STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

DOCKET NO. IR 22-076

Electric Distribution Utilities

Investigation of Whether Current Tariffs and Programs are Sufficient to Support Demand Response and Electric Vehicle Charging Programs

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY INITIAL COMMENTS

DEMAND RESPONSE

Legal and Regulatory Framework

There is not legislative authority that explicitly prioritizes demand response ("DR") programming over any other form of utility investment. Though indirectly RSA 374-F:3, X does support an expansion of existing demand response programs:

> Energy Efficiency. Restructuring should be designed to reduce market barriers to investments in energy efficiency ***and provide incentives for appropriate demand-side management*** and not reduce cost-effective customer conservation. Utility sponsored energy efficiency programs should target cost-effective opportunities that may otherwise be lost due to market barriers.
> (Emphasis added.)

But even without RSA 374-F:3, X, there is nothing preventing the Commission from expanding DR programs, and the customer interest in these programs is at an all-time high, with programs in neighboring states continuing to expand and New Hampshire being fully subscribed In addition to earning incentives for reducing consumption during peak demand periods, commercial customers enrolled in utility-run demand response programs value the program as a means to reduce overall energy costs and lower ICAP charges. If the Commission were to find utility demand response program proposals to be just, reasonable and in the public interest, New Hampshire could expand DR programming beyond what is currently offered, and there are benefits to expanding demand response programming.

Function and Objectives of Demand Response: How it Works and What it Should Do

Existing DR programs are utility-offered programs and provide customers with incentives for their participation in helping to reduce load on the ISO-NE grid during system peaks. These programs are conducted on an opt-out basis; there is no penalty per se for opting out of an event, but any opt outs are factored into the customers' performance for the program period and their incentives are calculated or reduced accordingly. By reducing load during the top few regional electric load hours of each year using a varying number of DR events, depending on program offering, the existing DR programs reduce long-term forecasted needs for transmission and distribution investments. The avoided system costs are beneficial to New Hampshire customers by reducing the overall costs of the regional energy system and accordingly, distribution rates that pay for maintaining that system.

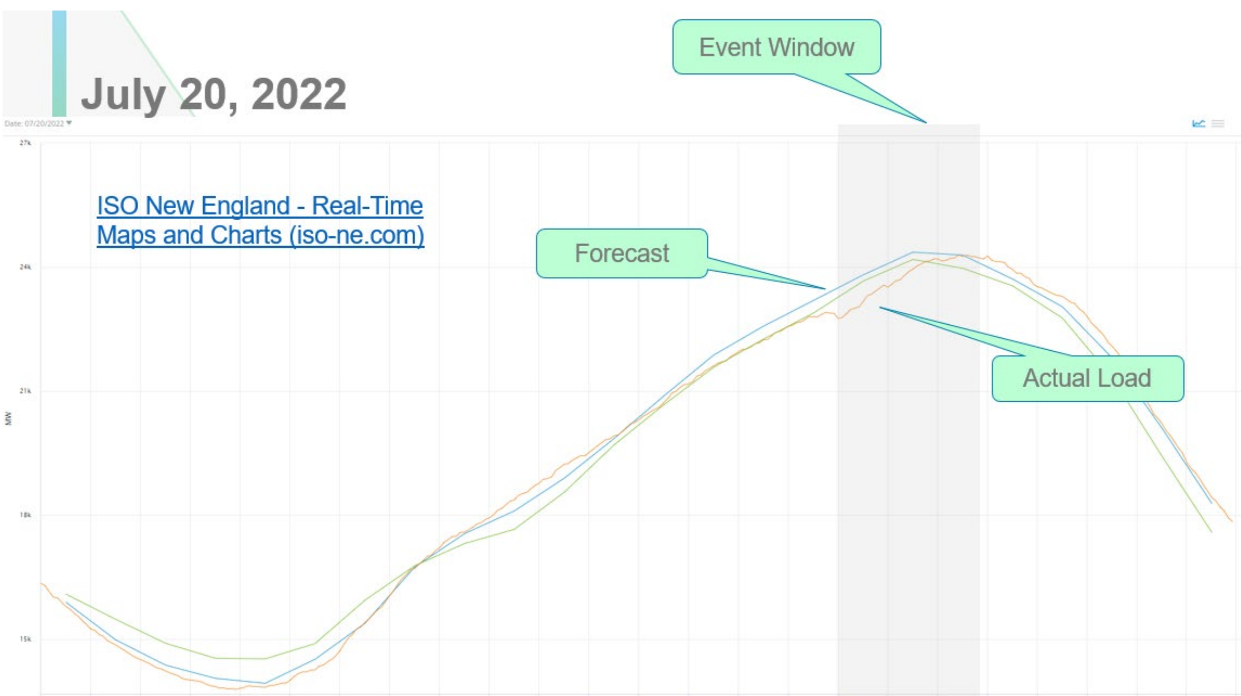
As electric vehicles, heat pumps, and other electrification measures continue to be installed on the grid and rates of adoption increase, the need for managing demand on the transmission and distribution systems will become less of a progressive policy concept and more of an imperative. One electric vehicle adds approximately 14 kW of demand to the average existing household demand of 4-6 kW, effectively tripling household demand. Adding just a few electric vehicles to a single circuit makes a significant impact on the demand for that circuit, and electric vehicles are just one example of electrification. These impacts ripple through the distribution and into the transmission system. As electrification continues, demand management of total customer energy needs will become a necessity to maintain and operate the grid safely, reliably, and at a reasonable cost. Given these conditions, expanding DR to stay current with the expansion of electrification could be an easily implementable method for sustaining a safe and reliable grid at a reasonable cost. It is worth noting that, to the extent other states' policies more aggressively promote DR programs targeting summer peaks, New Hampshire runs the risk of seeing its share of overall transmission network charges increase during those months.

One of the advantages to the DR offerings the Company utilizes is the simplicity of the offering—it is not contingent on rate designs. Incentives are a more flexible mechanism that can be adjusted more easily to achieve desired outcomes. The only instances where rate design may impact DR behavior is if a particular TOU rate design would add to the savings a customer would receive because the DR program was curtailing use during the TOU rate's peak, that customer may be even more motivated to enroll in the DR program to automatically manage their usage during peak times. But TOU rates aren't what drive customer enrollment—the incentives, ability to incorporate various technologies and devices, and ease of participation drive enrollment and participation. Rate design alone does not necessarily drive the desired customer behavior of avoiding usage during peak times because of the complexity and responsibility it puts on the customer to track and modify behavior, and the risk of paying higher rates if the customer fails to shift sufficient energy usage to off-peak periods. Fortunately, DR programs can run fully and successfully without any corresponding rate design.

Eversource's current DR programs are bring-your-own-device, pay-for-performance offerings. The programs enroll existing customer devices in the program to increase the capacity that can participate in the DR events to maximize reduction of peak demand. For large C&I battery projects in particular, the potential to earn ongoing incentives from the DR programs can be the deciding factor in making a battery project financially viable for a developer, so DR can be a significant driver for getting more storage on the grid. Additionally, the newly-launched Energy Storage Solutions battery program in Connecticut is a customer-funded DR program that offers both an upfront incentive in addition to ongoing pay-for-performance incentive for the purpose of motivating developers to pursue battery installations and get more storage online. Combining the upfront incentive with the ongoing pay-for-performance DR incentives clears market barriers for larger battery storage projects and enables the development of assets that can contribute to mitigation of demand peaks.

Current Eversource DR Programs

Currently more than 81,000 residential devices and 800 large commercial & industrial sites are enrolled in Eversource's DR programs across its three state service territories of New Hampshire, Connecticut and Massachusetts, with less than 1,100 of those enrollments attributable to New Hampshire. Residential customers participate in DR events by allowing Eversource to adjust their thermostat settings, pause their EV charging, and discharge their batteries. Large commercial & industrial customers execute customized plans to reduce energy consumption in their facilities that they have developed with curtailment service providers (CSPs) in addition to allowing Eversource to draw power from their batteries and thermal storage systems. Customers are paid incentives at the end of the season in September for their participation in DR events. The customer agreements for DR programs allow Eversource to call up to eight "targeted" events per season, which runs from June to September. Events include all enrolled customers to have the most noticeable impact on the ISO-NE grid. Some devices such as thermostats and batteries are called on more frequently in July & August ("daily" program). In 2022, Eversource was able to reduce the peak load by over 187 MW through these DR programs. The graph below illustrates the aggregated impact that DR programs from utility-administered programs across New England had on a peak days during the summer of 2022.



The impact, as seen in the graph above, was significant, resulting in a downshift of approximately 300MW for events was called between the hours of 4pm - 7pm.

As previously discussed, there are no rate mechanisms associated with Eversource's DR programs – DR is simply incentive-based programming. Rate design can be used in conjunction with DR, but to date DR programs have been both more popular and more effective in reducing peak demand over time-varying rates, in Eversource's experience. Customer acquisition is critical to program success as Eversource's data indicates that customers rarely opt out of individual events or unenroll from the program entirely, so customer enrollment is the primary driver for robust participation and increased load shed.

Bulk data for DR events is uploaded into a Distributed Energy Resource Management System ("DERMs") The DERMs platform allows the company to enroll, connect to, control, and receive data from customers devices which is critical to executing the DR program and achieving load reductions. Connectivity to the DERMs and the ability to automatically dispatch customer assets for DR events is essential to the success of the program as it does not require any manual action on the part customer, though they do retain the ability to opt out of events if necessary. The automation enabled by DERMs makes it easier for customers to reduce load during peak events and earn participation incentives with minimal effort. For the current DR program, data is used only to confirm participation and calculate performance after the fact; it does not enable real-time utility control over customer devices. But real-time data exchange is not necessary for successful DR, and likely would not enable any additional value or functionality for DR programs. Existing DERMs functionality addresses all DR programmatic needs.

The table below provides information regarding incentive levels and 2022 performance for Eversource's DR programs across its three state service territories as of January 2023. As depicted in the table, incentive levels are generally higher for the programs that call a greater number of events per season. Of all program offerings, load shed (performance) during peak events primarily results from curtailment of C&I customer devices and residential thermostats, which is in part due to higher enrollment. For targeted events during which all assets are called, the contribution from C&I programs is over three times that of residential programs.

C&I Program	**MW Enrolled (based on nominations)**	**Events per Season**	**Annual Incentive**	**2022 Performance (MW)**	**Total Incentive Payout**
Daily storage	9	30-60	$200/kW	5.5 MW	$1,096,000
Targeted storage	3	3-8	$100/kW	0.8 MW	$81,100
Targeted curtailment	194	3-8	$35/kW	137 MW	$4,805,500
Total	**206**	**n/a**		**143.3 MW**	**$5,982,600**
Residential Program	**Devices Enrolled**	**Events per Season**	**Annual Incentive**	**2022 Performance (MW)**	**Total Incentive Payout**
Thermostats	76,878	Up to 15	$20*	36.8 MW	$1,520,000
EVSE	1,819	Up to 15	Varies	0.2 MW	$36,000
Batteries	2,094	30-60	$225/kW	5.6 MW	$1,269,000
Total	**80,791**	**n/a**		**42.6 MW**	**$2,825,000**

**Customers also receive a one-time $50 enrollment incentive.*

Market Barriers

Market barriers for projects like storage and even EV adoption can be ameliorated through DR incentives. In fact, as mentioned previously, a DR incentive program can make a viable business case for installing a device that would not exist otherwise. So to that extent, DR does clear market barriers and enable greater market participation. However, DR is not a function of the competitive market – it is a policy-driven, regulatory market intervention intended to achieve the policy objective of leveling off peak demand on the grid (and avoids costs associated with those peaks). Market barriers aren't preventing greater DR management. Growth in DR would require regulatory-initiated programs that authorize utilities to provide greater DR programming and increase customer enrollment, because, as mentioned, current programming is at capacity. Even without marketing or promotion of the DR offerings in New Hampshire, the C&I program has a waitlist. At this time the residential program is 30-40 times smaller than comparable programs in Connecticut and Massachusetts, respectively. The customer demand and opportunity for greater access to DR programs in New Hampshire exists, but expansion of DR programming is contingent upon a policy determination and regulatory action.

The Competitive Market

DR is intended to alleviate pressure on the grid at peak periods and reduce overall demand at that peak. But DR programs in and of themselves are not a function of the competitive market—DR programming arise from regulatory initiatives which intervene in the market in a targeted way to achieve specific energy policy goals, such as peak demand shaving to reduce future capacity requirements. It should also be noted that just because New Hampshire promotes the competitive electric market and has implemented other mechanisms such as time varying rates, both the competitive market and rate designs are contingent upon customer participation to achieve the desired policy purpose. Many customers do not have the means or desire to participate in either the competitive market or enroll on a time-varying rate with its attendant costs and efforts on the part of the customer—from getting an electrician to install new metering equipment, to tracking and changing energy usage behavior. Demand response and managed charging programs enable effective and impactful load management in ways that are beneficial to customers and the system as a whole without relying on a change in customer behavior and require minimal action by customers. As discussed above, all that is really needed is customer enrollment, from there the programs themselves are what achieve the desired policy objectives.

In New Hampshire, the competitive retail electricity market has for many years involved the opportunity for end-use customers to procure electric supply service from a registered competitive electric power supplier ("CEPS") instead of through default service provided by the regulated electric distribution utility and its wholesale power supplier. Starting this year, community power aggregation ("CPA") programs sponsored by municipalities and counties will provide a third alternative to many customers. The electric supply service for customers participating in a CPA program will be provided either by a contracted CEPS or by the CPA itself acting as a load-serving entity ("LSE"), in each case pursuant to the applicable provisions of RSA Chapter 53-E and the Commission's Puc 2200 rules.

In virtually all such cases, the LSE, whether it is a CEPS, a wholesale supplier for utility default service, or a CPA acting as an LSE, will be the entity responsible for the related Load Asset in the wholesale market settlement system administered by ISO New England ("ISO-NE") under its tariff and market rules. As the holder of a Load Asset in the ISO-NE competitive wholesale market, the LSE is responsible for energy, capacity, ancillary services, net commitment period compensation, administrative charges, and other related charges and assessments based on the LSE's wholesale load obligation. ISO-NE is a public utility under the Federal Power Act, and its tariff and related market rules are subject to regulation by the Federal Energy Regulatory Commission ("FERC"). The FERC has exclusive jurisdiction over ISO-NE and its tariff and rules and, accordingly, state regulators lack authority to direct or approve changes to its competitive wholesale market designs, procedures, participation requirements, settlement processes, and related rates and charges.

As just discussed, DR programs exist separately from and do not depend on the competitive retail or wholesale electricity markets, so such programs do not make the existing markets more competitive per se. Instead, DR programs are intended to incentivize customer load reduction at times of peak demand, thereby reducing forecasts of capacity requirements.

As noted above, while time-varying rate designs may potentially provide additional value to certain customers participating in DR programs, the rate design itself is not the primary driver for DR adoption and customer value. Rather, it is the incentives built into the DR programs that serve as the motivation for customer DR uptake. Moreover, the Company's experience has strongly suggested that customer interest in time-varying rates or any competitive market alternatives is limited, as many customers do not have the means or motivation to actively participate and achieve the potential benefits available.

In summary, there are meaningful opportunities for DR program expansion that may be achieved through initiatives adopted at the retail regulatory level, as may be approved by the Commission, and without changes to existing competitive retail electricity market structures or to FERC-jurisdictional wholesale power market structures.

Expansion of Demand Response

Eversource 2022 Total DR program kW reduction results by state:

		Total kW reduction
C&I		
	MA	71,818
	CT	64,783
	NH	6,995
Residential		
	MA	20,184
	CT	21,764
	NH	659
		Total kW reduction
	MA	92,002
	CT	86,547
	NH	7,654
TOTALS		186,203

Of the company's 187 MW reduction on the ISO-NE grid during 2022 peak events, only about eight percent of that reduction came from New Hampshire customers enrolled in the company's DR programs. However, New Hampshire comprises approximately 20 percent of Eversource's total electric customer base and therefore has far fewer DR participants in both absolute and relative terms, which means there is excellent potential for expansion and growth.

In fact, the company has waitlists for both residential and C&I customers who want to enroll in existing DR programs. Eversource has been contacted directly by C&I customers such as the City of Dover, which is interested in the C&I curtailment program as a means to save taxpayer expenditures on energy while providing the grid benefits described in these comments. On the residential side, the table below shows significant growth in thermostat enrollments in MA and CT since 2020. However, the true expansion potential for DR in NH is unknown, as Eversource has had to refrain from marketing DR programs more broadly because the programs have had static funding since 2020 which is preventing new enrollments. Current budgets prohibit new enrollments from being accepted because the levelized funding is needed to continue to retain customers already enrolled from previous years. Should expanded funding become available customers on waitlists could be enrolled and marketing efforts could commence. Theoretically, expansion of DR programming in New Hampshire could happen relatively quickly and with only modest effort. The table below shows that with promotion and funding, DR programs in Connecticut and Massachusetts are growing at rapid pace, while in NH residential DR enrollment has leveled off.

Residential Enrollment

WiFi Thermostat	Eversource CT	Eversource MA	Eversource/Unitil NH
2020	14,680	17,088	1,480/111
2021	15,777	19,617	1,027/798
2022	**33,756**	**42,095**	**1,027/768**

Transactive Energy

Transactive retail electricity markets have become topics of interest in recent years, although the concept is not clearly defined within the scope of this docket, or in New Hampshire in general. One potential model for transactive energy is contemplated by the recent amendments to RSA 362-A:2-b, the Limited Electrical Energy Producers Act; however, that particular model is currently under review in Docket No. DE 23-026 to determine whether threshold federal jurisdictional issues would preclude or restrict implementation of the pilot programs described in that legislation.

Transactive energy is a broad concept that can be applied to varying degrees and for both broad and specific policy purposes. Rather than moving forward on assumptions, or with multiple, competing concepts of how to apply transactive energy to this DR discussion, further discussion of what transactive energy should mean in the context of DR and what the corresponding objectives are would be helpful prior to discussing how transactive energy can be enabled in this docket so that all parties have a uniform understanding of this concept and how it is to be applied to DR programming. It may be premature to spend significant time or resources in consideration of an unclearly defined concept that has associated open issues of jurisdiction and regulatory authority.

Fortunately, consistent with the discussion above, it is not necessary to adopt new market structures to facilitate DR program expansion in the state, and there is plenty that can be done to advance and achieve policy objectives within the existing retail energy market framework.

Further examination and consensus on what transactive energy should mean in the DR program context and the corresponding objectives and options would be helpful prior to deciding whether and how transactive energy might be considered in this docket. That initial step would enable all stakeholders to have a common understanding of transactive energy market concepts and how they might potentially be relevant in the context of DR programming.

With respect to Electronic Data Interchange ("EDI"), EDI in the electric utility context is designed to serve as a mechanism for data-sharing between competitive suppliers and utilities, and now municipal aggregations and utilities as well. Typically, that data is provided on a "batched" basis and at periodic intervals, typically overnight. EDI is not designed for the exchange of real-time metering or system operational data, and therefore it is not useful for any type of control or dispatch in real-time of distributed energy resources, such as those related to existing DR programs. The Company is not aware of any EDI systems that have been – or even could be – modified to provide such real-time data exchange as might be needed to facilitate transactive energy retail market transactions. And even if that were possible at a reasonable cost, it is unclear what added value or benefits for customers would be produced by real-time data exchange, and so the cost effectiveness of such changes are questionable.

It is also worth reiterating here that, just because competitive market or transactive energy mechanisms might exist, it is likely that the great majority of customers will not have the means or the motivation to participate. Fortunately, DR, demand management, and managed charging programs all but eliminate any responsibilities or burden on customers for active daily participation, and still enable the utility to manage loads in ways that are beneficial not only to individually participating customers but to the system as a whole while delivering economic benefits to New Hampshire customers.

ELECTRIC VEHICLES

Legal and Regulatory Support

There is both a legal and regulatory framework supporting the development of EV charging infrastructure in New Hampshire. As described in the settlement agreement for Docket No. DE 21-078, signed by all parties to the docket and approved by the Commission, SB 517 passed in 2018 and SB 131 passed in 2021 both find value and a certain degree of necessity for developing EV infrastructure throughout the state, and recommend utility EV infrastructure "make-ready programs" as the preferable vehicle for this development. As part of the mandate of SB 517 creating the Electric Vehicle Charging Stations Infrastructure Commission ("EV Commission"), the EV Commission was to make recommendations on: development of zero emission vehicle technology and infrastructure, including installation of EV charging stations; the development of EV charging stations, including high-speed charging stations, in state and federal highway corridors and at public transportation hubs and parking garages, and; changes needed to state laws, rules, and practices, including building codes and public utilities commission rules, to further the development of zero emission vehicle technology and infrastructure.[1] By October 2020, the EV Commission had issued its final report and among its

[1] Final Report Electric Vehicle Charging Stations Infrastructure Commission Senate Bill 517 (2018), page 1, available at: https://www.des.nh.gov/sites/g/files/ehbemt341/files/inline-documents/2020-12/20201030-final-report.pdf.

recommendations was authorizing public utilities to deploy EVSE make-ready programs.[2] The EV Commission specifically found that utility make-ready programs are particularly well-suited for enabling the advancement of EVSE deployment, and recommended the adoption of such programs.[3]

The Legislature expressed similar support for the important role utilities can play in EV infrastructure implementation when it passed SB 131 in July 2021, signed by the Governor on August 10, 2021. With SB 131, the General Court found:

> I. Availability of electric vehicle supply equipment (EVSE) is critical to facilitating the development of the overall electric vehicle (EV) market in the region and will support our tourism-based economy. Adequate EVSE in New Hampshire, and in particular direct current fast chargers (DCFC) along major travel corridors in the state, is necessary to enable travel within and through the state, promote tourism, generate jobs, and support consumers, businesses, and automobile dealers and manufacturers. The state should commit to the development of zero emission vehicles (ZEV) technology and infrastructure, including the state, private and rental residence, business, and municipal installation of EVSE.
>
> II. Electric utility investments in grid infrastructure to support the installation of EVSE lowers the barriers to such installation. Electric distribution companies (EDC) are uniquely positioned to enable strategic electrification as part of larger investments in grid modernization capabilities, specifically investments in electric vehicle charging infrastructure. EDC owned or funded behind the meter enabling infrastructure, also known as "make-ready" infrastructure, can accelerate charging infrastructure deployment, and it has the potential to put downward pressure on rates by spreading fixed costs over a greater volume of electric sales.

This legislative support provides the Commission with policy support and latitude to further develop EV charging infrastructure throughout New Hampshire, beyond the $2.1 million Eversource make-ready program approved in Docket No. DE 21-078 that pairs with funding from the VW Trust Mitigation Fund to develop charging stations along travel corridors in New Hampshire identified by DES. While this program is a much-needed step to begin catching up to development in neighboring and regional states that contribute to New Hampshire's travel and tourism economy, there is more to be done to create a reliable EV charging network throughout the state to ensure New Hampshire doesn't lose travel and tourism revenue, and can instead usher in the growing acceleration of the electrification of the transportation sector. The Commission could enable further EV make-ready programs consistent with the legislative support of SB 131 and the work of the SB 517 EV Commission, should such programs be proposed by the New Hampshire electric utilities for Commission review and approval.

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[2] *Id.* at 6.

[3] *Id.* at 7-8.

Ratepayer-funded programming that exists today

Adequate EVSE in New Hampshire, especially direct current fast chargers along major travel corridors in the state, but also Level 2 chargers in long dwell time parking locations, is necessary to enable EV travel to, within and through New Hampshire. Availability of adequately spaced EVSE is essential to overcome "range anxiety" and enable and encourage broader adoption of EVs by New Hampshire residents and residents throughout the Northeast.

As manufacturers continue to introduce a wider variety of EV models which will be available to a greater number of consumers in the coming years. Drivers will be best served if New Hampshire's EV charging market supports multiple business models, which will also have the benefits of generating new jobs and encouraging innovation and competition in equipment and networks services.

Utilities are uniquely positioned to enable strategic electrification as part of larger investments in grid modernization capabilities, specifically investments in EV charging infrastructure. Utility investments in EV charging infrastructure can address the limited availability of public charging stations, the upfront cost of charging infrastructure, and a lack of consumer awareness about EVs. Through such investments, utilities can accelerate charging infrastructure deployment enabling greater EV adoption and easing or removing range anxiety to provide for travelers to and through New Hampshire. This is particularly important to maintain the travel and tourism revenue that residents and businesses throughout New Hampshire rely upon.

Outside of New Hampshire, Eversource has demonstrated its proficiency in charging infrastructure deployment in neighboring Massachusetts, where the Massachusetts Department of Public Utilities ("DPU") authorized the investment of $55 million to implement the make-ready model to install, own and operate the infrastructure to support up to 4,200 Level 2 and DC Fast Charger charging ports at approximately 500 commercial customer sites, and with the approval of the DPU is launching an additional $188 million program building on the success of this initial implementation effort and expanding to include residential and fleet customers. Additionally, the Connecticut Public Utility Regulatory Authority ("PURA") has authorized Eversource to launch a 9-year make-ready investment program in Connecticut supporting thousands of new ports in residential and commercial locations.

In New Hampshire, in addition to the $2.1 million Eversource make-ready program approved in Docket No. DE 21-078, federal funding is available through the Infrastructure Investment and Jobs Act, (IIJA) approved in 2021, which includes $5 billion for light-duty EV charging infrastructure to be allocated across all states through the National Electric Vehicle Infrastructure ("NEVI") program. Of that $5 billion, approximately $17 million has been earmarked for New Hampshire over the next five years, through a process administered by the New Hampshire Department of Environmental Services. Other federal grants totaling $2.5 billion nationally through the NEVI program will be available for application through a competitive bidding process.

Customer contributions

Currently, commercial EV charging station installations in New Hampshire, regardless of how they are funded, follow the standard Eversource interconnection policies for any new work installation. While the load profiles of EV charging stations may be unique compared to other standard commercial building uses within their rate class, the infrastructure and interconnection is consistent with the normal course of business that the Company has always provided.

EV Charging and peak demand

The unique load profiles of public and other commercial EV charging applications are based on how charging stations are utilized by drivers; when, where and how drivers choose to charge their vehicles. Optimizing charging behavior to ensure efficient integration of this new load onto the distribution system, especially as EV adoption continues to grow, is critical to long term planning. There is nothing inherent about EV charging infrastructure itself that enables cost effective reduction of electricity consumption during periods of unusually high demand, however solutions have been and are being developed to address this.

In practice, there are a number of methods that customers can employ to control their EV charging loads, including:

- Power-sharing EVSE, where the combined demand across multiple EVSE is managed;
- Co-location with battery energy storage, where the net demand on the grid is managed;
- Co-location with other building or site loads managed as part of a Building Energy Management System;
- Vehicle or charger timing management by the customers (e.g., customers scheduling their vehicles to charge at midnight);

Some commercial chargers come with power sharing kits[4] or integrated battery storage[5]. In other jurisdictions, Eversource also has EV managed charging programs to encourage drivers to manage the timing of their charging. As a part of the Company's ratepayer-funded infrastructure programs, Eversource also requires public charging stations to be networked to facilitate future participation in utility-based load management programs.

Time of Use Rates

Finally, rates designed to encourage charging away from periods of peak demand are another tool that can be utilized in conjunction with the above solutions. Both commercial and residential EV-only TOU rates were approved for Eversource in DE 20-170. It is the Company's experience that TOU rates are not the most effective or efficient solution for changing customer EV charging behavior to reduce peak demand. As a matter of ratemaking policy, and supported by the Company's experience, residential customers prefer simplicity in rates and billing.

[4] For example, the ChargePoint CT4000 Level 2 station has a Power Management Kit available. https://www.nationalcarcharging.com/products/chargepoint-ct4000-pmgmt

[5] For example, see FreeWire charging products at https://freewiretech.com/.

Various customer employed load management options mentioned in the bullets above have given customers flexibility to manage their electric use. However, the Company has found that customers typically do not want to actively manage their usage unless it can be easily effectuated through a straightforward tool. In the Company's experience, utility intervention through load management programs like managed charging have been the most efficient and cost-effective solution for encouraging beneficial charging behavior that can achieve charging policy objectives such as reducing peak demand. For commercial EV customers and site charging hosts, demand charges in rates are of greatest concern, and TOU rates present a challenge because these commercial charging station customers are offering a service and therefore must be available to potential consumers, regardless of the time of day. Because of the nature of commercial EV charging load curtailment is generally not feasible – at least for public charging - unless the host is able to utilize a load management solution mentioned above.

CONCLUSION

Eversource appreciates the opportunity to provide these introductory comments to address at a high level the concepts outlined by the Commission in the Order of Notice for this docket, at looks forward to further engagement on these issues.