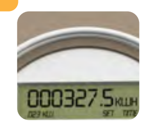
REPORT | August 2020

VERMONT
DEPARTMENT OF PUBLIC SERVICE

ADVANCED RATE DESIGN INITIATIVE

Vermont Public Service Department



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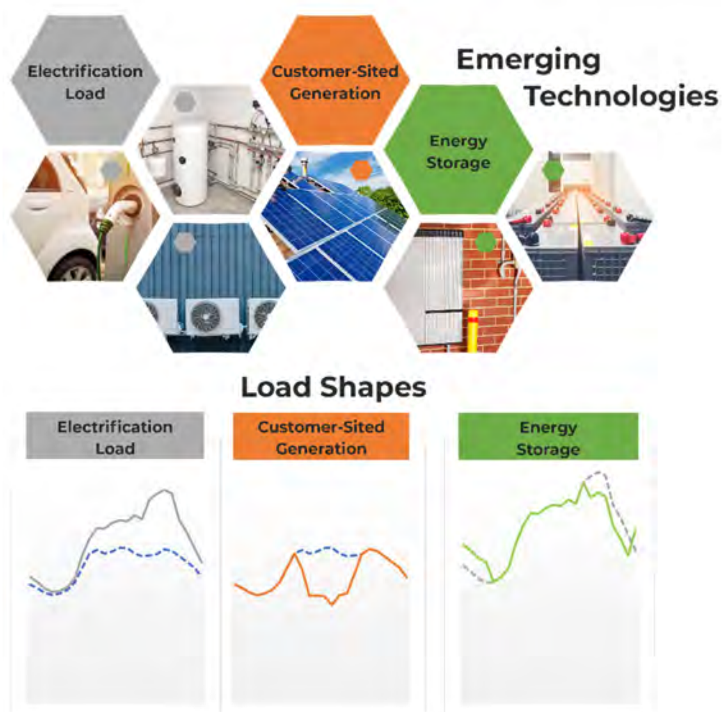
EXECUTIVE SUMMARY

In September 2019, the Vermont Department of Public Service (the Department or PSD) retained the services of NewGen Strategies and Solutions, LLC (NewGen) to assist with an Advanced Rate Design Initiative Study (Study). The purpose of the Study was to analyze innovative retail rate applications and other forms of Load Control Programs for electric utilities in the State of Vermont (Vermont) in response to the anticipated rapid adoption of Emerging Technologies, as defined herein. This Study is premised on the view that Load Control Programs can support Vermont in achieving its energy objectives while containing costs.

Load Shapes and End-Use Technology Adoption

The patterns of electricity usage around the country are evolving as a function of technology adoption. Such technologies include:

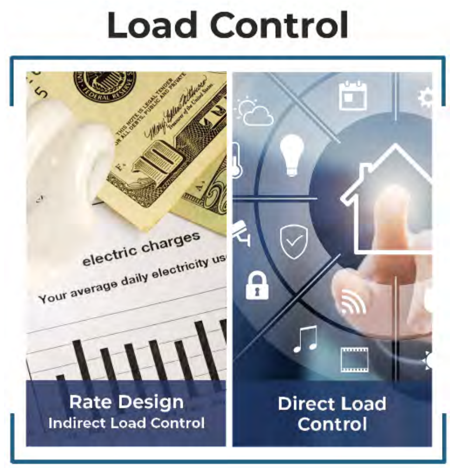
1. **Electrification Load:** Technologies that provide a service to end-use customers (e.g., transportation, space condition, and water heating) that have traditionally been provided by directly burning fossil fuels (e.g., gasoline, natural gas, propane, fuel oil, etc.), but are now electric.
2. **Customer-Sited Generation:** This Study specifically addresses the impact of Distributed Solar Photovoltaic (PV) generation systems (e.g., smaller scale, typically located at the customers' premises).
3. **Energy Storage:** This Study does not differentiate between different energy storage technologies, but instead refers to all such technologies as "Storage."



Throughout this report, these types of technologies are referred to collectively as "Emerging Technologies." These Emerging Technologies are the subject of this Study because their adoption is increasing, and because they can be flexible in how and when they consume electricity. When properly managed by the customer, utility, and/or 3rd parties, this flexibility can save money by improving the efficiency of Vermont's electric system operations.

Types of Load Shape Management

Emerging Technology adoption is changing and driving substantial new costs for electric utilities that are maintaining reliable electric service. Historically, electric utilities may have addressed increasing costs by planning to build new assets or additional purchases from the market. With increasing flexibility available in Emerging Technologies, and advanced metering, communications technology, and device automation, electric utilities are increasingly seeking innovative ways to manage changing load shapes.



The purpose of this Study was to analyze two types of innovative load shape management tools:

1. **Rate Design**, or Indirect Load Control; and
2. **Direct Load Control,** or direct control of end-use customer electricity usage by the utility and/or a 3rd party.

Electric utilities across the country are moving forward with Load Control Programs of various forms. Such programs are designed to deliver utility services at lower system costs. Utilities are constantly balancing their financial, economic, and operational concerns between maintaining their systems and investing in the future, all while delivering a reliable service at a competitive cost.

The Value of Load Control Programs

Specifically, Rate Design has traditionally been seen as a cost accounting exercise and a mechanism by which a utility recovers its investments and on-going operating costs. However, specific charges and elements within Rate Design are quickly becoming part of a more strategic effort coupled with Direct Load Control to foster more efficient use of the electric system. Combining strategic Rate Design and Direct Load Control avoids future system costs through proactively managing load shapes.

The Flexibility of Emerging Technologies

An important characteristic of Emerging Technologies is their flexible nature to deliver valuable services to the grid when and where they are needed. Consumer Electric Vehicles (EVs) and electric heat pump water heaters with a water tank are flexible loads, as their electricity consumption profile can be shifted with minimal impact to the customer. Cold Climate Heat Pumps (CCHP) coupled with back-up space conditioning can also be flexible electricity consumption source.

The flexibility of Emerging Technologies offers utilities the opportunity to manage customer load shapes through Load Control Programs and Rate Design pricing signals. Rate Design can send substantial pricing signals to customers in certain hours of the year, thus changing load shapes. Such a Rate Design also allows a customer the choice to pay more to consume electricity during more expensive times of the day and year. Direct load control allows the utility to leverage its core competency in system dispatch and management by curtailing or accruing value-added services from the customers load on their behalf, or reducing load during expensive hours (e.g., peak periods on the system). In exchange for the reduction in customer load, they are compensated with direct payments or other incentives (such as certain investments made by the utility).

Implementation Challenges of Load Control Programs

Time-differentiated Rate Design is not a phenomenally new concept in the electric industry. However, absent a regulatory mandate, it is common for such Rate Designs to see low levels of program enrollment and participation.

> ***The efficacy of Load Control Programs is largely a function of customer participation or enrollment, which is critical in the implementation process for innovative rates.***

It is recognized that Load Control Programs require investments in systems for communications, metering, billing, and/or data management and other infrastructure. Such investments take time to plan, implement, and evaluate, and are very specific to each utility. Evaluating and pursuing future Load Control Programs to manage costs will need to incorporate the cost and time required for these investments as appropriate.

Study Objectives

In initiating this Study, the Department sought to engage Vermont stakeholders in a dialogue regarding the impacts of Emerging Technologies on the state's future electricity market, and to discuss the prospect of utilizing innovation in Load Control Program design to manage the increased costs associated with the future market. This report serves as documentation of the Study process, discussions, modeling efforts, feedback, and recommendations gleaned from five Stakeholder Engagement workshops and extensive system and financial modeling tailored to the Vermont system. In facilitating this Study, NewGen developed recommendations for Vermont's regulators, utilities, companies, and other industry stakeholders to leverage innovative Load Control Programs in an effort to proactively manage the future impacts of Emerging Technology adoption.

Study Recommendations

The following provides a summary of the recommendations and challenges the Study identified:

Study Outcome

Innovative Load Control Programs provide a platform to address unmitigated load to benefit customers, the utility, and the State of Vermont

1. Electric rates should create stability, equity, and recover costs, but can also be seen as a resource to manage future costs through price signals to change customer behavior and incentivizes participation in flexible load management.
2. Implementation of innovative rates face enrollment challenges. However, improved Rate Designs as well as regulatory encouragement (e.g., relying more heavily on default rate plans that encourage participation, or mandating participation through regulation) may improve their success.
3. Electric rates should target certain types of loads (e.g., flexible load) and specific rate offerings (e.g., EV-only or EV-linked rates or rate riders) that are more responsive to price signals, which improves response and program enrollment. Specific rate implementation strategies should be tailored and uniquely developed by each utility.
4. Utilities should actively market innovative rate and related program offerings. For example, creatively and proactively targeting customers where electric consumption is part of the transaction (e.g., when disbursing incentives, such as EV chargers, or engaging the customer at

the point of sale for EVs, electric heat pumps, etc.) leads to increased customer participation. Marketing efforts should include clear and concise educational campaigns regarding the benefits of Rate Designs targeted to specific customer segments.

5. Utilities and state regulators should look to new business/service models as technologies further evolve. These new business models should allow and encourage participation of 3rd parties in the market as partners to both utilities and their customers.

Rate Implementation Strategies

Utilities in Vermont, and across the country, face challenges in implementing Load Control Programs. Rate implementation strategies identified during this Study are meant to be cumulative, with each successive step increasing the complexity and ability to manage load. The figure below provides a summary of five steps recommended in this Study to support the integration and adoption of more complex rates for the Vermont utilities and stakeholders. Some utilities indicated they were already well along the continuum of successive steps; others indicated that while later steps were not sequential, they were important to implementation of advanced Rate Design. The intent of this graphic is to suggest a series of individual strategies tailored to each utility with the goal of increasing adoption of Load Control Programs in their service territories to address the need for load management and identify areas for cost reduction.

SECTION 1
INTRODUCTION

The electric sector across the country is remarkable for its scale, reliability, and its relative pricing and technology stability over the last century. However, the industry is rapidly evolving as new technologies are adopted by an increasingly technology-oriented customer base. Technology evolution, the expansion of wholesale power markets with independent transmission organizations, environmental concerns, and state and local mandates for change are driving innovation in utilities' efforts in recovering and managing the cost of providing reliable electric service. How customers adopt technologies and how utilities, regulators, and other entities respond to the future reality will change the manner in which utilities operate and policymakers regulate the sector.

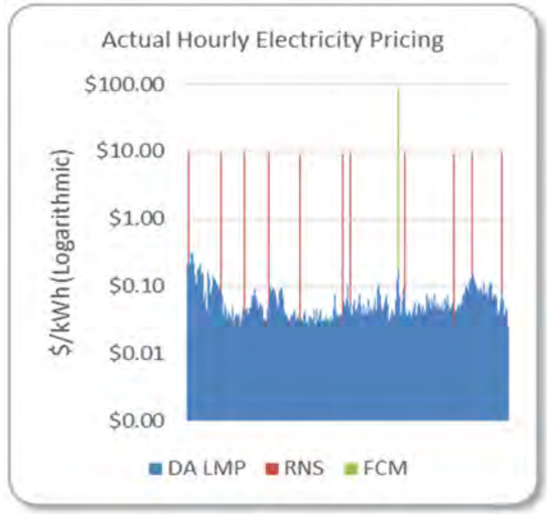
1.1 The Vision for Vermont's Energy Sector

Embedded in state law and described in detail in the Vermont Department of Public Service's (the Department or PSD) Comprehensive Energy Plan (CEP), the State of Vermont (Vermont) has established ambitious goals for decarbonizing its electric sector and the broader state economy. These ambitions are likely to grow in the future and the electric utility sector is a key point of leverage in achieving these goals. The CEP framework currently enjoys broad support from industry stakeholders and provides solid industry guidance. The work of the Department, the Vermont Agency of Natural Resources, and the Energy Action Network (EAN) further help to provide updates on renewable energy and decarbonization efforts by sector, which are necessary to measure the state's pursuit of its environmental goals. Energy consuming sectors of particular emphasis and opportunity identified in the CEP are transportation and buildings. Other areas identified in the CEP include increasing adoption of clean energy technologies, of which Vermont is a leader in the country.

A host of factors will impact the structure and operations of Vermont's future utility environment. These factors include, but are not limited to, the adoption of Emerging Technologies (as defined herein, by end-use customers), utility strategic planning efforts, responses to utility requests for investments by regulators, environmental concerns by the general public and policy makers, and general economic conditions in the state and across the country. Similar to most jurisdictions, Vermont utility and industry planners focus their efforts on pursuing the least-cost methods to meet peak energy demand. Further, such efforts occur in conjunction with the pursuit of Vermont's decarbonization and other environmental policy objectives. Historically, investments to serve peak demand are fixed assets with significant planning and investment requirements. Changes in market dynamics generally reduce the fixed nature of a utility's investment in generation assets. However, additional transmission and distribution system capacity require planning efforts, which include a thorough analysis of how their costs are recovered and from whom.

1.2 Technology Adoption, Evolving Load Shapes, and Electric Utility Costs

The Advanced Rate Design Initiative Study (Study) is focused on evolving electric load shapes in Vermont as a result of increasing Emerging Technology adoption. Electric utilities incur costs of providing reliable electric service to customers in various ways, a vast majority of which vary based on how individual end-use electric customers consume power, and how that consumption is aggregated to produce an electric load. The types of costs analyzed within the Study include the following utility functional areas:

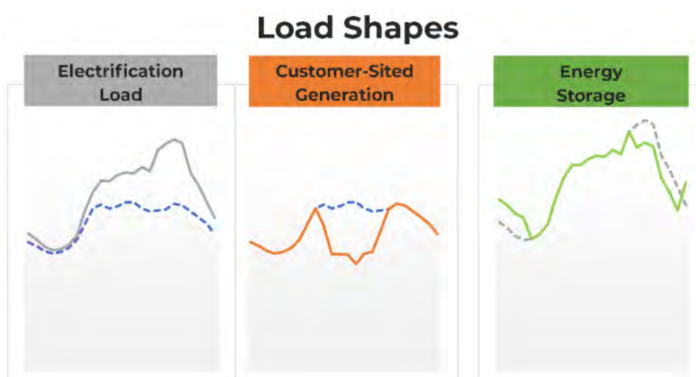


1. Wholesale Capacity and Energy purchases from ISO-New England (ISO-NE)
2. Renewable Energy Credit (REC) purchases for Renewable Energy Standard (RES) compliance
3. Regional Network Service (RNS) Transmission
4. Distribution System Capacity

Utilities incur costs from each functional area above as a function of electric load on the utility's system during specific times of the day/month/year, as measured at different points on the Vermont electric system.

Electric load shapes in Vermont are evolving as a function of technology adoption at the end-use customer's location. Such technologies are generally categorized as[1]:

1. **Electrification Load:** Technologies that provide a service to end-use customers (e.g., transportation, space condition, and water heating) are traditionally provided by directly burning fossil fuels (e.g., gasoline, natural gas, propane, fuel oil, etc.). Advances in technology have prompted a switch to electricity from direct consumption of fossil fuels as the prime energy source for several of these end-use applications. Vermont's decarbonization policy objectives support the adoption of Emerging Technologies to achieve the state's environmental objectives. "Electrification" is a term commonly used in the electric industry to reflect converting these devices from direct consumption of fossil fuels to electricity. For this Study, such technologies include:



   a. Electric Consumer Vehicles (EV)
   b. Cold Climate Heat Pumps (CCHP) providing space conditioning
   c. Electric Water Heater, typically Heat Pump Water Heaters

2. **Customer-Sited Generation**: Electricity generation technologies located at the customer's premises, reducing the customers' electricity consumption from the electric utility when the customer's generator is producing. For this Study, Customer-Sited Generation focuses on smaller scale, Solar Photovoltaic (PV) generation systems sited at the customers' premises.

[1] Throughout this report, these types of technologies are referred to collectively as "Emerging Technologies." This list is not exhaustive nor comprehensive for all newly emergent technologies in the electric market, but serves to define the scope of this Study and guides the discussion of results and recommendations presented herein.

3. **Energy Storage:** Technologies that consume electricity from the customer or utility generation and store that electricity for consumption at a later time by the customer and/or export the electricity to the grid during other times. This Study does not differentiate between different energy storage technologies, but instead refers to all such technologies as "Storage."

These Emerging Technologies are critical to the Study for two reasons: 1) because the adoption of these technologies is increasing and 2) their inherent flexibility relative to how and when they consume electricity. Properly managed by the customer, utility, or 3rd parties, this flexibility can reduce costs by improving the efficiency of Vermont's electric system operations.

Increased adoption of Electrification Load and Energy Storage will drive an increase in electricity consumption in the state. This increase in electricity consumption then drives new costs of providing electric service. However, this increase in the electric cost of service is offset by a reduction in consumption and fossil fuel purchases otherwise required by the incumbent technologies.

1.3 Load Impacts and Control of Emerging Technologies

It is reasonable to assume that a substantial portion of Electrification Loads will utilize the electric system in a largely coincident fashion or will tend to consume electricity at the peak system consumption periods. This is due to customers conditioning their homes, heating their water, and charging their EVs in the evenings upon returning home from work, which often aligned with the Vermont electric system peak demands. This coincidence is exacerbated by space conditioning technologies utilized most frequently during the hottest and coldest days and hours of the year.

> **Study Results**
>
> **Modeled results conclude unmanaged load growth from Emerging Technology adoption will create substantial upward rate pressure**

Concentrating the electric usage of Electrification Loads into a period of a few hours can drive substantial costs to the Vermont electric system. Such costs are associated with capacity that the state's utilities must build or purchase to deliver enough power to serve peak demand at the time in which it occurs. This includes purchases in the ISO-NE Forward Capacity Market (FCM), RNS transmission pool costs, and distribution system upgrades. Based on the modeling completed for this Study and depending on actual timing and adoption rates of Electrification Loads, Vermont's system could see an increase in capacity-related costs of up to 80% by 2040. This represents an incremental $500 million (M) in capacity costs for providing reliable electric service.[2] Such costs do not include savings realized by Vermont's population from avoiding fuel purchases as a result of adopting Emerging Technologies.

Typically, electric utilities plan for these capacity needs by either planning to build new assets or increase purchases from the market. However, with innovations in metering, device communications, and automation, electric utilities may now look to manage the increasing capacity needs and changing load shapes from Emerging Technology adoption in new ways:

1. **Indirect Load Control**, **or Rate Design:** This form of load control involves the electric utility using time-differentiated Rate Design. Time-differentiated Rate Design charges a premium for electric consumption during the times aligned with peak periods that drive substantially higher costs to the utility. Such pricing signals lead to changes in customer load through some combination of

[2] As described more fully in Appendix A, this outcome is driven by assumptions for Emerging Technology adoption.

technology adoption or behavioral change. It is also likely the efficacy of the load control increases as the pricing differential between on- and off-peak periods increases.

2. **Direct Load Control:** This is the utility (or a 3rd party) directly controlling the end-use customer's device(s) and/or electricity consumption to better manage the timing of electric usage on the utility's grid. Typically, such direct load control includes a financial incentive for the customer, the 3rd party (if applicable), and the utility, the latter of which can reduce costs of service through better shaping load.

This report presents how Indirect and Direct Load Control measures taken by the utility can manage the impacts of increased adoption of Emerging Technologies. Collectively, both Indirect (Rate Design) and Direct Load Control are referred to as Load Control Programs. As demonstrated in this report and the modeling completed for this Study, the value of Load Control Programs in managing the impacts of Emerging Technologies is substantial. In comparison to the $500M upward cost pressure outlined above, it is estimated that a reasonable deployment of Load Control Programs to manage impacts of Emerging Technologies can save utilities and customers in Vermont $150M – $200M annually versus the unmanaged Technology Adoption Scenario (as defined herein).

This report presents the value that Load Control Programs can bring the utility in managing load shapes. However, such Load Control Programs may require investments in certain Information Technology (IT), communications, broadband, metering, billing, and/or data management infrastructure prior to development and implementation. Such infrastructure may represent a substantial investment by the utility, which should be acknowledged in the context of the $150M - $200M savings identified for Load Control Programs. Further, such investment in infrastructure takes time. Feedback from stakeholders engaged in this Study suggests it takes several years to replace a legacy metering, billing, and/or meter data management system. Thus, utilities should evaluate the costs and time required for IT infrastructure investments with the benefits of Load Control Programs prior to substantial Emerging Technology adoption by customers.

1.4 Advanced Rate Design Initiative Study

In September 2019, the Department retained the services of NewGen Strategies and Solutions, LLC (NewGen) to assist with the Study. The purpose of the Study was to analyze innovative retail rate applications and other forms of Load Control Programs for electric utilities in Vermont in response to the anticipated rapid adoption of Emerging Technologies. This Study is premised on the view that Load Control Programs support Vermont's efforts in achieving its energy objectives while containing costs.

Analytical elements to support this Study were accomplished using NewGen's proprietary platform called the Load Shape Analysis Model (LSAM™), which was customized for this Study based on feedback received from the Department and other stakeholders. LSAM™ forecasts the evolution of load shapes as a function of technology adoption and responsiveness to pricing signals and employs Rate Design and dynamic load management as tools to identify and mitigate forecast cost increases. The results of the LSAM™ analyses were utilized to initiate discussions, inform decision making, and present Study findings for a series of facilitated Stakeholder Engagement workshops, beginning December 2019 and concluding July 2020. Feedback and consensus from the workshop participants were critical to the success of this Study.

1.4.1 Study Goals and Objectives

In the process of evaluating innovative Rate Designs for Vermont, the Department and Study participants designed a series of Study goals and objectives. Specific Study outcomes included the following:

- Present a vision of collective load for the Vermont (system) with respect to the cumulative impacts of Emerging Technologies on hourly load profiles.
- Provide a mechanism for stakeholders to evaluate Load Control Program concepts to achieve specific objectives as they relate to system efficiency, environmental policy (including decarbonization and renewable energy goals), and least cost resource planning objectives, while recognizing the need to maintain revenue adequacy and equity objectives in Rate Design.
- Communicate the Study processes and findings through a series of facilitated Stakeholder Engagement workshops to increase awareness of potential impacts of future load and Emerging Technology scenarios and the role of Load Control Programs as a resource for managing future costs.
- Establish a modeling tool useful to utilities and stakeholders to better understand the risks and opportunities for making more effective use of Load Control Programs.
- Establish a guidance document (this report) for utilities and Department advocacy centered on opportunities for innovation in Rate Design, including the success in the character of new rates, and potential strategies for greater success in implementation. This report is also intended to help inform the Vermont Public Utility Commission (Commission) on the impacts to load as a result of changes in technology and how Load Control Programs can influence a utility's load profile.

This Study facilitated a dialogue on Load Control Programs and developed a modeling framework to facilitate strategic decision making. Groups represented at these Stakeholder Engagement events included many of the Vermont utilities; Vermont's statewide bulk transmission provider, state agencies; non-governmental organizations (NGOs); industry consultants, industry representatives including energy efficiency providers and providers of distributed resources and net metered systems; customer groups; and 3rd party service providers.

As identified during the stakeholder process, Vermont faces a series of challenges in implementing Load Control Programs that achieve greater levels of customer enrollment and participation. These increased levels of customer participation are required to manage the expected increases in load and accompanying capacity-related costs of service that come with wider adoption of Emerging Technologies. This Study addresses implementation challenges to some extent, but additional future work is required to adequately address challenges in various regulatory settings, such as before the Commission for the state's 17 electric utilities, as well as before the Board of Directors and City Councils / Advisory Boards of the various publicly owned utilities in the state. This report offers insight distilled from the Stakeholder Engagement events on various approaches to address implementation concerns; however, each utility's strategic approach to Load Control Programs must be individually tailored to recognize their unique financial, operational, and customer-use characteristics.

1.5 Report Structure

This report provides a future vision of the Vermont electric system and how innovative Rate Design can assist in managing that future. Section 1 (Introduction) provides a background of the elements developed for this Study, including an introduction to the selected end-use technologies driving change in Vermont's electric sector. Section 2 (Vermont Rate Vision) summarizes the state's vision for future rates, how Rate

Design is anticipated to impact load, and the Study metrics. Section 3 (Quantitative Findings and Modeling Results) provides the relevant findings of the Study, including a projection of the resulting metrics, as well as the results of how various rate and rate projections are anticipated to impact future load. Section 4 (Study Recommendations) provides a summary of the rates recommended for consideration by Vermont utilities, as well as a five-step plan for implementation. Appendix A provides a summary of the LSAM™ functionality, as well as a list of the assumptions and sources utilized in the modeling effort. Appendix B describes the Study methodology and definitions. Appendix C provides a summary of the agendas and attendees for the Stakeholder Engagements events. Appendix D provides a summary of the survey of innovative rates.

1.6 Acknowledgements

NewGen gratefully acknowledges the time, effort, and resources spent by all the stakeholders and participants of this Study. A list of the utilities, companies, regulatory bodies, organizations, and other stakeholder groups that have participated in this Study is presented below in alphabetical order.

- Aegis Renewables
- Agency of Commerce and Community Development
- Burlington Electric Dept. (BED)
- DC Energy Innovations
- Demand-Side Analytics
- Dynamic Organics
- Energy Action Network, Vermont
- Energy Futures Group
- Efficiency Vermont
- Green Mountain Power (GMP)
- Grassroots Solar
- Greenlots
- JouleSmart
- MMR LLC
- Norwich Technologies
- Oracle
- Packetized Energy
- Peck Electric
- Public Service Department
- Regulatory Assistance Project
- Renewable Energy Vermont
- Vermont Electric Cooperative (VEC)
- VEIC
- Vermont Electric Power Company (VELCO)
- Vera Renewables
- Vote Solar
- Vermont Public Power Supply Authority (VPPSA)
- Washington Electric Cooperative

Further, the utilities in the state, including especially GMP, BED, VEC, and VELCO, provided staff and resources to investigate specific analyses related to their system and were respectful and helpful in the process of developing the Study. The Stakeholder Engagement process provided valuable insight and direction for the Study, and NewGen is grateful for those that gave their time and effort to attend, present, and participate in those events. NewGen gives a special thanks to Jared Duval and Carolyn Wesley of EAN for providing the online platform by which the Stakeholder Engagement events could continue despite the challenges regarding the Coronavirus Disease 2019 (COVID-19) pandemic. Many others assisted by lending technical assistance, logistical support, and helped by guiding the process, as well as shaping the direction of the effort, conclusions, and recommendations that unfolded. This material is based upon work supported by the U.S. Department of Energy's, Office of Energy Efficiency and Renewable Energy (EERE), under the State Energy Program Award Number DE-EE0008668/0000.

SECTION 2
VERMONT'S RATE VISION

2.1 Rate Design Impact on Load

Growth in Emerging Technologies is a relatively new and promising opportunity for utilities in Vermont and is generally consistent with state goals. Technologies historically powered by fossil fuels are increasingly replaced by electric technologies powered by a progressively renewable electric grid. The increasing adoption of Emerging Technologies is driving load growth expectations, but the exact timing of technology adoption and the resulting specific mix of load shapes remains uncertain.

Generally, forecasted load growth brings expectations for downward pressure on electric rates through the amortization of electric utilities' costs over a greater number of kilowatt-hours (kWh). The load growth from Emerging Technologies supports this downward pressure, but also presents the risk of significant cost increases across the state if unmanaged. Under high growth scenarios, the Vermont system peak demand will increase to unprecedented levels and continue to grow rapidly. Even "clean" and flexible Electrification Loads can drive significant rate increases absent strategies to manage load shapes and corresponding costs.

Effective strategies to manage the impacts of Emerging Technologies can help lower costs of electricity and rates for Vermont ratepayers, while achieving Vermont's energy and environmental objectives. The impacts of widespread PV adoption are already being felt and are expected to continue. Such impacts represent a challenge for the system to manage. As with other emerging technologies, PV represents an area ripe for consideration of Rate Design solutions – broadly framed to include both net metering payments and retail costs for service.

As identified above, the projections for load growth in the state are largely associated with adoption of the Emerging Technologies identified for this Study. Key questions for utilities and their regulators to consider for future discussions will include:

- How to best accommodate Emerging Technology loads without requiring substantial investment in new infrastructure?
- If load growth from Emerging Technologies requires new infrastructure, who pays for such investment?
- How are these costs recovered?

A conservative estimate of future costs to support unmanaged incremental load associated with selected Emerging Technologies suggests a significant increase in key utility cost indicators. It is possible that some utilities will choose to assign a portion of the distribution-related costs to specific customers using Line Extension policies or other such directives, if such costs may be reasonably directly assignable to a single end-use customer. However, these cost recovery efforts may discourage fuel switching, which could hamper progress towards Vermont's decarbonization objectives. Further, a substantial portion of these anticipated higher electric costs are associated with wholesale power supply capacity, RNS transmission costs, and the potential need to substantially upgrade the state's distribution system. Such capacity investments are not easily assignable to specific customers, and thus likely recovered more broadly from the state's electric customers through retail rates.

Electric utilities across the country are developing Load Control Programs as the industry evolves to meet the needs of its customers, its businesses, its regulators, and society more broadly. Utilities are constantly balancing their financial, economic, and operational concerns between maintaining their systems and investing in the future, all while producing a reliable service at a competitive cost. One type of Load Control Program – Rate Design – is traditionally seen as a cost accounting exercise and a mechanism for utilities to recover investments and ongoing operating costs. However, Rate Design alone (or coupled with Direct Load Control Programs), are an increasingly strategic effort to foster more efficient use of the electric system by avoiding potential costs associated with fuel switching.

Utility Load Control Programs referenced in this Study are dynamic in their pricing and are dependent on advanced utility metering, communications, automation, and controls necessary to price, dispatch, or manage end-use devices and distributed resources. Such programs are considered “forward-looking” as they recognize a utility’s marginal (and avoidable) costs, are generally dynamic in nature, time-based, and aligned with market prices and environmental conditions. They also may provide direct connections to customers’ Emerging Technologies and may evolve to adopt non-traditional utility pricing strategies. Load Control Programs are designed to benefit the electric system, either economically by reducing or avoiding costs, and/or achieving a societal benefit through reductions in power generation emissions or other public policy objective. Load Control Programs are integral to the orchestrated effort to advance both ratepayer objectives for lower costs and public policy objectives for cleaner total energy services. The cost-savings from Load Control Programs may be shared directly with end-use customers, 3rd party aggregators, service providers, or socialized across all customers, or some combination thereof for greater impact.

Selected aspects of Load Control Programs have historically served sophisticated customers, such as large industrial users, and provided the basis for many utility-based Demand Response (DR) programs. While these programs often proved worthwhile investments in many jurisdictions, the underlying pricing schemes of such programs are not adopted on a widespread basis across the country. Utilities in Vermont have initiated efforts to actively leverage Load Control Programs in recent years in pursuit of policy objectives, including time-of-use (TOU) rates and Direct Load Control of behind-the-meter energy storage systems.

Opportunities exist for Vermont utilities to employ additional Load Control Programs to reduce the future costs associated with adoption of Emerging Technologies. Such Load Control Programs should be designed to shift future load from anticipated peak periods to non-peak periods, thus reducing the energy- and capacity-related costs utilities incur during peak periods. Such an approach to Load Control Programming may include incentives and pricing that provides values directly to the customer or 3rd party service providers that may manage load shapes on the customer’s behalf. This Study evaluated specific Load Control Programs to shift load and reduce future costs associated with increased demand from the adoption of Emerging Technologies in Vermont.

2.2 Electric Rates as a Resource

Historically, structural rate changes were more cautions, measured, stable, and static in character. Rate Designs and structures were not significantly changed, though pricing is frequently updated to reflect a change in the utility's underlying costs. Typically, rates that included a time-varying price signal (such as static TOU rates[3]), are modest, and participation in such rates is optional with limited marketing. Therefore, participation in these rate programs is low, and the programs fall short in affecting customer behavior.

Voluntary TOU rates often lead to a self-selection bias: those customers with electric usage that inherently aligns with TOU periods often opt into the program, do not change behavior, and still save money on their bill. This self-selection bias ultimately results in lower revenues to the utility but does not often come with an accompanying decrease in the utility's cost of service. Additionally, applying a single TOU rate to an entire household or business may require a substantial amount of time and effort by the customer to shift electric usage of multiple appliances or other end-uses, when customers generally do not wish to pay such close attention to their electric consumption. Further, where such load shifting results in making sacrifices to space conditioning, the customer's comfort may also suffer. Sacrificing comfort can deter customer enrollment in these rate offerings. Finally, rate offerings are often based on a relatively minimal pricing differential between on- and off-peak periods, which mutes the benefit a customer receives to change their electric usage.

For Rate Designs that offer time-varied pricing that is not static, but is dynamic based on market pricing, tradeoffs occur in terms of complexity in on-peak period timing (e.g., it does not occur at the same time on the same days of the week) and less frequent need for the customer to change electric consumption patterns. For customers to respond to such a dynamic pricing program, ample communication to the customer is required to provide a clear indication of pending on-peak events and allowing the customer time to plan and respond accordingly. For less complex users and customer classes with larger numbers of customers, the utility is generally in a better position to attempt to manage load directly on the customer's behalf in response to dynamic market pricing. For dynamic pricing, the price signals largely mirror upstream wholesale market conditions, especially bulk transmission, resource capacity, and ancillary services (e.g., frequency regulation). Examples of dynamic rate pricing include Real Time (RT) Pricing, Critical Peak Pricing (CPP), Variable Peak Pricing (VPP), Peak Time Rebates (PTR), and others.

2.3 Load Control Programs Differentiated by End-Use

Certain loads, such as those associated with EVs, CCHP, and water heaters, have the ability to fluctuate or shift consumption over time without significant disruption to the customers. There are many variations on this theme, but flexible loads in general require coordination between the utility and the customer, either through notice or through automation and direct control, to provide broader system benefits. The range of options for Rate Design and load control systems include simple end-use clock-based solutions or "feathered" controlled systems for residential customers. For example, a utility could curtail 200 megawatts (MW) of load at 8:00 PM for two hours, but then only allow 50 MW to come back in each hour starting at 10:00 PM. This would allow the load to come back gradually, avoiding the creation of a

[3] Static TOU rates are those that define the time periods and pricing in the utilities published tariff and are set for the period for which the rates are applicable.

new peak immediately following the curtailment period. For complex flexible loads, strategic load interventions with larger customers typically involve formal notification and specific programs. Advance versions of flexible load management systems include automation and remote control over devices like EV charging equipment or battery storage.

This Study evaluates the use of various device-centric rates (such as EV-only rates), as well as dynamic pricing programs (such as CPP) to determine the potential impact on customer behavior and consumption. Beneficial changes in customer behavior result in shifting peak period energy usage and a reduction in the total system costs associated with meeting load during those periods. The concept of using rates as a resource aligns with Vermont's rate vision of managing incremental technology-related load growth to benefit of the customers, the utility, and the state.

EV Only Rates

EV load is flexible and is highly elastic to even modest on- to off-peak pricing differentials, creating substantial opportunity for targeted Load Control Programs

Another key end-use that should be considered in designing Load Control Programs is the unique character of commercial and industrial (C&I) loads. C&I loads are largely outside the scope of this Study, which focused on Emerging Technologies primarily at residential locations. C&I loads are typically much larger than residential loads, can be flexible, and may yield substantial shifting of loads to help manage a utility's system. Many Vermont utilities have developed C&I Load Control Programs for specific applications, such as snow making equipment to support the Vermont ski resorts. As Vermont and the greater ISO-NE electric region continues to evolve, such C&I loads may be incentivized to shift load to mid-day periods when solar production is at its greatest and marginal energy prices are at their lowest. Further, as C&I loads have modified their operations in response to past incentives, they shifted consumption to evening or off-peak hours. These previously off-peak hours may become on-peak due to the impacts and consumption profiles of Emerging Technology adoption. Therefore, utilities should continue to engage C&I customers and consider developing additional Load Control Programs to incentivize such loads be flexible to evolving cost drivers.

2.4 Implementation and Efficacy Challenges for Load Control Programs

Customer enrollment in Load Control Programs is often limited due to pilot program design, customer interest, perceived or actual inconvenience of changing behavior, risk of increasing electric bills, and/or other factors. It is a common experience in the electric industry for utilities to have "on-record" long-standing, time-differentiated rates, or other similar Load Control Programs with limited marketing, enrollment, and/or pricing differentials between on- and off-peak period. Consequently, such legacy rate offerings typically lead to limited or no impact on load shapes. The main exceptions to these programs with limited impact on the system are commercial or manufacturing enterprises that have the capability and capacity to respond to dynamic Load Control Programs on an ongoing basis.

As large-scale success with Load Control Programs is lacking in smaller customer segments, the Study focuses on evaluating a path for developing Load Control Programs that will elicit greater rates of participation and efficacy in managing anticipated costs of providing electric service. Further, the goal is to facilitate a transition to Load Control Programs that are dynamic in the face of an evolving market and support the state's environmental policy objectives by managing the impacts of Emerging Technologies on the Vermont system. For Load Control Programs to be effective in managing the expected increases in peak demand on the Vermont electric system, it will require the enrollment of larger numbers of customers. As more customers participate and potential benefits to the system grow, the load shapes must then be managed through some combination of customer behavioral changes or management of the load by automated technology, the utility, or a 3rd party service provider.

2.5 Scenario Analysis and Key Performance Indicators

For this Study, three scenarios were developed with input from the Stakeholder Engagement process to evaluate specific impacts and costs related to operating the Vermont electric system.

- **Baseline Scenario:** The first scenario provides a baseline for benchmarking impacts. This includes the projection of selected costs assuming limited growth for the entirety of Vermont during the forecast period. The Baseline Scenario assumes a 0.5% annual increase in customer counts in Vermont, which reflects the most recently available state average customer growth rate.
- **Technology Adoption Scenario:** The second scenario develops an "unmanaged" electric system growth driven by the adoption of certain Emerging Technologies in addition to the existing load forecast.
- **Technology Adoption with Rates Scenario:** The third scenario applies innovate rates and rate programs to incentivize customer behaviors and manage increased costs associated with the adoption of Emerging Technologies in the second scenario.

For these modeling scenarios, a forecast for technology adoption and resulting changes in load was developed and applied to assumptions on rates for different functional areas (e.g., production, transmission, and distribution functions) of the collective Vermont electric system. Rates for these functional areas were developed with specific input from the following stakeholder participants:[4]

- The Department provided forecast pricing on ISO-NE energy and capacity costs, RECs for RES compliance, and embedded RNS transmission rates.
- Embedded and incremental RNS rates were developed in conjunction with the Department, VELCO, and Efficiency Vermont.
- Incremental distribution unit costs were developed in collaboration with GMP and VEC.[5]
- Incremental transmission costs were developed in collaboration with VELCO staff.

Additional detail regarding the Utility Cost KPIs is included in Appendix B. These Utility Cost KPIs are a critical aspect to understanding the financial and operational impacts of the selected Emerging Technologies on the Vermont utility system, as well as in quantifying the potential value of innovative rates and program offerings designed to manage load and mitigate potential future costs.

The sum of the Utility Cost KPIs are not equivalent to the total revenue requirement for the Vermont system as a whole, nor for any individual utility. Instead, the Utility Cost KPIs represent required changes in revenues to cover their respective portion of total revenue requirement. These Utility Cost KPIs represent the investments and costs that are most sensitive to load growth, increased Emerging Technologies adoptions, and distributed energy resources. The Study did not include costs associated

[4] It is important to note that the scope of this Study is focused on a projection of changes in electric costs, and not total costs of energy for end-use customers in the state. For this Study, increased costs associated with Emerging Technology adoption, specifically refers to increasing electricity costs. This does not include the potentially larger decrease in non-electricity costs that are associated with no longer purchasing fossil fuels required to service the incumbent technologies that are being replaced by Emerging Technologies.

[5] As mentioned in detail in Appendix A of this report, the distribution cost estimates will vary by utility and individual circuit.

with routine or ongoing capital replacement needs, depreciation (for investor owned utilities), margin or return, taxes of any kind, or any consideration of overhead costs (e.g., Administrative and General (A&G), customer service-related costs, transactional-related costs, etc.). Such costs vary substantially between utilities and have been excluded from this system-level Study. The Utility Cost KPIs included in this Study account for less than 50% of the total estimated revenue requirement of the system as of 2019.

In 2020, the average rate for all of the Utility Cost KPIs (i.e., load and generation-sensitive categories of costs) in the Baseline Scenario were approximately $0.0741/kWh. However, as the Vermont electric system load evolves and grows based on the underlying Emerging Technology adoption forecasts, the average rate of the total Utility Cost KPIs begins to vary across scenarios.

- By 2030, the average rate for the Utility Cost KPIs in the Baseline Scenario is $0.0968/kWh, whereas the average rate for the Technology Adoption Scenario is $0.1115/kWh or an additional $0.0147/kWh.
- By 2040 the incremental difference between these two scenarios expands to $0.0605/kWh, as indicated in Figure 2-1.

These costs and effective rates provide an indicative “order of magnitude representation” or comparison of conditions in the future rather than a precise electric rate forecast. The results suggest that future cost increases and rate levels, in addition to potential negative impacts on other policy ambitions, represent a material concern for Vermont. This also highlights the potential impact and costs of failing to effectively leverage Load Control Programs to benefit the Vermont electric system and retail customers.

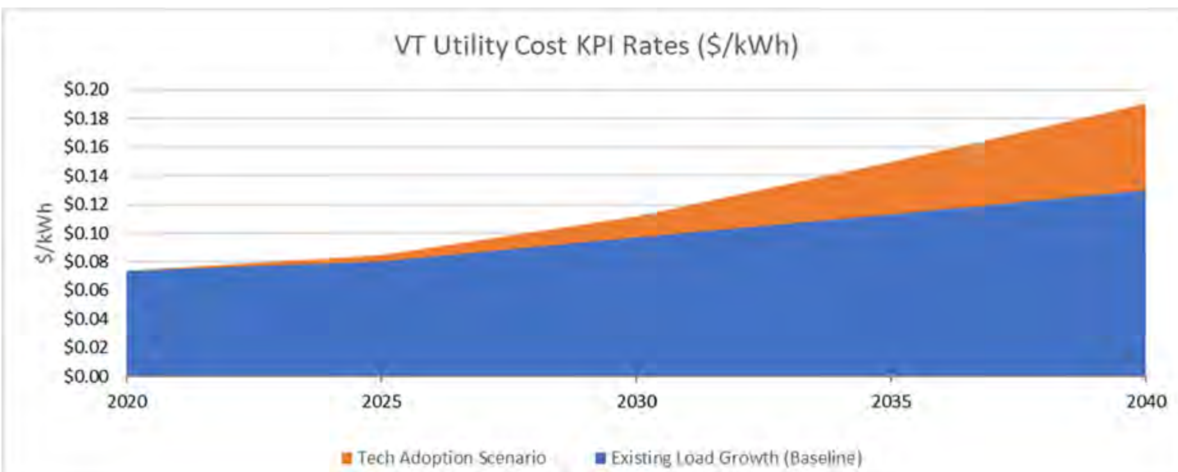


Figure 2-1. Projected Utility Cost KPI Rates for Vermont System

As Figure 2-1 demonstrates, the Technology Adoption Scenario (e.g., unmanaged Emerging Technology growth) results in increased electric sales (load) and a corresponding increase in revenues to utilities. However, in the modeled results for this Study, these increasing revenues from Emerging Technologies are driven by increased costs and capital investments relative to the Baseline Scenario. To optimize the current and future Vermont electric system and manage rate increases, this Study suggests that load be managed through Load Control Programs that incentivize load shifting to off-peak periods with lower capacity and energy costs.

SECTION 3
QUANTITATIVE FINDINGS AND MODEL RESULTS

3.1 Introduction

To support the facilitated Stakeholder Engagement workshops of this Study, NewGen customized LSAM™ to reflect Vermont's statewide electric system. LSAM™ is designed to allow users the ability to toggle numerous input assumptions around Emerging Technology adoption while evaluating the impacts of such changes in real-time. This section provides a summary of the LSAM™ modeling results and quantitative analysis conducted to support this Study, framing results in terms of the defined Utility Cost KPIs.

The Study's modeled results indicate the impact of future unmanaged Emerging Technology adoption and its corresponding load growth results in significant additional costs to the state's utilities and their customers (Technology Adoption Scenario) as compared to the Baseline Scenario. However, this modeling also demonstrates substantial opportunity and value from strategically designed and deployed Load Control Programs. Such programs implemented across Vermont may avoid costly expansion of both distribution and bulk transmission networks by optimizing the use of the overall electric system and shifting the Emerging Technology load growth to off-peak hours.

The precise timing of these modeled future cost increases is highly dependent on the exact timing and magnitude of Emerging Technology adoption(s). However, the model suggests that by 2030, there could be a 22% increase to the Utility Cost KPIs representing a $100M increase in costs as compared to the Baseline Scenario. By 2040, such costs are modeled to increase to $500M per year, representing an 80% increase over the Baseline Scenario.

While the Technology Adoption Scenario indicates significant increases costs to Vermont customers and utilities, the Technology Adoption with Rates Scenario offers an opportunity to manage these impacts and mitigate the upward pressure in rates and costs. Deploying strategic Load Control Programs in the Technology Adoption with Rates Scenario, simply to manage the timing of EV load impacts among the Emerging Technologies, indicates a potential savings of $50M per year in 2030 over the unmanaged growth in the Technology Adoption Scenario. These savings increase to $150M per year in 2040 as compared to the unmanaged Technology Adoption Scenario. Further, increasing the prominence and utilization of at-work EV charging could save an additional $50M per year in 2040, for a total of $200M per year.

It is important to note that such savings from Load Control Programs does not include increased costs associated with enhancing, developing, or replacing IT, metering, communications, data management, or other infrastructure to support such programs. Costs for these infrastructure investments should be subtracted from the estimated savings delivered from Load Control Programs. Further, the length of time required to prepare for and implement such infrastructure investments must be considered in the strategies to manage growth on the system. Stakeholders suggested that these infrastructure investments likely take years to evaluate, propose, approve, and integrate with the existing system, which are often prerequisites to offering expansive Load Control Programs. Each utility must weigh the benefits of Load Control Programs against the necessary infrastructure investments. The purpose of this Study is to demonstrate the value of Load Control Programs, assuming the necessary investments are made, and to discuss pathways to implement programming to provide greater benefits to Vermont's electric customers.

3.2 Innovative Rate Survey

As part of this Study, NewGen conducted a survey of innovative rates and presented the results to the Department as an effort to understand the state of utility rate offerings across the country. A summary of rate information from this survey is provided in Appendix D. In addition to the data compiled, the Smart Electric Power Alliance published a robust survey of EV-only rates, entitled “Residential Electric Vehicle Time-Varying Rates That Work: Attributes that Increase Enrollment.”[6] The contents of that resource are not replicated nor summarized herein, but is acknowledged as valuable to the rate review in this Study.

The rate survey suggests that Vermont is a leader in designing innovative Load Control Programs to manage the impacts of Emerging Technologies. While there are numerous examples of static TOU rates offered on a voluntary or even mandatory basis in the industry, as well as CPP and RTP pricing programs, it is apparent that there is as much, if not more, innovation occurring in Vermont as in other parts of the country.

In particular, based on the survey conducted and NewGen’s experience, Vermont’s active Direct Load Control Program(s) for both EV charging and behind-the-meter storage are largely unprecedented in scale and enrollment in the country. Vermont utilities should be commended for their work in developing pilot programs and seeking to scale those pilots to all applicable end-users. NewGen recommends this innovation continue with appropriate Vermont regulatory support to manage future impacts of Emerging Technologies in the state.

3.3 Unmanaged Load Growth

As indicated in the previous section, the “unmanaged” load growth is anticipated to be primarily driven by the Emerging Technologies identified for this Study. This load growth associated with the Technology Adoption Scenario is incremental to the Baseline Scenario, as defined in Section 2. Figure 3-1 illustrates the anticipated increase in load associated with the Technology Adoption Scenario (orange) and the Baseline Scenario (blue).

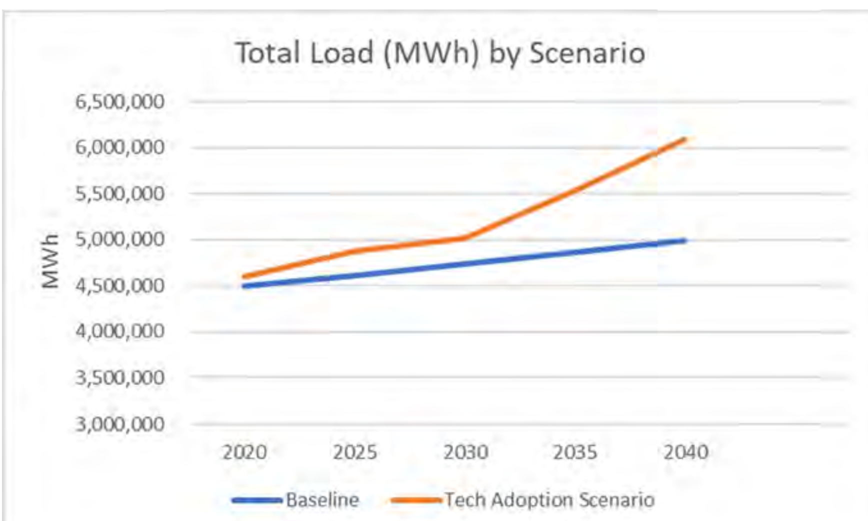


Figure 3-1. Projected Total Load by Scenario for Vermont System (MWh)[7]

[6] As of July 2020, the report is available here: https://sepapower.org/resource/residential-electric-vehicle-time-varying-rates-that-work-attributes-that-increase-enrollment/

[7] The Baseline scenario reflects a 0.5% annual growth rate in customer counts in the state, which is based on available statewide billing data. Electric usage per customer is held constant in the Baseline Scenario.

The Study suggests that the total costs for the Utility Cost KPIs[8] for the Technology Adoption Scenario are slightly higher than the Baseline Scenario at the beginning of the Study period while increasing in later years. This is primarily due to the lower Emerging Technology adoption rates in early years compared to the higher adoption rates in later years. As Emerging Technology adoption rates increase, the costs for the Technology Adoption Scenario also increase with the increase in load. The resulting increased Utility Cost KPI is summarized in Figure 3-2 and defined for selected years of the Study in Table 3-1.

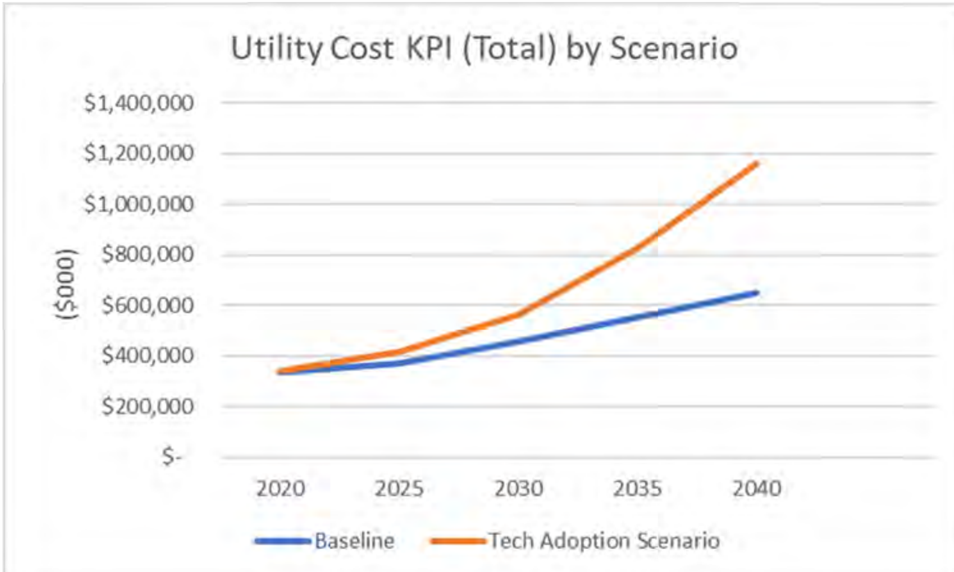


Figure 3-2. Utility Cost KPI (Total) by Scenario over Study period

Table 3-1
Utility Cost KPI (Total) by Scenario for selected Study years ($000s)

Scenario	2020	2025	2030	2035	2040
Baseline	$334,000	$370,000	$459,000	$550,000	$648,000
Technology Adoption Scenario	$341,000	$414,000	$560,000	$827,000	$1,159,000
Increment for Technology Adoption	$7,000	$44,000	$101,000	$277,000	$511,000

The modeling conducted for this Study is designed to evaluate the Utility Cost KPIs for a selected year under the three scenarios defined in Section 2: Baseline, Technology Adoption, and Technology Adoption with Rates. For any given year, such costs are compared, and divided by projected retail energy sales, to produce an indication of changes in rates specific for the costs identified for this Study. The results are not designed to be compared longitudinally, or summed over multiple years, as certain KPIs (e.g., purchased capacity and energy in ISO-NE) are presented on an annual basis, while others (e.g., transmission and distribution capacity costs) are presented as embedded costs representing the

[8] The Utility Cost KPIs included in this Study are associated with a subset of total utility costs that tend to vary with load growth and load peaks (load shapes). While these costs are significant, they account for slightly less than half of the total electric utility cost of service for Vermont in any given year. Most of a utility's cost of service is associated with historic (embedded) costs from past investments that will be recovered in rates over time and cannot be avoided through improvements to rate design and load management that is the focus of this Study.

total difference in peak demand (either coincident or non-coincident demand) across the three scenarios. Results provide snapshots of cost comparisons in selected years, but total costs cannot be summed across years without double counting certain Utility Cost KPIs, which represent estimates of the future embedded costs of service.

3.4 Study Load Control Programs

This Study evaluated the combined effects of reasonable combinations of strategic Load Control Programs on the projected Utility Cost KPIs to inform recommendations regarding the value of deploying such programs for innovate rates in Vermont. The term “reasonable” is subjective and unique to each utility in the state, and therefore a list of the primary assumptions utilized for this Study is provided in Appendix A (LSAM™ Assumptions / Functionality). This section provides a summary of the modeled Load Control Programs as they apply to the total Vermont system, which are included in the Technology Adoption with Rates Scenario.

The impacts of at-home EV charging represents a substantial proportion of the negative impacts from Emerging Technology adoption on the Utility Cost KPIs. Left unmanaged, EVs could lead to increased peak demand, and a corresponding increase in generation, transmission, and distribution capacity costs and related investments. In addition, EVs, CCHP, and water heater loads are also anticipated to drive an increase in consumption during on-peak hours on the system. Direct Load Control capacity, or Electrification Load and/or Storage capacity assumed available for direct control, provides a substantial opportunity for utilities or 3rd parties to directly manage load on behalf of customers. A summary of the individual components of the modeled Load Control Programs is provided below.

3.4.1 EV-Only Rates

Developing rates specifically for EV charging represents an opportunity for utilities to shape load and substantially decrease peak demand. As discussed earlier, EV load is highly elastic and flexible, thereby presenting an opportunity for load shifting with limited to no negative impacts on the customer. It should be noted that the EV-only rates may be structured as a separate rate class by the utility and individually metered, or they may be sub-metered at the premise location. Further, the EV rate may be structured as a stand-alone rate or it may be a rate-rider that accompanies a specific rate offering. The rate implementation strategy is not defined in this report, but is left to the individual utility to consider relative to their suite of customer rate offerings

The “EV-only” rates modeled assumed 90% of EV drivers would enroll in the Load Control Program. The modeled EV Rate Design included a static TOU structure with an on-peak period beginning at 4:00 PM and ending at 8:00 PM. The on-peak energy rate is modeled at 1.5 times the off-peak rate (referred to as the pricing differential between on- and off-peak times). No demand charges were applied to the EV-only rate. This Rate Design was applied to both EVs charged at-home and at-work.

The details of the EV-only rates modeled are important and provide insight to program designs. The goal in modeling this selected EV rate was to reflect an acceptable Rate Design with reasonable on- and off-peak periods without an overly aggressive pricing differential. Because EVs are highly flexible and elastic to pricing, industry research suggests aggressive pricing differentials (e.g., 3x or 4x) are not necessary to produce a meaningful reduction in load. In addition, for modeling this specific EV rate, it is not suggested that the off-peak rate be set below a “floor” value that includes recovery of reasonable marginal costs plus any margin or fixed cost contributions. These costs were not explicitly determined for this Study; however, they are an important consideration in Rate Design for revenue adequacy and equity in utility cost recovery.

The EV adoption scenario selected for modeling assumed 20% of consumer vehicles in Vermont will be EV by 2030, and 50% by 2040. An important assumption seen in the modeled results is the percentage of drivers with access to EV charging at their workplace. The Utility Cost KPIs were calculated under two assumptions for this variable: at the low end, 10% of trips ending at-work have access to EV charging, and at the high end, it was assumed that 50% of the trips have access to charge at-work. The difference between the low and high end of this assumption results in an additional $50M in Utility Cost KPI savings in 2040 (by shifting more charging at-work and reducing the charging at-home).

3.4.2 Critical Peak Pricing

In addition to EV-only rates, another Load Control Program evaluated was a CPP program. This program was modeled to specifically recover costs associated with the RNS Capacity Rate for transmission over a series of utility controlled CPP events. In each modeled year, CPP events were limited to a maximum of five per month, one CPP event per day, and a maximum duration of four hours. Actual limitations for a utility's CPP program will be unique as their need for and ability to implement such a program may vary significantly. The number and duration of CPP events modeled for this Study evolved in different years based on savings that could be achieved by managing load shapes. The actual RNS Capacity Rate recovered in rates varied with the number and duration of CPP events, translating the forecast RNS Rate into a $/kWh charge to be recovered over the total number of CPP hours modeled.

As discussed throughout this report, customer enrollment in Load Control Programs is crucial to substantial management of load shapes. For the CPP program, assumptions included a relatively small number of Residential (10%) and Small Commercial customers (15%), with a larger number of Industrial customers (40%) participating in the program. The larger number of industrial participants was based on larger customers' historically higher levels of participation in demand-side management programs. To the extent actual future participation in a similar CPP program falls below these assumptions, the amount of load shifted would decline, producing fewer savings to the Utility Cost KPIs. Likewise, the inverse is true: if more load participates in a CPP program, then more load is shifted and savings to the Utility Cost KPIs increases.

Customer response (elasticity of demand) to increased pricing during a CPP event was assumed the same for all load except for the EV load participating in the CPP program. EV load is more elastic, thus assumed to respond at higher levels to the CPP events than non-EV load, based on the EV-specific elasticity derived from data available from Department of Energy research. Elasticity values for customer load and EV-specific load are provided in Appendix A. Modeled EV load reductions from CPP events were assumed to occur *after* any load responding to the static TOU rate offered in the EV-only rate, i.e., only the amount of load potentially remaining after responding to the TOU signal was responsive to a CPP event.

The CPP program was modeled as revenue neutral, and thus reduced the effective retail rates by the amount of total revenue that was recovered through the CPP program. However, costs for potential metering, data management system, communications, or other incremental costs that may be required to initiate a CPP program were not included in the analysis conducted for this Study. Such costs would ultimately increase the Utility Cost KPIs and therefore, decrease the total amount the estimated savings from the implementation of a CPP program. However, the total CPP programmatic costs are not likely substantial in comparison to the annual savings estimated for the Load Control Programs.

3.4.3 Direct Load Control

In addition to EV-only rates, and a CPP program, it was assumed a theoretical utility operator would have access to a certain amount of directly controlled load to curtail on command or dispatch. The Direct Load Control capacity assumed availability up to half the amount of peak EV demand for each year. Direct Load

Control was constrained to curtailing load up to 24 times per year, to a maximum of four hours per event, and was not allowed to exceed one event per day.[9]

Similar to the CPP program, the incremental costs of Direct Load Control, either to pay for any programmatic costs (e.g., communication or technology equipment required to facilitate such a program) or to compensate the end-use customer for curtailed load were not included in this Study. It was assumed a substantial portion (if not all) of the capacity subject to Direct Load Control would be EV load, and that future EV-only static TOU Rate Design implied customer participation in Direct Load Control. Consequently, it was assumed that the compensation for EV customers participating in the Direct Load Control Program would be the EV-only rate offering. This EV-only rate includes an off-peak rate that allows the EV customer to save money compared to the otherwise effective residential and/or commercial rate, depending on whether the customer charged their EV at-home or at-work.

3.4.4 Utility Cost KPIs with Rate Implementation

The Technology Adoption with Rates Scenario included modeling the EV-only rate, applying a CPP rate to a small portion of non-EV load and a large portion of EV load, and applying a substantial amount of future EV capacity to Direct Load Control. The result of this combined strategic Load Control Program was a reduction in costs of $50M per year by 2030, increasing to $150M per year in 2040, compared to the Technology Adoption Scenario. By increasing the at-work EV charging access from 10% to 50%, the savings increased by an additional $50M per year by 2040 to a total of $200M. Table 3-2 below provides the results of the modeling effort for these scenarios, summarized in five-year snapshots over the Study period.

Table 3-2
Utility Cost KPIs with Rate Implementation ($000s)

Scenario	2020	2025	2030	2035	2040
Technology Adoption Scenario	$341,000	$414,000	$560,000	$827,000	$1,159,000
Technology Adoption with Rates Scenario	$338,000	$387,000	$510,000	$704,000	$1,010,000
Potential Savings from Rates	($3,000)	($27,000)	($50,000)	($123,000)	($148,000)
Potential Additional Savings from Increasing At-Work EV Charging (1)					($50,000)

(1) Due to the iterative nature of CPP and Direct Load Control events, the increase in at-work EV charging from 10% to 50% was modeled only in 2040.

3.4.5 Analysis of Cumulative Rate Impacts

Beyond the total dollars saved on the system, the resulting impacts of the strategic Load Control Programs on projected Utility KPI retail rates is material. Figure 3-3 below provides a comparison of the average rates (Utility Cost KPIs divided by annual retail energy sales) across the three scenarios (Baseline Scenario, Technology Adoption Scenario, and Technology Adoption with Rates (Load Control) Scenario).

[9] Modeled Direct Load Control Program design parameters were selected to be reasonable in limiting inconvenience to the customer and to limit the efficacy in shifting load given the historic information on when peak events occur in the model. In actual operation, such a program may be capable of controlling customer load more frequently, for longer duration, and/or may have access to differing amounts of controllable load.

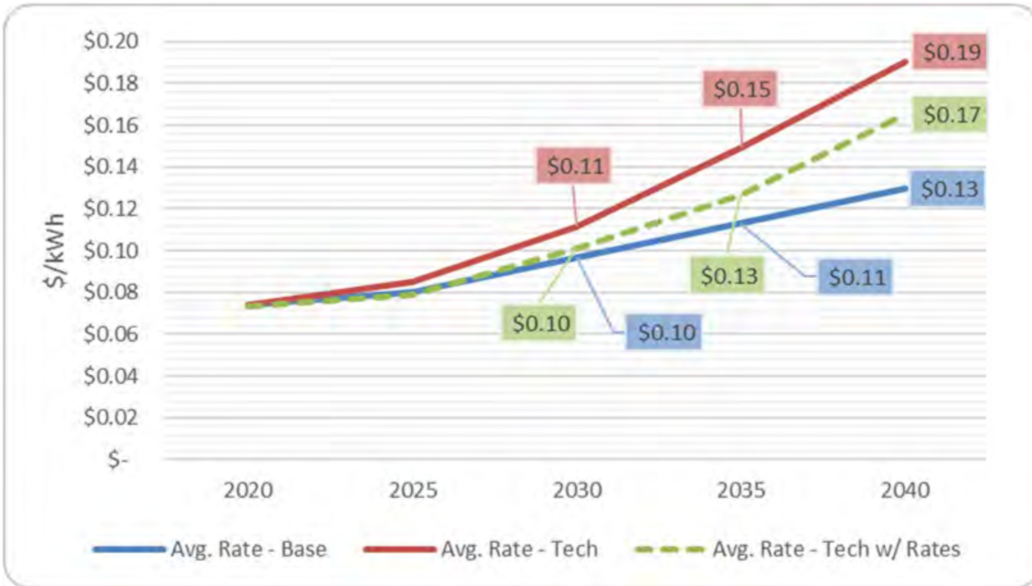


Figure 3-3. Utility KPI Rates for Selected Years and Scenarios

As Figure 3-3 demonstrates, the modeled impacts of the Load Control Program almost eliminated the upward rate pressure in 2030 (both the Average Rate Baseline and Average Rate Technology Adoption with Rates are $0.10/kWh). In addition, the Load Control Program reduced the upward rate pressure by almost 50% by 2040 (from $0.19/kWh for the Average Rate Technology Adoption to $0.17/kWh).

3.5 Carbon Key Performance Indicators

As part of the stakeholder workshop process, carbon emissions (as carbon dioxide, or CO_2) reductions were identified as a KPI for this Study. Input to this KPI was provided by the Department, EAN, and other stakeholders to develop reasonable assumptions for how carbon emissions would be reduced as a function of three elements material to this Study:

1. EV adoption relative to burning gasoline in internal combustion engine consumer vehicles;
2. Increasing REC purchases in compliance with Vermont's RES, which was modeled to achieve the current 75% by 2032 metric; and
3. Carbon savings associated with switching space conditioning and water heating away from incumbent technologies to CCHP and electric heat pump hot water heaters. The non-electric carbon content associated with incumbent technologies was based on the carbon emissions of a portfolio of technologies fueled by an assumed composite of propane, natural gas, fuel oil, and wood, which was developed with input from stakeholders.

Carbon emissions reductions were not an output controlled by the modeling for this Study to drive results but were instead an output of other model inputs. To clarify, the carbon reductions calculated for this Study were a function of inputs for Emerging Technology adoption but were not modeled for impacts by the design and deployment of Load Control Programs. Evolving solar policy assumptions could drive PV adoption projections, which could impact the carbon content of the electricity consumed by newly adopted Emerging Technologies. However, the driver for carbon reductions in Vermont's electricity supply come from RES compliance and REC purchases. Thus, the amount of PV modeled impacted these purchases, rather than specifically decreasing or increasing the carbon content of Vermont's associated electricity demand.

Figure 3-4 provides the carbon emissions output modeled in the Technology Adoption Scenario resulting from the KPI analysis for this Study.

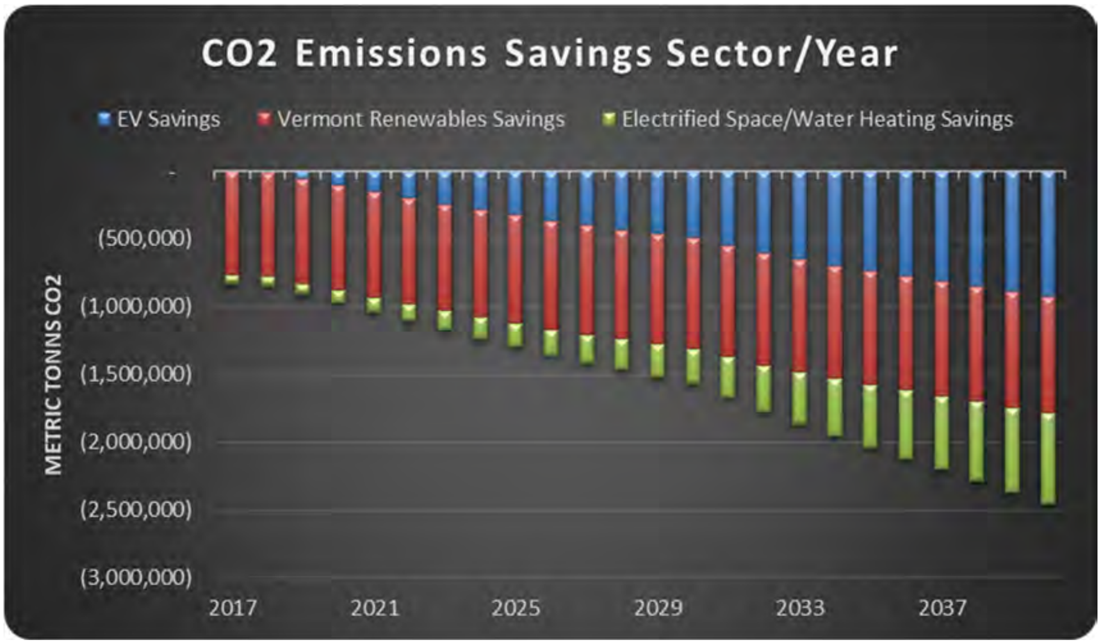


Figure 3-4. CO_2 Emissions Savings / Year by Sector[10]

As the figure demonstrates, total carbon emissions from Emerging Technology adoption and RES compliance in the electric sector equal roughly 1.5 million metric tonnes in 2030, increasing to nearly 2.5 million metric tonnes in 2040. The bulk of these emissions reductions are achieved through EV adoption and RES compliance. If the adoption rate for CCHP and water heaters were increased, a larger amount of carbon reductions would result. However, as an increasing number of customers switch to CCHPs and water heaters the electric load would increase the other calculated Utility Cost KPIs presented previously.

3.6 Future Considerations in Load Control Programming

In producing the modeled results of the Load Control Programs, care was taken to avoid overlap in CPP and Direct Load Control events. Due to the nature of peak demands on the system, in many cases one peak was addressed by a CPP event, only to produce a new peak occurring immediately after the CPP event. Because a large amount of the load shifted was EV load, it is critical that modeling efforts limit pressure on EV load to shift to ensure consumers' vehicles are fully charged by the next morning. In actual operation, this would be an important consideration, and as such, this Study did not develop an "optimal" combination of CPP and Direct Load Control events for a specific peak day. Instead, the model limited the events to not occur in succession on the same day.

Additionally, in later years when substantial amounts of CPP or Direct Load Control capacity was utilized, the "snap-back" effect became problematic. As a CPP or Direct Load Control event ended, the next hour set a new peak for the day as the curtailed load "snapped-back". This phenomenon was also mentioned by stakeholders who stressed that as more capacity was managed by the utility, efforts to stagger load control events or deliberately limit curtailments to a portion of available capacity during a given event will

[10] Additional information on estimating carbon savings is provided in Appendix B.

be critical. Another option to address the snap-back is to extend the curtailment events and “feather” in the curtailed load over a longer period of time after the on-peak period ended, as described in Section 2.

3.7 Implementation Issues / Regulatory Support

A critical element of the Study included the feedback and comments from the Stakeholder Engagement events. Comments from these events recognized a key risk to a successful Load Control Program lies with the “pain” perception of the customers as a result of increased electricity prices and overly complex rates and programs designed to reduce cost pressure. Concerns also included mandating rates and the ability of Utilities to offer Load Control Programs on a voluntary basis. Additionally, participants stressed the importance of Load Control Programs getting to a level of scale (beyond just piloting a program) in an efficient manner. This means that programs require some level of consistency across stakeholder groups and across the state. Further, costs for these programs must be recovered by the utilities, even if the results fall short of their anticipated goals.

The customer requirement for simplicity is a key to ensuring success. For many Programs, the utility needs to make decisions for the customers while making programs simple and compelling. The resulting “package” needs to be marketed in a collaborative fashion, which includes clear and concise customer education programs, as suggested by stakeholders. At the state level, policy makers must recognize that there are a variety of issues that impact smaller utilities that may not have the resources of the larger utilities. Developing a strategy to identify and reduce the innovative rate making barriers and constraints for smaller utilities could increase the success of Load Control Programs. Additional collaboration on a state-level may further facilitate or enhance this strategy for smaller utilities. Load Control strategies also need to be proactive, rather than reactive, which suggests that the planning efforts initiated by this Study should continue.

Increased Department and the Commission support for Load Control Programs leads to an expanded role and consideration in various proceedings. Examples from the stakeholder workshops included requiring expansion and evaluation of Load Control Programs in the Integrated Resource Planning process, or in proceedings related to the Vermont System Planning Committee (VSPC). Stakeholders generally voiced their approval for the workshops of this Study and expressed an interest in continuing to engage on issues related to strategic Load Control Programs going forward.

Finally, C&I class perspectives should be considered in the future, and utilities need to tailor messaging to these classes, while recognizing cost allocation and potential subsidization issues between smaller and larger customers within these classes.

SECTION 4
STUDY RECOMMENDATIONS

4.1 Introduction

Vermont operates in a regional market for wholesale power supply and transmission services, and each utility maintains its own electric distribution system. Over time, increasing peak loads likely creates upward pressure on the cost of power supply, transmission, and distribution capacity requirements to provide reliable electric service to the state's customers.

Identifying and managing marginal costs of power supply, transmission, and distribution capacity provides the basis for designing programs to manage load shapes and to reduce electric utility costs. Utilities can manage load shapes either directly (through load management linked to rate plans and incentives) or indirectly through Rate Design by sending price signals to incentivize changes in load shapes (collectively, Load Control Program(s)).

4.2 Pricing a Load Control Program

Implementation of innovative Load Control Programs entails an iterative process for pricing, which builds on the current foundations of embedded cost of service studies. This embedded cost foundation requires utility Rate Design or Direct Load Control Programs be priced with revenue adequacy, fairness, and economic efficiency in mind. Beyond these traditional pricing constructs, moving to a more innovative pricing scheme requires consideration of avoided marginal costs when load shapes are managed.

A key barrier to utilities developing effective Load Control Programs is relatively low customer participation or enrollment in voluntary programs, as there is a lack of any regulatory mandate that would require customer participation. As indicated previously, costs for the necessary infrastructure to support Load Control Programs may be significant and require many years to plan, design, implement, and integrate with existing systems. Utilities will need to evaluate the costs for these systems relative to the projected savings or policy objectives associated with Load Control Programs, as appropriate.

4.3 Mitigating Implementation Barriers and Low Program Enrollment

The first set of Study recommendations largely revolve around strategies to increase customer enrollment in Load Control Programs absent a regulatory mandate for customer participation. These recommendations are described below.

4.3.1 Program Structure

Advancements in Rate Design and load management achieve little without widespread adoption of a rate plan. For advances in rates to be effective, in addition to targeting end-use Emerging Technologies for flexibility, utilities must improve and/or expand their marketing capacity and aggressively pursue enrollment. Another approach is to adopt Load Control Programs as a default service from which customers can “opt-out”, rather than as a voluntary “opt-in” structure.[11] Further, many of the Emerging Technologies currently enjoy policy support in the form of utility provided incentives. To receive an incentive, consumers could be compelled or encouraged to enroll in, or receive marketing materials from, Load Control Programs that reduce the customer’s and the utility’s operating costs. Points of sale for Emerging Technologies should be considered as valuable touchpoints with the customer, and an opportunity to leverage broader marketing efforts. Stakeholders suggested that intentional and focused outreach and education programs should be a requirement when offering these new Load Control Programs.

4.3.2 Load Control Specific to End-Use Emerging Technology

If Load Control Programs are not mandatory, and thus require some degree of voluntary participation, they should be designed to maximize enrollment to increase their efficacy. Certain Emerging Technologies are more flexible than others. For some Emerging Technologies, a change in electricity consumption profile leads to very little or no discernable impact on the service the technology provides to the end-use customer. Examples include EV charging, high efficiency heat pumps, water heaters, as well as other specific end-uses in commercial applications.

Utilities should target specific Emerging Technologies for Load Control Programs based on the characteristics of the technology’s flexibility. This flexibility impacts a “consumer comfort” factor, or answers the question: “How uncomfortable or inconvenienced would the customer be if the electricity usage profile of an Emerging Technology were altered?” As an example, during extreme weather events, utilities could limit curtailments of electricity usage for space conditioning (heating or cooling). During these times, system peak events often occur, and system-related costs may be at their highest. However, this is also when customers need or want electricity service the most. Thus, utilities should strive to target the specific hour or hours that drive system costs, ultimately minimizing the duration and frequency of peak-event Load Control Programs. Conversely, programmable loads with a defined duration that can be completed during off-peak hours may be managed with static TOU rates (such as EV charging).

Loads that vary with changes in weather, such as space conditioning, may be better managed with a dynamic TOU rate program, or via Direct Load Control by the utility. However, voluntary enrollment in dynamic TOU rate program may be limited by the consumer comfort factor and impacts. A Direct Load Control Program may offer more success as it may cycle the operation of a specific appliance to limit those impacts to the consumer. Ultimately, the more frequent or substantial impacts a Load Control Program has on consumer comfort, the less likely customers are to voluntarily opt into such a program. For such a Load Control Program to be effective and successful in managing load shapes, program participation must be mandatory, or customers would need to be compensated sufficiently to justify their discomfort. An alternative to impacting customer comfort is targeting Load Control Programs to specific Emerging Technologies that are more flexible. By targeting Load Control Programs, it limits customer discomfort, improves enrollment, and increases program efficacy in managing load shapes and utility costs.

[11] Stakeholders provided divergent views on mandatory and/or “opt-out” program structures. Certainly, different utilities may have alternate views on the appropriateness of each, but such programmatic structure considerations are provided herein as a means to increasing customer enrollment and/or program efficacy.

4.3.3 Utility Marketing

Utility marketing efforts should focus on customer segments investing in selected technologies, in addition to identifying and leveraging partnerships with technology vendors. Where incentives are offered to the customer (for example, Tier III programs or efficiency programs), utilities should establish default enrollment in specific rate programs, with the option to opt-out of the program after a certain period of time. Such marketing plans should apply to EV charger incentives, smart thermostats, and other energy efficiency incentives that would require enrollment in a specific new rate offering. In other opportunities for consumer education or communication, Load Control Programs should be advertised with simple and clear cost and benefits. Stakeholders reinforced the idea that utilities are the customer's trusted advisor. Utilities should build on their position as a trusted advisor to increase adoption of Load Control Programs and enhance customer decisions.

New business models should be considered to manage the anticipated load from end-use technologies. Utilities will need to increase the potential role for 3rd parties to be involved in packaging or managing customers' consumption of electricity. The opportunity to engage with these actors includes technology partnerships between 3rd parties and the utilities (i.e., relationships out of view of the customer), white-label relationships in which 3rd parties act as agents of the utility, or semi-autonomous relationships in which customers interact with new agents that are seamlessly connected to utility controls. As technology evolves and where there is mutual benefit to the customer and the utility, the industry will need to look to new models of service. This may include differing utility vs. 3rd party offerings, or fixed fee(s) for service offering a total cost reduction with direct load management responding to dynamic utility cost drivers.

As adoption of Emerging Technologies unfolds, there will likely be new actors, agents, and business models leveraged to create customer value. Customers adopting Emerging Technologies are likely to be "first movers" or "early adopters," which may reflect a customer group engaged in managing their energy consumption and/or carbon footprint. Such customers may be interested in being "part of the solution," in increasing the efficiency of the Vermont electric system, and thereby more likely to enroll and actively participate in a Load Control Program than other customers. Feedback from the stakeholders and customer survey data showed customers are at least partially adopting new technologies or enrolling in new Load Control Programs because they place a value on being "part of the solution." Utilities should leverage and integrate this insight with their marketing efforts.

4.3.4 New Business Models

As the electric utility market and load shapes continue to evolve as a function of Emerging Technology adoption, Vermont should continue its desire for innovation by pursuing various alternative business models that may facilitate increasing load management without sacrificing the customer's experience in consuming electricity. As utilities design more aggressive pricing for Load Control Programs, the business case for 3rd parties to enter the market assisting customers in managing their electricity consumption is expected to increase. Further, as new technologies become available increasing the connectivity and automation capabilities of in-home and in-business devices, responsiveness to Load Control Program pricing will increase. However, the emergence of utility Load Control Programs may be required as a first-mover to stimulate such business model and technology innovation and adoption. Consequently, Vermont utilities should expand customer access to Load Control programs to both manage future costs, and signal to the market the opportunity for value in managing customer load shapes on their behalf. In addition, "subscription programs" are an alternative to the existing "pay for consumption" model of the electric utility. This "pay for consumption" model is often criticized for failing to incentivize energy efficiency. However, with proper technologies and Direct Load Control measures in place, there are mechanisms to leverage in dissuading customers from consuming electricity irresponsibly.

4.4 Rate Recommendations

Specific rate recommendations for this Study range from the development of time-based rates such as static TOU to rate programs to management load directly by the utility. These rate recommendations include developing specific end-use rates for various types of flexible load. TOU rates have a long history in Vermont, with varying degrees of success in gaining desired adoption levels. For rate innovation to lead to significant customer adoption, effective plans must be in place to foster adoption. The recommendations below are not only for innovations in pricing plans, but also for building strategies that lead to greater adoption and more effective participation by participants.

4.4.1 EV-Only Rates

The Study recommends that the Vermont utilities establish specific rates for incremental EV load (EV-only rate) that are time-differentiated by on- and off-peak periods (static TOU). Utilities should consider the potential for adding or coupling direct load control with TOU rates, or “staggering” the TOU periods for different groups of customers to reduce the potential for snap-back phenomena, as discussed herein. On-peak periods should be consistent with the hours in which electric utilities in the state incur the highest costs. Higher costs are predominantly driven by ISO-NE FCM peak timing, and RNS Vermont peak timing, but may also include ISO-NE Energy prices that may be higher or lower during certain periods of the day or year. Generally, this entails setting an on-peak period between 5:00 PM and 9:00 PM Monday through Friday, excluding holidays, though this may fluctuate from season-to-season, and may evolve as the Vermont and ISO-NE systems evolve. Static TOU pricing should recognize that peak load periods across the region, the state, and portions of the utility system may change. Static TOU rates may need to adapt to new on- and off-peak periods or may need to infuse some dynamic elements that address the twin challenges of shifting peak periods and snap-back effects that create new peaks.

The Study recommends the pricing differential between on- and off-peak periods be a minimum ratio of 3:2; such that the on-peak periods for EV charging are at a minimum 1.5 times the rate of the off-peak period. As EV charging is more flexible and responsive to a lower pricing differential, this on- to off-peak pricing premium can be substantially lower for an EV-only rate than for a whole-house Residential TOU rate. Utilities should develop such EV-only rate offerings with a differential large enough to stimulate responsiveness but should not develop an off-peak rate that lower than the utility’s fixed costs and/or margins.

In addition to, or in lieu of, a significant price differential during on- and off-peak times, Vermont utilities may assign EV-only load to a CPP program as an incentive for customers to either voluntarily reduce load during the CPP events or to allow the utility to control the EV load at those times (see discussion of CPP program recommendations below).

Vermont utilities should encourage anyone purchasing an EV to be placed on an “EV-only” rate, with the requirement that customers can opt-out of the EV rate after a certain period of time. However, where the customer is receiving any type of incentive (in the form of a rebate, free charger, etc.) participation in the EV-only rate program should be mandatory (or at least a default rate with provision for opt-out). As it represents an incentive for customers to enroll in EV-only rates, Vermont utilities should consider covering the cost of installing the technology required to sub-meter the EV load.

4.4.2 EV Market Transformation and Awareness

Additionally, Vermont utilities should consider providing an effective incentive, either through a credit or by providing Electric Vehicle Supply Equipment (EVSE), for customers willing to allow the utility to manage the EV load through Direct Load Control. This is the ideal situation for the utility and the system in allowing the utility to determine when all or a portion of the EVs in their service territory are charged. Under such a situation, the utility should subsidize the costs of control equipment, which should be considered a prudent investment by the Commission so long as there is value in future avoided capacity coming from managed EV load shapes. Customers should retain the ability to override a "shut-off" period from the utility, while incurring the additional incremental cost for charging during this period.

The Vermont utilities should establish relationships with their local automobile dealerships that sell new and used EVs to foster increased knowledge and understanding for EV-only rate offerings. This may be in the form of a partnership, extended customer relationship, or educational outreach effort by the utility at the point of sale. Tradeoffs in gasoline cost savings as compared to electricity prices are already part of the sales pitch to a prospective EV customer. Utilities should further leverage this point of communication by using this as an opportunity to market EV-specific rate programs that could save the customer more money. Further, educational outreach can also focus on the economics of EVs compared to internal combustion engines and the contribution of EVs towards the state's environmental goals for reducing carbon emissions.

4.4.3 Direct Load Control

Based on this Study's review of innovative rates, utilities in Vermont currently manage some of the more expansive and robust Direct Load Control Programs in the country. As Emerging Technology adoption continues to increase, Vermont utilities should pursue opportunities to expand the amount of capacity under Direct Load Control to manage peak demand events. However, as mentioned above, as more Emerging Technology demand comes onto the Vermont system, it will become increasingly important that capacity under utility control be managed in tranches to minimize the snap-back effect that would occur if the entirety of Direct Load Control were handled in a coincident fashion.

The benefits of Direct Load Control over other Load Control Programs include the increased likelihood that a load curtailment will coincide with a peak event. The utility is in the unique position to manage all of its customers' aggregate load in a manner to benefit the entire system. However, end-use customers managing load are doing so to maximize savings on their own bill and not on the broader systems. Each individual customer's bill savings may or may not translate into wider spread savings for all utility customers. One of the challenges of developing a Direct Load Control Program is navigating the start-up process, procuring the requisite technology, and developing the internal capacity for operations. Since some utilities in Vermont are already operating such programs, further expansion in the state should leverage information sharing of best practices between those that are already leveraging and realizing value from Direct Load Control to those utilities looking to develop such programs.

In the Load Control Program modeling efforts described herein, Direct Load Control and CPP was an effective combination for managing peak events. Operating both programs together allowed portions of capacity to be managed through Direct Load Control, and others through a CPP event, which helped to manage snap-back. Further, allowing customers to select from various options is beneficial from a marketing perspective. A Direct Load Control offering provides the customer the option to "let the utility take care of it," while CPP allows the customer greater choice in deciding whether to respond to a CPP event or ride-through and pay the premium to continue consuming electricity during that time.

4.4.4 Critical Peak Pricing Programs

As Emerging Technologies increase in adoption, and new technologies are introduced to a dynamic market, dynamically priced Load Control Programs such as CPP can offer the opportunity for a Load Control Program that can rapidly respond to changing wholesale market signals. In addition, as compared to a static TOU Rate Design, CPP can reduce the number of events in a given month and year requiring customers to change behavior, or for devices to cycle.

As with other Load Control Programs identified for this Study, the degree to which CPP programs can be targeted to particularly flexible loads are paramount to achieving successful load shape management with minimal impact to the customer. EV load and tanked electric heat pump water heaters are prime examples for end-use technologies that may be targeted for such programs. However, there are also likely specific larger commercial loads, or portions of commercial facilities, that are similarly flexible and should be pursued for CPP participation. Stakeholders discussed loads associated with Vermont's ski industry and snowmaking devices as a flexible load resource that has been effectively managed to shape load. Additional opportunities in the commercial sector likely exist and should be pursued aggressively.

4.4.5 Water Heaters

Vermont utilities should consider unique Load Control Program offerings for new heat pump hot water heater equipment that features a water tank. Such "tanked" water heater applications may be cycled or curtailed without a measurable impact to the appliance's performance, representing a flexible load that can be leveraged in a Load Control Programs. However, as consistent with the recommendations generally discussed herein, such a program should be designed with the end-use in mind. The duration of higher priced periods, or Direct Load Control curtailment events should not exceed the heat storage capacity of the prevailing technology. As is the case above, this consideration is key to ensuring customer enrollment and participation, which leads to higher amounts of capacity to be managed by the utility in its Load Control Program.

4.4.6 Cold Climate Heat Pumps

CCHP devices offer challenges to the utility deploying a Load Control Program. Like curtailing air conditioning during the hottest part of the year, customers will likely balk at having their CCHP devices turned down or off during the coldest parts of the year. There are options to back-up CCHP devices with fossil fuel-fired systems, though such options run counter to the state's decarbonization policy objectives. However, there are also options for backup space conditioning systems utilizing fuels (e.g., wood or biodiesel) that do not run counter to Vermont's environmental policy objectives. Depending on commercial availability and/or market maturity, availability of such technologies may allow for greater flexibility of CCHP without the customer sacrificing too much comfort.

Nonetheless, as CCHP adoption is expected to increase, utilities should consider developing approaches to managing this load. One option may include the type of demand-side management programs currently in place for utility control and cycling of air conditioners. This cycling allows for some portion of the assets under utility control to be cycled while others continue to run. This option requires technology to manage a group of CCHP devices in concert, which entails costs and capacity to manage such a program, but the opportunity should be considered to manage the future electric costs of Emerging Technology adoption.

4.4.7 Net Metering and Solar Policy

A key Rate Design policy consideration that was not widely discussed during this Study is Vermont's net metering and ongoing PV policy. As modeled, a portion of the upward rate pressure modeled and presented in Section 2 is a result of the reduction in retail energy billing determinants from the continued deployment of customer-sited solar, which assumed a portion of PV generation to offset the full retail rate.[12] Such a reduction in retail energy billing determinants reduces the denominator in the average rate calculation presented herein, but also reduces wholesale energy purchases from ISO-NE at a rate less than the retail energy rate. Consequently, revenues from retail energy sales decrease by an amount greater than corresponding cost decreases stemming from reduced ISO-NE energy purchases, which results in upward rate pressure.

Discussions of solar policy are often contentious, and the development of solar policy recommendations for Vermont were beyond the scope of this Study. The modeled change to net metering included in this Study was based on ongoing net metering proceedings in the state and represents a reasonable and conservative assumption for the policy going forward.

4.5 Rate Adoption / Implementation Strategies

The Vermont utilities face challenges in implementing Load Control Programs in which a substantial number of customers participate based on the recommendations provided herein. Rate implementation strategies recommended for this Study are meant to be cumulative, with each successive step increasing the complexity and ability to manage load. There is no time frame associated with these recommended strategies, as each utility will need to tailor them to their own customer needs and levels of sophistication. However, recognizing there may be certain time and financial challenges in developing internal data and billing systems and other communication systems before such innovative rates and programs can be offered, the importance of beginning the process sooner rather than later should not be understated.

Figure 4-1 shows five steps in a strategy supporting integration and adoption of more complex rates for the Vermont Utilities and stakeholders. Some Vermont utilities may already be well down this proposed path; others may consider incorporating elements from this graphic into their own strategies for rate reform.

Figure 4-1. Five Steps of Rate Strategy

[12] The modeled future scenario assumed a change in net metering structure from its current state in which all PV production is compensated at or slightly higher than the retail energy rate (depending on the specific distribution utility). The PV policy underlying the modeling presented herein assumed that in any hour when PV production is equal to the amount of onsite load is compensated at the retail energy rate. However, any PV production exceeding onsite load in that hour would be compensated at an assumed $0.09/kWh in 2020 dollars.

The first step is to build a firm foundation of fair and adequate base rates. The second step is to layer onto the foundation a mechanism that incorporates forward-looking price signals that is largely revenue neutral in the short-term but serves the utility's longer-term objectives for system cost containment. The third step is to foster rate strategies like end-user rates that receive higher rates of adoption and more price or controlled load responsiveness. The fourth step is to apply new bundled service arrangements that are understandable by consumers for greater adoption, but also align with objectives for load management (system cost containment) and foster innovations in product differentiation (such as those that are focused on low income, renewables, environment, etc.). The last step is to create an environment that allows for pathways to greater adoption of Load Control Programs. It should be noted that the last three steps of this rate strategy may not require completion sequentially, as stakeholders indicated varying degrees of progress with certain aspects of each of the last three steps.

The foundation of fair and adequate base rates is critical to the process of initiating rates that are both transparent in their relationship to costs by customer class and sufficient for the utility's revenue needs. The establishment of "base rates" (Step 1) to recover the utility's embedded costs is how most utilities are currently developing their cost analyses in Vermont. Traditionally, this analysis is accomplished through a fully allocated embedded cost of service study analysis.

Step 2 of the recommended process for implementing Load Control Programs involves offering incentives and forward-looking price signals to incorporate the utilities avoided / marginal costs. This step includes developing processes that reflect underlying system cost drivers and acknowledge that energy usage during very specific times of the month and year is significantly more expensive than other times. Stakeholders commented that a process such as a distribution system planning procedure has been deployed in neighboring jurisdictions and is seen as a transparent process for utilities to evaluate and quantify marginal costs that can be avoided by Load Control Programs.

From such processes, time varying rates can be developed to serve as the basis for incenting changes in customer energy usage and/or technology adoption and should be considered by the utility in conjunction with or alongside programmatic offerings for Direct Load Control. This includes development of static TOU rates, as well as dynamic priced rates, such as those associated with CPP, VPP, RT Pricing, or other types of rates / rate programs. This step should address long-term costs that may be beyond the time frame of a given rate review period.

New rates developed during this process should focus on unique separate rates, such as EV-only rates or riders to existing rates, depending on the utility's rate strategy. It is recommended that the utility consider including an element regarding the dynamic nature of the underlying costs in TOU rates. This should focus primarily on costs associated with the wholesale power purchases and the necessary transmission costs for the ISO-NE system. Incentives or variable pricing elements can be introduced during this process either as revenue-neutral or slightly revenue positive to spur the introduction of innovative rates by utility. Pricing plans should be considered to accompany 3rd party alternatives by allowing the introduction of rates through an open access framework provider (with no incentive, but compensation for incremental costs of utility 3rd party).

Utilities need to consider the tradeoffs in costs associated with facilitating 3rd party entrance to the market compared to their own rate offerings. Both models will likely drive new costs in program administration and operations, in addition to necessary upgrades in systems and/or communications infrastructure as previously noted. Such system costs should be measured against cost savings and/or policy objectives for managing load to evaluate the efficacy of Load Control Programs. In the interest of providing least-cost electric service to customers, different business models should be considered, including a combination of Load Control Programs from the utility and/or 3rd party. The optimal approach will stem from the unique utility's circumstances, customer choice, and the ultimate efficacy of the program to manage load, reduce system costs, and achieve specific policy objectives.

The third step in the process is to focus on Load Control Program offerings to specific Emerging Technologies. This step is designed to create new pathways for adoption of new rates and/or rate riders. Device centric pricing packages, like unique rates for EVs or for Direct Load Control of behind-the-meter storage, provides a pathway to gaining high levels of participation and customer responsiveness.

The risk/reward proposition for the customer to adopt a Load Control Program can be made clear at this step. The intent of this type of rate is to manage only the device (such as the EV), rather than the entirety of the load at the meter location, such as a residence or business. It is recognized that not all loads warrant separate treatment and thus unique rates, or rate riders, are not likely appropriate for all devices in the home or business. This Study has identified major loads associated with EVs, water heater, and potentially CCHP (with backup or cycling of appliances) that are significant and flexible enough to be appropriate for such treatment. Fundamentally, these loads behave differently than other loads at a customer location.

Other areas for consideration include the continued pursuit of programs targeted to behind the meter battery storage. Storage operates both as a load and a dispatchable source of generation capacity and should be treated in a unique manner. There are a range of metering solutions available that allow time-varying energy usage measurement, which enables time-varied Rate Design to incentivize the customer or the utility to manage costs. The impacts of responsiveness to this Rate Design need to be measured by the utility, which can be facilitated by separating the load under the "device-centric" rate.

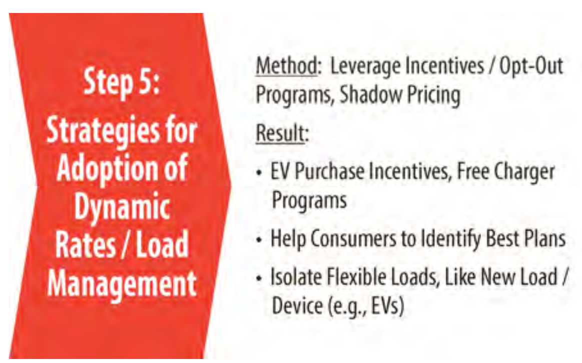
Likely preceding Step 3, but certainly by initiation of Step 4, utilities should develop a marketing and implementation strategy for their innovative Load Control Programs. Marketing should focus on customers who invest in Emerging Technologies and marketing plans should identify partnerships with technology vendors to save customers money. Where incentives are offered to the customer, utilities should require mandatory enrollment in specific rate programs, with the option to opt-out after a certain period of time. Such marketing plans should apply to EV charger incentives, smart thermostats, and other energy efficiency incentives, in addition to any rebates offered for

storage, CCHP, and/or heat pump water heaters. At other points of interaction with customers, utilities should clearly communicate the benefits of their Load Control Program. Finally, marketing of Load Control Programs should emphasize equity by seeking to include low- and moderate-income populations in education and outreach efforts when utilities are seeking to increase program enrollment.

New business models will need to be considered to manage the anticipated load from end-use technologies. Utilities will need to increase the potential role for 3rd parties to be involved in packaging or managing customer load. As technology evolves and where there is mutual benefit to the customer and the utility, the industry will need new service models. These may include differing utility versus 3rd party rate offerings, or fixed fee(s) for service that offer a cost reduction with direct load management that responds to dynamic utility cost drivers. However, such “subscription” models should guard against waste and any perceived or actual elimination of a price signal towards energy efficiency.

New business models should consider the creation and rolling out of “bundled” packages for load management. Utility load management packages, subscription services, and service contracts should be considered by the utility or in conjunction with 3rd parties as either partnerships or cooperative retail competitors. Utility packages can be offered with a dividend to the utility and non-participating ratepayers. Such 3rd party partnerships or cooperative competitor packages should be offered at the utility’s incremental costs of the arrangements. Utilities should consider starting with bundled offerings for new rate classes and include subscription rates for remote load management ability (for example, BED’s eCharger pilot program).

The final step in this process is to create an environment and specific strategies that allow for high levels of adoption in both dynamic Rate Designs and Direct Load Control Programs. Vermont utilities face similar challenges to other utilities in the country, which stem from lower adoption of optional opt-in pricing arrangements. It is recognized that state mandates for adoption likely face practical and political challenges. A better strategy is to create a more effective enabling environment for customer adoption. Such a strategy includes leveraging incentives to participation, where possible (e.g., EV purchase incentives, free charger programs). Additionally, such programs should be developed as an opt-out arrangement, rather than opt-in arrangements. Utilities should establish shadow pricing schemes that help consumers to identify best plans. Additionally, utilities should offer rates that enable consumers to isolate flexible loads for greater plan participation and likely greater new device (e.g., EV) adoption. A strategy for deploying Load Control Programs should be coupled with best practices in fostering new Program plans, including recognition of the long lead time for preparation, partnerships between utilities, leveraging 3rd party agents, and/or cooperative retail competitors.



Appendix A
LSAM™ ASSUMPTIONS / FUNCTIONALITY

A.1 What is LSAM™?

To assist with achieving the goals and objectives of this Study, NewGen customized its LSAM™ application to reflect the load and resource characteristics of the Vermont electric system. LSAM™ is an hourly load forecast model designed to predict future load shape evolution in the context of technology adoption and changes in customer behavior in response to retail Rate Design. Because LSAM™ is a prediction of future load profiles, it is highly dependent on the assumptions made regarding customer behavior, responsiveness to price signals in the form of rates, responsiveness to technology adoption, and the underlying customer electricity usage during the year. The assumptions used in LSAM™ include the underlying hourly load for the entire Vermont system, which is 2018 customer usage data obtained from participating utilities. Similarly, existing adoption of Emerging Technologies is based on information provided by participating utilities and the Department.

The load assumptions underlying the hourly forecast in LSAM™ is interval advanced metering infrastructure (AMI) data from GMP for Residential; Small, Medium, and Large Commercial; and Industrial customer classes. This AMI data from GMP is characterized as hourly usage per customer, and LSAM™ has the ability to input customer counts to scale the modeled system. For the purposes of analyzing the impacts on load of technology adoption and Rate Design for this Study, customer counts were scaled to approximate Vermont's aggregate utility load in 2020.

Figure A-1 provides a snapshot of an hourly load projection developed in LSAM™. This figure provides a comparison between the projected existing load growth with the anticipated impact of the Emerging Technologies for a single day in the future (July 5, 2030) for the entire Vermont system. The comparison suggests that load in the early part of the day (prior to 7:00 AM) will be similar for both existing load (Baseline Scenario) and the Technology Adoption Scenario; essentially, there are few technologies that would impact this portion of the anticipated daily load. However, after 7:00 AM, the impact of increased distributed PV begins to change the load shape, as the incremental generation off-sets what would have been anticipated to be used during the middle part of the day (until approximately 4:00 PM). After 4:00 PM, the anticipated impact of EVs dramatically increases the hourly load shape, resulting in an anticipated increase in load of approximately 25% during the evening hours. This increase in end-use technology load drives the increase in peak load and the subsequent increase in Utility Cost KPIs to the Vermont electric system.

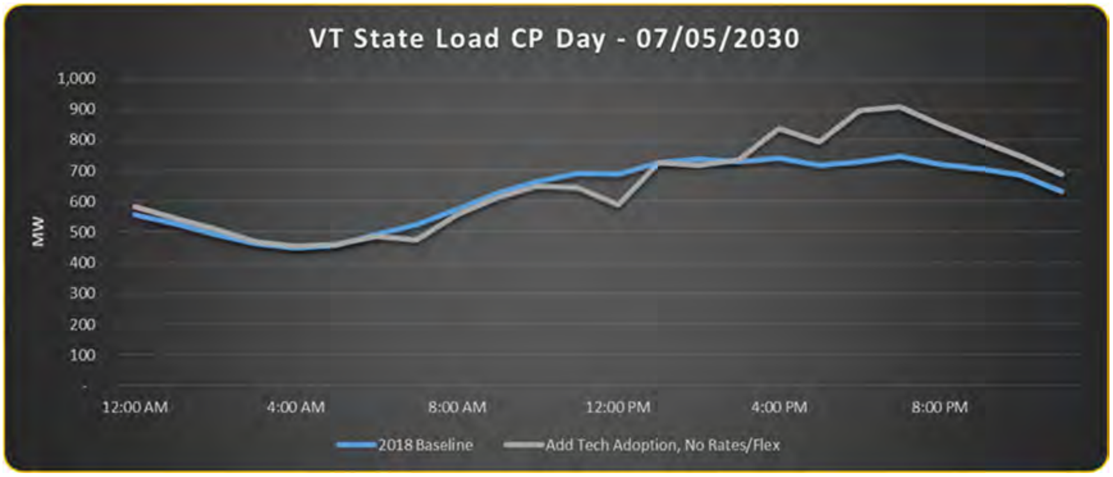


Figure A-1. Forecasted Hourly Load Shape with Existing Load and Emerging Technologies in LSAM™ for July 5, 2030

A.2 Emerging Technologies

To forecast Emerging Technology adoption in LSAM™, the Department provided information from individual Vermont utilities, other state agencies, and other publicly available sources.

As technology adoption increases, the manner in which customers utilize their electric services will change. Customers with installed distributed generation systems, such as residential PV applications, are driving system load reductions during the day with increased ramping requirements to meet load during the evening hours as the solar power begins to wane with the setting sun. This results in a characteristic "duck curve,"[13] and subsequent series of operational and regulatory requirements to maintain proper balance between load and system capacity on a minute to minute basis.

Technologies included in this Study focused on commercially available, end-use products and services that are relatively simple for customers to operate and understand. Specifically, this Study included analyses of three different technology types: PV, EVs, and appliance electrification. For this Study, appliance electrification refers to specific electric space conditioning and water heating applications, CCHPs, and heat pump water heaters. Each technology type has its own set of characteristics that respond to economic price signals and have unique impacts on the electric system.

Solar Photovoltaic

In Vermont, as of the beginning of 2019 there were just over 300 Mega Watts, Alternating Current (MW-AC) of installed PV capacity in the state. This capacity consists of the following:

- Roughly 118 MW of "wholesale" PV, or PV either owned directly by the utilities or the output of which is directly purchased by the utilities through a Power Purchase Agreement;
- Roughly 85 MW is installed under a "Virtual Net Metering" (VNM) structure whereby a larger PV facility is installed, the generation of which is apportioned to offset energy usage of certain subscribing end-use customers; and

[13] https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

- Roughly 69 MW and 33 MW installed on-site at Residential and Commercial customer locations, respectively.

On an annual basis, for 2019, this installed PV generates approximately 370,000 Megawatt-hours (MWh) that is used to serve load and offset wholesale power purchases, depending on the type of transaction structure. The current regulatory environment for behind the meter (distributed) PV provides an effective bill credit for each kWh of solar generation between $0.17-$0.18/kWh, depending on the utility, customer class, and energy rate. When combined with reductions in installed costs for PV systems, this has resulted in a rapid increase in customer adoption across the state. For the purposes of this Study, the Technology Adoption Scenario assumes that the current regulatory rate structure will remain in place, and customers will continue to install solar in response to their economic interests. Figure A-2 provides a graphical representation of the estimated adoption of PV utilized for this Study.

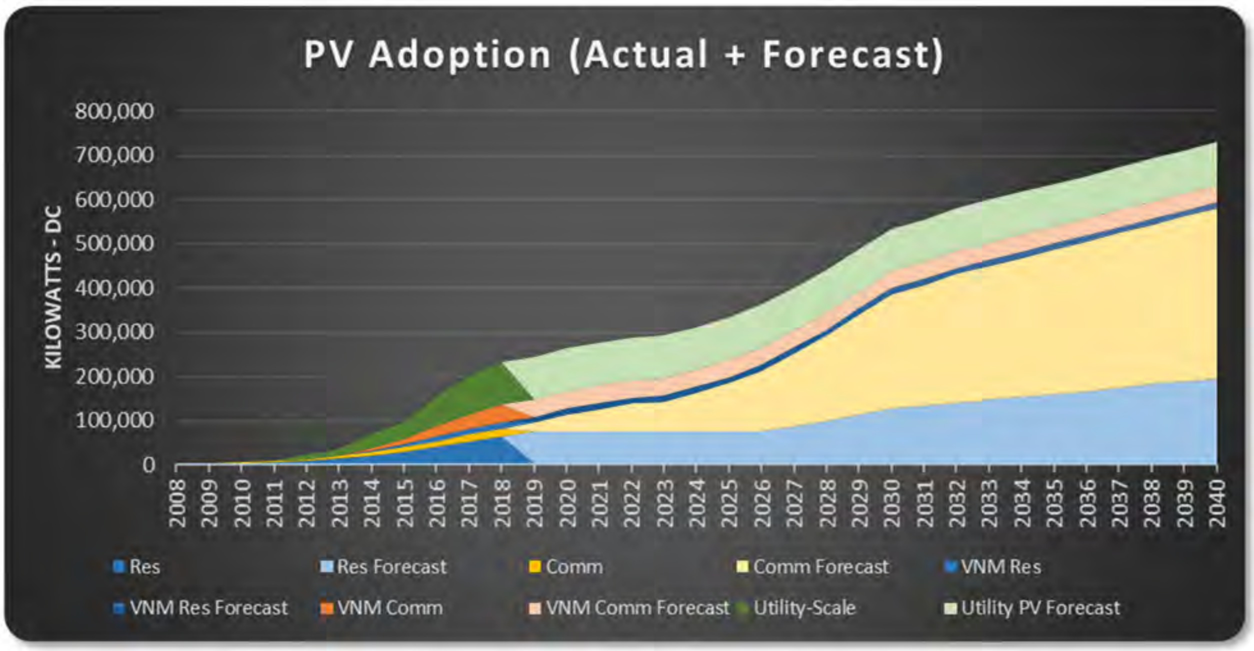


Figure A-2. PV Adoption Forecast for Vermont[14]

The colored aeras of the PV adoption graphic in Figure A-2 represent the current and future projections of different PV capacity types, as explained above. The utility scale PV is represented by the green shading, the VNM by the orange shading and dark blue line, the commercial PV by the yellow shading, and the residential PV by the blue shading.

Electric Vehicles

Adoption of EVs represents an opportunity for energy sales growth for utilities in Vermont and across the country. EVs and their charging equipment (EVSE), can potentially result in significant increase in load for

[14] Due to scaling of input customer/meter counts in LSAM™, the total solar capacity demonstrated in Figure A-2 for 2019 is less than the actual installation in Vermont in 2019. This is due to fewer total customers/meters modeled relative to total customer/meter counts found in Vermont utility billing data for the state. This scaling is performed to better match the Vermont modeled state utility peak load in 2019 to actual data, which creates a more accurate basis from which future capacity costs are compared to current. As described herein, this comparison of capacity costs is a Utility Cost KPI for this Study.

electric utilities, which during times of declining load, may result in new cost recovery opportunities. However, EV charging can also lead to substantial new capacity requirements on the system if EV load occurs during peak periods. EV load can be managed either directly by the utility or a 3rd party or indirectly through Rate Design and customer responsiveness to pricing signals. Unmanaged EV load often coincides closely with the system evening peak driven by increases in hourly space conditioning load when many residential customers return home from work.

More critically for this Study, due to relatively higher charging voltages and the corresponding speed at which EVs can be fully charged, EV load can also be seen as "flexible load". This presents an opportunity for the utility and/or 3rd parties to manage EV charging to benefit the customer and the utility through decreased future system costs.

There are approximately 3,000 EVs registered in Vermont as of 2019. This Study allows for the evaluation of future EV adoption scenarios that anticipate a substantially larger number of EVs on the road in Vermont. This future EV scenario is an important modeling exercise in anticipating their impacts on the Vermont utilities' system. The growth in EVs is critical to the state's decarbonization goals by reducing fossil fuel emissions, which is facilitated by converting internal combustion engines to electric motors.

Charging location and utility cost recovery policies are key in analyzing EV impacts on Vermont's system. The majority of existing EV owners currently charge their vehicles at home. For the purposes of this Study, the Technology Adoption Scenario assumes that all EVs in the state will be charged at home, but that 20% of vehicles will have the ability to also charge at work. Based on data from the National Household Transportation Survey (NHTS), which has been used for decades in transportation planning, the majority of at-home EV charging is likely to occur in the 5:00 PM and 9:00 PM timeframe.[15] This coincides with system peak hours and will lead to upward pressure on capacity-related Utility Cost KPIs. Conversely, at-work charging occurs during the middle of the day, when solar energy (PV) production is at its highest and which does not typically coincide with system peak demand periods. Increased consumption of energy during the day will increase ISO-NE energy costs during that period, but such timing does not typically coincide with periods of expensive wholesale energy.

For many at-home charging systems, existing distribution infrastructure has capacity available to serve the incremental load associated with EV charging at current adoption levels. However, as EVs become more abundant in the state, the capacity for each circuit to serve the incremental load may become strained. Several utilities, including Vermont Electric Coop, require a homeowner to directly pay for any additional investment necessary to serve their increased load on an individual circuit basis. The rational for this cost recovery is typically found with a utility's line extension policy. This additional cost to the end-use customer may or may not have an impact on the pace of EV adoption in the state. As discussed, EVs represent a unique load that can be flexible and has demonstrated a responsiveness to innovative Rate Design.

[15] NHTS data reflects an EV charging profile that differs from that observed with sub-metered EV load on the GMP system. GMP's EV charging data suggests a peak demand that occurs later in the evening (8:00 PM – 10:00 PM) relative to the NHTS data. The impacts of EV charging occurring later in the evening create both upward and downward pressure on system peak demand. Later charging would be coincident with reduced (or zero) PV production and thus would result in upward pressure on system peak, Later charging would also be coincident with a reduction in non-EV loads (especially commercial loads) on the system, and thus result in downward pressure on system peak relative to the NHTS modeled scenario. For this Study, NHTS data was utilized to reflect average driving characteristics for all Vermont drivers, rather than specifically charging profiles for current EV owners in GMP's service territory.

Figure A-3 provides a representation of the Technology Adoption Scenario modeling assumption for EV adoption in the state. This figure assumes a rapid increase in EV adoption by Vermont utility customers, from less than 1% of consumer vehicles in 2019, to 20% or roughly 125,000 vehicles in 2030, and 50% or roughly 330,000 vehicles in in 2040.

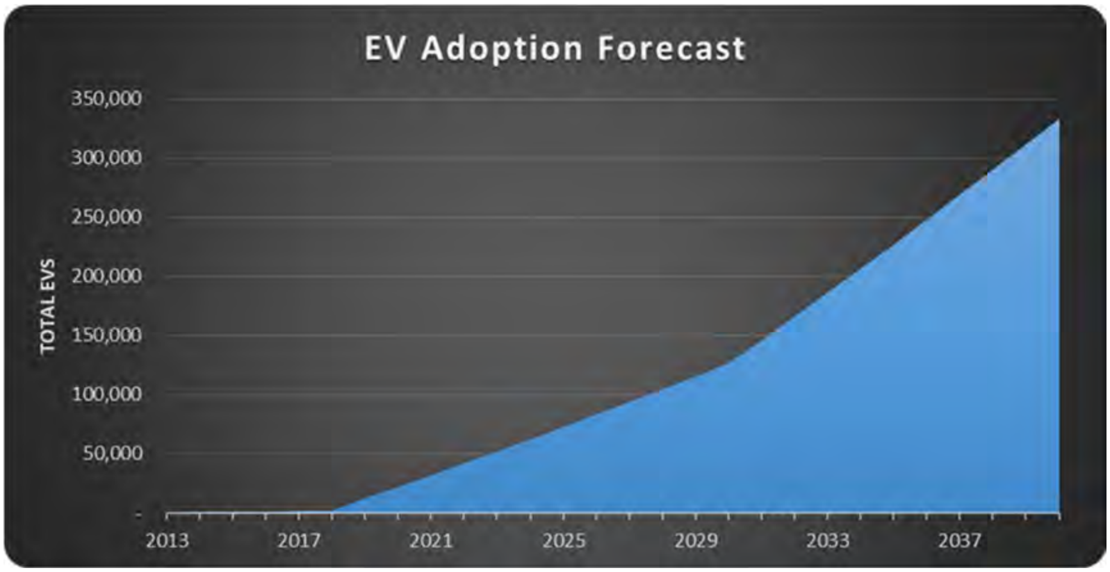


Figure A-3. EV Adoption Forecast for Vermont

In addition to the number of EVs purchased over time, assumptions were developed for the voltage of the EV chargers installed at customer premises. LSAM™ allows the user to determine the market share for three EV charger voltages (e.g., 1.8 kilowatts (kW), 7.2 kW, and 12 kW) in each year of the forecast, as a percent of the total. These values represent a range of voltages for commercially viable EV charges available. Figure A-4 below provides the assumptions used to develop the Technology Adoption Scenario for the projection of installed EV charging voltages over the period of the Study.

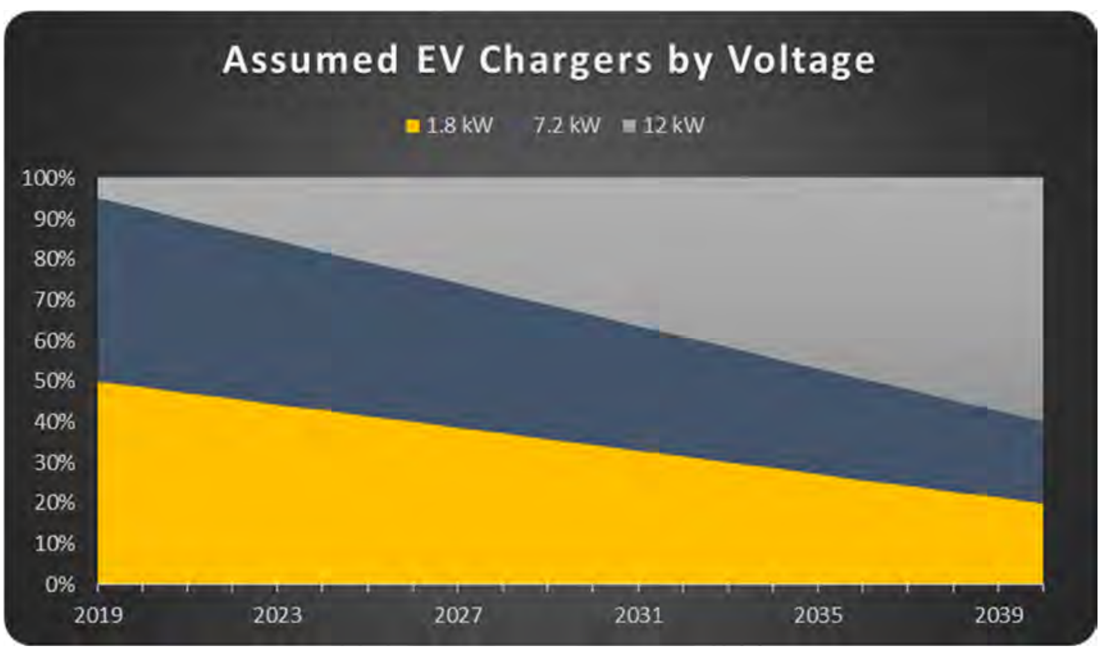


Figure A-4. Annual EV Charging Voltage Market Share Assumptions

To-date, the EV charger market has evolved to offer customers more options for increased charging voltages, providing a correspondingly shorter charge duration. Consequently, the Technology Adoption Scenario modeled assumes a continued expansion of the market share for 7.2 kW and 12 kW chargers over the duration of the Study period. Stakeholders indicated that the assumed high levels of 12 kW chargers in the later years may be overly aggressive as it may be reasonable to assume that most residential EV owners can fully charge their vehicles overnight utilizing 7.2 kW systems. Further, stakeholders suggested that current distribution system capacity and panel sizes at the customer premises may constrain the adoption of 12 kW charger systems.

This feedback was considered during the development of the Technology Adoption Scenario for this Study. It was decided that a more aggressive higher voltage charger adoption assumption reflects trends in the EV market and customer preference for faster charging. Further, in the context of purchasing a relatively expensive EV, upgrading the panel size or increasing available amperage at the home may be a reasonable expense to ensure that a customer's EV will not likely run out charge.

Finally, the ultimate impacts on system capacity between higher adoption rates of 7.2 kW and 12 kW chargers were not substantial. This results from the tradeoffs from faster charging for the 12 kW chargers and the diversity on the system when a customer begins charging. As more customers charge at 12 kW, customers are able to fully charge in 2 – 3 hours, instead of the 4 – 6 hours required for a 7.2 kW charger. Thus, while each individual customer's peak demand is higher, the cumulative peak demand of all EV load is estimated to be relatively constant between scenarios of higher proliferation of 12 kW and 7.2 kW chargers. Consequently, the increase is 12 kW EV charger adoption was selected because it reflects current trends and an EV charging future that will likely continue to evolve.

Appliance Electrification

Appliance electrification can refer to any process by which an application switches from one source of fuel to electricity. For the purposes of this Study, appliance electrification refers to the adoption and expanded use of electric space conditioning and water heating systems in residential locations across the state. Such systems include CCHPs and electric water heaters. As of 2019, CCHP systems are installed in roughly 6% of residential households in the state, reflecting roughly 16,000 systems in place. These installed CCHP units currently consume approximately 35,000 MWh per year.

While electric water heaters have been around for some time, higher efficiency heat pump water heaters are less common. Higher efficiency electric heat pump water heaters are installed at roughly 4,000 residential households as of 2019, representing approximately 1.5% of residential customers. The annual energy consumption of these higher efficiency electric heat pump water heaters is approximately 10,000 MWh. Currently, CCHP and electric water heaters often have a "back-up" system that relies on fossil fuel (natural gas or heating oil) to ensure reliability.

The technology for CCHP and electric water heaters is rapidly improving in terms of efficiency and reductions in costs. Based on economics, state policy support, and public support for decarbonization efforts, it is anticipated that this "new generation" of systems will continue to be adopted by customers in the state. For the purposes of this Study, an independent projection of CCHP / high efficiency water heater adoption in the state was not conducted. However, anticipated growth in the electrification of these systems was assumed based on feedback from the Department.

Like EV load, CCHP and high efficiency water heater loads can be flexible, and thus offer an opportunity for customers, utilities, and 3rd party entities to manage load during critical times to manage peaks and corresponding capacity costs across the system. Figure A-4 provides a summary of the assumed growth of these systems in the state. For CCHP systems, residential adoption is assumed to increase from approximately 6% of households in 2019 to 20%, or 55,000 systems, in 2030, moving to 50%, or 145,000 systems, in 2040. For high efficiency water heaters, residential adoption is assumed to increase from approximately 1.5% in 2019, to 5%, or 13,000 systems, in 2030, and to 10%, or 29,000 systems, in 2040.

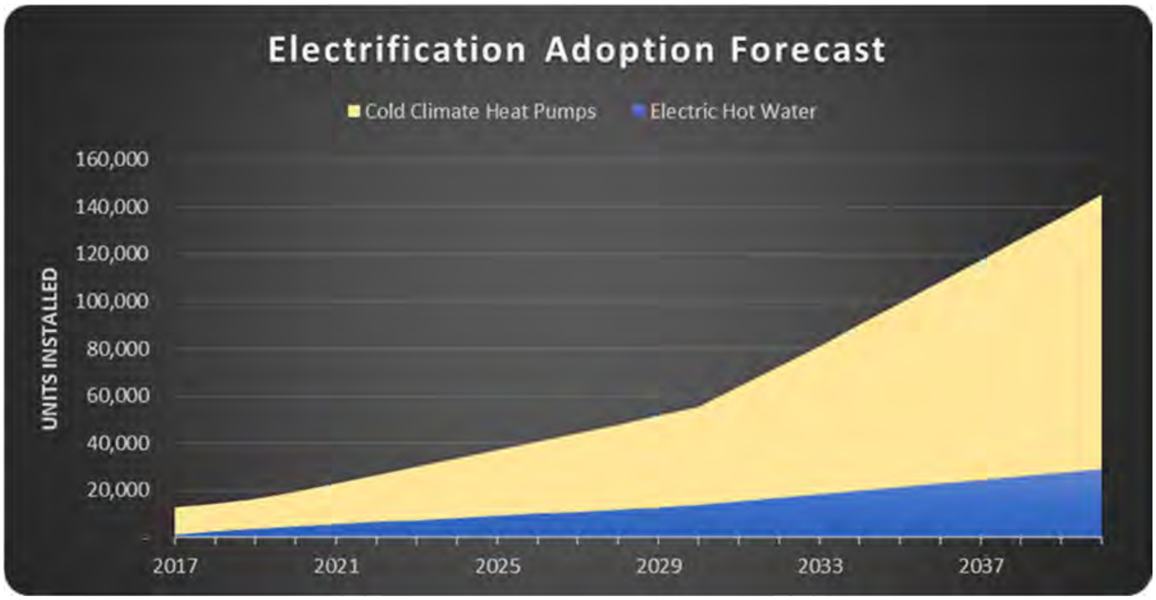


Figure A-4. CCHP and High Efficiency Water Heater System Adoption Forecast

EV Elasticity of Demand

Based on a review of EV load research and publicly available literature, on-peak to off-peak pricing differentials do not need to be as severe for EV loads to produce a meaningful response to TOU pricing. As provided in Figure A-5, the anticipated response to an on-peak price that is twice the off-peak price is expected to produce a roughly 70% reduction in EV load. As a point of comparison, for standard household load, this same pricing differential is assumed to only produce a 5% - 10% reduction in load.

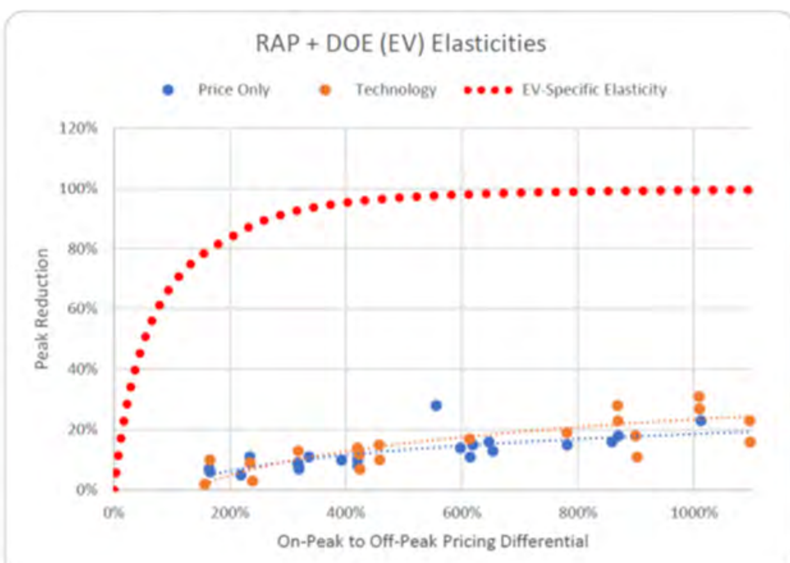


Figure A-5. RAP + DOE (EV) Elasticities of Demand by Technology

Summary and Comparison of Emerging Technology Adoption

Table A-1 provides a summary of the assumptions utilized for the Emerging Technology adoption parameters for this Study. This table provides a comparison of the projections utilized by NewGen compared to the projections developed by VELCO. [16]

Table A-1
Assumptions for Emerging Technology Adoption Parameters

<table>
<tr><th></th><th colspan="2">Year 2030</th><th colspan="2">Year 2040</th></tr>
<tr><td>Technology</td><td>NewGen Assumption</td><td>VELCO / Itron Assumption (1)</td><td>NewGen Assumption</td><td>VELCO / Itron Assumption (1)</td></tr>
<tr><td>Electric Vehicles</td><td>20% or 125,000</td><td>15%</td><td>50% or 330,000</td><td>55%</td></tr>
<tr><td>Cold Climate Heat Pumps</td><td>55,000</td><td rowspan="2">100,000</td><td>145,000</td><td rowspan="2">175,000</td></tr>
<tr><td>Heat Pump Water Heaters</td><td>13,000</td><td>29,000</td></tr>
</table>

(1) VELCO / Itron Assumptions from “Expected” Case for technology adoption

[16] VELCO/Itron assumptions for the “Expected” Case accessed 8/4/2020: https://www.vermontspc.com/library/document/download/7040/IRPFcst20_June8.pdf

Appendix B
STUDY METHODOLOGY AND DEFINITIONS

Appendix B includes additional insight into the KPIs utilized to measure the results of the modeling efforts, as well as background information on the underlying selected end-use technology projections.

Key Performance Indicators

The KPIs are intended to serve as the metrics of the projected impact of the increase in end-use technologies on the Vermont system. The majority of the KPIs selected for this Study are included as the Utility Costs as summarized in the body of the report. One additional KPI is a projection of the compliance with the carbon emissions as a part of the state's decarbonization efforts to reduce reliance on fossil fuels for the electricity, as well as transportation sectors.

ISO-NE Capacity

ISO-NE charges Vermont utilities for their contribution to the overall New England peak demand during the hour in which the ISO hits its peak for the year. Historically, this peak demand has occurred between the hours of 2:00 PM and 6:00 PM during a summer month. This charge is paid by VELCO and recovered on a monthly basis from the Vermont utilities based on their demand at the time of the ISO-NE peak (coincident peak). The current rate for ISO-NE capacity is $5.30/kW-month. Based on estimates from the Department and VELCO, it is anticipated this value will decrease from 2020 – 2023 and then increase to roughly $8.00/kW-month in 2040, as indicated in Figure B-1.

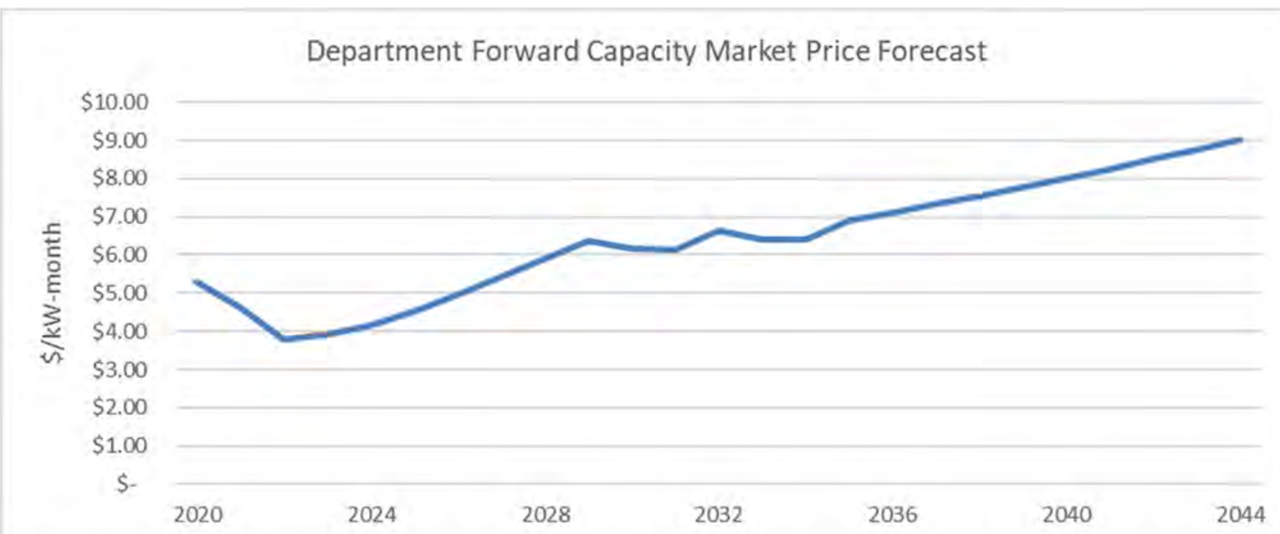


Figure B-1. Forward ISO-NE Capacity Market Price Forecast (2020 – 2044)

The current total payment for the combined Vermont utilities for 2018 for ISO-NE capacity charges were approximately $65M. It is assumed for this Study that the mechanism of capacity cost recovery by ISO-NE for generation will remain in place.

ISO-NE Energy

The ISO-NE charges Vermont utilities for monthly energy usage based on the hourly clearing prices for the New England system. The average monthly energy price for ISO-NE in 2018 was approximately $44/MWh. It is anticipated that over the Study period, the average price of energy will grow by a compound annual growth rate (CAGR) of 2.8% each year.

Renewable Energy Standards Compliance

The RES compliance standards are required by the State of Vermont for its utilities to increase purchases of renewable energy and reduce reliance on fossil fuel generation. Compliance costs are quantified based on the purchase price of RECs, currently estimated to cost approximately $30/MWh and represent approximately 3.5% of total generation costs (ISO NE Capacity and Energy and RECs). As the Vermont utilities increase energy purchases and consumption, REC purchases and associated costs must also increase to maintain RES compliance. The current Vermont target is for its electric utilities to acquire 75% of their generation from renewable resources by 2032, which is the basis for the projections utilized in this Study. This value may increase to 100% by 2030 based on policy changes made in the future; however, that policy change has not been implemented as of the date of this Study.

Regional Network Service Capacity (Embedded)

The Vermont utilities pay for RNS transmission service through VELCO to ISO-NE. The costs of managing the RNS system at its current capacity are referred to as embedded costs for RNS. These charges are applied monthly to the collective peak of the combined Vermont utilities' load, independent of that Vermont peak timing as it relates to the broader ISO-NE load. Similar to the ISO-NE Capacity charge, VELCO recovers these costs from the Vermont utilities and remits payment to ISO-NE. However, the Vermont utilities set the peak collectively on a monthly basis for this charge. The RNS Capacity charge is currently $120/kW-year applied to the average of the monthly peak loads of the combined Vermont utilities. The Vermont state peak has typically occurred between the on-peak hours of 4 :00 and 7:00 PM during each month.

Changes in peak load by individual utilities in Vermont may shift recovery of RNS costs to other utilities in Vermont and in the broader ISO-NE transmission pool. If one Vermont utility reduces its load, but another Vermont utility increases during a given peak hour, the result is a cost shift between the two utilities (assuming all else equal). If the Vermont combined peak can be reduced, the monthly RNS costs for Vermont will shift to non-Vermont utilities within the region. Similarly, if other utilities within the ISO-NE region collectively reduce their peak, there may be a cost increase to Vermont utilities, regardless of changes in their collective behavior. Given the nature of the RNS market design, the potential for reducing RNS costs for the Vermont Utilities collectively may be limited. However, for this Study, it is assumed that the RNS market design remains constant.

Incremental Regional Network Service Transmission Cost

The current and future Vermont transmission system is anticipated to have sufficient capacity to meet approximately 1,200 MW at peak load. Due to the long-term planning and substantial capital investment required to install new transmission capacity, the modeling developed an incremental cost of RNS transmission capacity investment that would be required once the collective state peak load was projected to meet or exceed 1,100 MW. Current projections anticipate that without any reductions in peak load associated with rates, the Vermont transmission system load would be approximately

1,100 MW in year 2026. Reductions in peak load as a result of innovative Rate Design are anticipated to push the requirement for new RNS transmission capacity out to the 2030 – 2035 timeframe. Costs associated with incremental RNS transmission capacity investment are estimated to be approximately $94,000/MW in 2020 dollars and are assumed to grow at the rate of inflation over the forecast period.

Distribution Capacity

As indicated previously, distribution capacity costs are unique to each circuit and each utility. The cost estimate developed for this Study was based on input from GMP and VEC and represents an "average" cost per installed incremental unit of capacity ($/kW) driven by an increase in system demand. To calculate a simplified assumption for how much investment would be needed as a function of growth of load on the distribution system, GMP modeled EV adoption on a circuit-by-circuit level, and estimated the level and frequency at which the incremental load growth would overload the rated capacity of various distribution equipment. Specifically, GMP looked at overload events of fuses, conductor, regulators, and reclosers, and provided an estimate of the associated costs. GMP data was utilized to develop a regression analysis between the incremental distribution investment (dollars) and load (kW). Figure B-2 provides the result of this analysis, which suggests a future value of approximately $300/kW for the incremental load growth associated with the end-use technologies on an "average" distribution system.

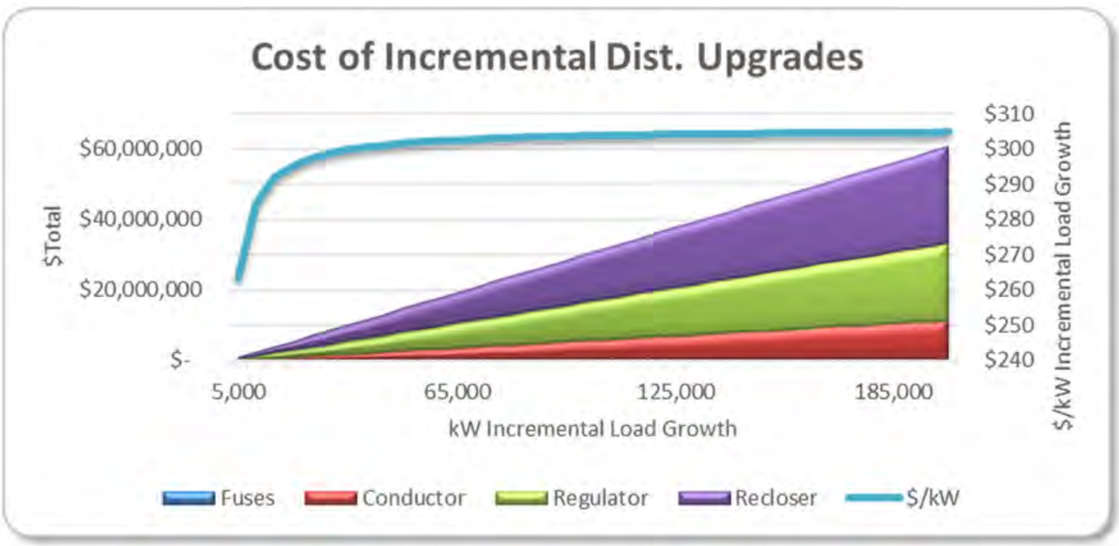


Figure B-2. Relationship between Incremental Load Growth and Distribution System Upgrade Costs for Average Distribution System

The cost of distribution system upgrades resulting from Emerging Technology adoption are highly specific to the individual utility, system, feeder, or even circuit where such technologies are installed. Stakeholders suggested the average $300/kW for distribution was higher than expected, while others provided data suggesting this estimate was lower than expected. The average value was utilized for this Study to provide an indicative impact on the distribution costs of Emerging Technology adoption, which may vary significantly on the specifics of the unique circumstances for each utility.

Carbon Emissions

Reductions in carbon emissions (as carbon dioxide, or CO_2) are a key driver of Vermont's CEP and broader state policy objectives. As part of the modeling conducted for this Study, carbon emissions reductions were estimated based on converting internal combustion vehicles to EVs and converting fuel-fired residential space conditioning and water heating to CCHP and electric water heaters. Additionally, carbon emission reductions were identified in the state's RES compliance efforts, including REC purchases which accompany the purchase of energy from ISO-NE. Figure B-3 provides the results of carbon emissions reductions modeled as part of the Technology Adoption Scenario.

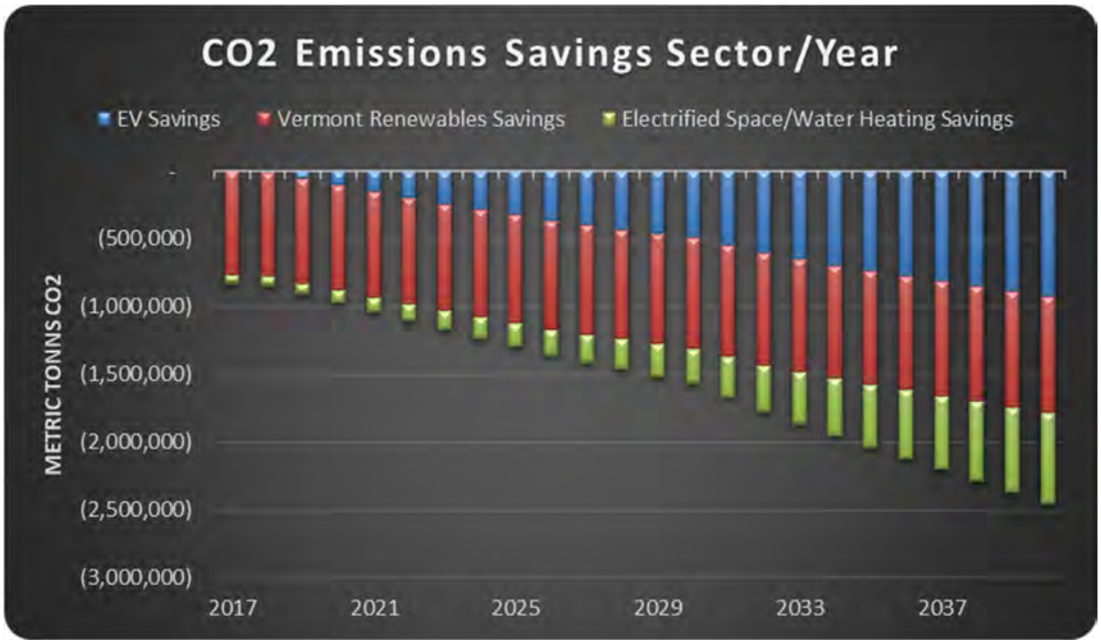


Figure B-3. Modeled Carbon Impacts of Technology Adoption Scenario

Each component of these modeled sources of carbon reductions is described in greater detail below.

- **EV Savings** are calculated as a function of the carbon emissions that occur from EVs consuming electricity with RES-compliant carbon content, which replaces the otherwise current levels of internal combustion engine vehicle emissions assumed from the consumption of gasoline/diesel fuel, utilizing a blended average fuel economy from the state based on analysis conducted by NewGen.
- **Vermont Renewable Savings** are calculated by comparing the carbon content of ISO-NE energy purchases to an average blended carbon content of ISO-NE energy purchases that are paired with RECs to maintain compliance in each year. The carbon savings in place currently reflect ongoing RES compliance and REC purchases currently made by the state's distribution utilities.
- **Electrified Space/Water Heating Savings** are calculated by comparing the fuel consumption and weighted average carbon content of existing fuel sources for these appliances to replacing these fuel types with electricity consumed with a RES-compliant carbon content, as appropriate. [17]

[17]Existing average fuel sources for current electrified space and water heating systems are 31% Fuel Oil, 27% Renewable, 2% Electric, 17% Propane, and 23% Natural Gas, based on an analysis of information provided by several stakeholders.

Appendix C
STAKEHOLDER ENGAGEMENT EVENTS

Stakeholder Events

NewGen and the Department facilitated five Stakeholder Engagement events during the course of this Study. The purpose of these events was to engage with stakeholders in Vermont and across the country that have an interest in innovative Rate Designs and helping construct the future of the electric utility industry. Below is a list of the participating organizations in the Stakeholder Engagement events held for this Study.

- Aegis Renewables
- Agency of Commerce and Community Development
- Burlington Electric Dept. (BED)
- DC Energy Innovations
- Demand-Side Analytics
- Dynamic Organics
- Energy Action Network, Vermont
- Energy Futures Group
- Efficiency Vermont
- Green Mountain Power (GMP)
- Grassroots Solar
- Greenlots
- JouleSmart
- MMR LLC
- Norwich Technologies
- Oracle
- Packetized Energy
- Peck Electric
- Public Service Department
- Regulatory Assistance Project
- Renewable Energy Vermont
- Vermont Electric Cooperative (VEC)
- VEIC
- Vermont Electric Power Company (VELCO)
- Vera Renewables
- Vote Solar
- Vermont Public Power Supply Authority (VPPSA)
- Washington Electric Cooperative

Workshop #1

The facilitated workshops began on December 12, 2019 with an in-person presentation of the team members, the objectives of the Study, the structure and process for the workshops, a discussion of rate trends, and an introduction to LSAM™. The workshop included two breakout sessions designed to encourage thinking about innovative Rate Designs and to assist in the development of specific KPIs and critical success factors for the Study.

Workshop #2

The second workshop was held in person on January 28, 2020. This workshop included a recap of the outcomes from the previous meeting, and a specific review of the LSAM™ efforts, including key assumptions and management of flexible loads. This workshop included two hands-on breakout sessions to allow participants to utilize interactive features of LSAM™ and record results relative to innovative rate impacts on load and other parameters.

Workshop #3

Due to restrictions on travel and safety concerns for participants with regard to the COVID-19 pandemic, the third workshop was held online, utilizing the Zoom platform graciously provided by EAN. This meeting occurred on April 16, 2020. This workshop included an update on findings from the LSAM™ effort, as well as two separate panel discussions. The first panel discussion focused on utility planning efforts in Vermont as they relate to the various state objectives. The second panel included experts from within and beyond Vermont presenting various solutions to innovative rate implementation challenges.

Workshop #4

Workshop #4 was held online, again utilizing the Zoom platform provided by EAN, on May 21, 2020. This workshop included an update on LSAM™ results, including responses to comments provided by the Technical Working Group, as well as a review of the summary findings with regard to rate solution recommendations. The workshop included a panel discussion of various areas of recommendation from state industry representatives, as well as a summary of previous workshop implementation methods. After a break for lunch, the workshop was split into four groups. Each was assigned an issue designed to solicit feedback, concerns, and consensus with regard to rates, implementation challenges, consequences of no change, and gauging the degree of alignment among participants. Additionally, a summary of goals, initial findings, and recommendations from the Study were presented.

Workshop #5

Workshop #5 was held online, again utilizing the Zoom platform provided by EAN, on July 16, 2020. This workshop included a summary of the NewGen report, including the findings and recommendations for implementation of innovative Rate Design. This workshop included a panel discussion from representatives of the electric utilities in the state to discuss their plans and perspectives relative to the Study findings and recommendations. A second panel was comprised of industry representatives to discuss next steps and feedback from the Study. The Commissioner of the Department provided some perspective relative to the Study findings and public policy evolution and how the concepts of the Study would be incorporated into future Department actions. NewGen and the Department closed with a statement of appreciation for all of the efforts of the stakeholder group and a request for written comments on the draft report.

Information Posted On-Line

The Department has posted the agendas, presentations and summary notes for each of the Stakeholder Engagement events as well as this report on their website:
(https://publicservice.vermont.gov/content/rate-design-initiative).

Appendix D
INNOVATE RATE SURVEY RESULTS

Table D-1
Innovative Rate Study Results

Rate Type	Utility	State	TOU (Y/N)	Demand (Y/N)	Rate Description
EV - Home Charge	Riverside Public Utilities	CA	Yes	No	EV on separate meter
EV - Home Charge	Braintree Electric	MA	Yes	No	Fixed credit for off-peak
EV - Home Charge	Pacific Gas & Electric	CA	Yes	No	On, Off, Shoulder peak prices
EV - Home Charge	Austin Energy	TX	Yes	No	Rebates, no charge for off peak, fee for program
EV - Home Charge	Portland General and Electric	OR	Yes	No	Unbundled. Credit for first 1,000 kWh/mo
EV - Home Charge	Excel Energy	MN	Yes	Yes	Pilot. Unbundled. TOU for Prod/Trans. Max Demand for Dist.
EV - Home Charge	Burlington Electric Department	VT	Yes	No	Credit applied if charging off-peak
EV - Home Charge	Hawaii Electric	HI	Yes	No	On, Off, Shoulder peak prices, separate meter option
EV - Home Charge	Turlock Irrigation District	CA	Yes	No	Winter / Summer difference; appx 2x rate differential
EV - Home and Public Charge	Alaska Electric Light and Power	AK	Yes	No	Winter / Summer difference; very small rate differential
EV - Home Charge	Seattle City Light	WA	Yes	No	Lease per month fee; normal residential rates
EV - Public Charge	Pacific Gas & Electric	CA	Yes	Yes (if over)	Subscription up to certain level
EV - Public Charge	Excel Energy	MN	No	Yes - Delimiter	Demand charge / 100 hours
EV - Public Charge	Southern California Edison	CA	Yes	No	Phase in Demand > 5 yrs.
EV - Public Charge	Burlington Electric Department	VT	No	No	Energy only rate; not customer charge
EV - Public Charge	San Diego Gas & Electric	CA	Yes	Yes	Grid Integration Charge + Energy Rate varies with market
EV - Public Charge	Riverside Public Utilities	CA	No	Yes	Same as commercial or industrial tariff but discounted for 2 years
NEM / NEM 2.0	Santee Cooper	SC	No	Yes	Charge for $/kW installed capacity. S/W rate differential
NEM / NEM 2.0	Turlock Irrigation District	CA	Yes	Yes	Credit at TID's short run marginal cost for the excess generation
NEM / NEM 2.0	NYSERDA	NY	NA	Yes	Energy charge based on real time pricing, Full Value of Solar Rate
NEM / NEM 2.0	National Grid	NY, MA, and RI	NA	No	Requirements/ rate varies by state, updated monthly

Table D-1
Innovative Rate Study Results

Rate Type	Utility	State	TOU (Y/N)	Demand (Y/N)	Rate Description
NEM / NEM 2.0	Mt Carmel Public Utility	IL	NA	NA	Parallel generation, available to qualified facilities
NEM / NEM 2.0	Mid American Electric Company	IL	Both	Both	Available to renewable electric generating facilities, 5% of Illinois peak
NEM / NEM 2.0	Ameren	IL	Both	No	Three methodologies, each has a TOU and a non TOU option
NEM / NEM 2.0	Hawaiian Electric	HI	NA	NA	Offers 4 programs: Customer Grid Supply, Supply Plus, Smart Export, Self Supply
NEM / NEM 2.0	Kauai Island Utility Coop	HI	NA	NA	Pilot program, credit paid/ rolled at end of the year
NEM / NEM 2.0	Portland General Electric	OR	No	Yes	Pilot program for small and medium systems, capacity allocated by a 24- hour lottery
NEM / NEM 2.0	Comed	IL	NA	NA	Energy and credit rates based on real time day ahead pricing
NEM / NEM 2.0	XCEL	CO	NA	NA	Two programs: incentivized and no incentivized, solar bank
NEM / NEM 2.0	Seattle City Light	WA	NA	NA	Solar bank, Credits forfeited April 30th if not used
NEM / NEM 2.0	Braintree Electric	MA	No	No	Credited at the current corresponding energy rate
Storage - Battery	Pacific Gas & Electric	CA	Yes	No	Storage that can also be sold back to the grid
Storage - Battery	State of Massachusetts	MA	Both	No	Customer receive annual payments based on load reduction
Storage - Battery	Eversource	New England	Yes	Yes	Eversource draws batteries peak events, incentives for load during events
Storage - Battery	Xcel	CO	NA	NA	Stapleton Pilot Project, batteries to for voltage regulation / reducing demand
Storage – Battery	New York State Public Commission	NY	NA	NA	Mandated IOU storage programs (2019)
Storage – Battery	NYSERDA	NY	NA	NA	Storage incentives based on kWh – different rates for NYC, LI, rest of state
Storage – Battery	Central Hudson Gas and Electric	NY	NA	NA	Minimum capacity of 5 kW, state of charge 200 calendar days
Storage – Battery	Braintree Electric	MA	No	Yes	Capacity must be >75 kW, reduced demand rate for battery kW
Storage – Battery	Austin Energy	TX	NA	NA	Austin Shine Program, residential, commercial, and community storage projects with PV
Storage – Battery	Arizona Public Service	AZ	No	Yes	Peak demand assessed based on kW during 3:00 PM to 8:00 PM, reduced volumetric charges

Table D-1
Innovative Rate Study Results

Rate Type	Utility	State	TOU (Y/N)	Demand (Y/N)	Rate Description
Storage - Thermal	United Power	CO	Yes	Yes	Special rates and incentives for thermal slab or thermal storage units
Storage - Thermal	Alaska Electric Light and Power	AK	Yes	No	Off peak heat storage program for residential/ commercial
Storage - Thermal	Florida Power and Light	FL	Yes	Yes	Commercial, time heat storage rate, minimum load removal requirements
Storage - Thermal	Daytona State College	FL	NA	NA	2.5 mgal storage tank installed, discounted electric bills, est. annual savings of $250,000
Riders	Commonwealth Edison	Multiple	NA	NA	Energy efficiency and Demand response adjustment
Riders	Commonwealth Edison	Multiple	NA	NA	Purchased electricity rider, applicable to basic electricity service
Riders	Commonwealth Edison	Multiple	NA	NA	Purchases of receivables with consolidated billing, allows utility to buy and sell from RES