumer Data and Third-Party Access

The various reports and comments submitted in Docket No. IR 15-296 reference certain principles surrounding utility and customer data, including facilitating third-party access to that data. They also note that additional work is necessary to make relevant determinations about whether or how certain data should be made available to third parties. While this additional work could continue within the framework established within the existing proceeding, recent legislative action has rendered that work unnecessary in this context.

In 2019, the Legislature enacted SB 284, which requires the Commission to open an adjudicative proceeding to review issues around access to utility and customer data, with the potential for requiring a consolidated statewide platform for such data in the future. In that the Commission will commence that proceeding in the near-term, extensive comments on this issue are not justified in this context.

Regardless, the Utilities still believe it worthwhile to highlight some relevant general positions and concerns to bear in mind to the degree the issue remains a topic of discussion in this docket. In the Utilities' judgment, it is paramount to remember that customers have the right and ability to use their own data as they see fit or to share it at any time with any third-party provider they desire. This allows individual customers to make their own choices about what data they wish to have shared, and with what parties, for whatever purposes those customers believe are significant. And, importantly, individual customers may desire to share nothing at all. In light of that, having a single statewide repository for such information that resides outside the direct control of either the individual customer or the relevant utility seems unnecessary, and will certainly present challenges. In the assessment of the Utilities, having utilities retain the obligation to collect, store, and manage customer data in a controlled and protected manner on an individual utility basis would be the better course.

Of further note, New Hampshire's utilities are already making progress in having customer data more readily available, such as through the Green Button Connect My Data tool, while maintaining the protections and safeguards necessary for such data. Additionally, to the extent that aggregated data is to be used or shared, the Utilities note that aggregation is presently a largely manual process, but that it could be automated and streamlined where it is found to be appropriate and where issues of cost, and protection of individual customer data, can be addressed. These issues can be explored in greater depth in the coming proceeding following SB 284.

New Hampshire's utilities have been, and will continue to be, responsible stewards of customers' information, and, at the same time, are committed to working with customers to assure that they have the freedom to make their own choices with their energy data to pursue the goals important to them.

4. Hosting Capacity, Locational Value, Interconnections

Hosting capacity analysis ("HCA") has three key objectives. The first is as a development guide to identify the areas with potentially lower interconnection costs. The second is to augment other forms of technical screens to provide relative indication of the need for more detailed interconnection study analysis. The third is to enable greater DER penetration by identifying potential future constraints. (ICF Report at 10)[1].

These use cases have the potential to deliver significant benefits to customers and DER developers in New Hampshire. Indeed, with relatively low levels of existing DER penetration, New Hampshire is in a favorable position to use HCA tools to encourage development in a way that minimizes cost and delivers maximum value.

As stated in the ICF Report, "there is widely recognized value in implementing hosting capacity analyses before DER penetration begins stressing any electric distribution or transmission systems. This enables utilities to start updating data and circuit models to support hosting capacity analysis and allows them to avoid unexpected issues as DER penetrations continue to increase." (ICF Report at 8).

One of the challenges most commonly cited in developing actionable hosting capacity maps is the availability of timely and granular system data. System hosting capacity calculations are based largely on load-to-generation ratios, typically in periods of light load. To provide actionable information at a specific geographic area, having data at the circuit or even circuit segment level is preferred.

As described in the ICF Report, utilities implementing HCA are doing so in a "deliberately phased approach." They are implementing roadmaps aimed at achieving desired outcomes by placing interim goals that incrementally expand capabilities over time. The Utilities agree with the expectation for a similar phased approach in New Hampshire characterized by increasing functionality and accuracy coincident with increasing data availability and modeling tools.

Consistent with the concept of a phased approach to building hosting capacity map capabilities, as the Utilities increase functionality with respect to data collection, management, and modeling, greater hosting capacity functionality will be possible.

One of the fundamental components of grid modernization is increasing capabilities associated with visibility and control of the distribution system, including enabling communications systems. The Utilities expect that building these capabilities will be a core component of each company's grid modernization strategy. Similarly, tools related to data management, modeling and forecasting will support multiple modernization functionalities, including HCA.

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[1] *Integrated Distribution Planning, Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*, July 2018 https://gridarchitecture.pnnl.gov/media/ICF_DOE_Utility_IDP_FINAL_July_2018.pdf

In parallel with building the data management and analytical capabilities to support actionable and accurate hosting capacity calculations, additional work will be necessary to create publicly available maps or other geographically-based hosting capacity information. As with the underlying analyses, hosting capacity maps should also be implemented in a phased approach. Initially, as utilities are developing data collection and analytical tools, maps could provide information useful to customers or developers such as installed and in-queue DER by feeder and basic substation and feeder characteristics. In subsequent phases, hosting capacity values should be available by circuit and ultimately circuit segment. In a future iteration, additional information could potentially be provided on distribution transformers in support of residential DER applications.

For both hosting capacity calculations and publicly-available hosting capacity maps, it is important to support consistency and standardization among the utility approaches. Given that the maps are customer and developer-facing tools, it is also important to provide ample opportunity for stakeholder feedback and suggestions.

In support of standardization and collaboration, the Utilities propose establishing a standing technical committee on DER integration. This committee would be comprised of utility representatives as well as stakeholders from environmental, customer and developer groups and would meet on a regular basis to review and discuss the Utilities proposals related to HCA and calculation methodology, hosting capacity map design, as well as other technical issues related to DER interconnection. The intent of this standing forum would be to encourage the development of consistent best practices and standardization, where applicable and possible. Given that the technical committee would be a standing forum, it would provide a forum for other stakeholders to provide feedback to the utilities as they continue to make progress on their phased implementation of hosting capacity capabilities.

Locational value analysis is another future capability that will inform DER siting decisions. Whereas hosting capacity analysis identifies areas of the distribution system where there are fewer constraints limiting DER interconnection, locational value analysis is a significantly more advanced analysis and takes into consideration short and long-term system needs and identifies locations where DER could potentially alleviate a given need.

The first phase of locational value analysis is collection of system data specifically relative to capacity and reliability. Many of these data are currently included in the Least Cost Integrated Resource Plan ("LCIRP") and will ultimately be included in the IDP. Continuing to build capabilities with respect to system visibility will enhance the granularity of data available in the IDP. Future phases of HCA will also be dependent on advanced tools for data management, modeling and forecasting that will be included in each utility's modernization strategy. Any locational value analysis should also be informed by the ongoing Value of DER study required by the Commission's net metering Order.

In advance of moving forward with any publicly available locational value analysis data, it is essential to understand the policy mechanisms that will determine how any identified value is captured and shared. In support of such policy development, demonstration projects may represent attractive options to gain greater insight into overcoming technical challenges as well as the value proposition for customers.

With respect to the topic of interconnection, the Utilities recommend that the standing technical committee on DER integration would be the proper forum to address these types of issues. The Utilities continue to work to ensure safe and reliable interconnection standards and support an interconnection process that meets or exceeds customer expectations. Each utility has an approved interconnection tariff that governs many of the policies and procedures related to interconnection.

To the extent that, over time, issues may arise related to the technical merits of an interconnection policy or a need to ensure consistency in technical and procedural approaches among the utilities, the standing committee made up of utilities and interested stakeholders proposed above would be the most efficient and effective forum to work towards mutually agreeable resolution. Adding interconnection-related topics to the grid modernization proceeding will broaden the scope significantly and will not address issues that come up over time as the penetration of DER increases in New Hampshire.

5. Annual Reporting Requirements

The Utilities see value in having an annual report to discuss the progress of the investment roadmap presented in their IDP. Examples of general topic areas for annual reports might include the following:

- Executive summary
- Implementation results
- Units deployed relative to plan
- Spending, including actual installations and expenditure versus plan
- Lessons learned and changes to plans

However, the Utilities recommend that annual reporting requirements, including investment-specific performance metrics, be proposed as part of the individual utilities' IDP, versus established at this time. It is challenging to determine reporting requirements in the abstract, whereas having a concrete IDP would inform what types of requirements would be appropriate for periodic reporting. It is also likely that the overall suite of appropriate reporting requirements may differ among utilities; hence, achieving consensus on the full set of reporting requirements across utilities may not be feasible or even desirable.

Meanwhile, the Utilities recommend a Working Group process to establish a small set of statewide performance metrics that may be common across utilities for inclusion in the utility-specific IDPs. Examples of such metrics could include: DER interconnections by circuit; system automation saturation by circuit (no. customers / no. of automated devices); and penetration of sensors by circuit. The Utilities would welcome a collaborative dialogue with other stakeholders on this topic prior to the presentation of their initial IDPs.

6. Rate Design Policy

The Staff Report recommended that each utility's IDP contain a proposal for rate design and that such proposal address a variety of issues including: demand charges, 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. Staff Report at 74. Additionally, the Staff recommended that any proposed rate design be supported by a cost of service study. *Id*. Though the Utilities do not necessarily disagree with the various issues that should be addressed through appropriate changes to existing rate design, the Utilities do disagree that such changes should be implemented through a utility's IDP.

Although it may be viewed as comprehensive, neither the LCIRP as it exists, nor the IDP as it is proposed, are the most appropriate forum for redesign of utility rates. Such changes should be undertaken in the context of a utility rate case. In that setting, the costs of the utility, and the most fair and appropriate means to recover those costs (as supported by a cost of service study), are in issue and are subject to the input of parties and a determination by the Commission. As described by the Staff, the IDP will describe "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." Staff Report at 66. Thus, it is not envisioned as a comprehensive review of costs, nor of the types of rate designs that might recover those costs in a fair and equitable manner. That view is bolstered by the Staff's description of the manner of cost recovery for items contained within the IDP. Staff Report at 76.

While the Staff's proposed IDP has not yet been approved or implemented, and the proposed IDP will most likely change through future Commission action, the underlying premise would remain. Specifically, that the IDP or similar program is not the comprehensive and thorough review of costs and cost recovery that would justify meaningful revision to rate design during its review. Rate design changes may be informed by the IDP, but amendments to rate design and the implementation of new rate designs should remain as issues in individual utility rate cases.

7. Strategic Electrification Policy

In the Staff Report, the Staff recommends that:

> [i]n 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 increase in electric demand that would result from an electrification strategy.

Staff Report at 73. The Utilities agree with this recommendation. The proposed plan for strategic electrification should take into account the fact that transportation and heating account for the largest shares of greenhouse gas emissions in the state (representing 42% and 29% respectively) and in excess of power generation (20%).[2] Accordingly, the IDP should present strategies for utilities to cost-effectively support the electrification of the transportation and heating sectors.

These strategies should address four main components.

First, distribution grid level investments to support the electrification of the transportation and heating sectors. For example, utilities should propose cost-effective investments to prepare the distribution grid for electric vehicles, which are projected to become a mainstream alternative to internal combustion engine vehicles over the next few years. This may include utility investments to build infrastructure to support public electric vehicle chargers such as the standard "Level 2" chargers and the faster "DCFC" options. In making such proposals, utilities should weigh the benefit of increased electric sales causally linked to each electrified vehicle causally enabled by the charger in question against the carrying cost impacts in rates to all customers of the infrastructure investments. A utility's proposal may also include grid level investments to support infrastructure needed to promote clustered charging areas, including multiple homes or businesses in close proximity with electric vehicle chargers. The same concept may also apply with respect to electric heating infrastructure, albeit, at this time, the impact is not projected to be as intense given that air source heat pumps are hyper-efficient and larger commercial-level electric heating options remain in their nascency.

Second, rate structures to support the electrification of transportation and heating. As with all rate design issues, this exercise must take into account the costs and benefits of serving individual electric vehicle and electric heating customers – including marginal cost to serve, impact on peaks, benefits to other customers of increased sales, etc. In doing so, utilities should take into account the cost of any individual metering needed to effectuate the rate in question. Alternative means of addressing electric vehicle and heating loads should also be evaluated – for example, bring your own device programs that pay customers an incentive in exchange for the utility being able to aggregate customer-owned devices and adjust them a few times per month to reduce yearly and monthly energy peaks. This evaluation should also consider the proper regulatory mechanism for such approaches (i.e., rate design versus efficiency offerings, etc.).

Third, load and peak forecasting and management approaches should also be part of the utility proposals. Electric vehicles and heating on their face have the opportunity to grow electric loads. If forecasted and managed properly, this can result in savings to all customers as a result of there being more kilowatt hours over which to spread fixed costs. If not forecasted or

[2] https://www.des.nh.gov/organization/divisions/air/tsb/tps/climate/ghg-emissions.htm. Reflecting the most recent data (2015 vintage).

managed properly, however, these sales could inadvertently increase costs and jeopardize safe and reliable service by overloading the distribution grid.

Fourth, proposals should take into account any energy optimization framework that is developed for future plans under the EERS program. A study to review energy optimization approaches, including electrification measures for efficiency programs, is currently under development and discussion in the Docket No. DE 17-137 Benefit Cost Working Group.

8. Consolidated Billing

In the Staff Report, the Staff recommended (page 62) undertaking cost/benefit analyses of third-party suppliers providing consolidated billing to "promote greater competitive alternatives for customers." The Utilities do not agree that third party consolidated billing should be implemented in New Hampshire. Third party consolidated billing allows competitive retail electric suppliers ("suppliers") to invoice and collect from customers monthly charges on the utility bill that reimburse utilities for, among other things, the costs the utility incurs to pay its line workers, trim trees, and maintain poles, wires, transformers and other equipment. The Utilities oppose this radical and unprecedented change in the current billing process for the following reasons.

The act of allowing suppliers to undertake consolidated billing will not necessarily promote greater competitive alternatives for customers.

- Opportunities to promote alternative supplier options already exist and are abundant. Suppliers routinely conduct direct marketing to potential customers via phone, email, in-store and door-to-door sales and through other methods. Information on shopping for competitive electric supply is also available on the Commission's website. Utilities also provide customers with unbiased, comprehensive information on energy usage and shopping for competitive energy supply on their websites and through bill inserts and bill messages.
- Significant percentages of customers receive their bill electronically and/or pay their bill online; the online customer experience has the highest volume of transactions and is the most effective and appropriate place to provide supplier information comparative analysis.
- So far as the Utilities are aware, most customers with suppliers pay rates that are higher than the utility's default service rate. Unfortunately, once a customer switches to a competitive supplier, there is no obligation, and, in fact, there is a disincentive, for suppliers to provide meaningful insight into alternative pricing that would be lower than what they offer. Promoting supplier savings is more difficult than providing actionable ways to reduce energy usage. Regulators and advocates in other states are investigating why the majority of customers (particularly residential customers) are paying more with a supplier than the utility standard offer rate. *See* Connecticut PURA Docket 18-06-02 and Massachusetts DPU Docket 19-AMP.

It is costly, unnecessary, inefficient and duplicative to create entirely new billing systems/processes.

- Utilities already operate and maintain sophisticated billing systems that issue bills to customers of suppliers, and timely remit the appropriate share of those funds to suppliers. Additionally, utilities already have experienced customer service professionals available to answer customer questions about bills, and other professionals that handle collection services. It would be duplicative and wasteful to now authorize potentially 18 suppliers (or more if they enter the New Hampshire market) to develop billing, customer service and collections processes that will duplicate the utilities' existing processes. Such duplication is expensive and inefficient, and retail suppliers will pass the additional costs onto consumers.
- The Utilities' current billing systems (and necessary upgrades) are investments previously paid for by ratepayers. A parallel system(s) would be very expensive to create and implement, and customers would bear the burden of those costs.

It is confusing and inefficient and burdensome for customers to receive potentially separate bills and for the Commission to manage potential complaints/issues.

- According to the Commission's website, there are currently 18 suppliers serving residential customers in New Hampshire. Customers using a supplier could receive different bills with varying information on the bill, leading to customer confusion and a potential influx in complaints regarding multiple, individual bills that would need to be managed by the Commission.
- The Commission would also need to manage multiple suppliers' compliance with regulatory requirements, including the disconnect timeline, and closely coordinate with the utility to perform disconnects on eligible accounts.
- Separate billing systems would negatively impact New Hampshire's limited income customers as the status of a customer's financial hardship protection would need to be provided to a supplier to protect the customer's account. In other states, limited income customers are being taken advantage of by suppliers who market higher rates to these customers. Further, suppliers would be required to develop and implement complex, tiered rate calculations for the low-income discount rate and other assistance programs to ensure accurate billing. They would also be required to place energy assistance vouchers and payments on customer's accounts timely and ensure that the customer receives credit for those benefits.

Multiple billers provide a ripe climate for scamming and spoofing.

- There have been many incidents of scammers impersonating utility employees in person and on the phone to procure "payment" from customers. To mitigate these fraudulent tactics, utilities regularly refer customers to their utility bill as the trusted source for charges and fees related to utility service. Allowing multiple suppliers to issue bills alongside, or in lieu of, the utility bill will create a ripe climate for scammers to send imposter bills to customers, increasing customer confusion and reducing consumer protections.

The customer experience will degrade under a multiple biller scenario.

- Supplier bills are currently not regulated. A multiple biller scenario will create a “hodge-podge” of different billing approaches in which some suppliers will elect to bill customers for all charges, whereas other suppliers will continue to have the utility submit monthly invoices for all charges. This confusion will be exacerbated when customers switch retail suppliers because, for example, a customer’s current supplier might direct-bill for all charges, but the customer’s new supplier could elect to have the utility issue invoices for all charges.
- Additional customer confusion will occur regarding who customers should call when they have questions about the non-generation-related components of their bill. Suppliers are unequipped to process calls about the half of the bill that does not relate to the generation charges. This will increase the duration of calls and create repeated customer calls for follow-up information, which will decrease customer satisfaction and increased hand-offs. In addition, suppliers are not required to provide quality customer service, unlike the utility. Customers have routinely expressed frustration over poor supplier customer service and separate supplier bills will further exacerbate the issue.
- For cancel/rebill/adjustments, the multiple layers and players will make the bill paying process more confusing and less timely for customers. It will also increase the cost of bill printing, stuffing, mailing and postage.
- Multiple suppliers have been penalized for deceptive practices and slamming, including false charges levied on customers. It will be difficult for the Commission and consumer advocates to manage and monitor compliance on multiple bills.

Suppliers have a history of default and overall financial volatility.

- When retail suppliers go bankrupt or have severe financial difficulties, they will be holding customer funds that belong to the utility. Those customer funds will be lost, or at best – after a long and expensive bankruptcy proceeding – only pennies on the dollar will be recouped. Bankruptcies and severe financial problems among retail suppliers are not hypotheticals.

    - In 2013, PNE Energy defaulted on its financial obligations to ISO New England and abruptly sold off its customer base in a case that led to multiple Commission dockets and court proceedings.
    - In 2014, People’s Power & Gas, LLC, went bankrupt and Dominion Resources Inc. abruptly announced its decision to sell its entire unregulated retail supply business because, among other things, it was estimated that its retail supply business lost approximately $100 million due to the 2013-14 polar vortex.

- January 2018: AmericaWide Energy LLC, defaulted on its financial obligations to ISO New England.
- February 2019: Great Eastern Energy, LLC, defaulted on its financial obligations to ISO New England and filed for bankruptcy.

Third party billing places timely and accurate tax collection at risk.

- Significant state taxes, municipal real property taxes and municipal personal property taxes are collected through non-generation-related charges on customer bills, which the Utilities timely remit to the State and municipalities. Multiple billers will increase confusion and slow remittance of tax payments to the state and local governments.

9. Consumer Advisory Council, Stakeholder Engagement

As stated throughout this docket, the Utilities believe in the importance of stakeholder engagement during the IDP development process. Therefore, each utility IDP cycle will establish a stakeholder engagement process that allows all interested stakeholders to provide input to be considered at key junctures throughout the plan development process. The three junctures envisioned are those discussed in the Working Group report:

1. Pre-planning
2. Project area identification and consideration
3. Investment type prioritization

The Utilities propose that each company hold three listening sessions to capture feedback on targeted questions regarding the topics above. Each listening session would also allow for an open forum for attending stakeholders to provide additional feedback that was addressed earlier in that session. Utilities will consider feedback during the three sessions for each subsequent stage and in the final IDP submission.

In addition, the Utilities are supportive of the full adjudicated regulatory process for IDP approval and expect that stakeholders and other intervenors will have additional opportunity to comment on the proposed IDP during the formal regulatory process for each utility's IDP, both in written form and in live testimony.

The Utilities feel this process is sufficient to provide ample opportunity for stakeholder engagement. As such, the Utilities agree with Staff in that they see no need for a Consumer Advisory Council or an equivalent body.

10. Capital Budget Process

Because the capital budgeting process is specific to each utility and best executed by its subject matter experts, it is inappropriate to subject the capital budgeting process to broader stakeholder dialogue. Instead, the Utilities recommend that each utility IDP contain a high-level overview of its capital budgeting process. The Utilities expect to provide an overview of the capital budget process that could include investment categories, descriptions and estimated budgets where applicable ahead of filing, but not a detailed discussion on project selection within a category. It is expected that the IDP would also include an update on non-wires alternatives, which will have been evaluated consistent with the agreed-upon cost effectiveness framework. Please also refer to the proposed outline of an IDP later in this document for the Utilities' expected discussion of capital budgeting.

11. LCIRP/IDP Integration

The Utilities support the transition from the older model of the LCIRP to a more comprehensive and holistic IDP. The current LCIRPs include many useful components that should be retained. For instance, the LCIRP includes data and projections for reliability and distribution capacity constraints based on established system design criteria. The projections take into consideration factors such as energy efficiency programs and expectations for output of distribution interconnected generators.

Going forward, the distribution grid and its operators will face increasing challenges and opportunities associated with the integration of DER and the transition to a system characterized by two-way power flow. The IDP must be structured to reflect these emerging dynamics. A holistic approach to the IDP will result in a plan that supports least-cost approaches to maintaining safety, reliability, resiliency and power quality while providing a platform to present the business case associated with technologies that increase the capacity and effectiveness of the distribution system to incorporate clean, cost-effective DER as grid assets.

The Staff Report contains a suggested outline and discussion of proposed content for the holistic IDP. The Utilities support an agreed-upon common framework for IDP content. A recommended IDP outline building upon the material provided in the Staff Report is included at the end of these comments.

The introductory sections will provide context relative to the purpose, objectives and guiding principles of the IDP. These sections will include overviews of the ten-year roadmap and traceability analysis. These sections will also provide background on the plan development, including a summary of stakeholder involvement in the plan. A third section, "Current Distribution System Overview with DER Interconnections" will provide further context with descriptions of key aspects of the service territory, including the extent of DER interconnections.

The next section, "Current Systems Capabilities" will augment the description of the service territory to provide details of the current functionality of key real-time, operational and customer business systems and communications infrastructure. This section will also describe the penetration of sensing and measurement, automation and metering technologies.

Section Five, "Current Planning Process Overview and Forecast Results" will capture the majority of the former LCIRP content with respect to system needs assessment. It will describe the current distribution system planning process used by each utility for both forecasting and needs assessment. It will describe the current process used for load and generation forecasting. It will also describe any plans to enhance forecasting methodologies in the future with enhanced tools for scenario analysis or probabilistic modeling including in the five-year capital and operating plans. Each utility will develop its own territory forecast for DER and EV penetration, rather than using common assumptions. Stakeholders will have the opportunity to provide comments as a part of the stakeholder engagement process described above. The results of the load forecasting process will be provided for the ten-year horizon at the bulk substation level and results of the DER forecasting process will be provided for the ten-year horizon at the system level. Forecast assumptions will be provided as well. This section will contain information on bulk substation equipment ratings, including a description of ratings methodology and provide ratings by bulk substation. The section will also include historical reliability results at the system and circuit level.

The Utilities recommend that HCA results and maps be available online using a methodology for updates on a more frequent basis relative to IDP filings. The IDP will include a link to the then-current hosting capacity maps, as well as a description of the methodological assumptions and a summary of the stakeholder review process undertaken by the technical committee on DER integration. The IDP will contain information on locational value to the extent a methodology has been reviewed and discussed by the technical committee.

This section of the IDP will also describe the current capital budgeting process and will provide an update with respect to any on-going or proposed non-wires alternative analysis or projects contemplated as a part of the capital budgeting process.

Section Six, "Five-Year Plan – Business as Usual" will provide the traditional capital plan focused on running the business to provide safe and reliable service. The plan will include line items with proposed investments in five categories, as well as a description of known large projects with estimated budgets over $1 million. (Note that many projects of this magnitude will not be fully defined with budget estimates in advance of plan filing.) The section will also have a description of key business and expected outcomes for each category and for large projects. Section Six will include key operations and maintenance budget items, including vegetation management.

Section Seven, "Five-Year Plan – Grid Modernization" will incorporate most of the new content contemplated for the IDP intended to support modernization to support DER integration. The section will begin with results of the traceability analysis depicting the relationship between a specific objective, the related capabilities developed, and the functionalities used to architect, design and develop solutions. The five-year capital budget will be outlined in eight investment categories, including a description of known projects with an expected budget over $1 million. In addition, this section will include incremental operating expense associated with each investment category. As applicable, the section will describe any architectural considerations relative to interoperability, future-proofing and critical system continuity.

All investments described in Sections Six and Seven will be evaluated relative to the agreed-upon cost-effectiveness framework. Any common assumptions used to complete cost-effectiveness and business case analysis will be noted in the appropriate IDP section. (See Section 2 for the Utilities' recommendation with respect to cost-effectiveness framework.)

Section Eight, "Ten-Year Grid Modernization Vision" will describe the high-level roadmap to longer term grid modernization objectives and outcomes. It will detail how the five-year plan will support and enable the ultimate grid modernization vision.

Section Nine, "Cybersecurity and Privacy" will provide details on cybersecurity programs and policies that will continue to ensure a secure grid taking into consideration the addition of new technologies and the continued emphasis on security of our legacy systems.

Section Ten, "Performance Metrics" will outline the metrics proposed to measure progress and performance relative to IDP implementation.

Proposed IDP Outline

1. Executive Summary
    a. IDP objectives
    b. IDP sections described
2. Introduction
    a. Company vision and guiding principles
    b. Overview of 10-year roadmap [see section 8 for detailed roadmap]
    c. Purpose of the filing
    d. IDP objectives
    e. Overview of traceability results
    f. Compliance with filing requirements
    g. Comparison to previous LCIRP submission
    h. Stakeholder involvement with IDP development
3. Current Distribution System Overview with DER Interconnections
    a. Narrative description of service territory (e.g., customers served – residential, commercial, industrial; service regions; towns; bulk and distribution substations; overhead/underground/secondary network circuits)
    b. Overview of connected DER by type and region and in-queue DER by type and region
4. Current Systems Capabilities
    a. Business applications (GIS, OMS, SCADA, CIS, MDMS, ADMS, WAM, PI, customer data access)
    b. Communications networks (WAN and FAN)
    c. Sensing and measurement
    d. Automation (DA and VVO)
    e. Metering infrastructure
    f. Engineering applications (load flow, forecasting and planning tools, hosting capacity analysis locational value analysis)
5. Current Planning Process Overview and Results
    a. Overview of annual distribution system planning process
    b. Load and DER forecast
        i. Existing forecast methodology
        ii. Ten-year Peak load forecast by bulk substation (confidential)
        iii. Ten-year EE/DG/EV & other electrification forecasts (system level)
    c. Equipment ratings
        i. Ratings methodology overview
        ii. Ratings by bulk station (confidential)
    d. Historical reliability (system and circuit level)
    e. Link to online HC maps
    f. Overview of annual capital budgeting process
    g. Commentary on NWA process and pending projects
6. Five Year Plan – Business as Usual
    a. Business drivers and expected outcomes

b. Five-year capital budget by category
    i. Run the business (e.g., capital repairs, metering, streetlights, pre-capitalized transformer replacements)
    ii. New customer (e.g., infrastructure deployed to interconnect new residential, commercial and industrial load)
    iii. Peak load growth (e.g., projects that address potential overloads at the circuit or substation level)
    iv. Regulatory requirements (e.g., special programs mandated by PUC order)
    v. Reliability and aging infrastructure (distribution automation, infrastructure relocation, end-of-life replacements)
c. Key project summary (projects over $1M in five-year plan with description including drivers)
d. Five-year vegetation management budget

7. Five Year Plan – Grid Modernization
    a. Traceability analysis
        i. Objectives
        ii. Capabilities
        iii. Functions
    b. Five-year capital budget by category (including results of cost effectiveness framework)
        i. Sensing & measurement (including field area network communications)
        ii. Field automation
        iii. VVO
        iv. Distribution system network operations (ADMS, DERMS)
        v. Engineering tools (modeling and forecasting, data management, DER portal)
        vi. Strategic electrification
        vii. Demonstration projects
        viii. Metering
    c. Five-year incremental operating expense budget by category
    d. 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 System
8. Ten Year Grid Modernization Vision
9. Cybersecurity and Privacy
10. Performance Metrics
    a. Business as usual – existing reliability metrics
    b. Grid mod metrics
11. Rates and Regulatory
    a. Cost recovery
    b. Revenue requirement and rate impact by customer class