clf
conservation law foundation

For a thriving New England

CLF New Hampshire
27 North Main Street
Concord, NH 03301
P: 603.225.3060
F: 603.225.3059
www.clf.org

September 6, 2019

VIA EMAIL AND HAND-DELIVERY

Debra A. Howland, Executive Director and Secretary
New Hampshire Public Utilities Commission
21 South Fruit Street
Concord, N.H. 03301

RE: Docket IR 15-296 Investigation into Grid Modernization
Comments of Conservation Law Foundation

Dear Director Howland:

Please find enclosed for filing an original and seven copies of Conservation Law Foundation's Comments in the above-referenced matter. This filing has been provided via email to parties on the service list in this docket.

Thank you for your time and attention to this matter. Please do not hesitate to contact me with any questions or concerns.

Sincerely,

Meredith A. Hatfield
Senior Attorney

cc: Docket No. IR 15-296 Service List (electronic service only)

Investigation into Grid Modernization

Docket No. IR 15-296

September 6, 2019

COMMENTS OF CONSERVATION LAW FOUNDATION

Conservation Law Foundation (CLF) submits these comments in response to the New Hampshire Public Utilities Commission (PUC or Commission) Order No. 26,254 requesting comments on eleven topics identified by PUC Staff in Staff's report on the May 15, 2019 technical session.

I. Procedural Background

The Commission opened this investigative proceeding on July 30, 2015 in response to HB 614 of 2015, which in part implemented the recommendation from the 2014 State Energy Strategy "that the Commission conduct an investigation or information-gathering proceeding as a first step, to give stakeholders a chance to learn about grid modernization and to explore to what extent that grid modernization is workable in New Hampshire."[1] The Commission held many meetings over the next several years culminating in the release of the Final Report of the New Hampshire Smart Grid Working Group, prepared by the Commission's facilitator, on March 20, 2017. Nearly two years later, on January 31, 2019, Commission Staff issued its Staff Recommendation on Grid Modernization.[2] Several parties filed comments on the Staff Report shortly thereafter, and the Commission scheduled additional opportunities for comments and technical sessions as discussed below.

II. Staff Report

The Staff Report builds on information from the Department of Energy related to its Modern Distribution Initiative, also called DSPx, which seeks to provide assistance and guidance to state regulatory commissions on the evolution of the electric distribution utility.[3] A result of this assistance is the recommendation from the Staff Report to focus on the submissions of distribution system plans by each of the distribution utilities. Specifically, "Staff proposes that utilities be required to submit integrated distribution system plans (IDPs), which will integrate grid mod initiatives and supporting documentation into their existing least cost integrated resource plans (LCIRPs), as required by RSA 378:38 et seq. Staff's approach first defines recommended objectives for electric distribution utilities, including capabilities and functionalities required by the distribution system to meet those objectives."[4]

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[1] Order of Notice at 2.

[2] Staff Recommendation on Grid Modernization, Docket IR 15-296 (January 31, 2019) (Staff Report).

[3] As described on the DSPx webpage, "This effort intends to inform decision-makers interested in pursuing grid modernization on any or all of the following goals: a) reliability, safety and operational efficiency, b) enabling customer adoption of distributed energy resources (DER), and c) the utilization of DER as non-wires alternatives. A key objective of the collaboration is to gain a consistent understanding of the functional and technological requirements that facilitate the adoption of a widely applicable set of technologies for planning and operations that meet each states' objectives for grid modernization. It is recognized that each jurisdictions' procedural paths and policy decisions will vary and as such the work plan that emerges should consider priorities for mutual efforts while respecting jurisdictional differences. The organizational structure of this initiative allows for other states to engage over the course of the effort." https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

[4] Staff Report at 7.

The Staff Report notes that by integrating the LCIRP with the new IDP will allow for better coordination and organization of the two plans. The IDP would be specific to grid modernization investments, which would be more comprehensive than the LCIRP. The IDP would look ahead on a 5- and 10-year basis in order to determine the least cost options for distribution and subtransmission systems and can optimize between utility-owned and non-utility-owned solutions.[5]

In order to effectively address the IDP and LCIRP plans, the Staff Report developed a set of objectives that can be used to measure whether a particular investment meets the set of objectives developed by Staff. The objectives identified in the Staff Report follows:

- 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]

The Staff Report was subject to comments submitted by parties, including CLF, on April 8 and 9, 2019. A technical session was held on May 15, 2019 to discuss the Staff Report, and Staff submitted a report on the technical session on May 16, 2019. That report memorialized several points from the technical session, including allowing for comments to be submitted, identifying a set of eleven topics to be open to comment by parties, and the agreement that there will be additional technical sessions after the submission of comments.[7] The eleven topics are:

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[8]

On May 29, 2019, the Commission issued Order No. 26,254 which set the schedule for parties to submit comments on the eleven topics identified by Staff, and two additional technical sessions to discuss the comments submitted and potential next steps in September and October.

[5] Staff Report at 8-9.
[6] Staff Report at 11.
[7] Staff Report on Technical Session at 2 (May 16, 2019).
[8] Id. at 1.

III. CLF's Comments

CLF appreciates the opportunity to submit comments, and thanks Commission Staff for preparing a thorough report on distribution system planning and the coordination of IDP and LCIRP. CLF is supportive of the general direction of this effort, as described in the Staff Report, as it could help to bring much needed transparency to an historically opaque planning process. CLF has partnered with Plugged In Strategies[9] to provide additional perspectives on the topic of grid modernization and distribution system planning and to inform the Commission on related proceedings occurring across the United States that we hope will inform the Commission as it determines next steps in this process.

CLF will focus these comments on three of the eleven topics: LCIRP/IDP integration; Strategic Electrification; and cost-effectiveness. These comments will also briefly discuss Hosting Capacity and Interconnection, Stakeholder Engagement, and Data Access.

A. LCIRP/IDP Integration

CLF is generally supportive of the creation of an IDP process to guide investments by New Hampshire utilities. Having greater visibility into the utilities' distribution planning processes looking out several years into the future will be vital to ensuring that investments are in alignment with customer preferences and adoption cycles, and other important policy goals such as advancing clean energy. Having an open process to evaluate utility distribution system investments provides opportunities for stakeholders to raise questions in advance regarding need, alignment with other utility processes, and reasonableness of specific utility investments. However, CLF believes that the Commission must make some important decisions in advance of an actual utility filing to provide guidance on some key topics.

In addition, though four years have passed and CLF certainly agrees with a sense of urgency to move forward with grid mod implementation, more work is needed in several areas before implementation can take place.

First, some of the conclusions in the Staff Report require additional analysis to determine and understand current utility practices regarding many of the topics identified in the Staff Report. For example, what is the current utility distribution system process, to what extent are system forecasters and planners in alignment on their assumptions and models, and are energy efficiency and demand response being used effectively today to maximize the efficiency of our systems? These types of foundational questions and processes have formed the basis of actions at other commissions around the country. For example, the PowerForward initiative at the Public Utilities Commission of Ohio (PUCO) investigated many of these same issues, to answer the basic question of what should Ohio's distribution system look like in 10 years. The final report issued by the PUCO outlined a basic policy framework for future utility investments, as well as the specific recognition that distributed energy resources (DER) would play an increasing role in the operations of the distribution systems across Ohio. As such, the

[9] https://www.puco.ohio.gov/industry-information/industry-topics/powerforward/phase-2-exploring-technologies/exploring-technologies-speaker-biographies/chris-villarreal-plugged-in-strategies/.

PUCO identified several topics for further policy and technical development, including distribution system planning requirements, data access, and non-wires alternatives.

New Hampshire can also look to a report prepared by GridLab on Integrated Distribution Planning as an example of what such a process may consider.[10] In that paper, GridLab notes that Integrated Distribution Planning is a response to the growth of DER, which is changing how the utility should plan its system. For example, a current distribution planning process may look like this.[11]

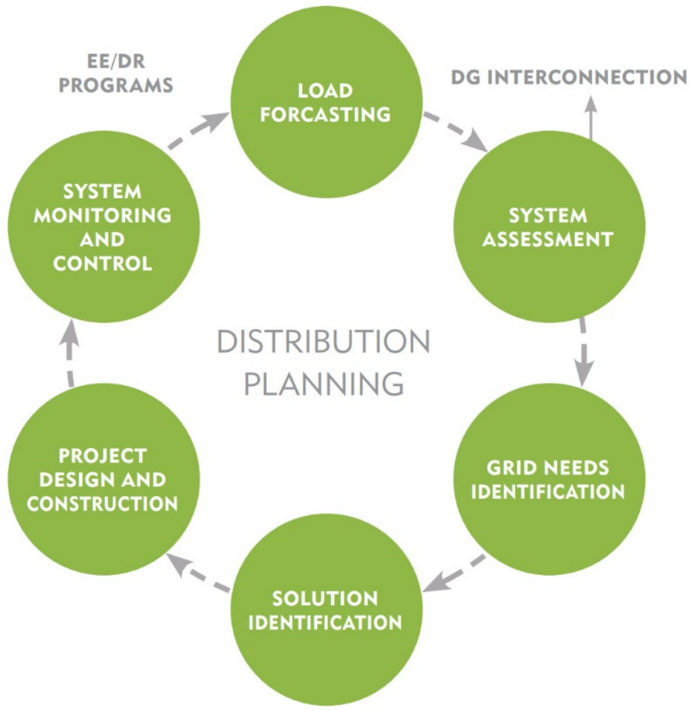


FIGURE 1. Typical Distribution Planning Process

With the growth of DER, and the greater availability of data, an integrated distribution planning process should start to look more like this[12]:

[10] GridLab, "Integrated Distribution Planning: A Path Forward." Available at: http://gridlab.org/wp-content/uploads/2019/04/IDPWhitepaper_GridLab-1.pdf.
[11] Id. at 7.
[12] Id. at 8.

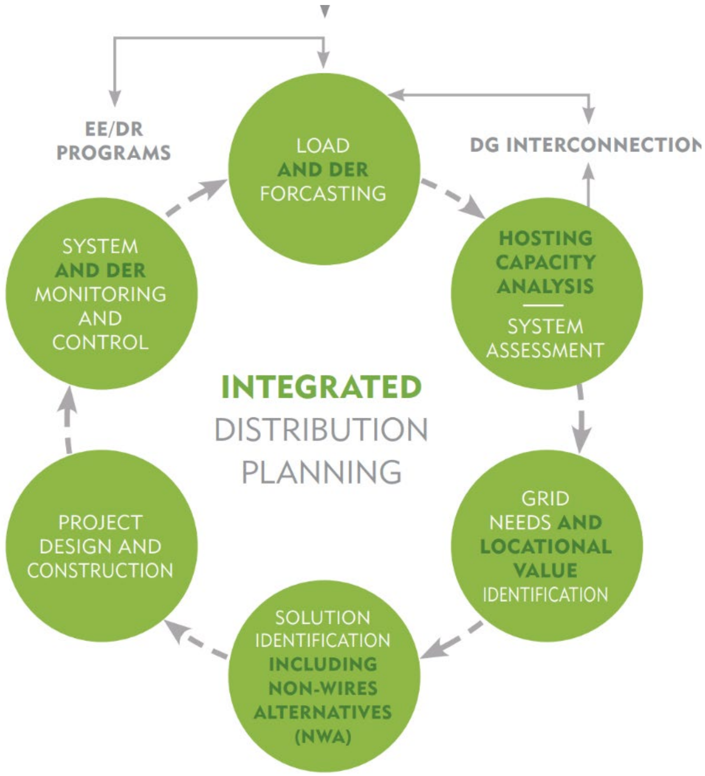


FIGURE 2. Transitioning to Integrated Distribution Planning

In the second image, new capabilities and functions are included, such as ensuring that information from the interconnection process is informing both the forecasting and the system assessment, that grid needs includes locational value identification, and that solutions includes non-wires alternatives.

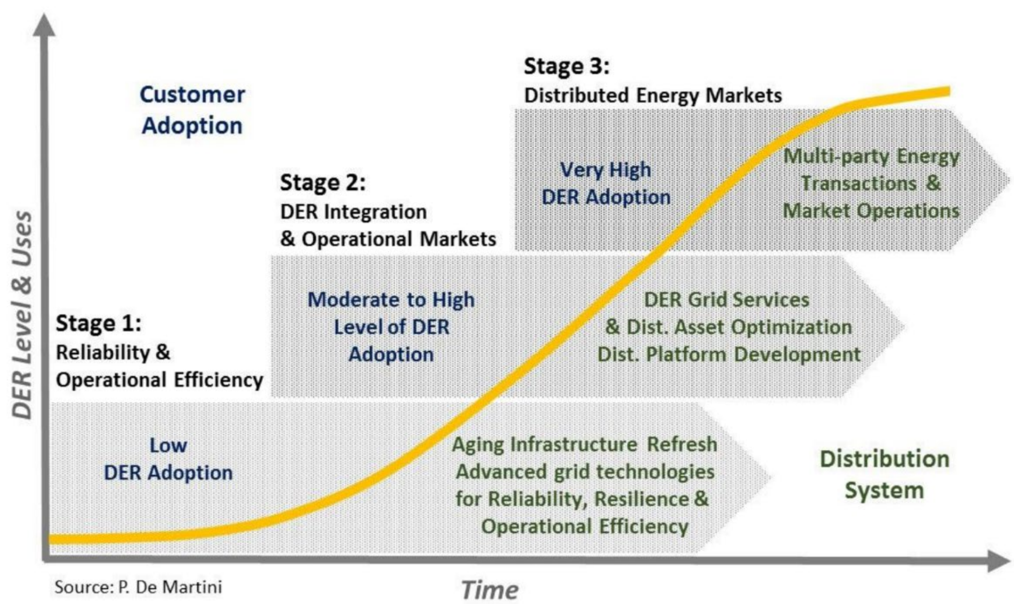
The Commission should recognize that without first understanding the current capabilities of the utilities and their existing distribution system planning processes, being able to effectively plan and develop forward-looking policies will be delayed. It is vital that the current planning processes are described, and then the Commission can provide guidance and direction for the evolution of those distribution planning processes for the future. As this model, and the DOE integrated planning model for the Minnesota PUC discussed below show, the utility planning process starts with data, capabilities, and needs, which are all currently invisible to stakeholders.

Second, the Staff Report points to a technology adoption curve developed by Paul DeMartini for the DSPx initiative shown below.[13] This chart highlights the stages of market development and ability of the distribution system to optimize or support those market developments. A key starting point in using that chart is to first identify where a particular state is on that chart, including current adoption levels for DER, including solar PV and electric vehicles, and an overview of the current status of utility investment. This is then plotted over a timeline of policy goals and guidance that lay out the expectations for the capabilities of a given utility system over some number of years. This chart has been used across the

[13] US DOE, "Modern Distribution Grid: Decision Guide," Volume III at 15 (June 28, 2017). Available at: https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf.

United States, including in the NARUC Distributed Energy Resources Rate Design and Compensation Manual,[14] and elsewhere. A related model is the "Walk, Jog, Run" nomenclature, also developed by Paul DeMartini.[15] In that example, the process follows the capabilities of each step along the way. In essence, one first must learn to walk before one can jog, and then run. The Staff Report does not first identify where New Hampshire is in relation to DER adoption or utility capabilities; instead, it recommends a future state without identifying where New Hampshire is today or clearly defining what needs to be done to get there.

Figure 4. Distribution System Evolution



This process cannot be short-circuited out of the desire to act, despite the fact that four years have passed since this investigation was initiated. To do so would increase the risks of choosing the wrong outcomes, investing in the wrong technology, and increasing costs to consumers for investments that do not provide benefits or get the state to an optimal location. In states that have or are currently investigating grid modernization policies, there is an overall direction from those commissions on the goals and expectations from a grid modernization process. New Hampshire needs that direction as well. States like Hawaii, California, and New York developed theirs in response to specific realities of their systems related to the growth of DER or a significant reliability event. Other states, like Minnesota, Ohio, Michigan, Rhode Island, and Illinois, used these discussions to lead to a process and pathway for evolving distribution system operations to become more optimized and efficient. This includes both investment by the utilities in infrastructure needed to support this emerging distribution system, but also a recognition of the value, benefits, and availability of non-utility resources and services. This

[14] "Distributed Energy Resources Rate Design and Compensation, A Manual Prepared by the NARUC Staff Subcommittee on Rate Design," NARUC (November 2016). Available at: https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

[15] See "Planning for More Distributed Energy Resources on the Grid: A Summary for Policy-Makers on the Walk-Jog-Run Model," GridWorks (2017). Available at: https://gridworks.org/wp-content/uploads/2017/01/Gridworks_Planning-Dist-Energy.pdf.

overarching policy goal or guidance is vital to ensure the success of initiatives like the one here in New Hampshire, is a necessary next step in this process.

Aligning the LCIRP and a new IDP makes significant sense in order for a utility to plan its system in the most efficient and beneficial way possible. This, however, must include clear expectations and outcomes planned over an implementation timeline. Creating a process that favors or overly relies upon utility investments up front without first understanding the current capabilities of the distribution system, the current amount of DER across the system, the alignment of the variety of utility planning functions, the age of existing infrastructure, and whether existing infrastructure has been fully utilized creates significant risks to customers through increased costs for unnecessary investments. The Staff Report seeks to accomplish all of this in one single, initial filing. That is unrealistic.

The Staff Report also references an image developed by ICF to assist in framing how a future integrated planning process will take place.[16] Unfortunately, the Staff Report fails to recognize key parts of that image. That image was also included in a report by ICF to the Minnesota Public Utilities Commission to assist that commission on development of an Integrated System Planning process for Minnesota.[17] The Minnesota PUC used it to first focus solely on the engineering component of the distribution system planning process. The Minnesota PUC held several stakeholder workshops which included presentations from the utilities that described their existing distribution system planning efforts.[18] In essence, using the technology adoption curve, then the planning process chart, the Minnesota commission identified as its first need to focus on the utility distribution system planning process. In addition, the Minnesota PUC recognized that its interconnection tariffs were outdated, so they initiated a separate proceeding to update them. The Minnesota PUC also directed Xcel Energy (the largest IOU in Minnesota) to develop a hosting capacity analysis, which has now gone through three updates, each time with more information.

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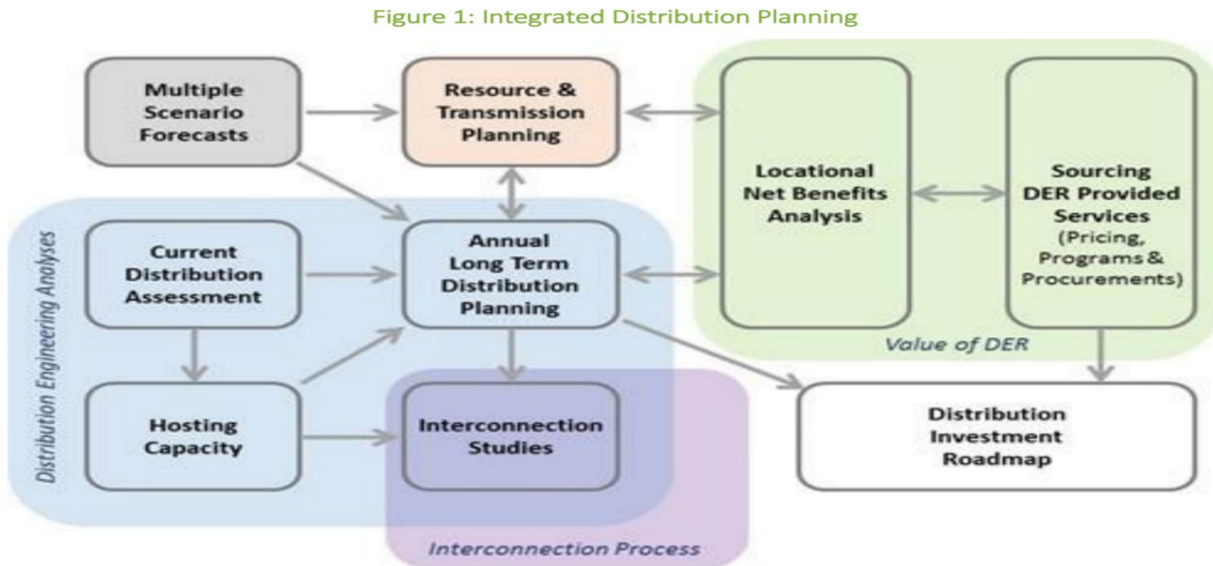
[16] Staff Report at 59.

[17] "Integrated Distribution Planning," ICF International (August 2016). Available at: https://www.energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf.

[18] See, for example, these presentations from Minnesota utilities at a September 25, 2015 workshop held as part of the Minnesota PUC's grid modernization proceeding, which provide an overview of the then-existing distribution system planning processes of the Minnesota utilities. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={3F9D803B-BCF2-4B6D-862F-DD6EE52DCC87}&documentTitle=20159-114157-01.



The lesson from Minnesota, and the other states in similar situations, is that this process requires that the Commission clearly address these issues in an appropriate sequence.

To do so, CLF recommends that the Staff Report recommendations be split into multiple components.

1. The long-term evolution of the utility should be considered as the Commission sets the long-term policy view. The immediate focus on the grid modernization proceeding should be on those areas identified in sections 4 and 5 of the Staff's proposed IDP filing.[19] Those sections should be considered as a starting point.
2. Upon successful completion of the education and understanding of utility distribution system planning processes, demand and DER forecasting, to what extent a distribution utility can run a hosting capacity analysis, and the investment plans and needs of the distribution utility, then the Commission can more forward on considerations on requirements, additions, timelines, and strategies.
3. CLF shares the belief underlying the Staff Report that a clear and transparent integrated distribution planning initiative is beneficial to New Hampshire, and will result in a more efficient and optimized delivery system. However, without first going through the process, as experienced in other states, and as recommended by the DSPx initiative itself, the Commission cannot set the state on the appropriate path forward to a more cost-effective planning and investment utility system. CLF believes that if implemented as proposed by Staff, this process will result in investments that frustrate several other goals, such as strategic electrification and cost-effectiveness, and result in a less efficient and effective process.

[19] Staff Report at 68-69.

B. Cost-Effectiveness

With respect to determining cost-effectiveness of grid investments, the Staff Report jumps to a conclusion without complete information about the risks or benefits of its modernization proposal. By reaching a conclusion, Staff itself provides a presumption that only through utility investments can Staff's conclusion be achieved. Stakeholders and Staff must first better understand what the actual needs are in the short term versus the long-term. For example, if a utility has very low penetration rates for rooftop solar, certain grid modernization investments may not be needed in the next 3-5 years, so that utility could focus on other investments, or begin looking at the ability of non-utility resources to mitigate certain needs through a non-wires alternative assessment. This is why developing the process for a distribution system plan is so important to these investments and assessments.

In considering how investments today, done in coordination with a distribution system plan, the PUCO in its PowerForward report adopted a principle of "net value." According to the PUCO, the principle to "Provide Net Value to Customers" means that the regulators "Insist that [distribution utilities] spend ratepayer dollars wisely and in a manner that delivers eventual net value to the customer." That is some investments may not be cost-effective under a traditional (or modified) cost-effectiveness test, but are, nonetheless, necessary for the operation of the distribution system. The PUCO envisioned that a robust and competitive marketplace would enable innovation that would provide value to customers, but that value could only be achieved by certain investments by the distribution utility. As stated by the PUCO, "the pursuit of an enhanced customer experience through innovation is more likely to succeed in the competitive marketplace than in a regulated environment. Assuming utility deployment of foundational assets through an architectural construct that provides access to non-utilities, innovative products and services can then be introduced."[20]

Having the Commission explicitly tie components of grid modernization to enabling markets and competition to grow and thrive would provide important policy guidance. The utilities have invested, and likely seek to invest in more large capital projects. Without guidance from the Commission that offers support for creation of new markets, and that certain technologies may be necessary for that market to grow, New Hampshire will miss potentially significant customer benefits. Some investments should be considered foundational, albeit still subject to Commission review.

Similarly, in its grid modernization filing with the Hawaii Public Utilities Commission, HECO did not provide a cost-effectiveness study for implementing advanced metering infrastructure because they considered it as a foundational component of its grid modernization plan and recognized that without it, HECO would not be able to implement other components of its plan to operate it system reliably.[21]

[20] PowerForward Report at 23.

[21] In the Matter of the Application of Hawaiian Electric Co., Hawai'I Electric Light Co., and Maui Electric Co. for Approval to commit funds in excess of $2,500,000 for the Phase 1 Grid Modernization Project, the Defer Certain Computer Software Development Costs, to Recover the Capital and Deferred costs through the Major Project Interim Recovery, and Related Requests, Application of Hawaiian Electric Co., Hawai'I Electric Light Co, and Maui Electric Co., Docket No.2018-0141, before the Hawaii Public Utilities Commission (June 21, 2018). Available at: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/grid_modernization/20180621_grid_mod_strategy_application_filing.pdf.

This is to point out that cost-effectiveness is no longer simply about determining if any one investment will provide benefits greater than its costs. Customer or societal benefits that may be enabled by certain investments are difficult to quantify. The NARUC DER Manual outlines two example cost-effectiveness methodologies, one by EPRI and the Standard Practice Manual. In both examples, the NARUC DER Manual points out that regulators will have to make some decisions in how it treats unquantifiable benefits in the application of any given methodology. Specifically, the NARUC DER Manual states that regulators may want to ask:

- To what extent does the grid provide benefits that are not captured by traditional measures of use?
- To what extent does DER lower utility costs?
- To what extent does DER benefit society at large?[22]

This means that New Hampshire will need to craft policies and expectations related to technological needs and the means by which New Hampshire will consider the cost-effectiveness of new investments. The Staff Report recognizes that some evaluations for certain technologies may not have a positive net benefit.[23] The Staff Report draws on examples from Hawaii and HECO's grid modernization strategy that reflects this consideration. However, the Staff Report fails to recognize the need to align the utility investments with a consideration against time and need. In essence, part of the consideration in the NARUC guidance is to consider not only the immediate impacts on utility and societal costs, but also to consider the investment as part of a longer-term strategy. Does this investment need to be made now, or can it be made in the future; is this investment necessary in order to realize a future benefit or a future investment?

Traditional means of determining cost-effectiveness of particular technologies will need to look beyond historical approaches. These investments are fundamentally different than other investments or policies such as energy efficiency. New investments must also look out longer than a 2-3 year cycle. This is yet another example of the need for a more organized and deliberative process to guide grid modernization policy and planning. The Commission and stakeholders cannot yet understand the needs of the system without a more detailed understanding of the distribution system and the distribution utility's plans and forecasting models. When non-utility resources can be used instead of utility capital investments, the Commission and stakeholders will need to understand what is necessary to enable non-utility resources, what is the need that the utility is trying to address, what is the circumstance and location of that need, and what are the societal benefits of using a utility resource compared to a non-utility resource and vice-versa.

Part of this evaluation includes considering a number of components for a cost-effectiveness model. To build on the questions raised by the NARUC DER Manual, some questions include:

- What is the value of the grid?
- What is the value of non-utility investments in technology and resources?
- What is the value of enabling customer/societal benefits?
- What is the value of interoperability?

This includes an expectation that the distribution utility may not be the optimal or most efficient entity to provide a solution. Innovation and increased benefits may come from non-utility sources, but those

[22] NARUC DER Manual at 154.
[23] Staff Report at 48.

benefits can only come from a policy statement supporting competition and a recognition that some investments by the distribution utility is necessary for those benefits to be realized. The Staff Report's utilization of "Least Cost/Best Fit" gets partially there, but that structure only focuses on utility investments that provide utility benefits. A "net value" approach has the ability to impute additional societal benefits by recognizing that customers and markets may better meet any given need than a utility investment.[24] As discussed in the next section, strategic electrification is an example of how utility investments in the basic components of the distribution system can enable a larger societal goal around electrification.

Additionally, any utility investment pursuant to an IDP must identify the need, the location, and a showing that the utility considered other alternatives, including potential non-wires alternatives. This showing must also explain how the utility chose the specific location and specific technology. Simply having the utility explain the results of its modeling is insufficient and does not allow the Commission or stakeholders to evaluate the inputs of the utility model or insert modifications into the investment model. Much like an IRP, stakeholders must have access to the underlying model and assumptions in order to run or modify certain assumptions. Determining the cost-effectiveness of any investment or opportunity is built upon the model, assumptions, and data.

C. <u>Strategic Electrification</u>

In the Staff Report, Staff recommends that electric utilities propose programs and tariffs to electrify certain aspects of customer's energy usage by shifting away from natural gas or oil. The Staff Report also includes electric vehicle programs as part of a strategic electrification strategy.[25] CLF believes that the Staff Report is too limited regarding the need for a broader strategic electrification strategy for New Hampshire. For example, the Staff Report is silent as to the impacts of a strategic electrification strategy on the natural gas utilities. While ensuring that electric utilities are providing opportunities to transition to electric options, a broader strategy is needed for New Hampshire. The Staff Report identifies heat pumps and electric vehicles, but this strategy should be looking at many other ways to electrify more parts of society. For example, water heaters have historically been used by utilities around the country as an important demand response program; utilities should look to increase adoption levels of electric water heaters and develop a tariff or demand response program that focuses on the dispatching of electric water heaters.

The Staff Report recommends that this strategy be included in a utility's IDP. Staff is correct that electrification will have an impact on utility planning. Electric charging for transportation is an example of an electrification strategy that will impact utility planning. As EVs, whether single passenger, fleet, or transit, increase in adoption, knowing the impacts on grid utilization, potential availability for demand response, or, in the case of a high voltage DC charger, where these chargers are located will be important for the utility and the charging infrastructure provider.[26]

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[24] PowerForward at 23. See also, "Valuation of Electric Power System Services and Technologies," PNNL (August 2016). Available at: https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf.
[25] Staff Report at 73.
[26] For example, several cities around the United States, such as the Chicago Transit Authority (CTA), are looking to electrify their bus system and use DC charging to maintain a certain level of service across the city of Chicago. The

A strategic electrification strategy must not be limited in focus to a handful of technologies. With highly variable costs for heating oil, there is an economic interest for customers to switch to electricity, but they need to know more about potential programs. A broader electrification strategy will look not only at such low hanging fruit, but also look toward the future with increasing electrification of transit and transportation, wider availability of grid-enabled appliances such as water heaters, and how best to accomplish this transition effectively, efficiently, and with little impacts on customers, but with benefits to customers. Strategic electrification, however, does not mean do everything at once. Again, having a plan that is in alignment with other utility assumptions on DER adoption, load forecasting, infrastructure upgrades, and identification of optimal areas for pilots or non-wires alternative solutions is necessary for a successful beneficial electrification strategy. This strategy would greatly benefit from greater Commission direction around long-term goals and outcomes, expectations of the electric utility, but also including natural gas utilities. The Commission may want to consider a proceeding that crosses industries since electrifying greater parts of demand may take away significant demand from the natural gas utilities. The Commission may want to consider if there are any options for natural gas utilities to assist or participate in a strategic electrification strategy, or simply have the natural gas companies, as well as the electric companies, submit strategic electrification filings. Proper IDP would evaluate potential load impacts on both electric and gas utilities, and draw conclusions on how both utilities can participate in the forthcoming strategy.

The development of potential tariffs must also reflect the difference in costs between times of use, and provide an opportunity for enhanced demand response options for those appliances and products that are dispatchable. For example, electric hot water heaters can be responsive to prices and grid conditions and, when aggregated, can provide a potentially significant asset that can be used by the distribution utility or the New England ISO. Indeed, the ability of certain appliances to directly participate in the ISO markets may also be a topic of interest for a Commission proceeding. The ability for demand side resources or household appliances to interact with the grid should be properly reflected in an IDP, and potential future procurement opportunities. IDPs would forecast these load shifts/changes, and adoption rates and forecasts, then evaluate system impacts through a hosting capacity analysis. Finally, these electrified demand-side resources may provide certain grid needs (determined locationally or otherwise) and be valued as a resource to be procured and dispatched, or a change to customer demand in response to a price. In either case, these are resources that are being under-utilized due to lack of available market opportunities, sufficient price signals, or the utility may simply not know that these resources are available. The Commission may wish to further pursue how these resources participate in the broader market beyond just the distribution system impacts.

CTA, however, needs access to certain information about the utility's service territory so that it can both ensure its electricity costs remain reasonable (i.e., not get hit with a high demand charge), but also to ensure that the DC charging infrastructure is located in places with sufficient capacity for multiple DC charging equipment and not harm utility reliability. In order to accomplish such a project, there requires greater planning and outreach with stakeholders, including community leaders, transit officials, and utility representatives. In essence, the utility needs to understand the goals of the community and have that be reflected into their own strategy and goals. Presentation of Chicago Transit Authority, Illinois Commerce Commission, NextGrid Initiative (February 14, 2018) https://nextgrid.illinois.gov/workinggroup1/Meeting4_Presentation-CTA.pdf.

D. Hosting Capacity and Interconnection

As discussed in the LCIRP/DRP section above, hosting capacity and interconnection are key components of a future utility distribution resource plan. Both hosting capacity and interconnection provide multiple streams of information, so CLF seeks to ensure that the Commission is not considering these components as entirely separate discussions.

As noted in the Minnesota PUC integrated grid planning image shown on page 8, both hosting capacity and interconnection provide important sources of data that must be considered in a distribution system planning process. The interconnection process provides information about the types, sizes, capabilities, and locations of new DER that is interconnecting with the distribution utility system. This information can then be used to inform the forecasting model, the DER adoption model, asset replacement cycle, and distribution system planning. For example, if a certain circuit is seeing greater amounts of rooftop solar interconnection activity, then the utility may choose to focus on that circuit for system upgrades even though another circuit, with less interconnection activity, may have satisfied traditional utility planning processes for an upgrade. In such a case, the asset utilization of certain technologies can be extended, and replacement can be deferred while the circuit seeing greater solar penetration can receive the focus.

Similarly, a hosting capacity analysis can assist the utility in identifying those locations above, at, or soon to be at or above capacity. This information can assist the utility in understanding how electricity is being used at a location and where areas of its system may be in need of upgrading. This visibility into the capabilities of the distribution system can provide developers with a better sense of where to target DER installations, and those areas with a greater chance of success for interconnection. It can also identify potential areas of opportunity to enhance hosting capacity through utilization of other technologies such as energy storage, demand response, or energy efficiency. Hosting capacity can also identify potential areas where a non-wires alternative project may be helpful in alleviating or enhancing hosting capacity at a particular area. It also needs to be noted that a hosting capacity analysis is time and location dependent and likely to be continually evolving. With a focus on beneficial electrification, as discussed above, significant electrification of buildings, businesses, and homes will impact any hosting capacity analysis. The utility, market participants, and developers can utilize this hosting capacity analysis to target locations where electrification could occur sooner, or areas where investments in infrastructure or DER may be necessary in conjunction with electrification. Hosting capacity can assist in a more optimal strategy and roll-out for strategic electrification.

Traditional utility planning on asset replacements is typically run it until it breaks; by using the data from interconnection and hosting capacity, the utility can take on a much more active asset maintenance program that appropriately focuses on those parts of the system under increasing or soon to be increasing stress compared to other parts of the system that are under less stress.[27]

[27] "Optimizing the Grid: A Regulators Guide to Hosting Capacity Analyses for Distributed Energy Resources," IREC (December 2017); "Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity," EPRI, Palo Alto, CA (2018); "Integrated Distribution Planning: Utility Practices in Hosting Capacity Analysis and Locational Value Assessment," Department of Energy (July 2018).

Utilities are not the only entities seeking to learn more about a utility system. The interconnection tariff and process must be up to date and be in alignment with significant updates to the underlying standard supporting interconnection. IEEE 1547, which is the technical foundation for most interconnection tariffs around the United States, was updated earlier this year. The importance of this update focuses on the ability of advanced inverters to provide certain functions that had previously not been allowed. For example, under IEEE 1547-2019, inverter-based resources, like solar PV, can perform voltage ridethrough functionality, which means that if the distribution system is lower or greater than its voltage tolerance for more than a certain period of time, the solar PV can continue to generate electricity and put it onto the distribution system. Under the previous standard, if the system was experiencing a certain amount of volatility, the solar panels would have to stop producing electricity. By having the interconnection tariff updated to include these functions, the fuller range of benefits provided by advanced inverters can be realized and utilized by the customer and the system.

Other updates to the interconnection process include more transparency in the process itself, including the creation of a fast track process that allows resources under a certain size to go through a fast track screen that allows for a quicker approval process. Additionally, by having an online portal for applications, this can assist in managing the interconnection queue and bring more transparency to the interconnection process itself. The Staff Report recommends addressing interconnection as a mid-term project, to be done in 4-5 years. CLF respectfully disagrees with that assessment. Reviewing and updating the interconnection process is a key project that should be done concurrently with developing an IDP process. States like California and Hawaii, who lead on the updates to IEEE 1547 did so because they are responding to the increasing growth of rooftop solar. However, other states have begun to review their interconnection tariffs and found them in significant need of reform. Minnesota recently updated its interconnection tariff.[28] Michigan is currently in the midst of updating their interconnection rules.[29] The Interstate Renewable Energy Council has developed several documents to assist regulators in reviewing and developing new interconnection rules and tariffs.[30]

Therefore, the Commission should prioritize interconnection reform. The need for interconnection reform is grounded in 1) updates to IEEE 1547, which serves as the technical foundation for interconnection tariffs, 2) anticipated growth in interconnection requests will require adoption of new interconnection policies related to queue management and fast track screening, and 3) information from the interconnection process itself, such as location of new resources, size and capabilities of those resources, and potential clustering of resources will provide invaluable information to the utility that can inform a utility's IDP.

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[28] *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611*, ORDER APPROVING TARIFFS WITH MODIFICATIONS AND REQUIRING COMPLIANCE FILINGS, Docket No. E-999/CI-16-521 (issued April 19, 2019).

[29] *In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection, a legally enforceable obligation, distributed generation, and legacy net metering*, Order, Michigan PSC, Case No. U-20344 (issued November 8, 2019).

[30] "Model Interconnection Procedures," IREC (2013); "Priority Considerations for Interconnection Standards: A Quick Reference Guide for Regulators," IREC (August 2017).

E. Consumer Advisory Council/Stakeholder Engagement

The Staff Report disagreed with prior recommendations that stakeholders have a greater role in development and review of utility distribution planning efforts. Staff noted "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."[31] CLF certainly does not want to get involved in the actual operation of the distribution system, but does disagree with Staff that stakeholders do not have a role in planning and designing the distribution system. Indeed, the Staff Report itself spends many pages describing the planning and design of a future distribution utility. For example, Staff describes a potential architecture for the distribution utility and the distribution system planning process and relies upon the Department of Energy's DSPx initiative as guidance for that discussion.[32]

The Staff Report describes grid architecture as "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. … 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."[33] However, Staff notes that grid architecture is based on a set of objectives that are mapped to functionalities, both of which are proposed by Staff.[34] Yet, Staff subsequently notes that for the IDP, "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."[35]

CLF believes that stakeholders have a strong interest in participating in the development of those objectives and functionalities of the distribution system that then make up the grid architecture that is foundational to the IDP. Having a stakeholder engagement process can ensure that the utility architecture is meeting the objectives of the state and stakeholders. CLF does not seek to have a stakeholder process that micromanages the utility architecture or operation of the distribution system, but putting the entire process, from objectives, outcomes, capabilities, and design in the utilities' control without a stakeholder engagement process may result in more contested issues as stakeholders attempt to understand the totality of the utility design. This would be inconsistent with practices around the country on related topics.

[31] Staff Report at 45.
[32] For example, see Staff Report at 28-29, 35.
[33] Staff Report at 27.
[34] Staff Report at 26.
[35] Staff Report at 27.

In Ohio, the PUCO created a working group focused on development of distribution system planning requirements.[36] In Minnesota, Xcel's distribution system planning filing was the subject of multiple stakeholder meetings in advance of their filing.[37] In Michigan, the PSC organized multiple workshops related to the contents of the distribution system planning filings of its utilities.[38] As Volume 3 of DSPx notes, "Given the implications of grid evolution to customers, stakeholders and grid owners, it is essential to have a common view of what the grid needs to enable and when it is needed. This requires proactive engagement between regulators, customers, utilities and other stakeholders."[39] Indeed, as described by Volume 3, a key component of the development of any grid modernization strategy is an overall guidance or vision for the future of the distribution system. In one vision, identified as "Current Path" in Volume 3, "This end-state is based on the current utility investment plans for electric distribution upgrades and smart grid technology adoption as identified in current rate cases and smart grid roadmaps. This end-state is the outcome of an incremental approach to infrastructure investment. **Lack of coordination or collaboration among stakeholders can create gaps in system planning and investment.**"[40] In essence, without sufficient input by stakeholders in the planning phase, the utility plan may not result in an optimal outcome. The importance of including stakeholders at various points of the planning process is made throughout Volume 3 of the DSPx. Notably:

- In discussing a transparent planning process, "Stakeholder participation and increased transparency becomes an important part of the distribution planning process, especially to enable participation by DER service providers and other third parties. This includes relevant data sharing in the annual planning process as appropriate."[41]
- In discussing annual distribution planning efforts, "Historically, distribution planning is done primarily by the utility, without much transparency or opportunity for stakeholder engagement. … Utilities can improve communication regarding planning assumptions, methodology and review of planning results with regulators and stakeholders."[42]
- In discussing operational needs for DER aggregation, "A starting point for discussions is understanding the current operational coordination of any existing utility and aggregator demand response programs. From this understanding, stakeholders can effectively discuss what needs to be done in a stepwise manner to develop a broader coordination framework that encompasses all participating DERs in both bulk power system markets and emerging distribution operational opportunities as non-wires alternatives."[43]

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[36] *In the Matter of the PowerForward Collaborative, et al.*, Public Utilities Commission of Ohio, Case Nos. 18-1595-EL-GRD, et al. (issued October 24, 2018).
[37] *In the Matter of Distribution System Planning for Xcel Energy*, Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy, Minnesota Public Utilities Commission, Docket No. E-002/CI-18-251 (issued August 30, 2018).
[38] In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their five-year distribution investment and maintenance plans and for other related, uncontested matters, Order Opening Docket, Michigan Public Service Commission, Case No. U-20147 (issued April 12, 2018). Information about the workshops can be found here: https://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-464286--,00.html.
[39] DSPx, Volume 3 at 17.
[40] DSPx, Volume 3 at 19 (emphasis added).
[41] DSPx Volume 3 at 47.
[42] DSPx Volume 3 at 48.
[43] DSPx Volume 3 at 73.

The development of any IDP, objectives, inputs, design, and process must include stakeholders along the way. Waiting until the submission of the utility's IDP is simply too late to affect change in the vision of the utility's IDP, and will not result in an efficient review of the utility's IDP before the Commission. Having a stakeholder process and engagement during the development of the utility's IDP will ensure that stakeholders are educated along the way, allow stakeholders an opportunity outside a contested case to provide feedback about the plans, provide stakeholders with education about technologies, plans, and expectations outside a contested case, and may assist in limiting potential disagreements between stakeholders and the utilities on the details of the IDP filings.

F. Data Access

CLF supports the development of a data privacy and data access framework for New Hampshire. With the passage of SB 284 of 2019, which establishes a statewide, multi-use online energy data platform, there is a greater need and urgency to develop rules and policies on the availability and privacy of customer energy usage. CLF believes that an overarching policy or guidance would be more effective than individual utilities developing their own policies and practices, and notes that these issues might be addressed in the adjudicative proceeding required to be opened within 90 days of the passage of SB 284. Consistency of policies, practices, and implementations will provide greater assurance to customers that their data is being protected under a common protocol, and will provide assurance to the market that they can expect a certain level of commonality in practices across the utilities. Additionally, with the development of a central repository for data, the Commission should consider developing a data privacy and data access framework to provide customers with a level of confidence in the protection of their usage data, but also a clear expectation around the availability of their data and ability to share it with a third party. CLF recommends the Commission consider a framework such as the Department of Energy's DataGuard initiative,[44] and also consider the rules adopted by the California Public Utilities Commission on data access and data privacy.[45]

IV. Conclusion

CLF appreciates the opportunity to comment on the Staff Report issued in this docket. CLF recommends that the Commission not adopt the recommendations included in the Staff Report at this time, and that the Commission should instead focus its immediate attention on the topics outlined in our comments. Specifically, CLF recommends that the Commission:

1) Gather information from the utilities on their current capabilities, distribution system practices, forecasting and modeling capabilities, and develop a guidance and strategy for grid modernization in New Hampshire with a focus on distribution system planning. CLF notes that states that have initiated similar proceedings included clear goals at the beginning of their process but they are missing here. For example, the questions that guided the Minnesota process were:

[44] https://www.dataguardprivacyprogram.org

[45] *Order Instituting Rulemaking to Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's own Motion to Actively Guide Policy in California's Development of a Smart Grid System*, Decision 11-07-056, California Public Utilities Commission, Docket No. R.08-12-009 (July 29, 2011).

- Are we planning for and investing in the distribution system that we will need in the future?
- Are the planning processes aligned to ensure future reliability, efficient use of resources, maximize customer benefits and successful implementation of public policy?
- What commission actions would support improved alignment of planning for and investment in the distribution system?

Answers to questions such as these would provide guidance that would be very beneficial to the process.

2) The Commission should undertake an immediate investigation of hosting capacity analyses for the distribution utilities. It is important to understand the current capabilities, what types of data is available, what data will be needed in the future for more robust analyses, and how information from a hosting capacity analysis can be or is integrated with the utility's distribution system planning and interconnection process.
3) The Commission should initiate a stakeholder working group to review current utility interconnection tariffs to determine the need to update the tariffs in response to changes to the standards, availability of new technologies such as advanced inverters, queue management practices, development of a fast track screening process, and how to better integrate information from the interconnection process with hosting capacity and system planning.
4) The Commission should confirm its interest and expectation that the utilities, both electric and gas, participate in the planning required to implement beneficial electrification strategies. This is an opportune time to consider programs, practices, and guidance associated with beneficial electrification programs, including their impact on electricity and natural gas demand.
5) The Commission should recognize that stakeholders must have a role in the ongoing grid modernization initiatives being developed by the utilities, including being part of an advisory group reviewing utility objectives and investments before the filing of an application or rate case. Including stakeholders in the development phase of any plan or proposal provides an opportunity for learning before a filing and stakeholders engage in a litigated proceeding.
6) CLF recommends that the Commission recognize the changing nature of cost effectiveness of utility investments, and that a traditional least-cost methodology may not be appropriate for some utility investments. With the evolution of the electricity system and increased adoption of DER, certain utility investments may simply be necessary even if they fail a traditional cost benefit test. Taking a broader look at net value may provide a better lens through which to consider what investments are beneficial to customers and society.

CLF believes that a stakeholder process is imperative to ensuring that we are building the distribution system for the future to enable greater efficiency, higher levels of DER, better utilization and optimization of all resources, and at an overall lower cost to customers. This is the time for New Hampshire to ensure that our distribution system is focused on the future. The Commission must provide that guidance and vision for the future so that the parties can work together to develop concrete paths forward to modernize New Hampshire's electric grid.