City of Burlington Electric Department 2020 Integrated Resource Plan

Prepared for the Vermont Public Utilities Commission

September 1, 2020

Executive Summary

In September 2019 the City of Burlington Electric Department ("BED") issued a comprehensive Net Zero Energy Roadmap ("the Roadmap") illustrating how the community could transition to Net Zero Energy ("NZE") by reducing and eventually eliminating fossil fuel consumption across the building and ground transportation sectors. The electric sector has already been converted to NZE with BED's achievement of 100% renewable energy in 2014; importantly, however, to convert transportation and heating to NZE, both the amount of renewable energy and the ability of BED's system to support load will need to increase.

Successfully moving toward NZE will require a significant shift in how the community thinks about and consumes energy in the thermal and transportation sectors. Making the transition will require policy changes, incentives, and significant investment in new technology. However, several key factors are beyond BED's control, including the pace of change for electric transportation and heating technologies, federal policies such as fuel economy standards and tax incentives, state policy initiatives including whether Vermont or the region prices carbon, and the potential for non-linear adoption rates for technology as prices come down. BED is currently working on two potential City policies related to weatherization in rental buildings and electrification of new buildings. Investment in new technologies is expected to be balanced by the financial and societal returns on such investments. Making capital funds available to invest in NZE initiatives such as loan funds tied to energy savings and similar mechanisms will be of material assistance and are already part of BED's approach with our Green Stimulus program.

The key focus areas of the Net Zero Energy Roadmap are:

- **Energy efficiency and electrification of buildings** – including weatherization, switching to efficient electric heating (such as heat pump technologies at residential and commercial properties), and renewable fuels where available;

- **Switching to electric transportation** – converting transportation needs across modes (bike, car, bus, etc.) to electric propulsion;

- **District energy** – successfully constructing and operating a thermal district energy system to reduce fossil fuel use in the commercial sector; and

- **Alternative transportation** – to reduce vehicle miles traveled and provide solutions for "last-mile" needs.

Additionally, moving toward Net Zero Energy will require the following considerations:

- shifting patterns of energy use to encourage increased electricity usage during less expensive and constrained times of the day;

- better integration of renewable resources as the amount of renewable energy demanded regionally increases;
- a focus on equity in the design of every policy and program;
- a rethinking of historic preservation to ensure every building that is renovated will provide an energy-efficient, comfortable, and healthy home or workspace while recognizing its historic character;
- comprehensive planning for community construction projects to ensure:
  - policies allow for increased density in key locations to minimize transportation needs;
  - buildings are designed and built to be high performance;
  - compact, mixed-use development is sited near places where residents work and recreate;
  - redesign of roads to significantly increase multi-modal transportation; and,
  - increased focus on and investment in public transportation so it is more accessible, runs more frequently during peak usage, and therefore can be better used to accommodate expanding needs;
- continuation of BED's practice of sourcing 100% of the City's electricity needs from renewables;
- efficient expansion of BED's distribution system to accommodate increasing load levels and timing, including the possibility of electric storage deployment; and
- a high level of stakeholder engagement including community, State, regional, and federal partners.

BED recognizes it is completing this Integrated Resource Plan ("IRP") during the COVID-19 pandemic, which has impacted our community like so many others. As a City department and community member, BED acknowledges the hardships our customers have been experiencing. Working toward our NZE goals while also addressing and overcoming pandemic-related challenges will require a concerted effort from the BED team. Accordingly, BED remains as committed as ever to its mission:

> *To serve the energy needs of our customers in a safe, reliable, affordable, and socially responsible manner.*

To help support our customers' progress toward NZE while also supporting local economic recovery, in June of this year BED launched its Green Stimulus programs. The Green Stimulus programs are planned to run for a limited time but may prove instructive in improving BED's efficiency and electrification programs in the longer term. Already BED is seeing indications of an increased pace of program uptake based on the Green Stimulus activities, including HVAC contractors fully scheduled for heat pump installations into the fall.

BED recognizes that at a moment of intense focus on social and racial justice issues in our community and across the country, it is imperative that our programs and services be available, accessible, and affordable to all our customers. We are undertaking new efforts, in coordination with City partners, to enhance outreach strategies, and our 2020-2021 Strategic Direction includes the following objective:

Ensure all programs are equitable and accessible, with a priority given to low-to-moderate income, rental, black, indigenous, and people of color (BIPOC), immigrant, and refugee populations.

If we continue to focus on ensuring that all customers have equitable opportunities to participate in our energy services, then attaining the NZE goal City-wide becomes more achievable as all community members are able to engage in the effort.

However, BED cannot achieve NZE status or realize Vermont's clean energy goals in the absence of additional investment and sources of funding for that investment. We are not proposing any additional charges at this time, and the transition cannot be solely funded by the Vermont electric utilities. Any increases to the existing charges for electricity or efficiency services would only result in upward rate pressure over time. If electric rates increase more than the cost of fossil fuels, it will undermine our efforts to encourage customers to transition to electric thermal and transportation measures, such as switching from natural gas heating to heat pumps.

Therefore, where additional expenditure will be necessary, it should be funded in such a way as to not increase the cost of electricity relative to fossil fuels. Additional statewide policy tools may also need to be developed to allow increase flexibility in the use of existing funding sources, such as those envisioned in Senate Bill ("SB") 337, which is currently under legislative review. If SB 337 becomes law, energy efficiency utilities ("EEUs") including BED and Efficiency Vermont ("EVT") would have increased flexibility to implement initiatives that complement Vermont's Tier 3 programs, furthering our efforts to reduce greenhouse gas emissions (but only to the extent they are using funds being collected at current rates). At the City level, BED is engaged in discussion of potential policies that would support NZE such as improving the thermal efficiency of rental properties and increasing existing local efficiency standards for new construction projects.

Finally, policy discussions are often focused on the upfront capital cost of protecting and sustaining our environment. In chapter 8 of this IRP, BED focuses instead on the net benefits. As further discussed in the Net Zero Energy Roadmap report, the net benefits of a transition to net zero energy are significant.[1] As Table 1 illustrates, net operational savings from pursuing the identified pathways amount to $474 million, resulting in $157 million in net benefits over the next 10 to 20 years. This is in a scenario where the state or region prices carbon at a value similar to the price that the Department of Public Service ("DPS") and the Public Utility Commission ("the Commission") already use to evaluate avoided costs in certain instances.

Table 1: Cost-effectiveness of NZE transition with a $100/ton CO2e price

Pathway (at $100/ton of CO2 e)	Present Value of Costs and Savings (in millions, 2019$) Capital costs	Operational costs	Net benefit/ cost	Total Net Energy Reduction 2020 - 2040 (trillion BTUs	Cost per Unit of Energy Avoided (2019$/ mmBTU)
Efficient electric buildings	$ 141	$ (202)	$ (61)	27	$ (2)
Electric vehicles	$ 113	$ (242)	$ (129)	7	$ (18)
District energy	$ 63	$ (30)	$ 33	9	$ 4
Total	**$ 317**	**$ (474)**	**$ (157)**	**43**	**$ (17)**

Estimated benefits include construction of a district energy system if it is determined to be feasible by a study BED is currently conducting.[2] Capital costs reflect the upfront capital expenditures incurred for equipment and weatherization projects. Operational savings are mostly from fossil fuel savings, as well as lower maintenance costs, where applicable. The costs and savings have not been allocated among customers or BED, but instead reflect societal costs and savings generally. Importantly, our analysis indicates that moving toward NZE can have a ratepayer benefit in the form of lowering rate pressures relative to the business as usual case. This occurs because the revenue from new loads outpaces the need for system investment to serve that new load, resulting in a more efficient use of the BED grid system.

For additional information on the net benefits of an NZE future, BED would encourage readers to review the Roadmap, as it demonstrates how communities can help their residents, businesses, and institutions transition away from fossil fuels. Furthermore, a recent national

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[1] A comprehensive discussion of the benefits of a NZE transition is provided in our Net Zero Energy Roadmap, included in the appendix of this document and at https://burlingtonelectric.com/sites/default/files/inline-files/NetZeroEnergy-Roadmap.pdf

[2] Since the completion of the NZE Roadmap in September 2019, the district energy system has been scaled back in size and scope, thus potentially improving the cost-effectiveness of this pathway in the future. However, additional analyses of the revised system design are still underway. It is hoped any DES would eventually be expanded in scope over time once the initial investment has been made.

study looking at significant decarbonization through electrification over a similar timeframe (2035) found significant jobs and economic benefits of such a transition.[3]

Finally, BED recognizes that NZE requires a shift in our own internal thinking. While BED is a regulated franchise provider for electric service, the electric technologies that move us toward NZE (such as electric vehicles and heat pumps) are not widely adopted and are competing in some instances against unregulated fuels such as gasoline. We see renewably sourced electricity, for example, as a less expensive and cleaner transportation fuel than gasoline. Analysis indicates that electric transportation fuel in Vermont keeps more dollars within the state than fossil fuels.[4] BED therefore must employ strategies first used in our energy efficiency programs to support outreach, customer education, vendor engagement, and partnerships to fully realize the potential for the electric transition.

Utility Facts

The following facts about BED provide additional context to the IRP decision process and illustrate the reasons why BED continues to pursue aggressive clean energy goals that reflect the community's environmental ethos.

- Burlington Electric Department was first established in 1905 as a municipal utility to lower the cost of electricity for residences and the City's streetlights.
- The total population of Burlington is approximately 43,000. The City is widely considered to be the economic, cultural, and educational hub of the State, as many Vermonters and tourists commute into the City to work, shop, and attend events.
- BED serves approximately 21,100 customers: 17,120 residential customers and 3,900 commercial customers.
- BED's service area spans approximately 13 square miles including the Burlington International Airport
- BED revenue bonds and general obligation bonds are investment-grade rated as A3 by Moody's Investors Service. This rating is attributed to solid debt service coverage, high degree of liquidity, a diverse renewably based generation resource mix and a diverse local economy. (Note: none of this debt is associated with the McNeil Generating Station; all debt relating to that facility has been retired.)
- The McNeil Generating Station, a 50 MW biomass plant, commenced operations in June 1984. BED is the majority owner (50%) and operator of the facility. In 2008, the owners installed state-of-the-art pollution control equipment. The equipment reduced local NOx emissions and allowed for the sale of high-value renewable energy credits

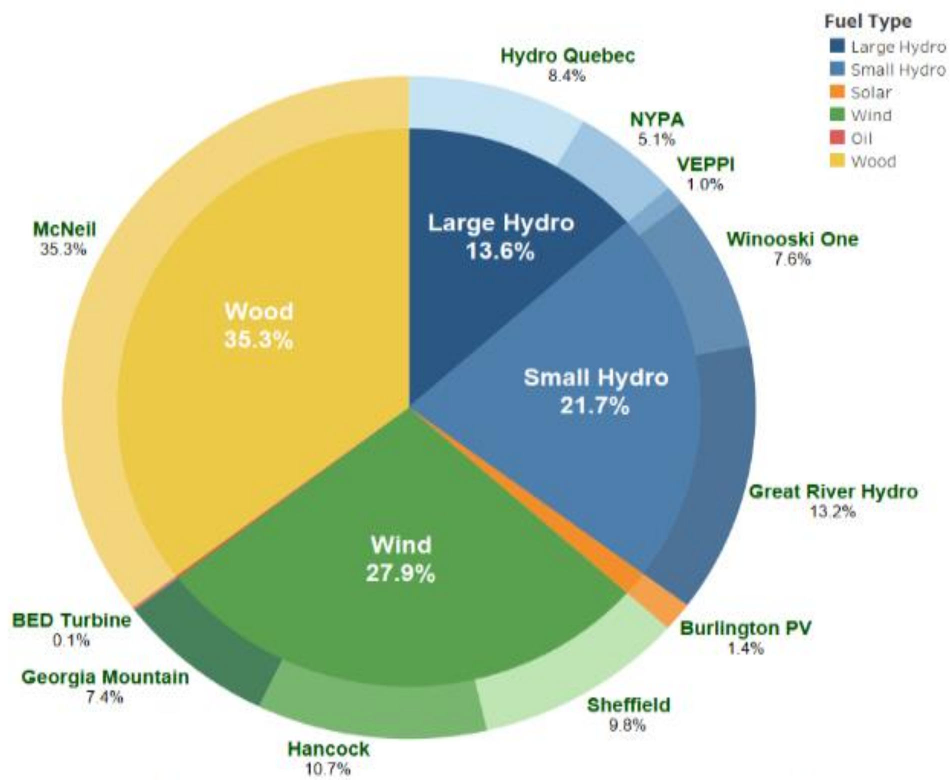
[3] A copy of this report can be found at: https://tinyurl.com/yx6pc99w

[4] See https://www.eanvt.org/wp-content/uploads/2020/02/pg21-staysleaves.png for additional information.

("RECs"). With the proceeds from REC sales, BED was able to achieve a two-year payback on its investment in pollution controls.

- With the purchase of the Winooski One hydro-electric facility in 2014, the City of Burlington's 15-year quest to source 100% of its electrical needs from renewable resources was achieved. It is important to note BED is recognized as being 100 percent renewable post-REC sales and purchases as well.
- BED's generation mix (before REC sales) includes biomass, large hydro, small hydro, wind, and solar, as highlighted in Figure 1.

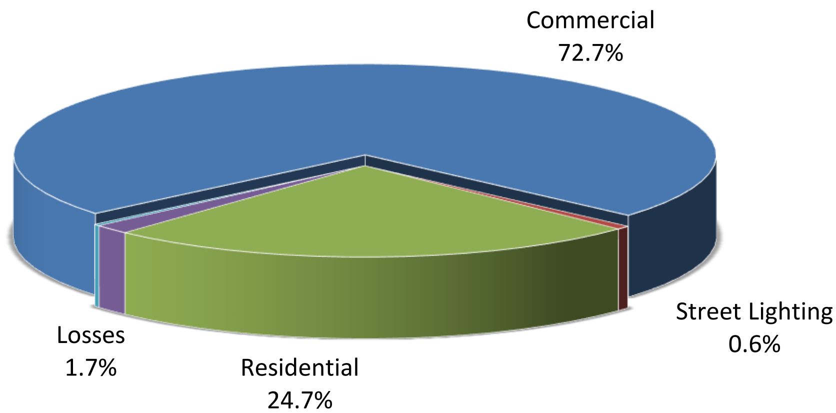
Figure 1: BED Energy Supply by Source



NOTE: BED has no contracts for resources fueled by Natural Gas, Nuclear or Coal. 0.1% of generated energy comes from Oil used at the BED turbine. The energy supply profile exceeded sales by 1.5%. The above represents energy supplied and purchased by BED prior to REC sales.

- In 2018, total system deliveries (including losses) amounted to 341,234 MWh, a 0. 7% increase over 2017 due to warmer weather. Peak demand in 2018 reached 67.3 MW (summer). Despite the small increase, MWh deliveries have been declining annually since 2010 by as much as 0.4%. Reductions in sales can largely be attributed to strong energy efficiency programs and new appliance standards that have been phasing in over the last 5 to 10 years.
- Commercial customers account for the largest share of electricity use with nearly 73% of the total. Residential customers account for roughly 25% of total energy requirements as shown in Figure 2.

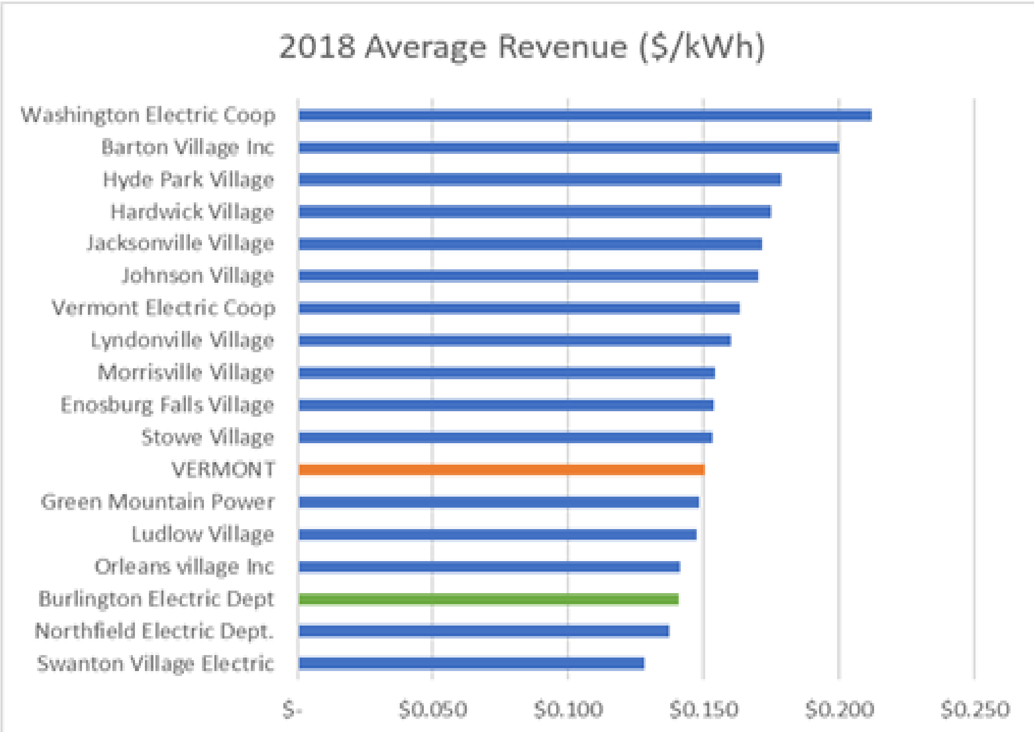
Figure 2: 2018 System Energy Requirements



- The 20 largest commercial accounts account for nearly 50% of the city's total energy load.
- On average, most residential customers use less than 450 kWh per month and incur $75 in monthly electric bills - less than most cellular telephone bills.
- In 1990, the City of Burlington approved an $11.3 million bond to fund demand-side management programs making BED the first "energy efficiency utility" in the state.
- Electric use in 2019 was 8.8 percent lower than in 1989.
- Investments in energy efficiency over the last 20 years have helped to essentially flatten load growth.
- 60% of residential customers rent their homes.
- 70 commercial customers leased their building space.
- Because a high percentage of customers are also college students, 35% of BED's accounts turn over to new customers each year.
- As shown in Figure 3, in 2018, BED collected the third lowest amount of revenues per kWh consumed in the State.[5]

[5] Per email from Department of Public Service.

Figure 3: Average revenue per kWh, VT electric utilities, 2018



Objectives

The primary objective of this IRP is to outline BED's approach to decision-making to ensure BED can reliably serve the needs of its customers in accordance with 30 V.S.A. §218c. Other themes of this IRP are:

- Environmental stewardship by transitioning to a Net Zero Energy ("NZE") community by reducing and eventually eliminating fossil fuel use in the electric, thermal, and ground transportation sectors by strategically electrifying, managing demand, realizing efficiency gains, and expanding local renewable generation while increasing system resilience
- Reliably and safely serving customers and the community
- Maintaining financial strength
- Modeling and understanding the potential impacts (costs, benefits, risks) to BED of actions taken to advance NZE goals
- Ensuring that BED's operations and capabilities can adapt to significant technological disruptions and customer behavioral changes.

This IRP satisfies the requirements of Vermont's 2016 Comprehensive Energy Plan for the following reasons:

- It identifies key input variables and risks that could impact operations;

- It describes how BED will manage those identified risks;
- It documents how BED can reliably meet the energy needs of its customers, after safety concerns are addressed, at the lowest present value lifecycle costs; and
- It highlights a series of priority action steps to be taken in the future.

Because the electric utility industry is rapidly evolving, BED has used the IRP process as an opportunity to develop, test, and demonstrate how its decision-making framework, methodologies, and tools will provide greater flexibility in the future so that the organization can act on opportunities as economic and technological conditions evolve. BED has used this IRP process to demonstrate how its decision-making methodology and tools can be used to evaluate future investment options for balancing supply and demand while also ensuring low-cost, reliable, and safe electric service.

In the absence of new policy tools or funding injections, in this IRP BED assumes that the current pace of future customer adoption of beneficial electrification, weatherization, and other clean energy initiatives will continue until those changes occur. Consequently, the findings and recommendations of this IRP primarily reflect a base case scenario for load growth, resource adequacy requirements, and infrastructure upgrades to provide a basis for evaluating the impacts of these changes when they are advanced. This baseline scenario is important for planning and for relative comparison to the NZE scenarios, which are discussed in a chapter on BED's commitment to help the City achieve its NZE goals the implications that near-term progress toward those goals could have for BED's delivering reliable energy services in accordance with 30 V.S.A. §218c.

2016 IRP Memorandum of Understanding

As a condition for approval of its 2016 IRP[6], BED agreed to do the following:

a) Research additional commercially available measures and technologies that control customer loads remotely and/or provide incentive programs for these technologies.
b) Provide an assessment of the lessons learned from current and future pilot projects such as the water heater, electric bus, and electric vehicle programs.
c) Provide a cost analysis of the various Tier 3 programs considered by BED in terms of first year acquisition costs. Analysis shall also include a discussion concerning the selection of measures to promote and how customer incentive levels were established.
d) Provide an analysis of the operations and economics of the McNeil power plant.

Items a), b) and d) above are addressed in this IRP's appendices and (c) is addressed in Chapter 5, Comprehensive Energy Services.

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[6] Case 17-0638, Petition of BED for approval of its 2016 Integrated Resource plan, final order of 11/15/2017.

Summary of Key Findings

Introduction: The Commission's overarching goal in reviewing and approving IRPs is to ensure that Vermont's electric utilities are engaging in appropriate *processes* to address the planning components defined in statute.[7] Accordingly, BED established a process described in this IRP for identifying operational risks and measuring their impacts on our cost of service.

Burlington's Demand for Electricity: Long-term energy requirements and peak demand forecasts are essential inputs into the planning process. The output from these analyses informs BED on the range of total energy and capacity that may be needed to provide reliable electric service. For this IRP, energy and capacity forecasts are based on statistically adjusted end-use models that rely on historical data related to regional economic growth, weather patterns, seasonality, net metering generation, housing starts, business formation, as well as customer usage and behaviors. This IRP forecast is BED's first to include sales of electric vehicles and heat pumps as customers adopt these technologies over time (but not at the pace of adoption that would be required to reach NZE by 2030 or 2040 per the Roadmap).

As shown in Table 2, BED's base case scenario energy requirements are expected to remain flat, increasing by 0.3% annually (after accounting for the effects of future energy efficiency programs, BAU electrification, and behind the meter generation). Meanwhile, peak demand is expected to increase 0.1% annually.

Table 2: Annual Energy Requirements & Peak Demand, 2019-2039

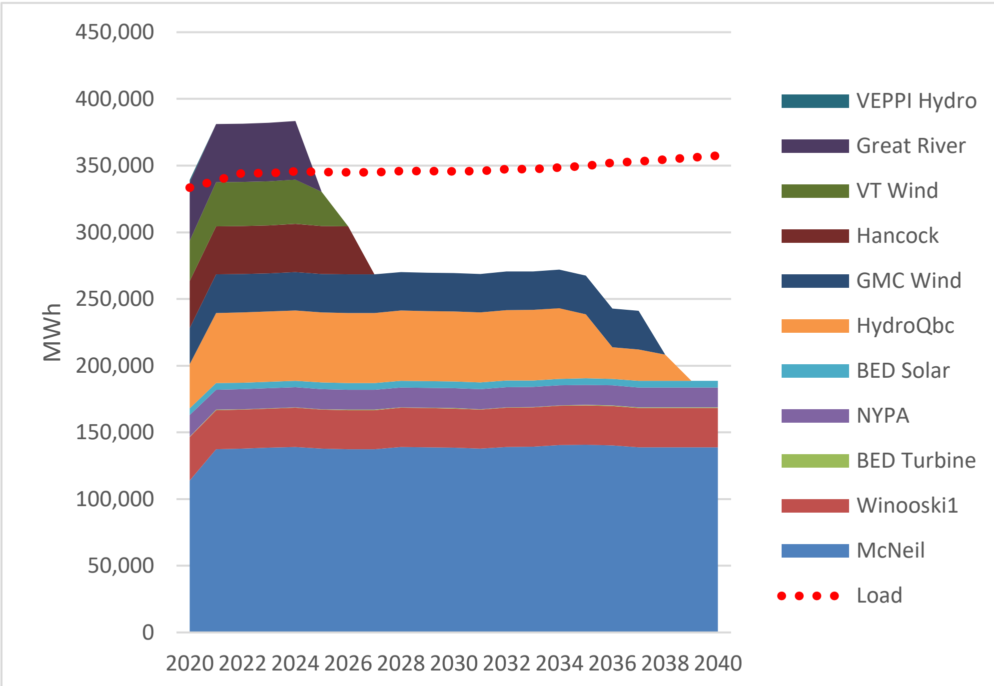
	2019	2024	2029	2034	2039	CAGR
Residential	81,171	82,702	87,053	95,864	107,315	1.4%
Commercial & Industrial	246,572	252,147	248,226	242,255	238,453	-0.2%
Street Lighting	2,160	1,976	1,792	1,608	1,424	-2.1%
Losses & Co. Use	6,499	6,675	6,622	6,518	6,475	0.0%
Total Energy Use (MWh)	336,402	343,500	343,693	346,245	353,667	0.3%
Peak Demand (MW)	64.5	65.4	65.4	65.4	66.0	0.1%

Generation & Supply Alternatives: Under base case assumptions, BED anticipates that its need for energy will exceed existing owned and contracted energy resources by 2025 even absent NZE activities due to contract expirations rather than load growth. Prior to 2025 BED possesses sufficient renewable energy to meet or exceed its BAU load projections. BED will need to supplement its energy resources through new power agreements beginning in 2025 to retain its 100% renewability. Absent such action, purchase of energy in the spot market would occur "automatically" but would not represent renewable energy. As illustrated in Figure 4, the

[7] Docket 17 – 0368, Order of 11/15/2017, at 9.

energy gap results from expiration of the Great River hydro contract in 2024. Extensions of existing contracts are a distinct possibility.

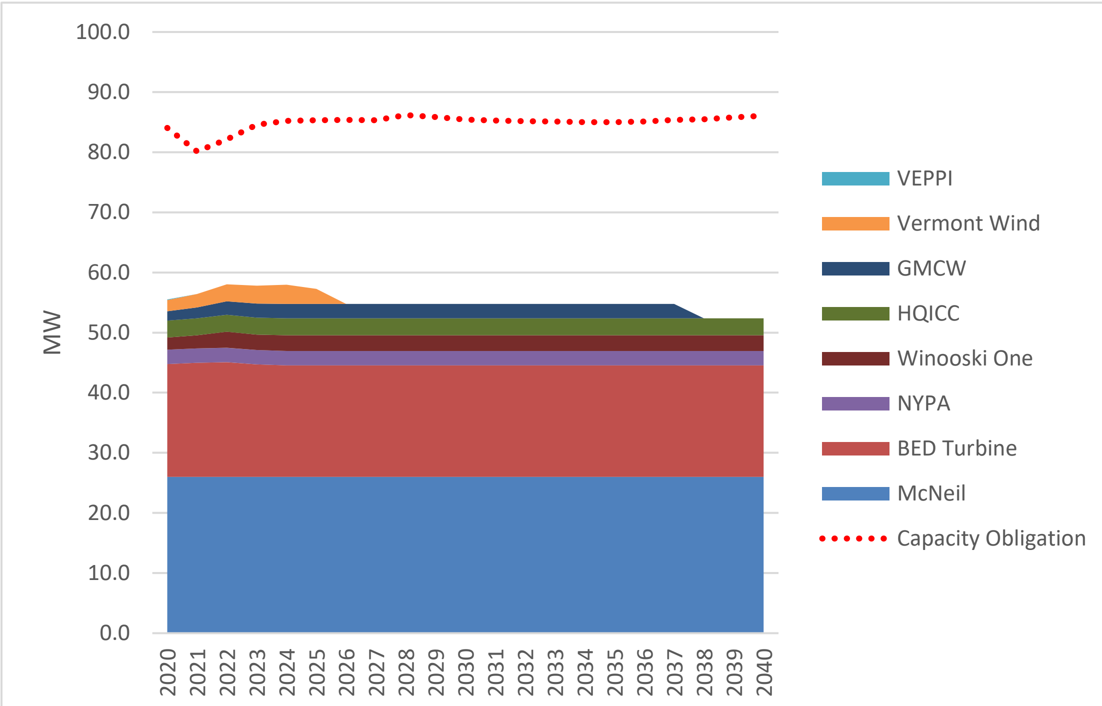
Figure 4: Forecasted Load v. Projected Supply Resources as of July 2020



Presently, BED either controls or contracts for capacity resources that are sufficient to satisfy approximately two-thirds of its capacity obligation, inclusive of the 15% reliability margin imposed on all distribution utilities by ISO-NE. Of the resources that BED controls, two facilities provide most of our capacity resource. These include BED's 25 MW share of the 50 MW McNeil Generating Station and BED's own 25 MW gas turbine.

As shown in Figure 5, BED's capacity obligation is 80.1 MW today but grows slightly to about 85 MW over the next several years. Thereafter, our capacity obligation is expected to remain relatively flat for the foreseeable future, unless customer adoption of beneficial electrification measures exceeds current expectations. BED's capacity position is similar to that of many Vermont distribution utilities and we anticipate the capacity shortfall will persist. Potential means of addressing this shortfall include contracting for energy that includes the associated capacity, building of another traditional peaking facility like BED's existing gas turbine, or, perhaps most promisingly, exploring the potential for capacity provided by battery storage technologies.

Figure 5: BED Projected Capacity Position as of July 2020



<u>Transmission & Distribution:</u> BED is committed to providing the highest system reliability, power quality, and system efficiency to its customers, and has excellent performance in this respect. This commitment is backed up by ongoing investments in distribution upgrades and process improvements to ensure maintenance of BED's high quality of service.

Similar to other utilities, BED tracks power interruptions and outages. An interruption of power is considered an "outage" when an event exceeds five minutes. BED's system reliability is measured by the system average interruption frequency index ("SAIFI") and customer average interruption duration index ("CAIDI"), pursuant to Commission Rule 4.900. Each year, BED analyzes outage information on the City's distribution circuits, identifies the worst performing circuits, and then updates the distribution action plan accordingly to improve service performance across the system.

In 2019, the SAIFI measured 1.03 interruptions per customer, significantly better than the service quality and reliability target performance of 2.1 interruptions per customer. The CAIDI in 2019 amounted to 0.75 hours, well below the target performance of 1.2 hours. Figures 6 and 7 below provide an historical account of BED's record for meeting the above performance measures. BED's system energy losses are extremely low as well, at just 1.8 percent on average. These metrics (reliability and system losses) are generally superior to those of any other Vermont utilities.

Figure 6: BED Historical SAIFI Values

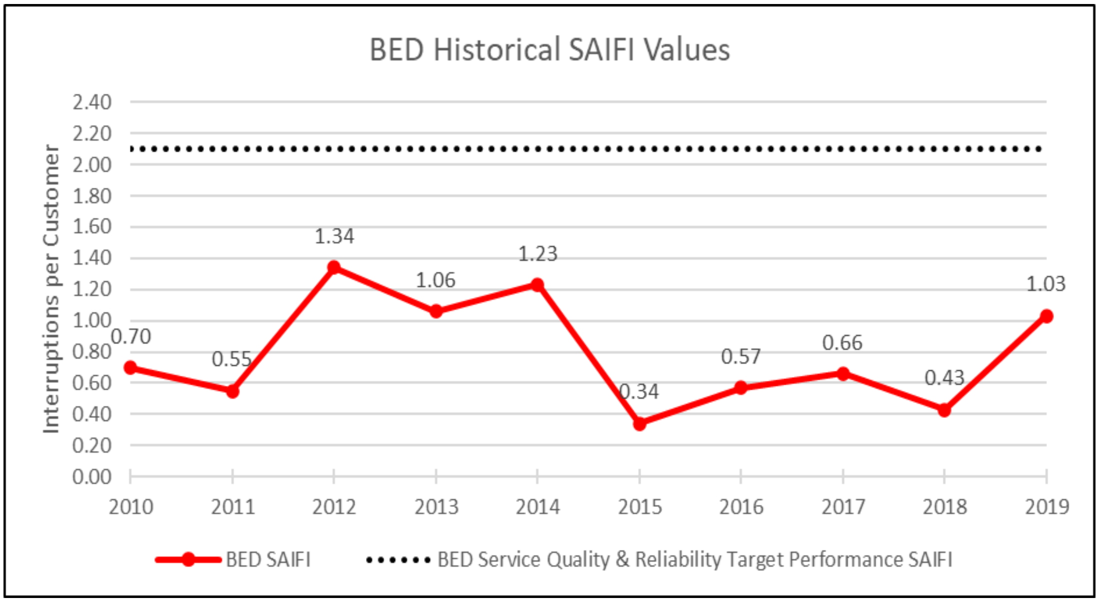
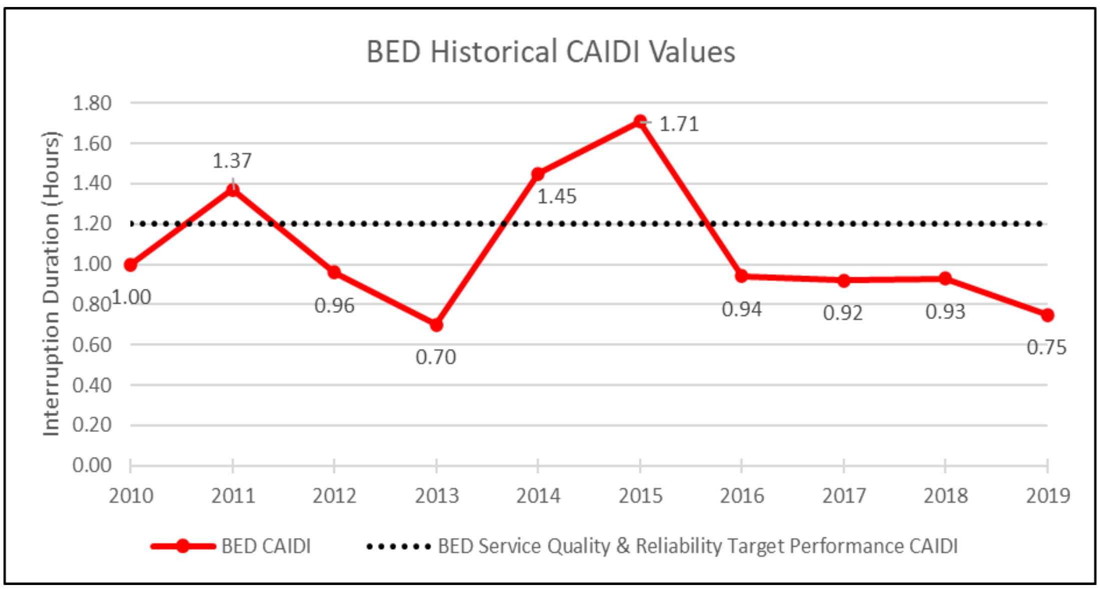


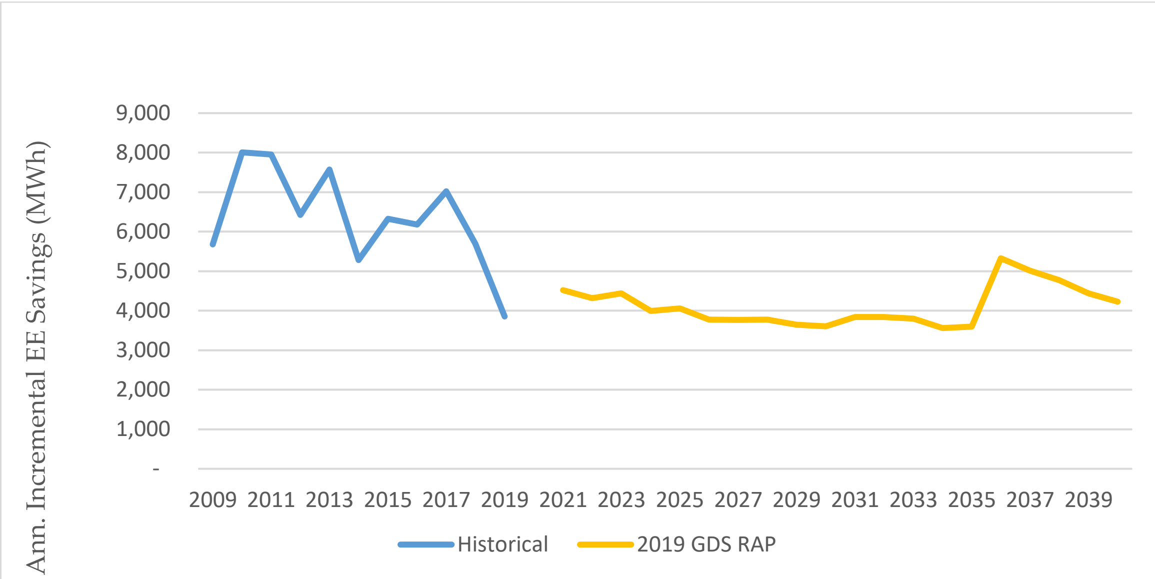
Figure 7: BED Historical CAIDI Values



Comprehensive Energy Services: To effectively address the energy needs of our customers, BED combines traditional electric energy efficiency with beneficial electrification services in a comprehensive, customer-centric manner. BED is unique in this respect as the only electric utility in Vermont that is also an efficiency utility, which has multiple beneficial effects such as lowering the cost of traditional electric savings by spreading delivery costs over additional services, reducing greenhouse gas emissions while lowering customer's energy bills, and improving grid utilization as customers begin to consume electricity during off-peak times by managing the load impacts of strategic electrification.

Assuming the Commission adopts our 2021–2023 demand resource plan, BED expects that its electric efficiency programs will reduce loads by roughly 4,000 MWh annually, as shown in Figure 8. The expected levelized cost of such savings should range between $0.04 and $0.06 per kWh.

Figure 8: Electric Energy Efficiency Historical vs. Forecasted Portfolio-Wide



On the other hand, beneficial electrification programs may increase electrical loads if new technologies are adopted in significant numbers, thereby potentially offsetting much of the forecasted savings. Under the base case scenario, however, BED does not expect adoption of such technologies to materially increase load in the near future. BED plans to provide incentives on a number of transportation and building technologies under its Tier 3 programs that will likely increase loads by 981 MWh, assuming all of the planned technologies are actually adopted by customers.

Financial Assessment and Potential Rate Pressures: This chapter discusses the pressures that could cause BED's to need to increase rates over time, represented in a graphical depiction of possible rate changes over time in terms of the average cost per KWh delivered to customers. This method of looking at cost pressures has the merit of recognizing that cost increases that are accompanied by increases in sales and thus revenue may actually reduce pressure on the need to increase rates.

BED's base case scenario does reflect an ongoing pressure to increase rates over time, however. This is not surprising as all organizations are exposed to cost increases from inflation. Although BED's cost-controlling measures and energy portfolio (which is not seriously exposed to fuel price changes) have allowed BED to avoid raising electric rates since 2009, at some point unavoidable pressures will cause the need to adjust rates. Establishing this base metric on pressure to increase rates allows BED to evaluate whether future decisions tend to increase or decrease this pressure, as well as to understand which variables that may be out of BED's control in whole or in part are most important to monitor and track ("key variables").

The Financial Assessment chapter also discusses BED's activities related to BED's rates for electric service, which are focused on rate modifications to support Burlington's NZE goals and to reduce or remove disincentives to efficiently use electricity for heating and transportation.

Decision Processes: This chapter outlines how BED reviews decisions in an IRP context. It is important to understand that BED does not attempt to use IRP decision methodology for all organizational decisions. Use of the level of rigor discussed in the Decision Processes chapter is particularly warranted when:

1. The decision is of a large magnitude
2. The decision is subject to significant uncertainty
3. Alternate competing options (including doing nothing) are viable

The IRP filing is an illustration of a utility decision-making process, and the basis for those decisions over the time before the next IRP (three years by statute). The evaluation period in an IRP is longer than three years to allow consideration of utility decisions that typically have long term impacts, and to make sure that current decisions do not have adverse impact or are not driven solely by short-term considerations, but it must also be remembered that where decisions will not be made for more than three years, another IRP will have been prepared and filed. In fact, if an IRP is approved by the Commission, all that is approved is the decision-making process. Any decisions discussed or contemplated in the context of an IRP still need to receive normal approvals.

BED has discussed above that its resource position is generally sufficient for energy through 2025. BED's capacity position is not well covered, but capacity prices are known though May 2024, and are falling through that period to extremely low levels. For the next several years BED believes its most important decisions will relate to climate change and will occur outside BED's direct control. Accordingly, BED has not evaluated a specific course of action that it will be taking in the near future but has instead provided a detailed consideration of the most interesting emerging technology (battery storage) that could meet BED's capacity needs effectively. BED believes that the IRP, along with this sample decision evaluation, will provide the Commission with the basis to approve BED's IRP.

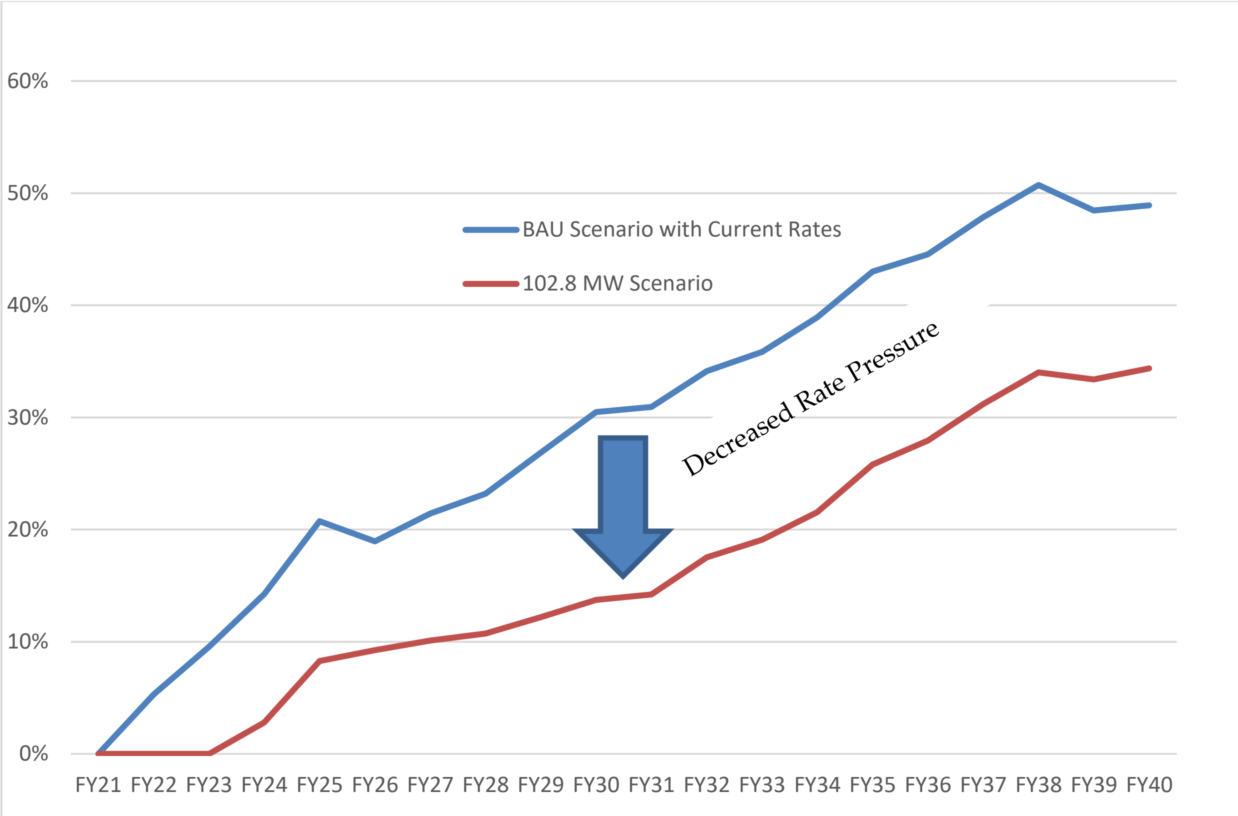
Net Zero Energy Roadmap Implications: As a part of its research into the benefits and costs of attaining NZE status by 2030, BED established a process for evaluating the incremental cost of service and associated revenues as more beneficial electrification technologies are deployed in

Burlington. Given the complexity of the engineering work involved in estimating the demands on the system of the full impact of the Roadmap (which is being performed), BED has evaluated the impacts of earlier stages of the Roadmap. For the purposes of the IRP, BED evaluated a load level of 102.8 MW from the Roadmap, along with the changes in load shape associated with that level of strategic electrification. A load of 102.8 MW was selected as being sufficiently large to require material upgrades to BED's system, but to be able to be evaluated in the time granted by the Commission in extending BED's IRP due date.

This process led to the conclusion that growth in winter peak demand to 102.8 MW (associated primarily with prospective heat pump installations) will require material upgrades and additions to BED's distribution system. Capital costs associated with these upgrades/additions are anticipated to be on the order of $19 to $24 million.

Although those capital upgrades would increase annual distribution costs ($1.8MM to $2.0MM) and the load that caused the need for those upgrades will add incremental power supply costs ($8MM to $10MM), so too would they add incremental revenue for BED related to the new load ($13MM - $14MM). Thus, working toward the NZE goal would likely lower rate pressure over time as beneficial electrification technologies are adopted (at least to the 102.8 MW load level). It is also noteworthy that alternative compliance payments, or their equivalent (i.e., customer incentives) that are used by BED to comply with Tier 3 of the renewable energy standard have not been included in this analysis as such costs are considered to be existing regulatory costs.

Figure 9: Rate Pressure by Scenario



In order to evaluate the impacts of providing service above the 102.8 MW, BED will need to perform additional distribution upgrades to ensure service reliability. The costs associated with such upgrades are currently expected to be significant. BED is evaluating the engineering requirements of the full Roadmap upgrades but conducting a full engineering study of the distribution upgrades needed to serve up to 140 MW of peak demand will take additional time.

BED believes that the current pace of electric technology adoption will not materially affect the cost of service over the next three to four years unless changes are made in the policies, rules, and laws surrounding heating and transportation. BED will monitor the rate of technology adoption and the effects in terms of loads, if any, to determine when additional investments will be needed to ensure continued reliable service.

Planning Priorities & Action Steps: The table below summarizes the priority actions that BED will take in the next several years, in accordance with our strategic plan:

Table 3: Action Steps

Functional Area	*Priority Actions*
Distribution & Operations	Continue capital replacement an improvement activities in support of system reliability and efficiency. Monitor customer adoption of beneficial electrification technologies in order to determine whether peak demand is increasing faster than our base case scenario assumptions and examine whether such adoption is affecting load shapes in the city.
Generation	Maintain and/or improve reliability of existing generating assets. Investigate opportunities to improve the efficiency and value of our generating resources.
Power Supply & Planning	Maintain 100% renewability Seek options to renew or extend existing renewable energy contracts at favorable prices Monitor the evolving market for storage for opportunities to deploy storage cost effectively Continue to monitor/participate in changes in tariffs and market rules that would impact the value of BED's resources Continue program design of new Tier 3 programs in support of NZE and to ensure equitable access to electrification programs for all customers.
Energy Services	Encourage and support customer participation in incentive and energy efficiency programs. This responsibility extends beyond traditional electric efficiency services and includes technical assistance and incentives for beneficial electrification measures (i.e. EVs, heat pumps, e-bikes etc.)
Customer Care/ Engagement	Provide service to customers that surpasses their expectations for meeting their energy related questions and needs.
Finance & Rates	Continue to closely monitor our financial performance and take any actions necessary to maintain our exemplar credit rating. Make additional improvements to the long-range financial forecast to better inform planning and decision making.

	Continue to research the feasibility of implementing additional innovative rate design practices, such as extending our residential EV rate to commercial customers, creating a new end use rate for cold climate heat pumps and revising our existing small general rate structure.
Information Services	Complete conversion of BED's core utility and business information systems Establish a new data center Enhance cybersecurity capabilities
Safety, Risk Management, and Facilities	Continued investment in BED equipment and facilities in support of NZE Support R&D efforts that relate to BED facilities Participate in the risk assessment related to pilot projects and devices
Net Zero Energy	Advance the City's NZE goal by working collaboratively with City and State officials and other stakeholders to establish effective supporting policies and regulations.

Introduction

IRP Objectives

The primary objective of this Integrated Resource Plan ("IRP") is to outline City of Burlington Electric Department ("BED")'s approach to decision-making to ensure BED can reliably serve the needs of its customers in accordance with 30 V.S.A. §218c. In addition, this IRP describes BED's methods and plans for:

- Environmental stewardship by transitioning to a Net Zero Energy ("NZE") community by reducing and eventually eliminating fossil fuel use in the electric, thermal, and ground transportation sectors by strategically electrifying, managing demand, realizing efficiency gains, and expanding local renewable generation while increasing system resilience
- Reliably and safely serving customers and the community
- Maintaining financial strength
- Modeling and understanding the potential impacts (costs, benefits, risks) to BED of actions taken to advance NZE goals
- Ensuring that BED's operations and capabilities can adapt to significant technological disruptions and customer behavioral changes.

This IRP satisfies the requirements of Vermont's 2016 Comprehensive Energy Plan for the following reasons:

- It identifies key input variables and risks that could impact operations;
- It describes how BED will manage those identified risks;
- It documents how BED can reliably meet the energy needs of its customers, after safety concerns are addressed, at the lowest present value lifecycle costs; and
- It highlights a series of priority action steps to be taken in the future.

Because the electric utility industry is rapidly evolving, BED has used the IRP process as an opportunity to develop, test, and demonstrate how its decision-making framework, methodologies, and tools will provide greater flexibility so that the organization can act on opportunities as economic and technological conditions evolve. BED has relied on this IRP process to demonstrate how its decision-making methodology and tools can be used to evaluate future investment options for balancing supply and demand while also ensuring low-cost, reliable, and safe electric service. We explain our decision-making processes in the chapters that follow and offer a sample decision analysis of utility-scale storage in Burlington.

In the absence of new policy tools or funding injections, BED assumes for the purpose of this IRP that the current pace of future customer adoption of beneficial electrification, weatherization, and other clean energy initiatives will continue until those changes occur. Consequently, the findings and recommendations of this IRP primarily reflect a base case scenario (sometime referred to as Business-as-usual) for load growth, resource adequacy requirements, and infrastructure upgrades to provide a basis for evaluating the impacts of these changes when they are advanced. This baseline scenario is important for planning and relative comparison of NZE scenarios.

Net Zero Energy Context

This IRP frequently references the City of Burlington's NZE goals and the implications that near-term progress toward those goals could have for BED's delivering energy services in accordance with 30 V.S.A. §218c.

In September 2019, BED issued a comprehensive Net Zero Energy Roadmap ("the Roadmap") illustrating how the community could transition to net zero energy by reducing and eventually eliminating fossil fuel consumption across the building and ground transportation sectors. The electric sector has already been converted to NZE with BED's achievement of 100% renewable energy in 2014; importantly, however, to convert transportation and heating to NZE, both the amount of renewable energy and the ability of BED's system to support load will need to increase.

Successfully reaching NZE will require a significant shift in how Burlington thinks about, invests in, and consumes energy in the thermal and transportation sectors. Making the transition will require policy changes, incentives, and significant investment in new technology. However, several key factors are beyond BED's control, including the pace of change for electric transportation and heating technologies, federal policies such as fuel economy standards and tax incentives, state policy initiatives including whether Vermont or the region prices carbon, and the potential for non-linear adoption rates for technology as prices come down. In terms of BED's contributions to advancing policy initiatives, BED is working on two potential City policies related to weatherization in rental buildings and electrification of new buildings. Investment in new technologies is expected to be balanced by the financial and societal returns on such investments over their lives.

BED recognizes that NZE requires a shift in our own internal thinking. While BED is a regulated franchise provider for electric service, the electric technologies that move us toward NZE (such as electric vehicles and heat pumps) are not widely adopted and are competing in some instances against unregulated fuels such as gasoline. We see renewably sourced electricity for example, as a less expensive and cleaner transportation fuel than gasoline. Analysis indicates that electric transportation fuel in Vermont keeps more dollars within the state economy than fossil fuels (https://www.eanvt.org/wp-content/uploads/2020/02/pg21-staysleaves.png). Therefore, when pursuing program and technology adoption in new spaces, BED must employ strategies first used in our energy efficiency programs to support outreach, customer education, vendor engagement, and partnerships to fully realize the potential for the electric transition.

Policy discussions are often focused on the upfront capital cost of protecting and sustaining our environment. In chapter 8 of this IRP, BED focuses instead on the net benefits. As further discussed in the NZE Roadmap, the net benefits of a transition to net zero energy are significant.[1] As Table 1 illustrates, net operational savings from pursuing the identified NZE pathway amounts to $474 million, resulting in $157 million in net benefits over the next 10 to 20 years. This is in a scenario where the state or region prices carbon at a value similar to the price that the Department of Public Service ("DPS") and the Public Utility Commission ("the Commission") already use to evaluate avoided costs in certain instances.

Table 1: Cost-effectiveness of NZE transition with a $100/ton CO2e price

Pathway (at $100/ton of CO2 e)	Present Value of Costs and Savings (in millions, 2019$) Capital costs	Operational costs	Net benefit/ cost	Total Net Energy Reduction 2020 - 2040 (trillion BTUs	Cost per Unit of Energy Avoided (2019$/ mmBTU)
Efficient electric buildings	$ 141	$ (202)	$ (61)	27	$ (2)
Electric vehicles	$ 113	$ (242)	$ (129)	7	$ (18)
District energy	$ 63	$ (30)	$ 33	9	$ 4
Total	**$ 317**	**$ (474)**	**$ (157)**	**43**	**$ (17)**

For additional information on the net benefits of a NZE future, BED encourages readers to review the Roadmap (www.burlingtonelectric.com/NZE), as it demonstrates how communities can help their residents, businesses, and institutions transition away from fossil fuels. Furthermore, a recent national study of significant decarbonization through electrification over a similar timeframe (2035) found significant jobs and economic benefits of such a transition.[2]

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[1] A comprehensive discussion of the benefits of a NZE transition is provided in our Net Zero Energy Roadmap, included in the appendix of this document and at https://burlingtonelectric.com/sites/default/files/inline-files/NetZeroEnergy-Roadmap.pdf

[2] Please this report for more information: https://tinyurl.com/y3bd43jr

Impacts of COVID-19

Although this IRP is submitted during the COVID-19 pandemic, it does not contain an extensive discussion of COVID-19's impacts on BED, since BED assumes that COVID-19 will be a short-term disruption, with impacts hopefully restricted to the last few months of BED's FY20 budget and some part of BED's FY21 budget. It is possible, however, that there will be longer term impacts that may be reflected eventually in BED's long-term planning. (One such example could be the potential impact of a permanent shift to dramatically increased telecommuting.)

BED did use its IRP modeling capabilities to estimate the short-term impact of the pandemic on BED's FY20 and FY21 budgets. recognizing that COVID-19 affects key variables identified by the Financial Assessment chapter of this IRP, specifically:

1. Customer sales and revenue (decreased commercial but increased residential values)
2. Charges associated with load, such as capacity and transmission
3. Wholesale energy prices (decreasing due to falling regional load)
4. BED's risk profile (the loss of retail sales, which increases BED's exposure to low market prices – see discussion of "long" vs "short" positions in the Financial Assessment chapter)

Furthermore, the duration of all the above impacts was uncertain. Accordingly, BED created several scenarios that consider the interaction of the above impacts on the remaining FY20 and FY21 periods over various lengths of COVID-19 disruption, from a steady decline in impact over time, to possible future "resurgences" of the virus in the fall. All of this helped BED to better prepare for potential future outcomes under significant uncertainty.

BED also took immediate action to help support our customers' progress toward NZE while also supporting local economic recovery: in June of this year BED launched its Green Stimulus programs, which will also help reduce the impacts of COVID-19 on BED's efficiency and electrification efforts. The Green Stimulus programs are planned to run for a limited period but may prove instructive in improving BED's efficiency and electrification programs in the longer term as well (in which case any long-term changes in program design would be incorporated into BED's long-term planning). Already BED is seeing indications of an increased pace of program uptake based on the Green Stimulus activities, including HVAC contractors fully scheduled for heat pump installations into the fall.

As a City department and community member, BED acknowledges the hardships our customers have been experiencing due to COVID-19. Working toward NZE while also addressing and overcoming pandemic-related challenges will require support and engagement from the community over an extended period. In addition, BED recognizes the present moment of intense focus on social and racial justice issues in our community and nation as an opportunity to ensure that our programs and services are available, accessible, and affordable to all of our customers. We are undertaking new efforts, in coordination with City partners, to enhance outreach strategies, and our 2020-2021 Strategic Direction includes the following objective:

Ensure all programs are equitable and accessible, with a priority given to low-to-moderate income, rental, black, indigenous, and people of color (BIPOC), immigrant, and refugee populations.

If we continue to focus on ensuring that all customers have equitable opportunities to participate in our energy services, it will support Burlington's NZE efforts, as attaining the NZE goal City-wide will only be achievable if all community members can engage in the effort.

IRP Organization & Chapter Summary

The following chapters, summarized below, comprise BED's 2020 IRP:

Chapter 1 – Introduction: Provides context, overarching thought processes, and a summary of the contents of the 2020 IRP.

Chapter 2 – Burlington's Demand for Electricity: Establishes Burlington's "business as usual" ("BAU") long-term energy requirement and peak demand forecasts. The output from these analyses informs the range of total energy and capacity that may be needed to provide reliable electric service absent specific actions taken to accelerate the transition to NZE. For this IRP, energy and capacity forecasts are based on statistically adjusted end-use models that rely on historical data related to regional economic growth, weather patterns, seasonality, net metering generation, housing starts, and business formation, as well as customer usage and behaviors. This IRP forecast is BED's first to also include sales of electric vehicles and heat pumps as customers adopt these technologies over time (but not at the pace of adoption that would be required to reach NZE by 2030 or 2040 per the Roadmap).

Chapter 3 – Generation & Supply Alternatives: Provides information on BED's existing resources (for energy, capacity), either owned or contracted, and compares them to the BAU load forecast from Chapter 2. Chapter 3 also includes a general review of the economics of various resource types under low, base, and high case values of key variables. The general review of resource economics is intended to guide the type of resource for which BED seeks more detailed proposals for potential action. If an actual resource decision is contemplated, actual pricing at a much higher level of rigor would be applied to the potential decision as illustrated in Chapter 7 – Decision Processes.

Chapter 3 also includes information on the ability of BED's existing resources and expected electrification program activities to meet the requirements for the three tiers of the Vermont Renewable Energy Standard ("RES") over the 20-year planning horizon.

It should be noted that it is perfectly normal for existing resources to not be sufficient to meet the projected 20-year requirements. BED does have sufficient resources to meet its energy and RES requirements over the three-year period prior to the preparation of the next IRP. The expiration or retirement of resources and a search for their replacements is a normal course of business for an electric utility. The tools created for this IRP would be used if a long-term (20-year+) resource procurement was to be contemplated during the next three years, but none is anticipated at this time.

Chapter 4 – Transmission & Distribution: BED is committed to providing the highest system reliability, power quality, and system efficiency to its customers, and has excellent performance in this respect. This commitment is backed up by continuing investments in distribution upgrades and process improvements to ensure maintenance of BED's high quality of service.

Chapter 4 discusses BED's transmission and distribution system and its capability of providing high-quality service for the projected BAU loads. Discussion of the needed upgrades and additions required for the system to serve increasing loads under the early stages of transition to NZE are discussed in more detail in Chapter 8.

Chapter 5 – Comprehensive Energy Services: To effectively address the energy needs of its customers, BED combines traditional electric energy efficiency with beneficial electrification services in a comprehensive, customer-centric manner. BED is unique in this respect as the only electric utility in Vermont that is also an efficiency utility. (The efficiency needs of the customers of the other Vermont utilities are served by Efficiency Vermont.) Chapter 5 contains information on BED's plans for continuing to provide energy efficiency and strategic electrification programs over the next three years, including the historical performance and future projections of both our traditional electric efficiency and Tier 3 beneficial electrification programs that are designed to ensure that BED is prepared to meet increasing customer demand for electricity, while simultaneously meeting the State required reductions in greenhouse gas emissions.

Chapter 6 – Financial Assessment and Potential Rate Pressure: Includes the results of a 20-year forecast of BED's BAU cost of serving its customers. This projection is stated in terms of pressure to increase rates over time, but it does not represent a projection of actual rate increase that may be needed. Rather, a projection of rate pressure under BAU permits BED to evaluate whether intended actions (either by BED or external to BED such as changes in laws/regulations) will tend to increase or decrease the need to raise rates over time. The establishment of a base case cost of service allows BED to evaluate which outside factors could impact those costs, and hence effect rate pressure, over short (5-year) and longer (20-year) horizons.

BED's base case scenario does reflect an ongoing pressure to increase rates over time. This is not surprising, as all organizations and individuals are exposed to cost increases from inflation.

Although BED's cost-controlling measures and energy portfolio (which is not seriously exposed to fuel price changes) have allowed BED to avoid raising electric rates since 2009, at some point unavoidable pressures will cause the need to adjust rates.

The Financial Assessment chapter also discusses activities related to BED's rates for electric service, which are focused on rate modifications to support Burlington's NZE goals and to reduce or remove disincentives to efficiently use electricity for heating and transportation.

Chapter 7 – Decision Processes: Outlines how BED reviews decisions in an IRP context. It is important to understand that BED does not attempt to use IRP decision methodology for all organizational decisions. Use of the level of rigor discussed in the Decision Processes chapter is particularly warranted when:

1. The decision is of a large magnitude
2. The decision is subject to significant uncertainty
3. Alternate competing options (including doing nothing) are viable

Chapter 8 also includes a detailed review of the potential for a long-term contract for storage located in Burlington as a demonstration of BED's decision-making process with sufficient detail to permit that process to be reviewed, and ideally approved, by the PUC.

Chapter 8 – Net Zero Energy Roadmap Implications: As noted above, the NZE Roadmap was published in September 2019. At that time, BED's deadline to file this IRP was January of 2020. The DPS asked BED to include in this IRP an evaluation of the potential impacts of the City's NZE goals. Accordingly, chapter 8 provides a NZE impact evaluation and includes a high-level assessment of various factors that could affect BED's costs to serve the City. The chapter looks at the anticipated changes to the BAU case resulting from an increase in loads resulting from NZE activities to a peak load level of 102.8 MW in the winter. This is a material increase from BED's current peak load of 65 MW (which occurs in the summer) but does not reflect the full load projected in the Roadmap. It does, however, reflect a load that will stress, and hence require additions/upgrades to, BED's distribution system. BED evaluates the impacts of the costs associated with those upgrades, the wholesale market and transmission costs associated with those loads, and the incremental revenues from those loads to understand how they might affect rates over time.

Chapter 9 – Planning Priorities & Action Steps: Summarizes the priority actions that BED will be taking in the next several years, organized by the functional area of BED that will be engaged in those activities. The activities contained in this chapter support BED's approved Strategic Plan and pave the way for NZE.

Appendices: Appendices to this IRP include:

- Itron Long-Term Electric Energy and Demand Forecast Report

- Net Zero Energy Roadmap
- BED Strategic Plan
- McNeil Generating Station Economic Impact Report & BED Staff Response
- Controllable Loads Research Report
- Pilot Program Report

Chapter 2 - Burlington's Demand for Electricity

Burlington Electric Department ("BED")'s 2020 Long-Range Forecast for this IRP informs BED's resource planning to meet the forecasted total annual consumption of electric energy. This is referred to as the system energy forecast and is expressed in terms of kilowatt-hours ("kWh"), megawatt-hours ("MWh"), or gigawatt-hours ("GWh"). This system energy forecast is made up of forecasts of electric sales to consumers, BED company use, and associated distribution and transformer losses. Together, these forecasts comprise the energy requirements that must be supplied by BED to meet customer needs.

BED's projected load requirements are also based on the expected maximum rate of use of electricity ("peak demand"), measured in kW or MW. If BED does not successfully generate or purchase enough generation from other resources to transmit and distribute to its customers to meet peak demand, customer loads could need to be curtailed to prevent overloads and/or system failure.

Table 1 shows the BED energy and demand forecast, after accounting for the effects of future energy efficiency and behind-the-meter generation.

Table 1: Annual Energy Requirements & Peak Demand, 2019-2039

	2019	2024	2029	2034	2039	CAGR
Residential	81,171	82,702	87,053	95,864	107,315	1.4%
Commercial & Industrial	246,572	252,147	248,226	242,255	238,453	-0.2%
Street Lighting	2,160	1,976	1,792	1,608	1,424	-2.1%
Losses & Co. Use	6,499	6,675	6,622	6,518	6,475	0.0%
Total Energy Use (MWh)	336,402	343,500	343,693	346,245	353,667	0.3%
Peak Demand (MW)	64.5	65.4	65.4	65.4	66.0	0.1%

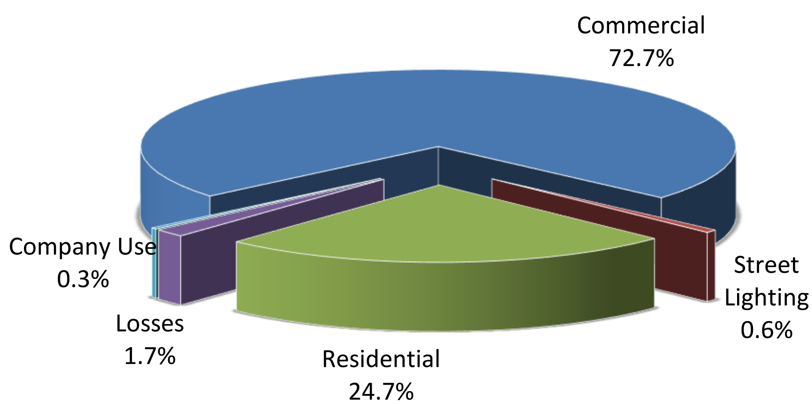
Over the next 20 years, base case system energy requirements average 0.3% annual growth with annual customer growth of 0.5%. Peak demand increases 0.1% annually over this period. In comparison, since 2010, system energy has declined on average 0.5%annually and peak demand has declined 0.1% per year. Positive forecasted energy requirements are largely the result of expected electric vehicle ("EV") sales' growth in the second half of the forecast period.

Background

BED provides electricity in its service territory of approximately 16 square miles, and the Burlington International Airport ("Airport"), located in South Burlington. BED is the third largest utility in Vermont, accounting for 6.1% of total retail kWh sales.

BED currently serves about 17,200 residential and 3,880 commercial customers. These customers required 341,204 MWhs of electricity during 2018 including roughly 334,417 MWh in sales and distribution losses and company (i.e. BED) use making up the remainder. The commercial customers account for the largest share of electricity use, with nearly 73%of the total (Figure 1). The residential class accounts for roughly 25%of the total energy requirements.

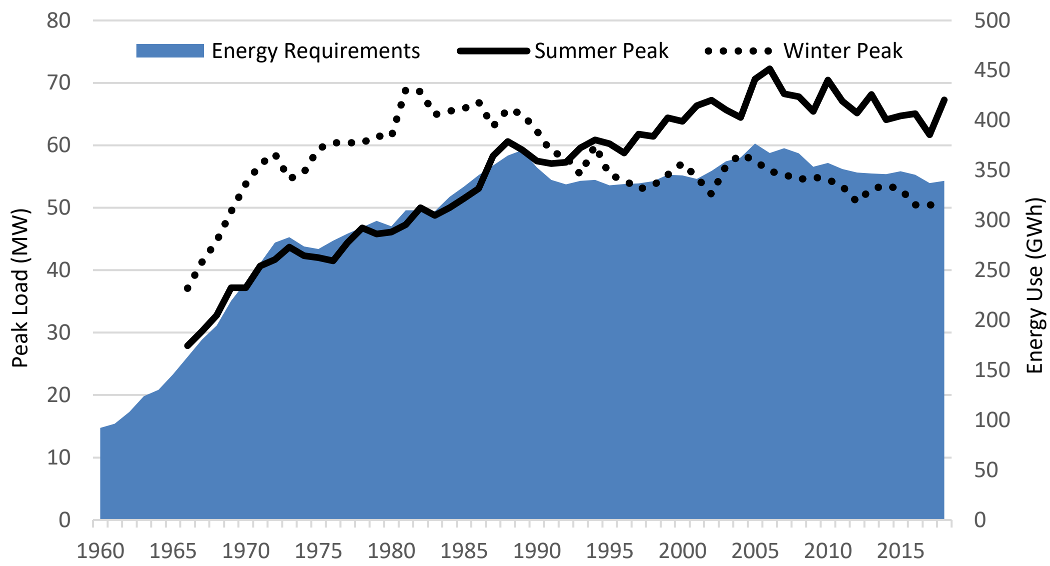
Figure 1: 2018 System Energy Requirements



Over the last 10 years, total kWh sales have been declining at a rate of 0.8%per year. This is a trend throughout Vermont and across much of the country. Utility efficiency programs have suppressed demand in all sectors, and the federal energy efficiency programs like Energy Policy Act of 2005 ("EPAct2005") and Energy Independence and Security Act ("EISA 2007"), have also played a key role in reducing energy use over this period. Figure 2 provides the long-term electricity use trends in Burlington. Overall, total electricity use in Burlington has increased by 2.3%per year since 1960, although this growth has not been uniform over time.

In the years prior to 1973, the utility industry benefited from a persistent decline in real electricity prices as this allowed for promoting "all electric living." Predictably, the proliferation of electric appliances and the use of electricity for space and water heating in the residential sector caused consumption per household in Burlington to rise dramatically. Electric space heating, virtually unheard of in 1960, was used in over 1,200 Burlington households by 1970. Total system energy use increased at a rate of 9.0%per year during this period.

Figure 2: Historic System Peak & Energy Requirements



Rising oil and coal prices and the delayed startup of Vermont Yankee contributed to higher power costs in the region by the early 1970s. By the end of 1973, the nation was in the midst of an energy crisis, and the era of aggressive load building was coming to an end. In New England, the next two decades would be characterized by sharply higher retail prices for electricity and moderating demand for power by customers. Utility regulators embraced the idea of seasonal rates, and utilities began offering conservation and load control programs.

Since 1989, the leveling off of electricity use can be attributed in large part to more vigorous demand-side management activities by the utility, but also has roots in fundamental demographic changes and changing economic conditions.

In 1993, Burlington's annual peak demand occurred in July. This was significant, since it was the first time BED had its annual peak demand occur during the summer. Beginning in the mid-1980s, the decline in the winter peak demand was attributed to the decline in the use of electricity for space heating and water heating. The summer peak load continued to rise, driven by the increasing use of air conditioning in the residential and commercial sectors. More recently, we have experienced a decline in both winter and summer peak demand, which can be attributed to energy efficiency programs and standards.

Burlington continues to be a summer peaking utility with significant load variation throughout the summer months; this variation is largely driven by air conditioning. Figure 3 shows the 2018 hourly net demand. Net demand – the total electric demand in the system minus customer-owned behind-the-meter generation – represents the demand that BED must meet with resources, contracts, or purchases from the ISO-NE spot market The summer of 2018 was much warmer than normal, with the maximum hourly demand occurring on July 2. The highest demand for electricity during the winter months occurred on January 15.

Figure 3: 2018 Hourly System Net Demand

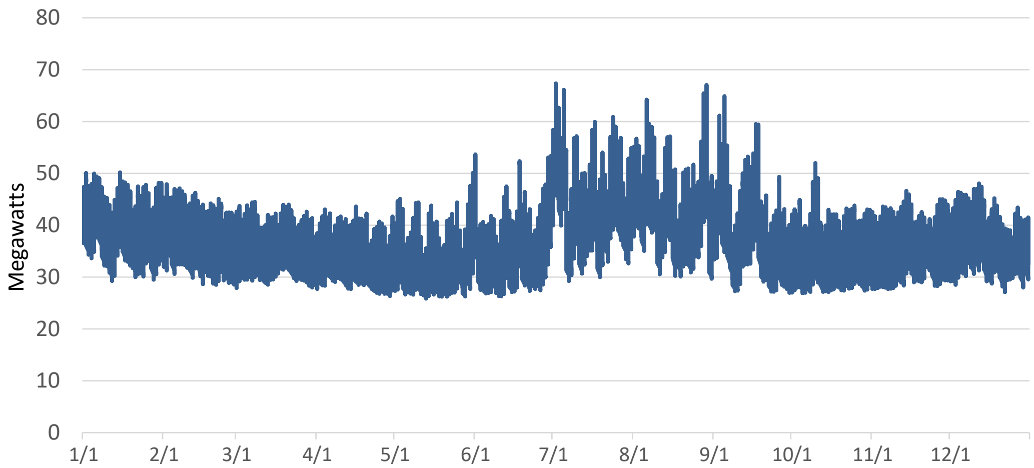
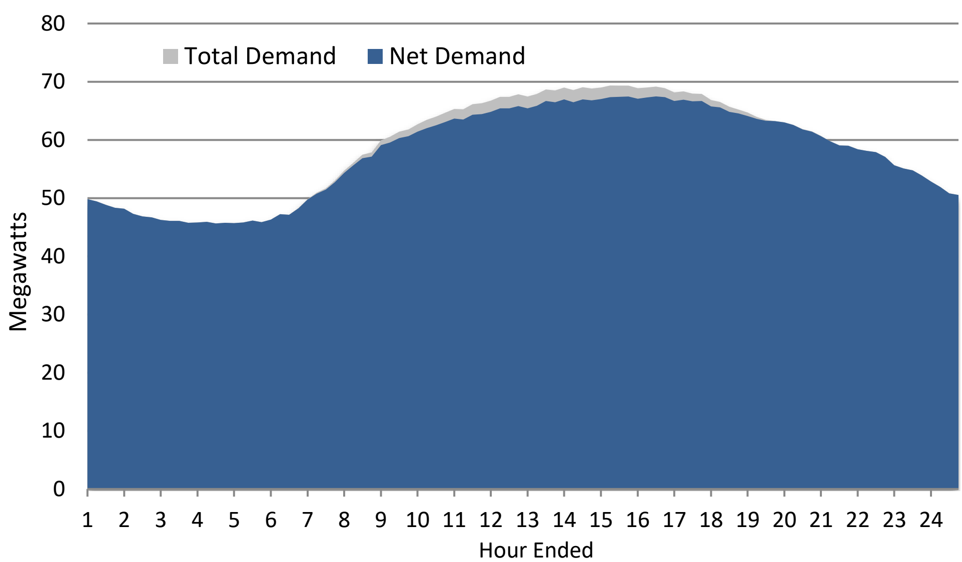


Figure 4 provides a view of the City's hourly demand on the summer peak day in 2018. The summer peak day is characterized by one daily peak period with load rising gradually until the early afternoon, before gradually declining after 5 pm. The summer peak demands occur most often between 2 and 5 pm, on days when the average daily temperature exceeds 80 degrees Fahrenheit. Burlington averages about 3-4 days per year with average daily temperature higher than 80 degrees Fahrenheit. The summer of 2018 was one of the warmer summers on record, with average daily temperatures exceeding 80 degrees on 12 different days, and the average temperature reaching a record level (88 degrees Fahrenheit) on the peak day.

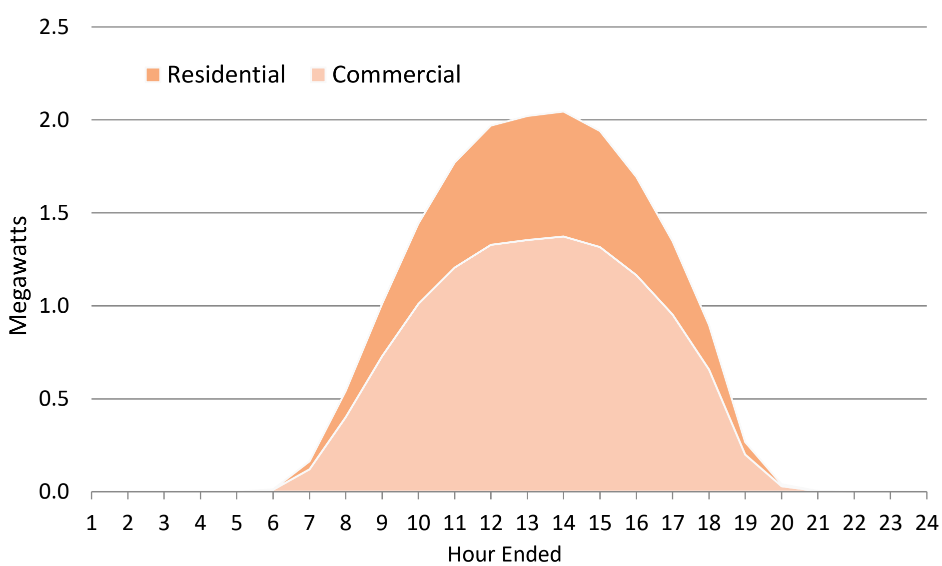
Figure 4: System Demand on July 2, 2018 (Peak Day)



The impact of behind-the-meter solar generation on peak demand is a function of the timing between solar generation and system hourly demand. On July 2, the maximum system demand reached 69.2 MWs at hour ended 3:00 pm. The maximum ***net*** demand (excluding the customer behind-the-meter generation) was 67.3 MWs, also occurring at hour ended 3:00 pm. The behind-the-meter solar generation reduced the system peak demand (-1.9 MW) but did not shift the peak hour.

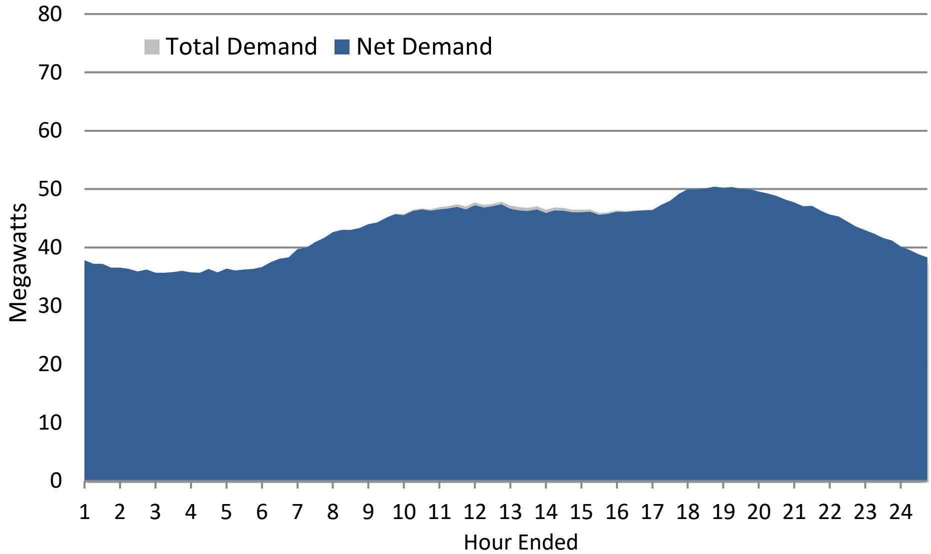
Figure 5 shows the total customer owned behind-the-meter solar generation in Burlington on that day. As the amount of solar generation on BED's system increases, the net peak demand will eventually shift to later in the day. On this day, it would have taken close to 8 megawatts of behind-the-meter solar generation to shift the peak hour to 7:00 pm.

Figure 5: Behind-The-Meter Solar Generation on July 2, 2018



During the winter months the system load increases rather abruptly in the morning, peaking by around noon, then drops slightly before increasing again after 4:00 pm, peaking around 6:00 or 7:00 pm. Solar PV capacity has no impact on the winter peak demand since the winter peak is in the evening hours when there is no solar generation.

Figure 6: System Demand on January 15, 2018 (Winter Peak Day)



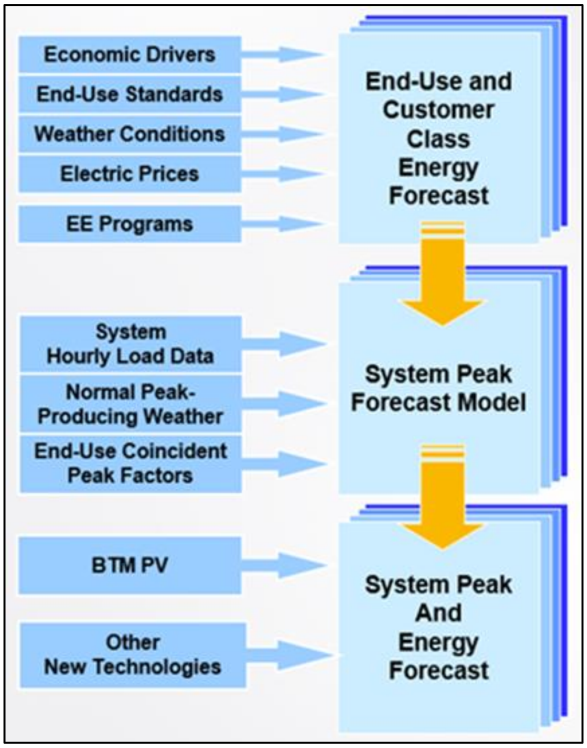
Forecast Approach

BED contracted with Itron, Inc. ("Itron") to develop a 20-year energy and demand forecast to support the IRP planning process.[1] The forecast was developed using the same methodology that was approved in BED's previous IRP, except that impacts from EV adoption was included in this forecast.

The system energy requirements and peak demand forecasts are derived using a "build-up" approach. This entails first developing residential and commercial forecast models that are then used to isolate heating, cooling, and non-weather sensitive end-use energy projections. End-use energy forecasts combined with peak-day weather conditions then drive system peak demand. Energy, peak, and hourly load profile forecasts are combined to generate a system baseline hourly load forecast. The baseline hourly load forecast is then adjusted for the impact of technologies including solar, EVs, and cold climate heat pumps. Figure 7 outlines the modeling approach.

[1] Itron's detailed report comprises Appendix A.

Figure 7: BED Long-Term Build-Up Model



The residential and commercial forecasts were based on Itron's Statistically Adjusted End Use ("SAE") modeling framework, which combines the end-use modeling concepts with traditional regression analysis techniques. One of the traditional approaches to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identify historical trends and to project these trends into the future.

In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the SAE modeling framework captures the strengths of both approaches. For instance, by explicitly introducing trends in equipment saturation and equipment efficiency levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time and identify end use factors driving those changes.

The SAE models leverage the U.S. Energy Information Administration's ("EIA") Sector-Level End Use Saturation and Efficiency Forecast for the Northeast Region as well as information specific to Burlington. The result is a long-term forecasting framework that captures long-term structural changes, short-term driving factors of usage levels such as economic activity, electricity price, and weather, and their appropriate interactions.

Furthermore, the framework facilitates the disaggregation of the sector level sales forecasts into end use-level forecasts in support of further evaluation.

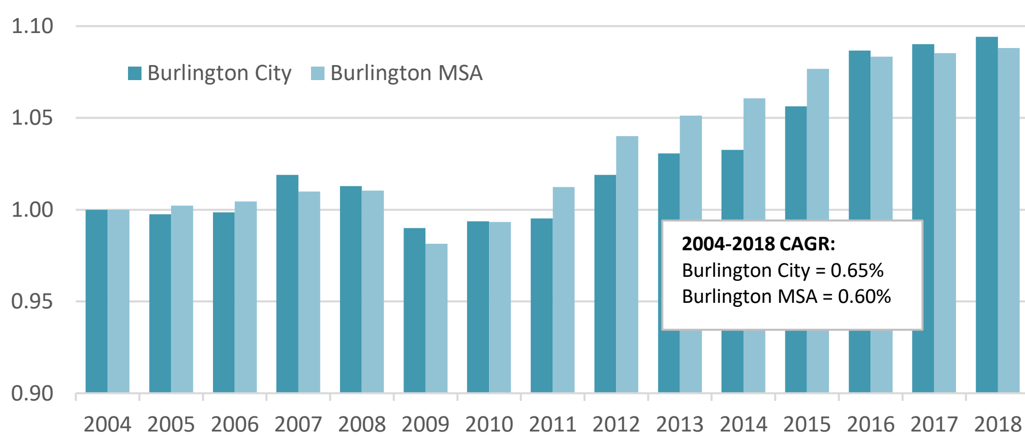
The residential and commercial forecast models were based on "reconstituted" monthly sales, where all behind-the-meter solar PV impacts were added back to the monthly billed sales. After the individual monthly forecasts were produced, the system load shape was adjusted to account for the impacts of existing and future behind-the-meter generation and EV adoption.

Base Case Assumptions

Several economic indicators were used as independent variables (forecast "drivers") in our energy forecasting process. For the residential class, income, population and number of households in the region were used as drivers. In the commercial sector, gross metro product and employment were used as drivers. These drivers are consistent with ones used in our previous IRP forecasts. The economic forecasting firm Moody's Analytics was the source for the forecast of these economic drivers. Moody's Analytics is a highly reputable firm in the macroeconomic forecasting arena with specialized competency in doing the work.

Economic forecasts were not available for the local area (Burlington City), so BED relied on forecasts for the Burlington/South Burlington Metropolitan Statistical Area ("MSA") as a proxy. The economies of Burlington City and the broader metropolitan area tend to be integrated and track fairly closely. For example, Figure 8 compares the employment growth rates for the City of Burlington and the Burlington MSA for the recent 15-year period. The year-to-year change and overall growth over the period was very similar.

Figure 8: Total Employment Growth by Region (2004 = 1.0)



BED's projected data is weather normalized. Historic daily weather data was available for the Burlington weather station for the period January 1978 to December 2018. Normal degree days were calculated using this data from the 20-year period 1999 to 2018. The heating and cooling degree variables were customized (from the typical 65-degree reference) separately for the residential and commercial sectors by evaluating daily kWh use and daily temperature. For the residential sector, cooling degree days were calculated with a 65-degree base, and heating degree days with a 60-degree base. The degree days were customized for the commercial sector in the similar fashion.

The residential sector incorporates saturation and efficiency trends for seventeen end uses. The commercial sector captures end-use intensity projections for ten end-use classifications across ten building types. The models rely on an analysis of EIA's Annual Energy Outlook forecast performed by Itron. EIA saturation projections were adjusted to reflect BED appliance saturation surveys and the mix of multi-family and single-family homes in Burlington. Care must be taken not to "double count" energy efficiency program impacts when using a methodology like SAE that accounts for efficiency trends on its own. To avoid double counting, efficiency savings projections were adjusted to reflect future efficiency savings embedded in the baseline sales forecast. The efficiency adjustment factors for each sector are estimated by incorporating historical efficiency savings as a model variable. For example, in the residential model, the efficiency savings variable is statistically significant with a coefficient of -0.20 indicating that 80.0% (1-.20) of future efficiency savings is embedded in the model; the efficiency adjustment factor is 0.20.

Once the sales forecasts are developed, the system load shape forecast flows from the class sales forecasts. The process is to use customer class load shapes and fit the forecasted sales requirement by customer class to these class load shapes. Historic class load shapes were developed using BED's AMI data.

Emerging technologies such as photovoltaic ("PV") systems, EVs, cold climate heat pumps, and other technologies will likely have an impact on future demand for electricity. Over the past few years, there has been an increasing penetration of customers owning solar photovoltaic generating systems in Burlington.

Class Sales Forecasts

Changes in economic conditions, prices, weather conditions, as well as appliance saturation and efficiency trends drive energy deliveries and demand through a set of monthly customer class sales forecast models. Monthly regression models are estimated for each of the following major revenue classes.

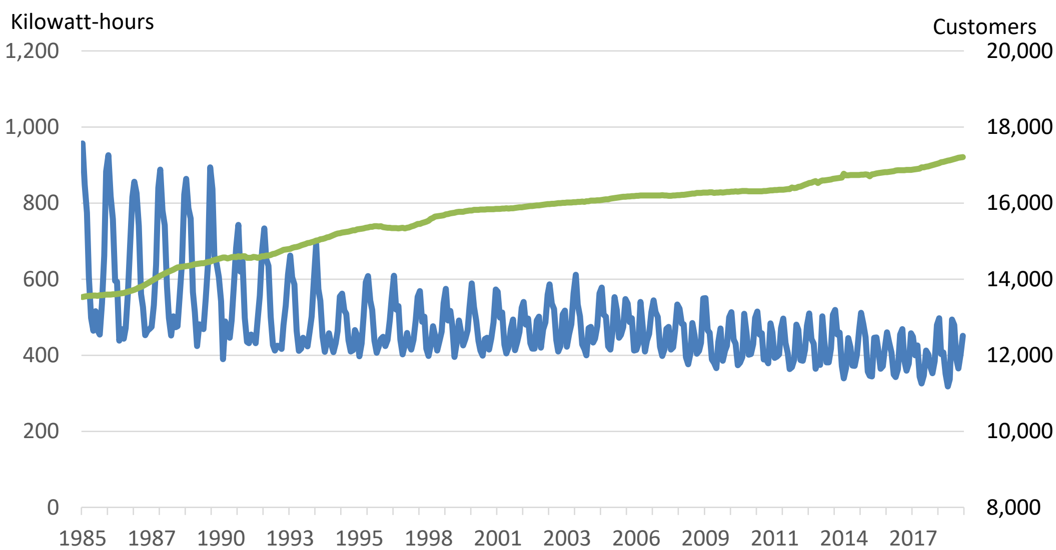
- Residential
- Commercial/Industrial
- Street Lighting

Residential Sector

The two main drivers of the residential forecast are the forecast of number of residential customers, and the forecast of use rate (electricity consumption per residential customer). The residential customers and use per customer are modeled separately and then the residential sales forecast is generated as the product of the customer forecast and the use per customer forecast.

Figure 9 shows the number of customers and the average monthly kWh use per customer for Burlington's residential sector for the period 1985 to 2018. Burlington has seen strong residential customer growth of 0.7% per year over the last 5 years, preceded by 15 years of growth rates averaging only 0.3% per year.

Figure 9: Residential Monthly Average kWh Use & Number of Customers



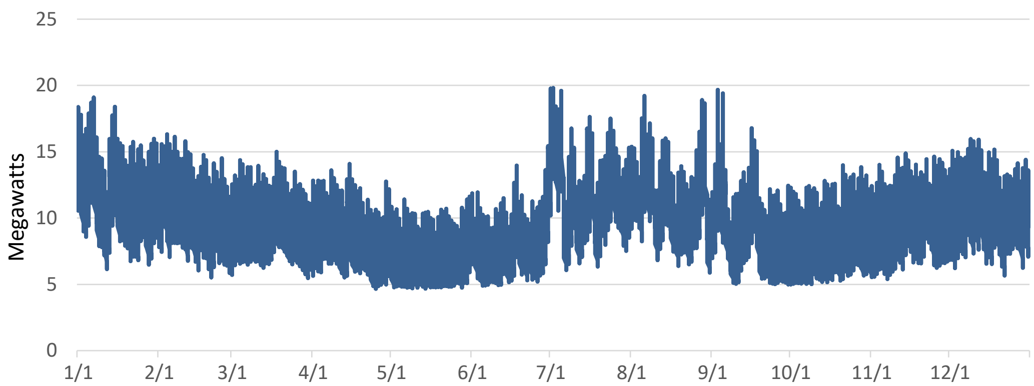
Declining use per customer reflects BED's history of energy efficiency, changing codes and standards, fuel switching, and end-use trends. Since 1985, residential use per customer has fallen more than 35%(from 7,533 kWh use per customer in 1985 to 4,889 kWh use per customer in 2018). The decrease has been particularly strong across the winter season, reflecting the impact of fuel switching and lighting efficiencies on usage.

By the end of 2018, there were 268 residential net-metering customers having a combined solar capacity of 1.1 MWs. The total solar PV generation in 2018 was 907,142 kWhs, lowering the average annual residential use per customer by 53 kWhs (1.1%).

Residential Load Shape

Residential electricity demand exhibits strong seasonal trends, with higher electricity use in the winter and summer months and minimum electricity use normally occurring during the spring and fall seasons. Demand levels during the winter and summer months tend to exhibit a significant daily variation in load, driven by extreme temperatures. The seasonal variability is demonstrated in Figure 10, which displays the residential hourly load profile for 2018.

Figure 10: 2018 Residential Hourly Net Demand



During 2018, the residential sector reached its highest (net) demand of 19,804 kWs during the hour ended 9:00 pm on July 2, 2018, which also happened to be the system peak day. The residential sector's maximum demand in the winter was not too far below the summer levels, reaching 19,102 kWs on January 7, 2018 at hour ended 7:00 pm.

Figure 11 and Figure 12 provide the residential sector "typical day" load profile plots for the summer and winter seasons. On average, residential loads tend to increase sharply during weekday mornings until around 8:00 am, followed by a levelling off or slight decline until 4:00 pm. After 4:00 pm, loads rise again peaking between 6:00 and 9:00 pm (depending on the season), and then taper off during the late evening hours. The weekend load profile is very similar to the weekday load profile, with the exception of the more gradual increase in the morning load. On winter and summer days where the temperature is extreme, the demand in all hours tends to be approximately 5 MWs higher than the average levels.

Figure 11: Residential Typical Day - Summer (Jun-Sep)

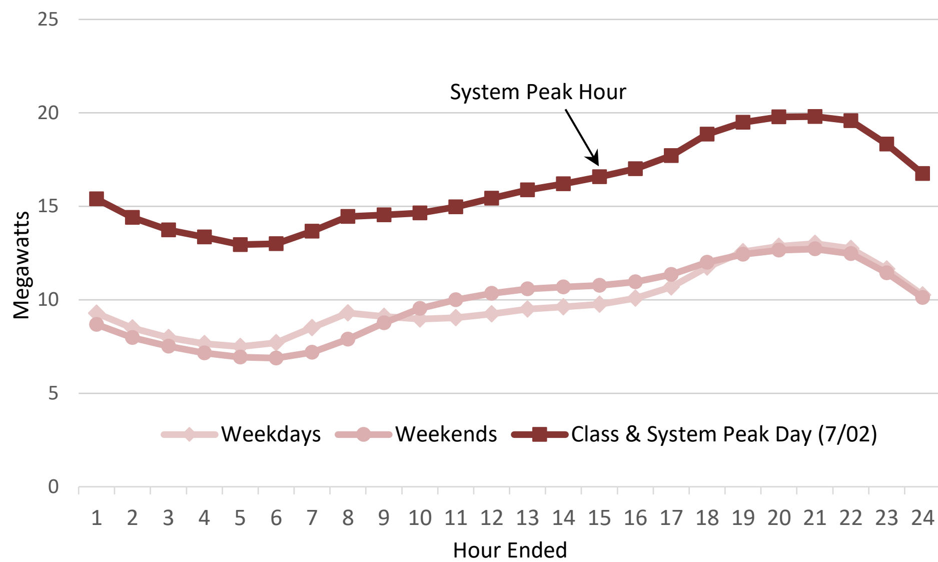
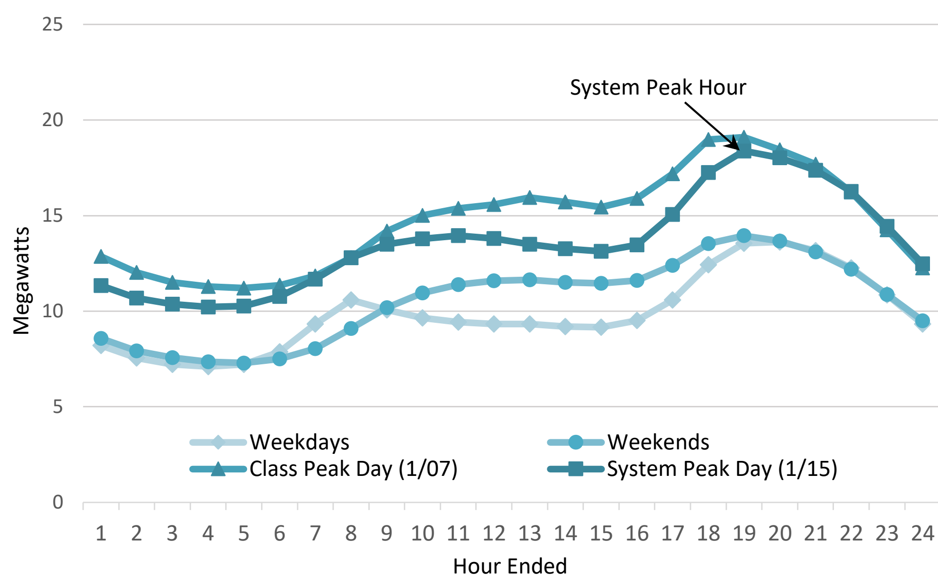


Figure 12: Residential Typical Day - Winter (Dec-Mar)



Residential Sales Forecast

The residential sales forecast is developed as a use-per-customer forecast multiplied by the forecasted number of customers. The residential use per customer is forecast using an SAE model. This model assumes that electricity use will fall into one of three categories: heating, cooling or other. The SAE model constructs variables to be used in an econometric equation where residential usage is a function of Xheat, Xcool and Xother variables.

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation;

heating equipment efficiency standards and trends; and thermal integrity and size of homes. The heating use variable is derived from information related to days per month, heating degree-days, household size, personal income, and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation; cooling equipment efficiency standards and trends; and thermal integrity and size of homes. The cooling use variable is derived from information related to days per month, heating degree-days, household size, personal income, and electricity prices.

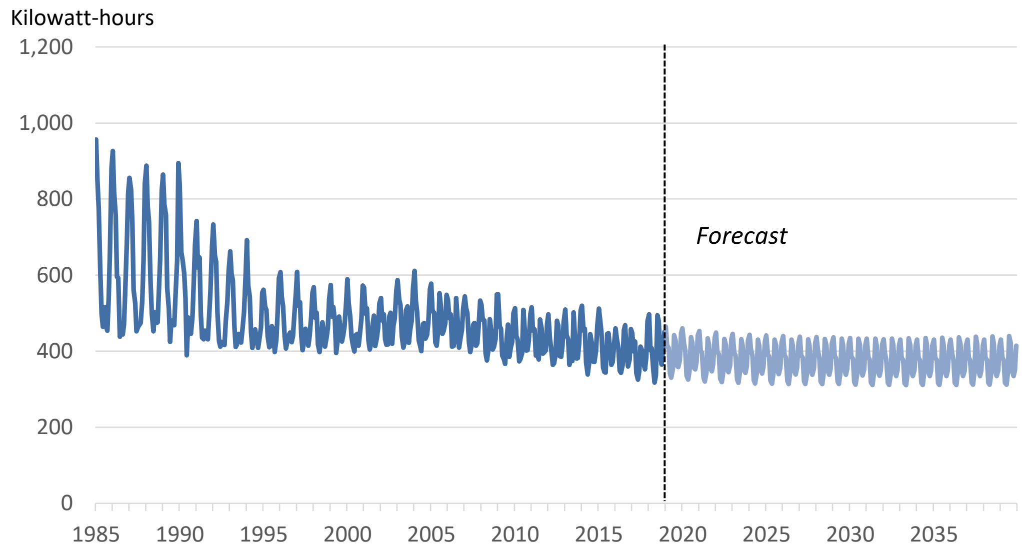
The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels, days per month, average household size, real personal income, and electricity prices.

The appliance saturations are based on historical trends from BED's residential customer surveys. The saturation forecasts are based on EIA forecasts and analysis by BED. The efficiency trends are based on DOE forecasts and Itron analysis. The thermal integrity and size of homes are for the Northeast Census Region and are based on DOE and Itron data and are calibrated to Burlington's mix of multi-family and single family housing units.

The economic and demographic assumptions that were used in the residential forecast models were supplied by Moody's Analytics, prepared in January 2019. The SAE model is estimated using over the period January 2010 to December 2018.

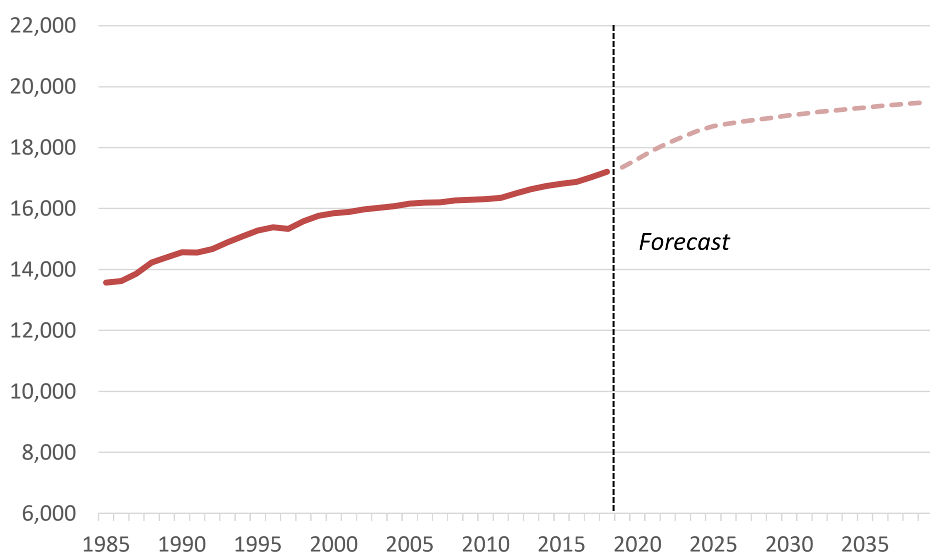
Figure 13 shows the residential average use forecast before making any adjustments for behind-the-meter generation and future EV adoption. Average use per customer is projected to decline further in the forecast period, albeit at a slightly slower rate. This is largely due to the continuing phase-out of the most common types of incandescent light bulbs mandated by the EISA and new end-use efficiency standards recently put in place by the DOE.

Figure 13: Monthly Residential kWh Use per Customer Forecast



The forecast of Burlington's residential customers is based on a monthly regression model using historical data from January 2010 to December 2018. The number of residential customers is forecasted using Burlington MSA housing unit projections as the major driver. Slightly stronger average customer growth rate in the period 2019-2025 is explained largely by the completion of a large residential project that is expected to add almost a thousand new customers over the next five years.

Figure 14: Residential Customer Forecast



Residential sales projections are then obtained by the combination of the customer projections and average use projections. With 0.3%decrease in average use and 0.6%increase in customer growth, residential sales average 0.3%growth between 2019 and 2039. Table 2 displays the annual residential sales forecast, excluding any impacts of behind-the-meter generation and EV adoption.

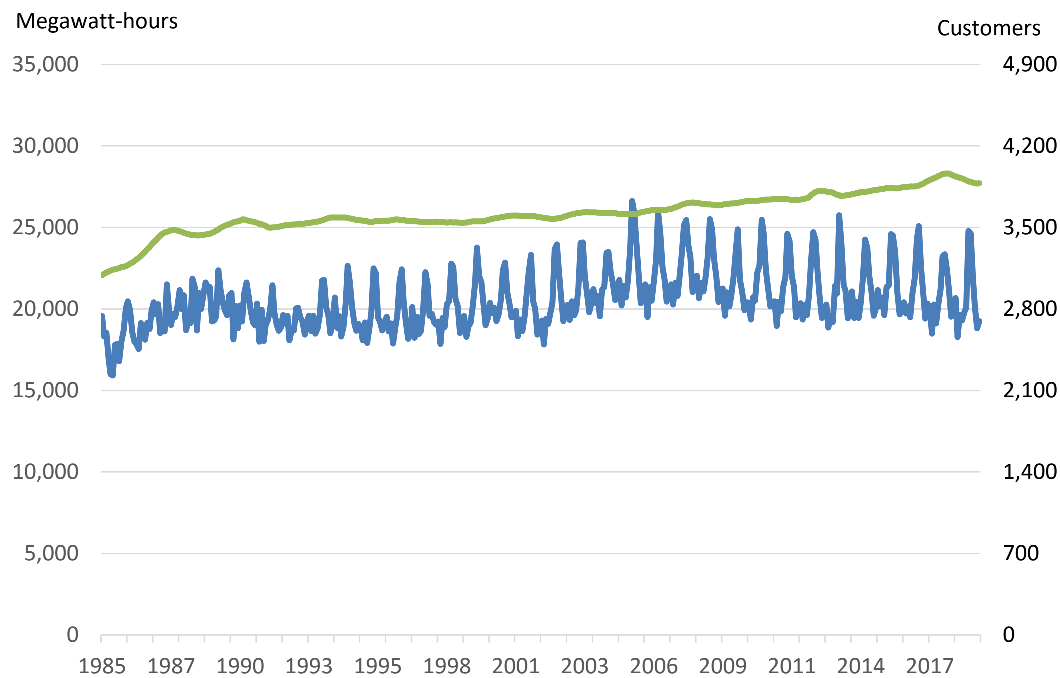
Table 2: Residential Sector Forecast (excluding PV and EV impacts)

Year	Total Sales (MWh)	% Chg.	Customers	% Chg.	Avg. Use (kWh)	% Chg.
2010	85,358	---	16,308	---	5,234	---
2011	84,876	-0.6%	16,350	0.3%	5,191	-0.8%
2012	83,671	-1.4%	16,502	0.9%	5,070	-2.3%
2013	85,481	2.2%	16,634	0.8%	5,139	1.4%
2014	83,628	-2.2%	16,741	0.6%	4,995	-2.8%
2015	83,479	-0.2%	16,810	0.4%	4,966	-0.7%
2016	82,422	-1.3%	16,876	0.9%	4,884	-1.6%
2017	80,590	-2.2%	17,032	0.9%	4,732	-3.1%
2018	85,334	5.9%	17,208	1.0%	4,959	4.8%
2019	82,057	-3.8%	17,353	0.8%	4,729	-4.6%
2020	82,452	0.5%	17,622	1.6%	4,679	-1.1%
2021	82,554	0.1%	17,902	1.6%	4,612	-1.4%
2022	83,128	0.7%	18,150	1.4%	4,580	-0.7%
2023	83,679	0.7%	18,354	1.1%	4,559	-0.5%
2024	84,512	1.0%	18,559	1.1%	4,554	-0.1%
2025	84,685	0.2%	18,702	0.8%	4,528	-0.6%
2026	84,859	0.2%	18,786	0.4%	4,517	-0.2%
2027	85,080	0.3%	18,860	0.4%	4,511	-0.1%
2028	85,555	0.6%	18,928	0.4%	4,520	0.2%
2029	85,613	0.1%	18,992	0.3%	4,508	-0.3%
2030	85,578	0.0%	19,058	0.3%	4,490	-0.4%
2031	85,632	0.1%	19,118	0.3%	4,479	-0.3%
2032	85,957	0.4%	19,173	0.3%	4,483	0.1%
2033	85,902	-0.1%	19,223	0.3%	4,469	-0.3%
2034	86,118	0.3%	19,268	0.2%	4,469	0.0%
2035	86,366	0.3%	19,315	0.2%	4,471	0.0%
2036	86,861	0.6%	19,363	0.2%	4,486	0.3%
2037	86,911	0.1%	19,407	0.2%	4,478	-0.2%
2038	87,152	0.3%	19,447	0.2%	4,482	0.1%
2039	87,346	0.2%	19,484	0.2%	4,483	0.0%
’10-‘18		0.0%		0.7%		-0.6%
’19-‘29		0.4%		0.9%		-0.5%
’19-‘39		0.3%		0.6%		-0.3%

Commercial Sector

BED’s commercial sector includes Small General Service, Large General Service, and Primary Service customer classifications. In 2018, this sector accounted for only 18%of total customers but 74%of the total kWh- sales. Figure 15 provides monthly MW sales and customer history for the commercial sector.

Figure 15: Commercial Monthly kWh Sales & Customers

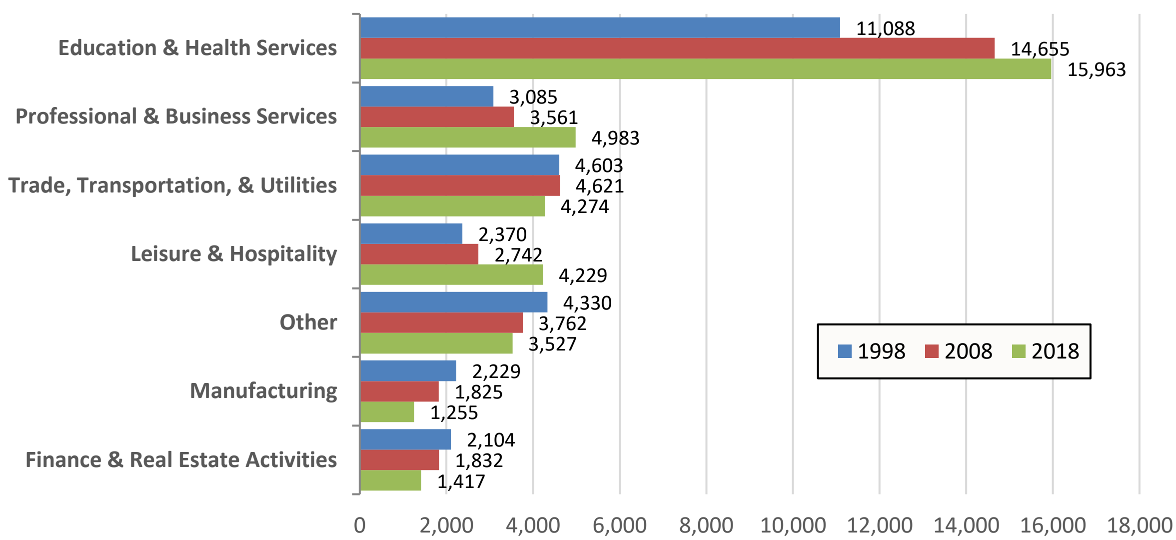


During the 20-year period prior to 1990, the commercial sector was experiencing 2.8%sales growth per year. Since then, commercial sector sales have remained relatively flat. This pattern can be attributed to changing economic conditions and energy efficiency programs and standards. Commercial sector load growth is linked to residential customer growth as demand for services, including healthcare, education, retail, food stores, and restaurants expand with population growth. However, as with the residential sector, changing codes and standards, and end-use trends have caused commercial sales to decline slightly in the last 10 years.

The major recessions have had a significant impact on employment in Burlington, particularly in the manufacturing sector. Manufacturing has traditionally been vital to Burlington because it creates well-paying jobs, draws investment into the area, and strengthens other sectors of the economy. Presently only 3.5%of Burlington's jobs are in the manufacturing sector – down from 15.3%in 1980. Two of BED's largest manufacturing customers left the City between 1990 and 2006, resulting in a significant loss of sales during that period.

Figure 16 provides a look at the employment trends by sector in Burlington over the last 20 years. The services sector, which includes education and health care services, represents one of the fastest growing employment categories in Burlington. UVM and the UVM Medical Center are the largest employers in the City, highlighting the importance of health and education services to both the growth and level of employment, as well as to electricity sales.

Figure 16: Burlington City Employment by Sector



There were 88 commercial net-metering (or group net-metering) BED customers by the end of 2018, having a combined solar capacity of 1.94 MW. The behind-the-meter solar impact on commercial sales in 2018 was 1,950,240 kWh (0.8%).

By the end of 2018, there were 88 commercial net-metering customers having a combined solar capacity of 1.9 megawatts. The total commercial solar PV generation in 2018was 1,950,240 kWs, offsetting commercial sales by 0.8%.

Commercial Load Shape

Figure 17 provides a plot of the aggregate hourly load for the commercial sector for 2018. We see increased loads during the summer months, which can be attributed to increased cooling requirements for these customers. The loads are quite consistent from day-to-day during the other times of the year, showing a consistent weekly pattern, with higher weekday loads and lower loads on weekends and holidays.

The commercial sector reached a maximum load of 50,619 KW on August 29, 2018, hour ending 3 pm, which was coincident with the second highest system peak of the summer. During the system peak hour, the load was 23%higher than the typical summer weekday load for this sector at this hour.

Figure 17: Commercial Sector: 2018 Hourly Load Profile

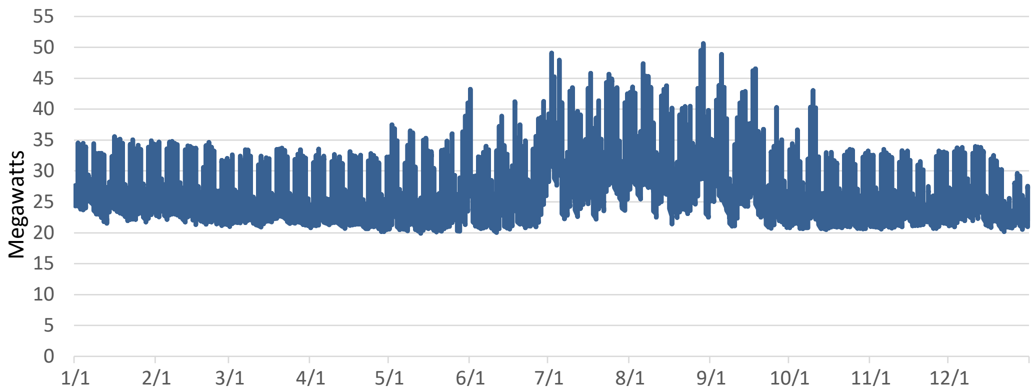


Figure 18 and Figure 19 provide the commercial sector "typical day" load profile for the summer and winter periods during 2018. During the weekdays, the commercial sector's load profile is characterized by one peak period, regardless of the season. During the day, loads increase sharply between 6:00 am and 12:00 pm, remain at high levels until about 4 pm, before gradually tapering off into the evening hours. During the summer months the commercial sector typically peaks around 2:00 or 3:00 pm during the weekdays, and slightly earlier in the winter months. Weekend loads are much lower in both the summer and winter months.

Figure 18: Commercial Typical Day - Summer (Jun-Sep)

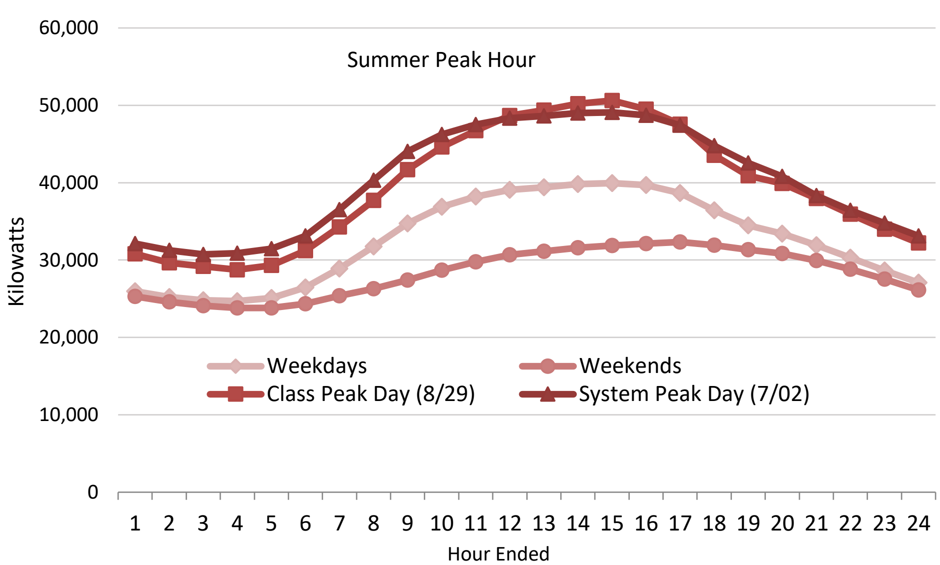
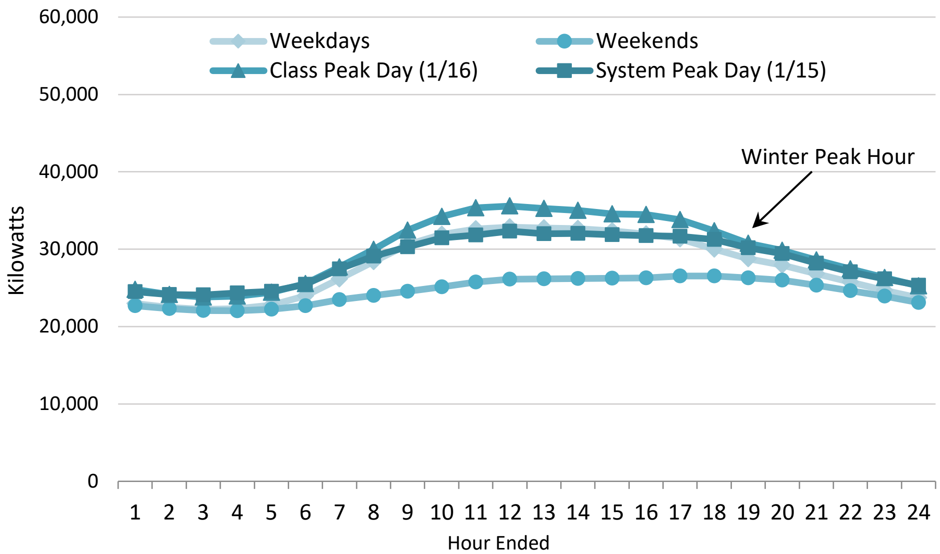


Figure 19: Commercial Typical Day - Winter (Dec-Mar)



Commercial Sales Forecast

Long-term commercial energy sales are forecasted using a SAE model. These models are similar to the residential SAE models, where commercial usage is a function of Xheat, Xcool and Xother variables.

As with the residential model, Xheat is determined by multiplying a heating index by a heat use variable. The variables incorporate information on heating degree-days; heating equipment saturation; heating equipment operating efficiencies; square footage; number of days in the month; commercial output and electricity price.

The Xcool variable uses measures similar to the Xheat variable, except it uses information on cooling degree-days and cooling equipment, rather than those items related to heating load. The Xother variable measures the non-weather sensitive commercial load. It uses non-weather sensitive equipment saturations and efficiencies, as well as billing days, commercial output and electricity price information.

The saturation, square footage and efficiencies are from the Itron base of DOE data and forecasts. The saturations and related items are from EIA's 2018 Annual Energy Outlook. The commercial output and employment data were provided by Moody's Analytics. The equipment stock and square footage information are for the Northeast Census Region, adjusted to Burlington.

The SAE is a linear regression for the period January 2010 through December 2018. As with the residential SAE model, the effects of EPAct, EISA, ARRA and EIEA2008, and other federal policies impacting end use efficiency are captured in this model.

BED's energy service engineers are in continual contact with the Burlington's large commercial customers about their needs for electric service. These customers relay information about load additions and reductions. This information is compared with the load forecast to determine if the commercial models are adequately reflecting these changes. If the changes are different from the model results, then add factors may be used to reflect those large changes that are different from those from the forecast models' output. Burlington recently lost sales due to a couple larger accounts (Burlington Town Center, and G.S. Blodgett). It is expected that sales will return as new customer enter these locations. In addition, there have been recent large additions at the University of Vermont, and others that are still expected (e.g., Tarrant Center), and these impacts will be applied as adjustment to the forecast.

Commercial sales are overall flat through the forecast period; improvements in end-use and building efficiency offset the impact of customer and economic growth. Table 3 shows the annual MWh sales forecast for the commercial sector, excluding any impacts from existing and future solar generation.

Table 3: Commercial Sector Forecast (excluding PV impacts)

Year	Total Sales (MWh)	% Chg.	Customers	% Chg.	Avg. Use (kWh)	% Chg.
2010	260,236	---	3,742	---	69,549	---
2011	255,266	-1.9%	3,737	-0.1%	68,302	-1.8%
2012	254,867	-0.2%	3,814	2.1%	66,833	-2.2%
2013	252,547	-0.9%	3,780	-0.9%	66,804	0.0%
2014	254,165	0.6%	3,821	1.1%	66,512	-0.4%
2015	258,489	1.7%	3,843	0.6%	67,268	1.1%
2016	256,346	-0.8%	3,898	1.4%	65,757	-2.2%
2017	250,821	-2.2%	3,945	1.2%	63,577	-3.3%
2018	249,734	-0.4%	3,878	-1.7%	64,392	1.3%
2019	249,064	-0.3%	3,893	0.4%	63,985	-0.6%
2020	251,154	0.8%	3,888	-0.1%	64,601	1.0%
2021	252,894	0.7%	3,880	-0.2%	65,173	0.9%
2022	255,635	1.1%	3,893	0.3%	65,667	0.8%
2023	255,422	-0.1%	3,905	0.3%	65,404	-0.4%
2024	255,834	0.2%	3,916	0.3%	65,336	-0.1%
2025	254,911	-0.4%	3,925	0.2%	64,942	-0.6%
2026	253,993	-0.4%	3,934	0.2%	64,556	-0.6%
2027	253,162	-0.3%	3,943	0.2%	64,206	-0.5%
2028	253,243	0.0%	3,951	0.2%	64,089	-0.2%
2029	252,183	-0.4%	3,960	0.2%	63,678	-0.6%
2030	250,716	-0.6%	3,969	0.2%	63,171	-0.8%
2031	249,432	-0.5%	3,977	0.2%	62,720	-0.7%
2032	248,998	-0.2%	3,984	0.2%	62,499	-0.4%
2033	247,389	-0.6%	3,991	0.2%	61,992	-0.8%
2034	246,504	-0.4%	3,997	0.2%	61,670	-0.5%
2035	245,687	-0.3%	4,004	0.2%	61,364	-0.5%

2036	245,556	-0.1%	4,011	0.2%	61,223	-0.2%
2037	244,343	-0.5%	4,018	0.2%	60,809	-0.7%
2038	243,790	-0.2%	4,026	0.2%	60,561	-0.4%
2039	243,879	-0.2%	4,033	0.2%	60,109	-0.4%
’10-‘18		-0.5%		0.5%		-0.9%
’19-‘29		0.1%		0.2%		-0.0%
’19-‘39		-0.1%		0.2%		-0.3%

Streetlighting

There are approximately 3,420 streetlights in the city of Burlington, and they accounted for less than 1%of total retail sales in 2018 (2,155 MWh). Since 2010, BED has increased efforts to replace streetlight fixtures with LED fixtures. By the end of 2018, more than 1,929 streetlights (56%) were converted to LED fixtures, resulting in a decline in street lighting sales of more than 29%during the period. Street lighting sales are fitted with a simple regression model driven by outdoor lighting energy intensity and seasonal variables. Between 2019 and 2039, street lighting sales are projected to decline by 2.1%per year.

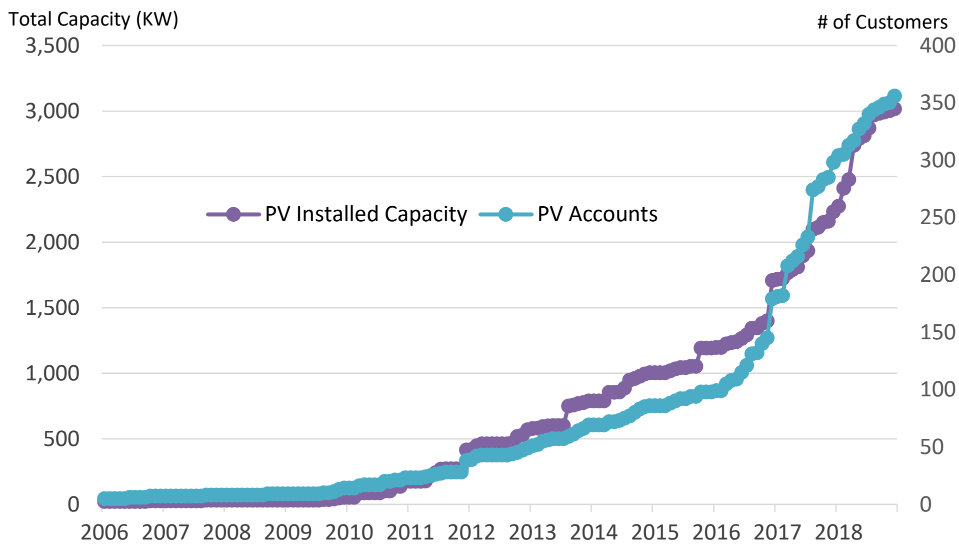
Adjustments for New Technologies

After class sales forecasts were developed, adjustments were made to account for the impacts of solar PV and EV adoption. The following section describes an overview of these adjustments, with further details provide in the Itron report in Appendix A.

Solar Forecast

The BED energy and peak forecast incorporates the impact of expected behind the meter PV adoption. Although relatively small in magnitude compared to the rest of Vermont, BED has experienced an uptick growth in the number and size of PV systems over the past two years. Part of the jump was due to customers racing to beat changes in net metering laws that reduced system incentives. While some of the recent adoption is incentive-driven, continuing system cost declines will drive future long-term adoption. Figure 20 shows the recent trends in PV adoption. By the end of 2018, BED had 356 net-metering customers, with a total solar capacity of 3.0 MWs and an annual reduction in sales of 2,857 MWs (0.8%of total BED sales).

Figure 20: Solar PV Adoption in City of Burlington



The PV adoption models (residential and commercial) relate the share of customers that have adopted solar systems to simple payback through a cubic model specification. The payback calculation is based on total installed cost, annual savings from reduced energy bills and incentive payments for total generation. With declining system costs and incentives, we are expecting to see solar adoption increase to 1,088 residential customers (5.6%penetration) and 177 commercial customers (4.4%penetration).

The installed solar capacity is the product of the solar customer forecast and the assumed average system size, for both the residential and commercial classes. The average assumed sized is 4.0 kWs for residential systems and 22 kWs for commercial systems, which is the average system size for all systems installed through 2018. The capacity forecast is then translated into a monthly generation forecast by applying monthly solar load factors to the capacity forecast. The monthly load factors are derived from a typical PV load profile for Burlington VT. The forecasted PV shape is from the National Renewable Energy Laboratory ("NREL") and represents a typical meteorological year ("TMY").

Table 4 shows the PV capacity forecast and expected annual generation impacts. By 2039, the solar capacity is expected to reach 8.3 MWs, providing approximately 10,491 MWhs of generation per year. The number of PV customers represents the number of customers who either install solar locally, and those who are part of a community solar array.

Table 4: Solar PV Forecast

	2019	2024	2029	2034	2039
Residential PV Customers	295	711	811	977	1,088
% of Total Residential Customers	1.7%	3.8%	4.3%	5.1%	5.6%
Commercial PV Customers	91	134	144	155	177
% of Total Commercial Customers	2.3%	3.4%	3.7%	3.9%	4.4%
Installed Capacity (MW)	3.2	5.8	6.5	7.4	8.3
Generation MWhs	3,947	7,255	8,013	9,132	10,279

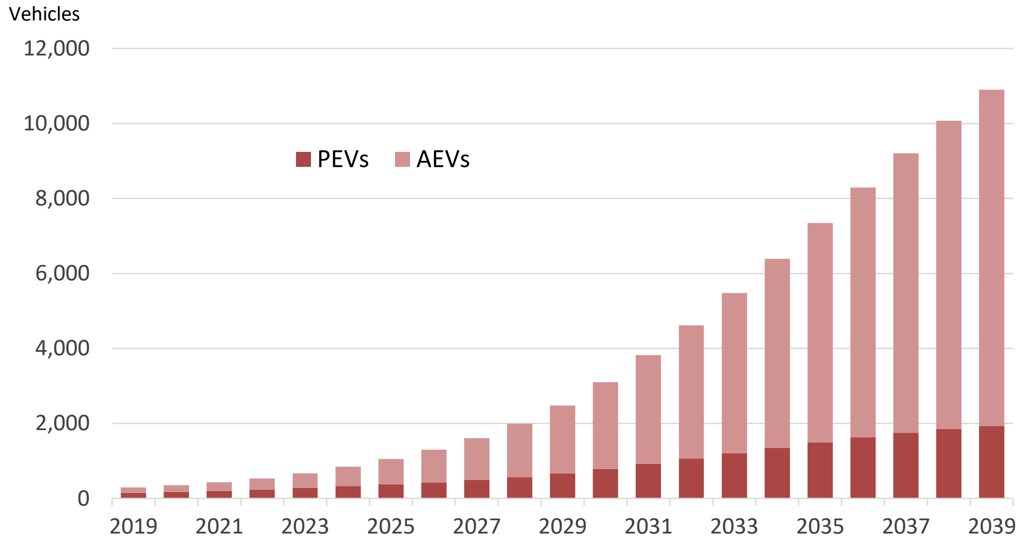
Electric Vehicle Forecast

For the first time, BED has integrated its forecast models with explicit individual forecasts of EV adoptions. At the time of the forecast there were 222 registered all EVs (“AEVs”) and plug-in hybrid EVs (“PEVs”) in Burlington. With 25,335 total registered light-duty vehicles, AEV/PEVs account for less than 1%of all vehicles on the road. While AEV/PEVs currently represent a small percentage of vehicles, improvements in charging infrastructure and continued state and federal incentives will ensure their increased adoption rate.

To quantify the impacts of EVs on the system over the 20-year period, BED reviewed EV forecasts from numerous sources and chose an EV adoption forecast based on a recent Bloomberg New Energy Finance forecast of AEV/PEV sales as a percentage of total new vehicle sales. Currently, AEV/PEV sales account for 2-3%of new vehicle sales nationally, this is forecasted to increase to nearly 60%by 2039. The forecast also accounts for the changing mix of AEV and PEV sales(currently the mix is approximately 50/50), but AEV sales are forecasted to increase to more than 80%of all AEV/PEV sales by 2039.

For the service area, the EV forecast involves a significant increase in the number of vehicles through 2039. Figure 21 shows the cumulative number of EVs, which is projected to increase from 222 to nearly 11,000 by 2039. The EVs will contribute more than 25,000 MWhs in energy demand growth in Burlington by 2039.

Figure 21: Projected Number of EVs



EVs' impact on the BED system profile will depend on when owners choose to charge their vehicles. Off-peak charging can be promoted by providing time of use ("TOU") incentive electric rates for vehicle owners. The forecast assumes two different charging profiles; a traditional profile in which vehicles begin to charge as drivers return to their homes, and an incentive profile in which charging is delayed to later in the evening with the use of a TOU incentive rate. BED assumes that 80% of the AEV energy will be charged based on the incentive profile and 20% on the traditional charge profile.

Table 5: EV Forecast

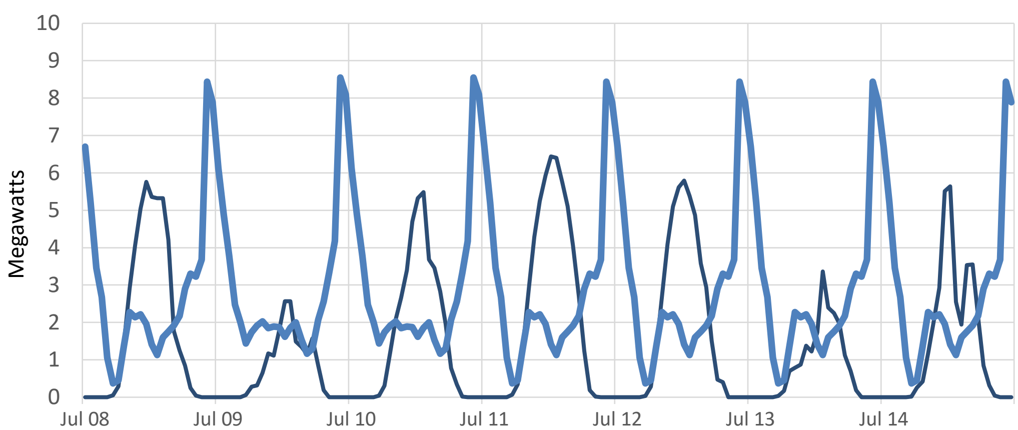
	2019	2024	2029	2034	2039
Total Number of Vehicles	25,552	27,327	27,965	28,371	28,688
Number of AEVs	145	519	1,809	5,035	8,967
% AEV	0.6%	1.9%	6.5%	17.7%	31.3%
Number of PEVs	149	325	666	1,356	1,935
% PEV	0.6%	1.2%	2.4%	4.8%	6.7%
AEV/PEV MWhs	569	1,758	5,496	14,629	25,411

System Load Shape Forecast

After developing the forecasts of monthly energy sales by customer class, a forecast of hourly system loads is developed in three steps. First, a monthly peak forecast is developed. The monthly peak model uses historical peak-producing weather and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. The weather variables include the average temperature on the peak day. The peak forecast is based on average monthly historical peak-producing weather. Next, class hourly load forecasts are derived by combining class load profiles with class sales forecasts. Class hourly profiles are expressed as a function of daily Heating Degree Days ("HDD") and Cooling Degree Days ("CDD"), binary for day of the week, month, seasons and holidays, and hours of light. Class sales forecasts are then combined with these hourly profile forecasts and adjusted for line losses to create a baseline load profile.

The baseline load profile forecast is then adjusted for solar PV and EV adoption. PV reduces system load and demand while EVs add to the baseline system load. Figure 22 shows projected PV and EV loads for the July peak week in 2039.

Figure 22: Solar & EV Load Impacts in July 2039



By 2039, EVs add 8.4 MW of load at 11:00 pm and behind-the-meter solar reduces load by 5.8 MW at 1:00 pm. The adjusted system load and projected peaks are derived by adding the PV and EV hourly forecasts. The combined impact of these adjustments moves the net system peak to hour 7:00 pm.

Over the next twenty years, base case system energy requirements average 0.3%annual growth with customer growth of 0.5%. Peak demand increases 0.2%annually over this period. In comparison, since 2010, system energy has declined on average 0.5%annually and peak demand has declined 0.1%on average. Positive forecasted energy requirements are largely the result of expected EV sales growth in the second half of the forecast period.

Table 6 shows the BED energy and demand forecast, after accounting for the effects of future energy efficiency and net-metering.

Table 6: Energy & Peak Forecast

Year	Energy (MWh)	% Chg.	Summer Peak (MW)	% Chg.	Winter Peak (MW)	% Chg.
2010	358,868	---	70.4	---	52.2	---
2011	353,211	-1.6%	65.8	-6.5%	53.5	2.5%
2012	350,753	-0.7%	63.6	-3.3%	50.9	-4.9%
2013	349,150	-0.5%	67.2	5.7%	53.1	4.3%
2014	348,338	-0.2%	64.1	-4.6%	53.5	0.8%
2015	350,950	0.7%	64.7	0.9%	53.0	-0.9%
2016	347,309	-1.0%	65.2	0.8%	50.5	-4.7%
2017	338,936	-2.4%	61.7	-5.4%	49.7	-1.6%
2018	341,234	0.7%	67.3	9.1%	50.3	1.2%
2019	336,402	-1.4%	64.5	-4.1%	51.0	1.4%
2020	338,299	0.6%	64.8	0.4%	50.9	-0.3%
2021	339,933	0.5%	65.2	0.6%	51.7	1.6%
2022	342,348	0.7%	65.4	0.3%	51.7	0.0%
2023	342,126	-0.1%	65.2	-0.2%	51.9	0.3%
2024	343,500	0.4%	65.4	0.3%	52.0	0.2%
2025	343,029	-0.1%	65.4	-0.1%	51.8	-0.3%
2026	342,657	-0.1%	65.3	0.0%	51.8	0.1%
2027	342,650	0.0%	66.3	1.1%	51.9	0.1%
2028	343,789	0.3%	65.5	-1.3%	51.9	0.0%
2029	343,693	0.0%	65.4	-0.1%	51.7	-0.4%
2030	343,418	-0.1%	65.3	-0.2%	51.6	0.0%
2031	343,637	0.1%	65.2	-0.1%	51.6	0.0%
2032	345,036	0.4%	65.3	0.1%	51.9	0.4%
2033	345,130	0.0%	65.2	-0.1%	51.8	-0.1%
2034	346,245	0.3%	65.3	0.0%	51.8	0.0%
2035	347,589	0.4%	65.3	0.1%	51.9	0.0%
2036	349,961	0.7%	65.5	0.3%	52.2	0.7%
2037	350,755	0.2%	65.6	0.2%	52.6	0.7%
2038	352,314	0.4%	65.8	0.4%	52.8	0.4%
2039	353,667	0.4%	66.0	0.3%	52.7	-0.1%
'10-'18		-0.6%		-0.4%		-0.4%
'19-'29		0.2%		0.1%		0.1%
'19-'39		0.3%		0.1%		0.2%

Alternative Forecast Scenarios

BED uses scenarios that represent possible futures that could unfold over the next 20 years. The role of the scenario is not to predict the future, but to offer us the opportunity to use an imagined future as a dress rehearsal. In this IRP, BED defined two electrification scenarios – each is to achieve net zero emission targets by specific target years – 2030 and 2040; the 2030 scenario is the more aggressive scenario.

Synapse Energy Economics was contracted to develop a net zero energy roadmap for the City of Burlington, and provided electrification impacts relative to our business as usual scenario. Table 7 and Table 8 provide estimates of the additional MWh impacts expected under the two electrification scenarios.

Table 7: Impact of Net Zero 2040 Scenario Relative to the BAU Scenario

Impact		2019	2024	2029	2034	2039
Res Electric Space Heating	*MWh*	1,313	20,186	38,009	42,099	45,350
Res Electric Water Heating	*MWh*	566	9,037	19,851	22,746	22,059
Res Electric Space Cooling	*MWh*	200	2,138	4,092	5,093	5,718
Res Efficiency	*MWh*	(234)	(789)	(853)	(884)	(919)
Electric AEV Vehicles	*MWh*	8	3,895	13,098	17,610	17,480
Electric PEV Vehicles	*MWh*	10	2,465	7,390	9,549	9,069
Res Behind the Meter Solar	*MWh*	(93)	(581)	(878)	(1,385)	(1,619)
Com Electric Space Heating	*MWh*	1,499	17,657	26,706	31,016	31,452
Com Electric Water Heating	*MWh*	177	1,767	3,622	5,108	6,013
Com Electric Cooking	*MWh*	590	9,165	21,398	33,593	37,807
Com Efficiency	*MWh*	(699)	(3,879)	(6,090)	(7,803)	(9,431)
Com Behind the Meter Solar	*MWh*	(82)	(805)	(1,289)	(1,552)	(1,921)
Total	***MWh***	**3,255**	**60,256**	**125,056**	**155,190**	**161,058**

Table 8: Impact of Net Zero 2030 Scenario Relative to the BAU Scenario

Impact		2019	2024	2029	2034	2039
Res Electric Space Heating	*MWh*	3,662	47,218	60,695	57,027	51,605
Res Electric Water Heating	*MWh*	689	11,233	21,867	22,743	21,871
Res Electric Space Cooling	*MWh*	433	3,939	5,500	5,883	5,973
Res Efficiency	*MWh*	(234)	(789)	(853)	(884)	(919)
Electric AEV Vehicles	*MWh*	53	6,570	26,345	33,318	28,400
Electric PEV Vehicles	*MWh*	49	3,906	9,699	9,336	5,772
Res Behind the Meter Solar	*MWh*	(93)	(581)	(878)	(1,385)	(1,619)
Com Electric Space Heating	*MWh*	1,801	36,070	46,421	47,930	41,164
Com Electric Water Heating	*MWh*	174	1,861	3,810	5,896	5,878
Com Electric Cooking	*MWh*	590	9,165	21,398	33,593	37,807
Com Efficiency	*MWh*	(699)	(3,879)	(6,090)	(7,803)	(9,431)
Com Behind the Meter Solar	*MWh*	(82)	(805)	(1,289)	(1,552)	(1,921)
Total	***MWh***	**6,343**	**113,908**	**186,625**	**204,102**	**184,580**

With a strong increase in cold climate heat pump adoption, peak demand shifts from the summer months to winter months. By 2030, the aggressive electrification scenario results in a peak demand that is more than double the business as usual peak demand forecast. Figure 23 and Figure 24 compare the hourly load shapes for the years 2030 and 2039 for each of the scenarios.

Figure 23: Scenario Load Comparison in 2030

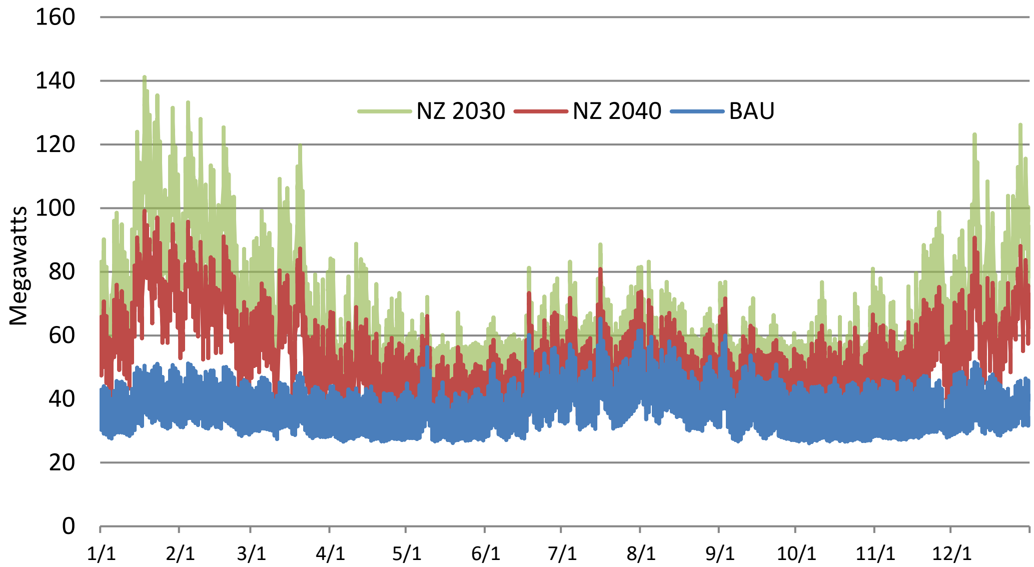


Figure 24: Scenario Load Comparison in 2039

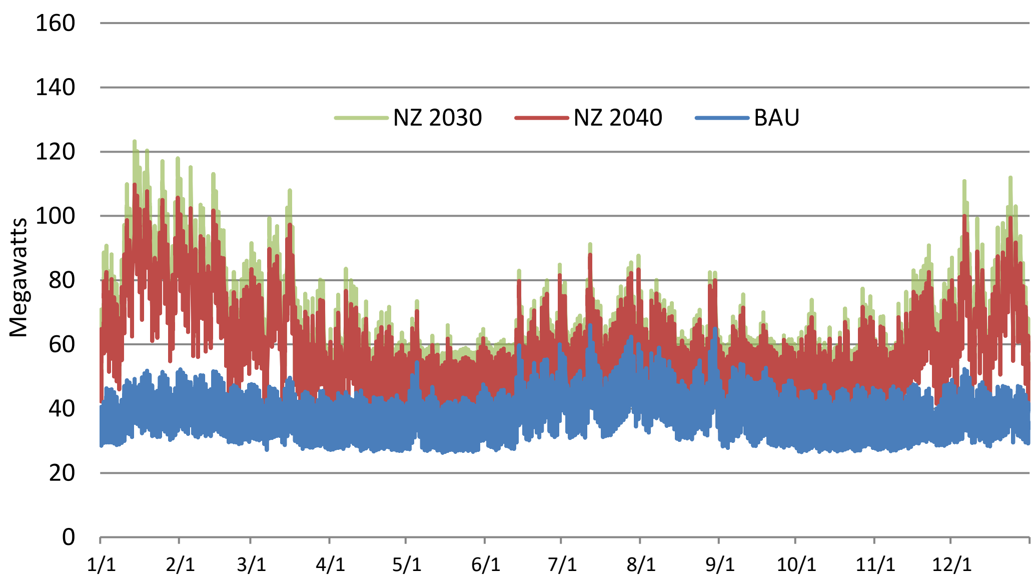


Figure 25 and Figure 26 provide a look at the peak day load shape in 2030 and 2039 for the Net Zero 2030 scenario. The load shape is characterized by dual peak periods occurring in the morning around 8:00 or 9:00 am, and in the evening at 11:00 pm.

Figure 25: 2030 Peak Day (1/18) assuming the NZ2030 Scenario

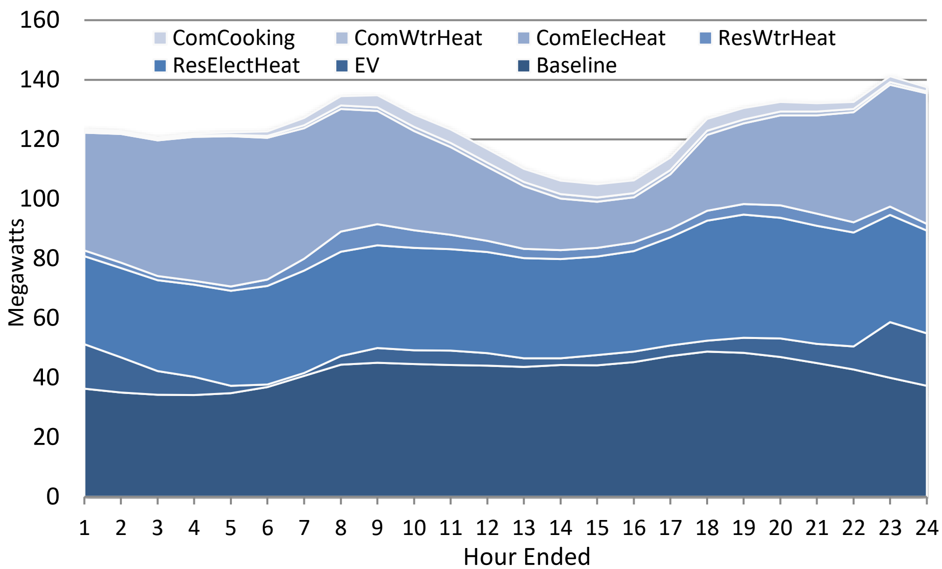
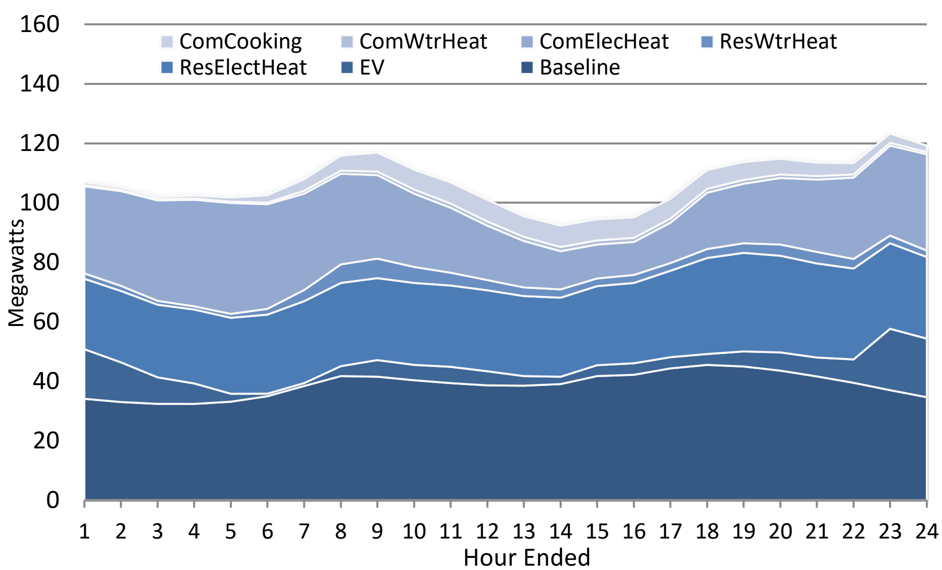


Figure 26: 2039 Peak Day (1/14) assuming the NZ2030 Scenario



Weather was not included as a sensitivity case for the system energy forecast because weather patterns tend to be sporadic and lean toward an average over the long term. The business as usual peak scenario was also evaluated using extreme peak day temperature (a one in ten chance of occurring). This resulted in peak loads that were about 3.7%higher than peaks under average peak weather conditions. Table 9 provides a final summary of the peak and energy forecasts for the various scenarios.

Table 9: System Peak & Energy Forecast Scenarios

	System Energy (MWH)			System Peak (MW)			
Year	BAU	NZE 2040	NZE 2030	BAU 50/50	BAU 90/10	NZE 2040	NZE 2030
2019	336,402	339,784	342,871	64.5	67.2	64.9	65.4
2020	338,299	347,394	365,940	64.8	67.5	65.7	67.3
2021	339,933	359,635	390,726	65.2	67.9	66.9	74.6
2022	342,348	376,142	417,098	65.4	68.1	68.4	85.7
2023	342,126	388,429	436,852	65.2	68.0	70.2	95.9
2024	343,500	403,762	457,413	65.4	68.2	75.1	102.8
2025	343,029	418,187	474,330	65.4	68.2	79.8	109.4
2026	342,657	431,557	488,349	65.3	68.1	84.3	114.2
2027	342,649	444,481	500,181	66.3	69.2	88.9	118.1
2028	343,789	457,867	511,237	65.5	68.3	91.5	120.3
2029	343,693	467,801	529,370	65.4	68.3	96.2	126.5
2030	343,418	475,770	559,027	65.3	68.2	99.1	141.2
2031	343,637	483,133	556,901	65.2	68.1	101.6	139.2
2032	345,036	490,715	554,908	65.3	68.2	102.4	135.5
2033	345,130	495,738	551,198	65.2	68.1	103.4	133.1
2034	346,245	499,275	548,188	65.2	68.1	106.4	132.9
2035	347,589	501,376	544,274	65.3	68.2	106.4	129.8
2036	349,961	503,328	540,124	65.5	68.4	106.0	126.1
2037	350,755	505,876	538,026	65.6	68.5	106.9	124.7
2038	352,314	509,573	537,093	65.8	68.6	109.0	124.4
2039	353,667	511,314	534,837	66.0	68.7	109.8	123.2
20-Year CAGR:	0.25%	2.06%	2.25%	0.11%	0.11%	2.66%	3.22%

Figure 27 and Figure 28 compare energy and demand net zero scenario forecasts against the business as usual case.

Figure 27: System Energy Forecast Scenarios

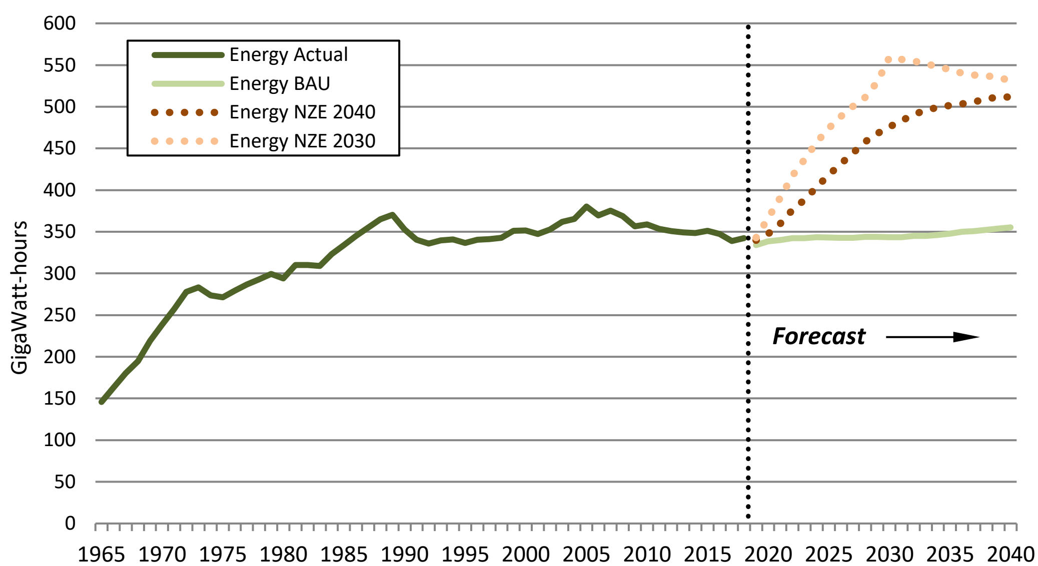
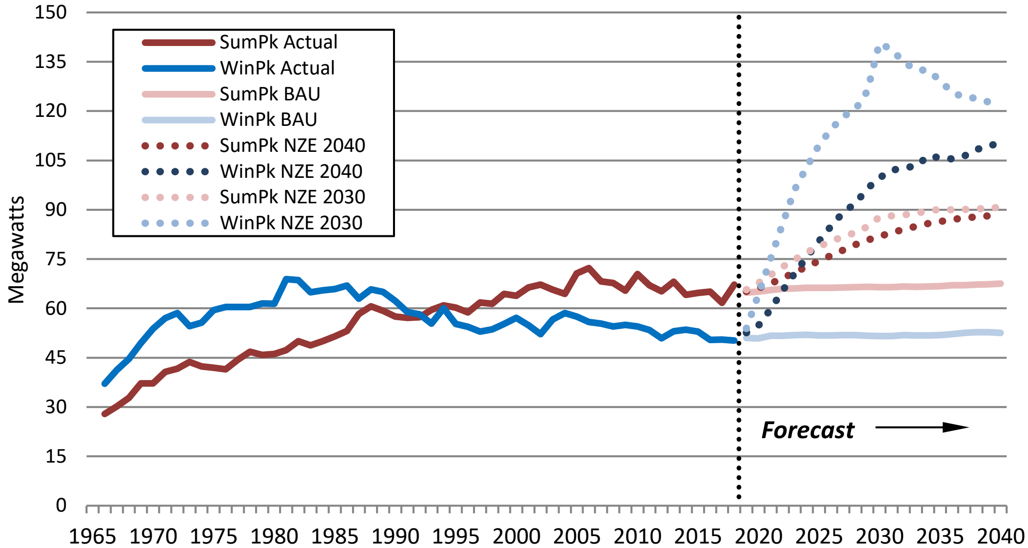


Figure 28: System Peak Demand Scenarios



Chapter 3 - Generation & Supply Alternatives

Consistent with 30 V.S.A. §218c, BED evaluated its future energy and capacity needs and compared them to its current resources and planned resource additions. Future energy and capacity needs are rooted in the 20-year load forecast, which reflects various scenarios including the potential impacts of strategic electrification initiatives, distributed generation resources and electric energy efficiency. However, this IRP rests on a final forecast that reflects our assessment of the most likely scenario for our future energy requirements and annual capacity obligations (i.e. demand at ISO-NE peak hour plus reserves).

In this chapter, BED provides an overview of its existing energy and capacity resources, as well as a description of the renewable energy credits generated from such resources. This chapter then provides a summary of BED's processes for evaluating future supply options. Lastly, this chapter includes an analysis of the potential resources available to BED to meet its future obligations.

Current Resources

Over the 2020-2040 IRP planning period, BED's existing resource mix is comprised of owned and contracted resources. Table 3.1, below, provides an overview of the basic characteristics of BED's existing resources and describes the growth and expiration of BED's contracted resources during the IRP period.

Table 3.1: 2020-2040 Power Supply Resources

Resource	Description	Fuel	Location	Expiration
BED Owned Resources				
McNeil	Dispatchable unit	Wood	VT Node 474	Owned
BED GT	Peaking unit	Oil	VT Node 363	Owned
Winooski One	Run of river hydro	Hydro	VT Node 622	Owned
Airport Solar	Fixed array rooftop solar	Solar	Internal to BED system	Owned

Resource	Description	Fuel	Location	Expiration
BED (585 Pine St) Solar	Fixed array rooftop solar	Solar	Internal to BED system	Owned
BED Contracted Resources				
NYPA	Preference power	Hydro	Roseton Interface 4011	Niagara: 2025 St. Lawrence: 2032
Hydro Quebec	7x16 Firm energy only	HQ system mix	Highgate Interface 4013 (via market bilateral)	2035 and 2038
VEPPI	PURPA Units	Hydro	Various VT Nodes	2020
VT Wind	Intermittent	Wind	VT Node 12530	2026
Georgia Mountain Community Wind	Intermittent	Wind	VT Node 35555	2037
Great River Hydro	Small hydro portfolio (7x16)	Hydro	Vermont Node 335	2024
Hancock Wind	Intermittent	Wind	Contract delivers to Vermont Zone 4003	2027.
Market	ISO-NE or bilateral energy	System mix	Various NE Nodes	No market energy contracts currently

Resource	Description	Fuel	Location	Expiration
Solar	Long-term contract - Intermittent	Solar	Internal to BED system	2032 and 2043
Solar	Net metering - Intermittent	Solar	Internal to BED system	N/A

- **McNeil Station:** BED is a 50% owner of the McNeil Station, which entitles BED to 25 MW of nameplate capacity (though peak capability is higher). The plant is projected to operate approximately 60-70% of the total available annual hours for the entire IRP period. The selective catalytic reduction unit installed in 2008 has allowed for the reduction of NO_x emissions as well as the ability to improve the economics of plant operations through the sale of Connecticut Class I RECs. BED bids the unit partially based on variable costs but recognizes that REC revenues will be received in addition to energy revenues.
- **Burlington Gas Turbine**: BED is the sole owner of this oil-fired peaking unit with a 25.5 MW nameplate rating. BED's Gas Turbine ("GT") is assumed to be available to provide peaking energy, capacity, and reserves.
- **Winooski One:** BED took ownership of the Winooski One facility effective September 1, 2014. This is a Low Impact Hydropower Institute ("LIHI") certified hydro facility electrically connected to BED's distribution system. LIHI's voluntary certification program recognizes hydropower dams that are minimizing their environmental impacts and enables such low impact projects to access certain REC markets. Winooski One currently produces MA Class II (non-waste) RECs in addition to the energy and capacity normally associated with such a unit. The unit is qualified in the Forward Capacity Market (as an intermittent resource) and operates at an approximate 50% annual capacity factor.
- **Airport Solar:** on January 26, 2015, BED commissioned its 576.5 kW DC (499 kW AC) rooftop solar facility on the Burlington International Airport Parking Garage. BED has a 20-year lease for this rooftop space. With this project, the airport has reduced the need to import energy from outside sources.

- **BED Rooftop Solar:** In October 2015, BED commissioned a 124 kW DC (107 kW AC) solar array on the rooftop of BED's Pine Street headquarters. This new solar array is a BED-owned asset and reduces the need to buy energy from outside sources.

- **NYPA**: BED receives approximately 2.616 MW of New York Power Authority ("NYPA") power through two separate contracts. The contracts, Niagara and St. Lawrence, expire in 2025 and 2032, respectively. Energy under these contracts is favorably priced but NY Independent System Operator ("NYISO") ancillary charges are incurred to deliver the energy to New England.
- **Hydro Quebec**: Along with many of the other Vermont utilities, in 2010 BED executed a contract for firm energy deliveries from Hydro Quebec. For BED, this contract started in November 2015 at 5 MW and will increase to 9 MW beginning November 2020. The current contract expires in 2038. Energy deliveries are by market transfer and are delivered during the "7x16" market period (i.e. hour ending 8 to hour ending 23, all days including holidays). This contract does not provide any corresponding market capacity.
- **VEPP Inc.**: BED currently receives a share (approximately 0.3 MW of nameplate rating) of the output from generators under a contract with VEPP Inc. BED modeled the VEPP Inc. units assuming normal weather conditions with individual unit contracts (and respective output) retiring according to their contract terms. Effective 6/1/2010, VEPP Inc. generators are considered intermittent resources and have a much lower capacity rating than in previous years. In accordance with 30 V.S.A. § 8009(g), as of November 2012, BED only must take an assignment of Ryegate energy if BED fails to meet its statutory baseload biomass requirement by generating at least 1/3 of its annual energy needs with McNeil biomass generation.[1,2,3] BED has met this requirement every year with McNeil generation and plans to continue to do so. During the first year of the IRP period, all the remaining VEPP Inc. contracts for hydro power will expire, but the impact on total energy supply will be quite small.

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[1] 30 V.S.A. § 8009(a)(2) "Baseload renewable power portfolio requirement" means an annual average of 175,000 MWh of baseload renewable power from an in-state woody biomass plant that was commissioned prior to September 30, 2009, has a nominal capacity of 20.5 MW, and was in service as of January 1, 2011.

[2] 30 V.S.A. § 8009(b) Notwithstanding subsection 8004(a) and subdivision 8005(d)(1) of this title, commencing November 1, 2012, the electricity supplied by each Vermont retail electricity provider to its customers shall include the provider's pro rata share of the baseload renewable power portfolio requirement, which shall be based on the total Vermont retail kWh sales of all such providers for the previous calendar year. The obligation created by this subsection shall cease on November 1, 2022.

[3] 30 V.S.A § 8009(g) A retail electricity provider shall be exempt from the requirements of this section if, and for so long as, one-third of the electricity supplied by the provider to its customers is from a plant that produces electricity from woody biomass.

- **Vermont Wind:** BED receives 16 MW of the 40 MW nameplate capacity of Sheffield Wind Farm in Sheffield, VT. This contract includes the energy, capacity, RECs and ancillary products from the facility throughout the lifetime of the ten-year contract and five-year extension, which will expire in 2026.
- **Georgia Mountain Community Wind**: In 2012, BED entered into a 25-year contract for 100% of the output from the 10 MW Georgia Mountain Community Wind facility. The contract includes energy, capacity, and other credits.
- **Great River Hydro:** BED has two and five-year agreements (covering the period 2018-2024) with Great River Hydro for 7.5 MW of output from a portfolio of hydro resources located on the Connecticut River. The contract is unit-contingent based on the combined output of the three facilities specified and includes the renewable attributes associated with the actual output delivered to BED.
- **Bilateral Market Contracts:** For any energy that BED needs beyond what is supplied by its owned and contracted resources, BED has a long-standing strategy of hedging its exposure to spot market price variability. Based on its energy needs, BED may purchase 1/3 of its remaining energy requirements for the future 7-15 month period at the end of each calendar quarter, if necessary. Such purchases effectively hedge most BED's energy requirements for the following 12-month period. This strategy has been approved by BED's Board of Electric Commissioners and the City of Burlington Transportation and Energy Committee. Additionally, BED's strategy allows for additional purchases if spot energy market prices are at a level that allows some measure of rate stability. Currently, BED does not have significant annual market exposure and is not expecting to rely on the structured purchasing policy in the near future.
- **Solar (Contracted):** BED has obtained the rights to the output of relatively small PV arrays located on several of the City's schools as well as on some non-profit housing properties. These projects are under long-term purchase power agreements that expire in 2032. BED also has the rights to the output of the 2.5MW South Forty Solar array, which expires in 2043.
- **Solar (Net Metered):** Burlington customers can install net metered projects (with solar being the predominant technology in BED's territory). Net metered projects reduce Burlington's load, and lower BED's capacity obligation. At the end of 2019, Burlington had net metered customers in all rate classes:

  Behind the Retail Meter Solar Accounts

    - Residential Service = 216
    - Small General Service = 7
    - Large General Service = 11
    - Primary Service = 1

- Total = 235

Grid Connected Solar Accounts[4]

- Residential Service = 68
- Small General Service = 52
- Large General Service = 28
- Total = 148

- **Vermont Standard Offer Contracts:** Since January 1, 2017, pursuant to PUC Order of January 13, 2017 in case 8863, BED has been exempted from purchasing Standard Offer energy. BED has continued to meet the requirements for this exemption and expects to continue to do so for the IRP period.

Renewable Energy Credits

As shown in the table below, BED obtains RECs from a variety of generation resources. BED generally sells its high value RECs to generate additional revenue. RECs generated from BED's resources could also be retired against load in the future if such retirements help BED to achieve renewable energy requirements at a lower cost than is possible by purchasing replacement RECs.

Table 3.2: BED REC Resources

Resource	Description	Fuel	REC Classification	Status
BED Owned Resources				
McNeil	Dispatchable Biomass	Wood	Connecticut Class 1	Active Sales
Winooski One	Run of River hydro	Hydro	Massachusetts Class 2 (non-waste)	Active Sales
Airport Solar	Fixed array rooftop solar	Solar	Massachusetts Class 1	Active Sales
BED (585 Pine St) Solar	Fixed array rooftop solar	Solar	Vermont Tier 2, Massachusetts Class 1	Active Sales

[4] 38 solar arrays were interconnected directly to the grid, with one or more customers taking a share of generation from these arrays.

Resource	Description	Fuel	REC Classification	Status
BED Contracted Resources				
VT Wind	Intermittent wind	Wind	Tri-Qualified (Connecticut, Massachusetts, and Rhode Island Class 1)	Active Sales
Georgia Mountain Community Wind	Intermittent wind	Wind	Tri-Qualified (Connecticut, Massachusetts, and Rhode Island Class 1)	Active Sales
In-City Solar (8 sites)	Long-term contract (PPA)	Solar	Massachusetts Class 1 (4 of 8 are currently registered); two are also registered as Vermont Tier 2	Active Sales
Hancock Wind	Intermittent Wind	Wind	Tri-Qualified (Connecticut, Massachusetts, and Rhode Island Class 1)	Active Sales

Gap Analysis

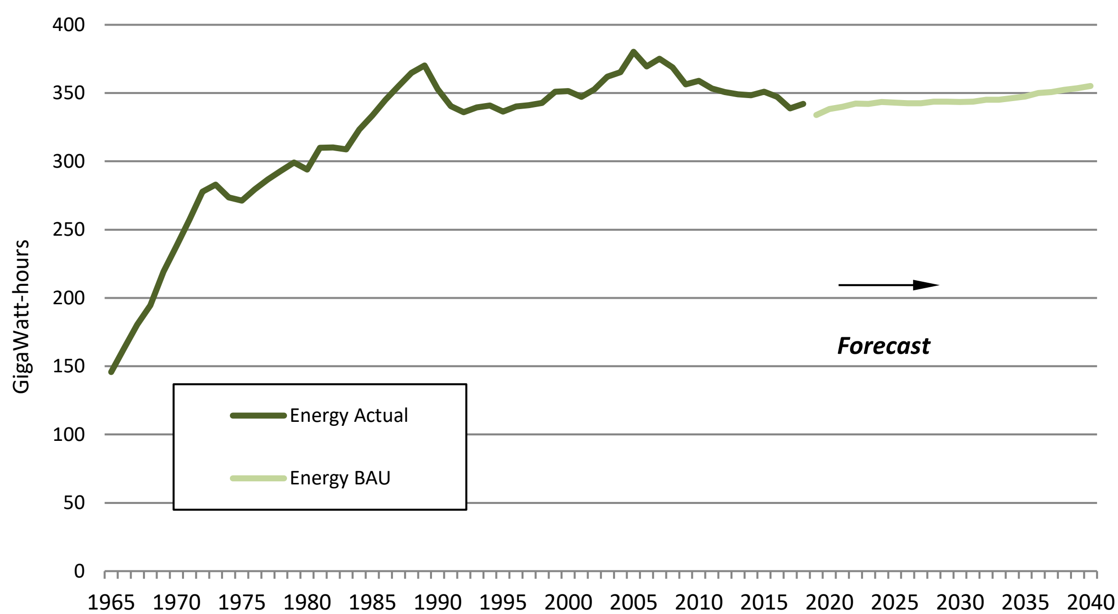
Under the BAU scenario, energy load in the City is expected to increase from 331 GWh to 342 GWh between 2020 and 2023. Thereafter, energy loads, in the aggregate, are forecasted to increase around 0.2% annually. Flat load growth during the outer years is generally perceived to be a function of aggressive energy efficiency programs, rising building codes/standards and appliance efficiency standards, and flat population growth.

There is, however, the potential for energy loads to increase at a faster pace than the BAU scenario. Factors that could drive electric energy loads up include but are not limited to a population growth rate that is higher than originally anticipated, a more robust economy that results in job and business creation and greater acceptance of energy transformation projects than projected or other activities taken by local or State governments that accelerates the pace of strategic electrification.

Energy loads could also decrease relative to the BAU scenario at least in the short term. Lower than expected energy demand would likely be due to increased levels of net metered PV installations, economic recession and/or population migration out of the City and/or Vermont.

Figure 3.1 reflects our BAU load forecast as shown in the Demand for Electricity chapter.

Figure 3.1 System Energy Forecast: 2020-2040



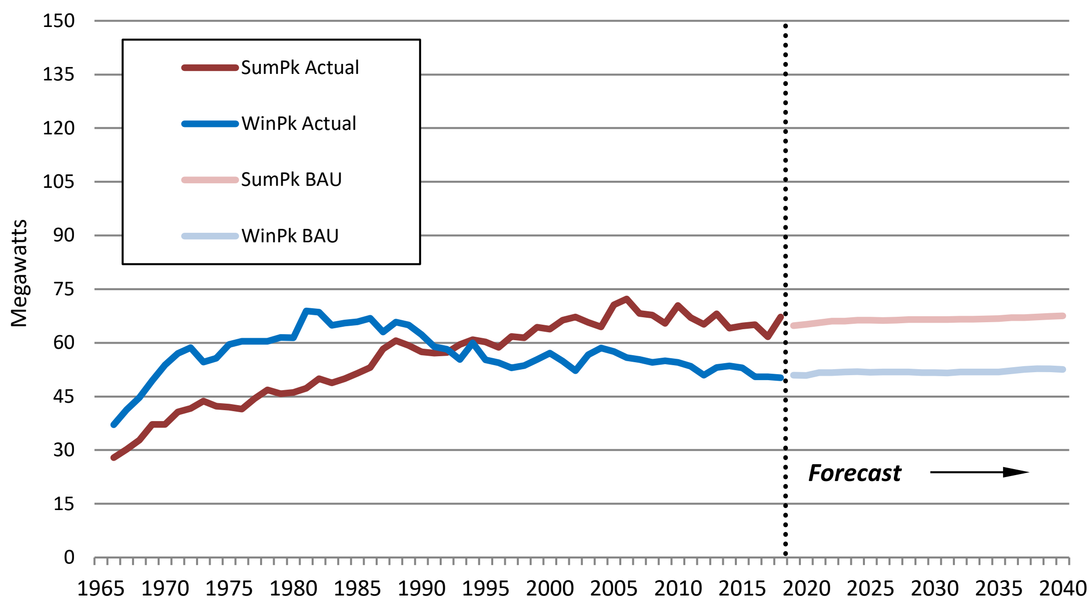
Similar to forecasted energy sales, system peak demand is also expected to remain flat over the short term planning period. Flat growth is contigent primarily on "normal" weather patterns continuing into the future; meaning, summer tempertures do not vary dramatically from historical trends. Under this base case scenario, BED also assumes that the duration of summer hot spells is not materially different than past experiences.

Higher than expected peak demand growth may, however, be driven by a variety of causes. The most likely reason would be hotter than expected summer tempertures. Demand could also rise due to increased population growth, higher employment and/or business formation levels than anticipated, as well as additional cooling demand in building areas that were not previously air conditioned. Such additional cooling load increases, if they occur, could be a consquence of increased adoption in cold climate heat pumps, which also serve as efficient cooling systems during the summer.

Additionally, winter peak demand could increase relative to BAU expectations due to higher than expected market penetration of cold climate heat pumps used for space heating. Since current peak winter demand is considerably lower than summer peak demand, increased use of cold climate heat pumps is not viewed as a potential reliability problem during the winter in the BAU scenario, however, as noted in the Net Zero Energy ("NZE") chapter, Burlington's peak may shift to the winter under the NZE scenarios.

Summer peak demand may also decrease in comparison with BAU in the short term at least. Reasons that may lead to lower peak demand include higher penetration of net metered PV and/or increases in demand resources. Decreases in population growth and economic malaise could also diminish both summer and winter peak demand.

Figure 3.2 System Peak Demand Forecast: 2020 - 2040



As noted above, customer adoption of energy transformation technologies may impact BED's energy and capacity needs in the future. A faster than anticipated rate of adoption of cold climate heat pumps, electric buses, and electric vehicles, for example, could increase BED's need for new energy resources. Also, if more net metered solar arrays are installed, BED's energy requirements could be lower than anticipated. Demand response, solar, and battery storage could reduce peak demand relative to expectations. Whether such technologies can offset one another as they are deployed is unknown at this time. At the current anticipated rates of deployment, BED does not envision a scenario in which such beneficial electrification technologies could have a material negative impact on system reliability. Nevertheless, BED will be monitoring when energy transformation projects are being deployed and the location of such projects to evaluate their impacts, if any, on BED's future energy and capacity needs.

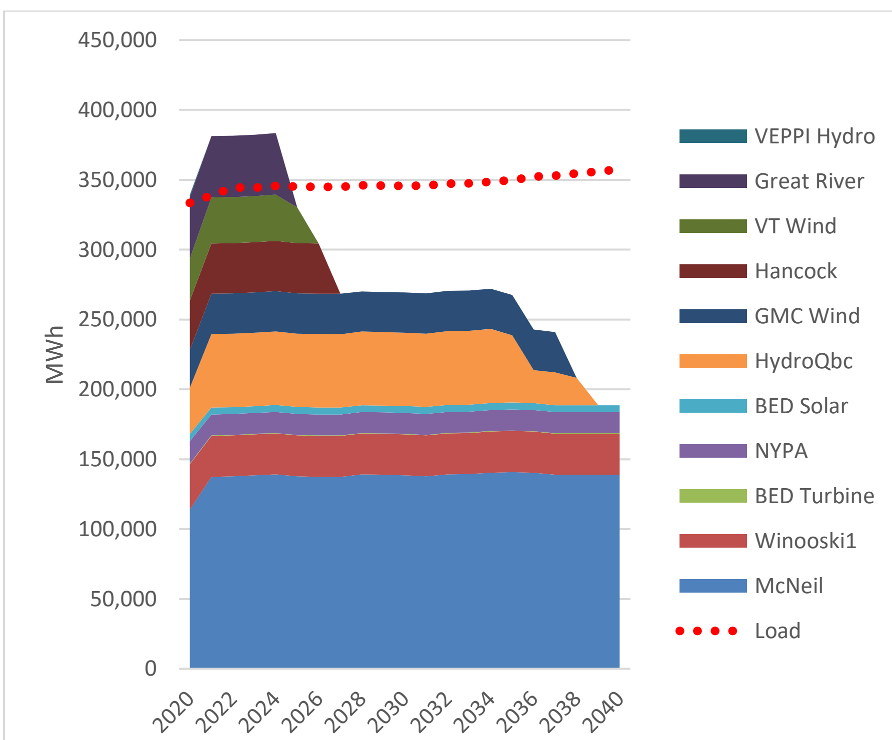
Energy Needs & Resources

BED anticipates that its energy needs will exceed its energy resources from owned and contracted sources by 2025 though this is subject to some risk of lower than anticipated output from intermittent resources. Thus, BED will need to acquire additional resources under contract or purchase spot market energy to close the gap that begins in 2025, as illustrated in

Figure 3.3 below. The energy supply gap beginning in 2025 results from the expiration of the Great River Hydro contract at the end of 2024 followed by the expiration of the extended VT Wind contract and the Hancock Wind contract. BED would require replacement contracts to be from renewable resources; preferably from resources located in Vermont–though an extension of an expiring contract for some time cannot be ruled out.

As in previous IRPs, approximately 40% of BED's energy supply is generated by the McNeil power plant. BED does not expect this situation to materially change during the IRP planning period. However, a long-term loss of McNeil's electrical output, which is highly unlikely, would significantly alter BED's energy position. Also, the economics of the McNeil facility depend on five key inputs: plant costs, capacity factor, the price of energy, the price of capacity, and the price of RECs (currently Connecticut Class 1). Due to historically low wholesale energy prices, the economics of operating the McNeil plant have been challenging over the past few years. For additional information concerning the economics of the McNeil plant, please refer to McNeil study in the appendix. While the McNeil plant operated at a loss in 2019, the study determined that its continued operations generate substantial societal benefits.

Figure 3.3: Forecasted Load v. Projected Supply Resources as of July 2020

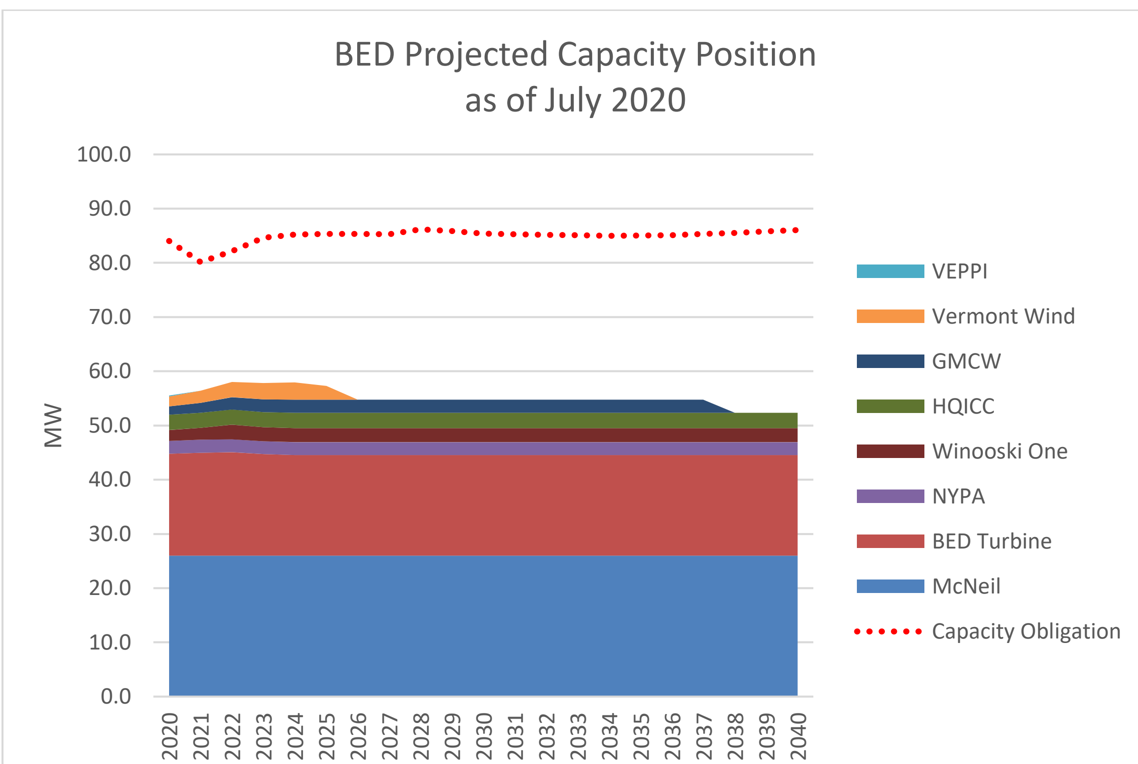


Resource Capacity

BED owns and contracts for generation resources sufficient to satisfy roughly two-thirds of its capacity obligation, inclusive of the 15% reliability margin imposed on all distribution utilities by ISO-NE (see Figure 4.4 below). Of the resources that BED controls, two facilities provide most of the capacity available to comply with regional requirements. These resources are the 50 MW McNeil biomass facility and the 25 MW gas turbine.[5]

To make up the capacity shortfall, BED is required to purchase additional capacity. Such payments are necessary to ensure generators in New England are able earn revenues during all times of the year even though they may only be needed during the hottest days of the year. This potential for a capacity shortfall is not unique to BED and many distribution utilities in New England are also required to pay generators for their capacity should it be needed. BED anticipates, as do many other Vermont distribution utilities, that this capacity shortfall situation will persist into the future. Accordingly, BED has undertaken additional evaluations of alternative resources to identify a cost-effective path forward. As discussed in more detail below, these additional evaluations might include building additional capacity resources, contracting with another generator, or pursuing demand response initiatives, including energy storage.

Figure 3.4



[5] BED owns a 50% share of the McNeil Plant.

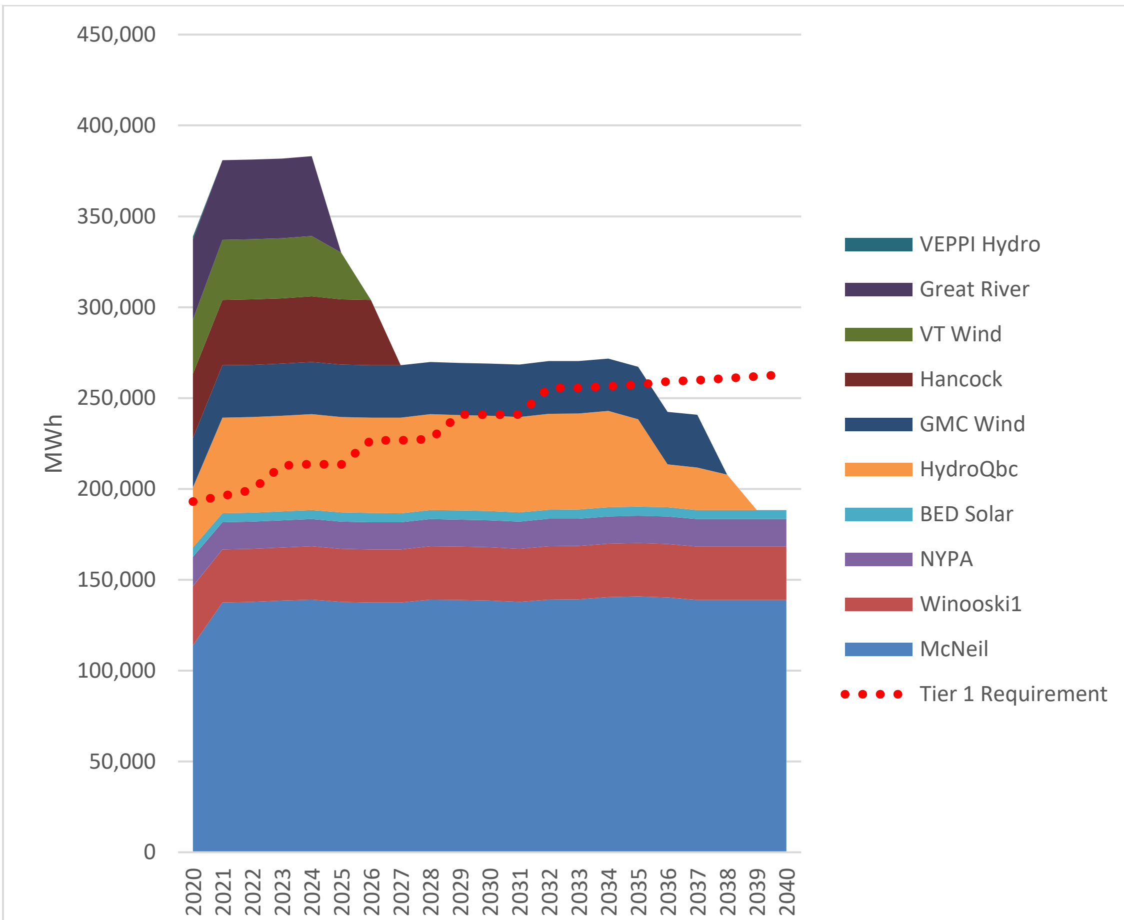
Renewability Needs & Resources

In addition to BED's own commitment to meeting 100% of its energy needs with renewable resources, BED is also subject to Vermont's Renewable Energy Standard (RES). The RES will impact BED's need for specific types of energy resources over the IRP time horizon.

RES Tier 1

With its current resources, BED is in a strong position to satisfy its Tier 1 obligation, which required 55% of retail sales in 2017 (increasing annually to 75% by 2032) to be met with renewable resources. As shown in Figure 5.4, BED expects to be greater than 75% renewable just with its current resources through 2034.

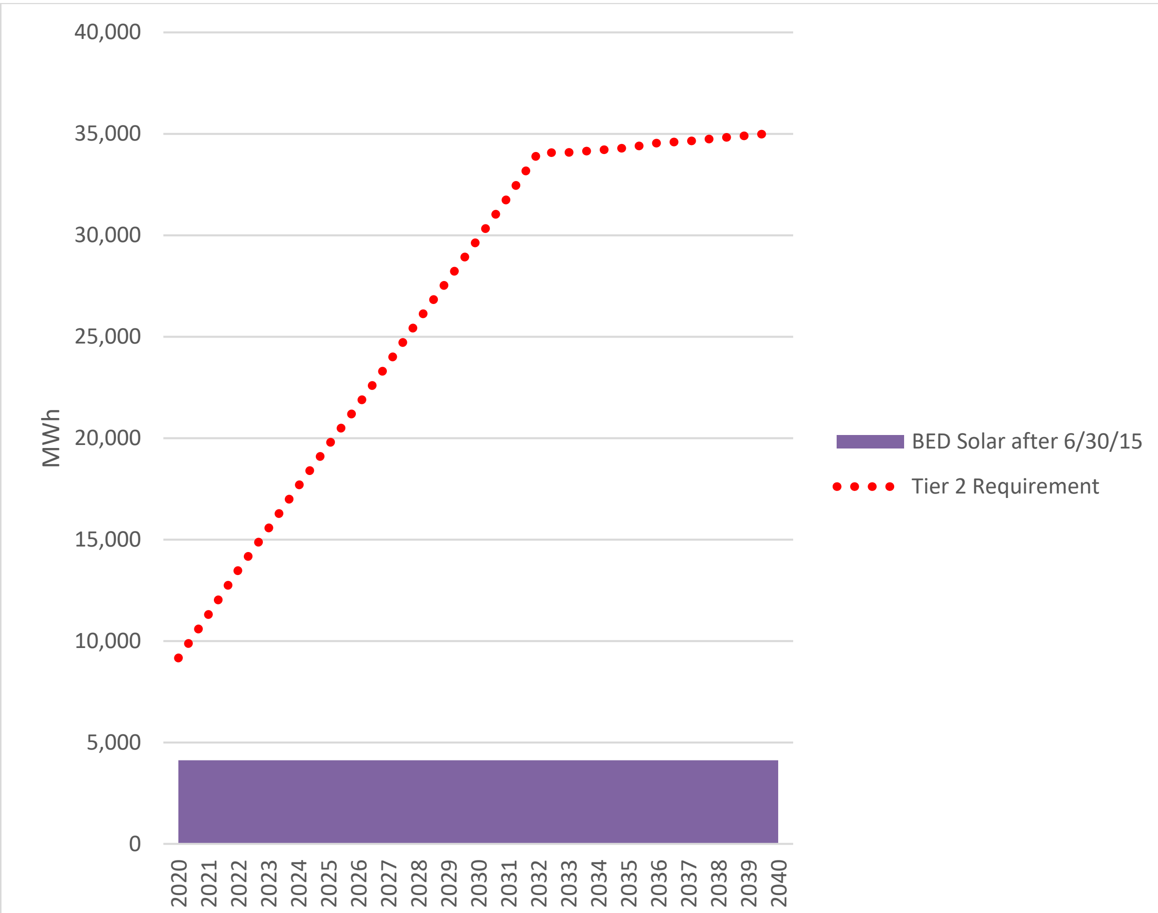
Figure 3.5: BED Tier 1 Requirement and Eligible Resources as of July 2020



RES Tier 2

Because of its renewability, BED has also been able to modify its RES Tier 2 requirement. Without such modification, the RES would have required 1% of BED's retail sales (increasing annually to 10% by 2032) to be met with distributed renewable generation. Because of the Tier 2 modification, BED will be able to apply non-net metering Tier 2 resources to its Tier 3 requirements. To comply with Tier 2, BED will still need to accept net-metering installations and retire the associated RECs it receives. As Figure 5.5 shows, if BED does not maintain its 100% renewability, there may be a large gap between its Tier 2 requirement and Tier 2 eligible resources. In that situation, BED does not anticipate that excess net metering credits would be available to apply to its Tier 3 requirement.

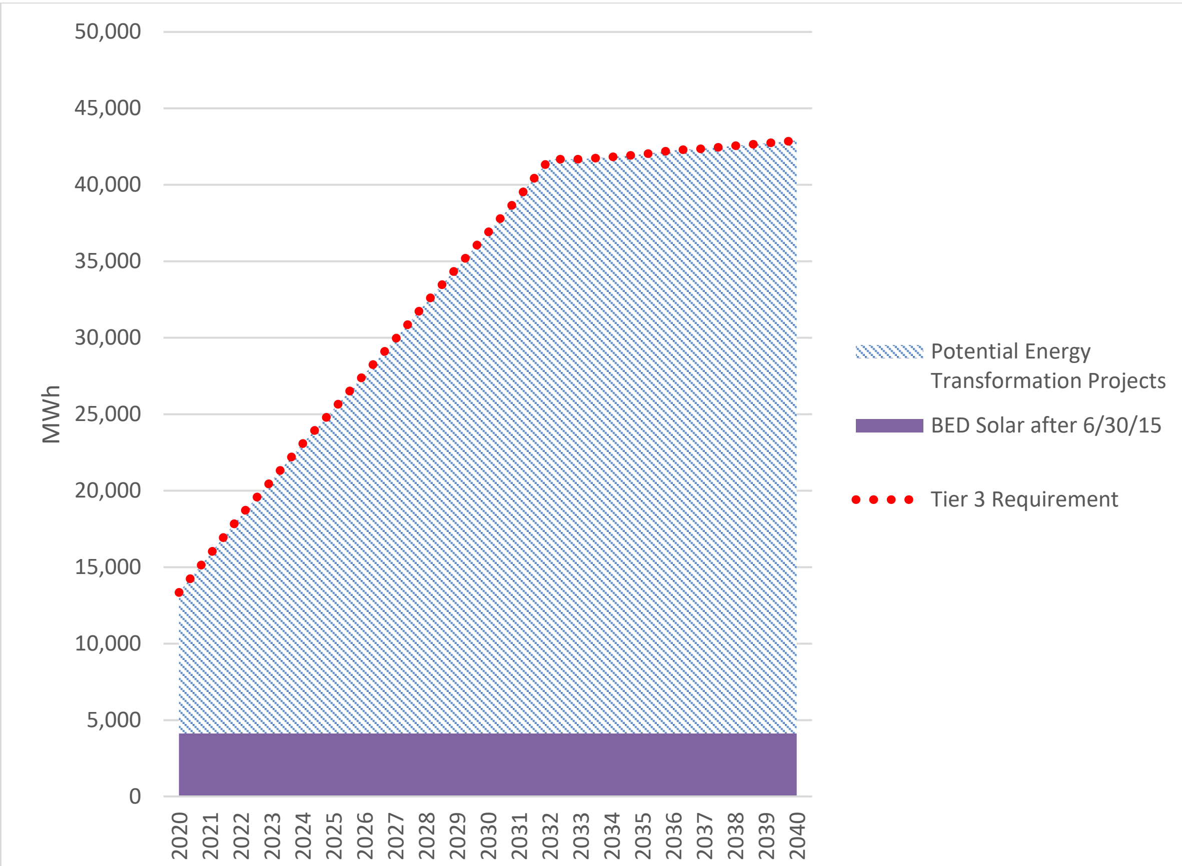
Figure 3.6: BED Tier 2 Requirement and Eligible Resources as of July 2020



RES Tier 3

The Tier 3 requirement, which began at 2% of retail sales in 2017 and increases annually to 12% by 2032, can be satisfied with non-net metered Tier 2 distributed renewable energy, additional distributed renewable resources, or with "energy transformation" projects that reduce fossil fuel consumption. As Figure 5.6 shows, even when Tier 2 resources are applied to Tier 3, there is a large gap between BED's Tier 3 requirement and its eligible resources. BED has a statutory right to pursue reductions in its Tier 3 requirement (based on its renewable status and status as an Energy Efficiency Utility). However, through analyses contained in the Energy Services chapter of this IRP, BED has concluded that sufficient Tier 3 potential in Burlington exists. For the first three years of the RES, however, BED did not reach its Tier 3 requirement with projects and relied on REC retirements to avoid alternative compliance payments. BED continues to advance energy transformation projects and has forgone its option to request modifications of its RES requirements thus far.

Figure 3.7: BED Tier 3 Requirement and Eligible Resources as of July 2020



Gap Analysis Findings

A comparison of BED's projected energy and capacity requirements against its available supply resources reveals several key issues:

- Although flat load growth is anticipated to continue well into the future, BED expects that it will need to continue making monthly capacity payments to comply with regional reliability requirements. The price of wholesale capacity could increase substantially if not hedged or actively managed.
- Loss of McNeil, the Gas Turbine or both would create a significant financial risk, as BED would be required to make up additional energy and capacity deficits by purchasing resources at wholesale market prices.
- Continued reliance on REC revenue exposes BED to REC market volatility.

- Maintaining BED's status as a 100% renewable distribution utility costs more than purchasing wholesale market/system power which is at historically low prices.
- As a 100% renewable provider, BED complies with Tiers 1 and 2 of the state's renewable energy standard ("RES"). The potential loss of McNeil, which generates up to 40% of BED's renewable energy, could undermine BED's ability to comply with the RES.
- Even if BED maintains its 100% renewability status, current Tier 2 resources can only meet about 10% of its Tier 3 requirements in the later years of the RES. Thus, BED will need to pursue energy transformation projects or Tier 2 resources.
- If BED is unable to maintain its 100% renewability status and cannot modify its Tier 2 requirement, then it will need to acquire significantly more Tier 2 eligible distributed renewable generation resources.

Tier 3 Activities Impact on Energy and Capacity Needs

As described in the Energy Services chapter, BED intends to pursue multiple energy transformation projects to comply with Tier 3 of the RES. Many of these projects will add energy loads and peak demands to the system over time. In its base case, however, BED expects that the annual electric energy consumption and peak demand requirements of these projects will be minimal relative to the total resources we have on hand. Additionally, energy efficiency resources will continue to help offset increases in load from such energy transformation projects, as will active demand resources and new net metered PV arrays. In general, the inclusion of Tier 3 anticipated loads does not change BED's resource questions substantially.

Alternatives Analysis Methodology

The gap analysis highlighted three major issues that needed additional consideration and analysis. These included:

- Effectiveness,
- Accessibility, and
- Costs

The following section provides an overview of BED's methodology and processes for assimilating data as they pertain to its assessment of a potential resource's overall effectiveness, accessibility and cost. In general, a resource is deemed effective based on its ability to reliably produce energy and capacity when needed, and if it is renewable. In terms of accessibility, BED considered whether the alternative resource would be available for acquisition during the IRP planning horizon and, if so, at what cost. As an example, BED's efforts did not consider coal as a resource since pursuing a coal strategy would have been incongruent with BED's overall objectives and Vermont's values.

Resource Effectiveness

The extent to which a specific resource can meet BED's projected energy, capacity, or renewability needs is a critical evaluation component. As noted in the gap analysis, BED has unmet needs for both energy and capacity, and has ongoing renewability targets. Generally, the ability for a single resource to meet multiple supply needs is advantageous. However, the difference in magnitude between BED's energy and capacity supply needs suggests identifying a single resource to meet both in a cost-effective manner could be challenging. Additionally, the generally poor performance of renewable resources as capacity providers further suggests that it will be difficult to meet renewable energy goals and capacity needs with the same resource.

Energy

There are many types of energy supply resources ranging from highly controllable and dispatchable generators (such as biomass and combined cycle natural gas) to intermittent and uncontrollable renewable resources like wind turbines and run of the river hydro units. Those resources that are controllable and dispatchable generally have a higher capacity factor and are viewed as more reliable energy resources.

Capacity

Traditional "peaker" resources such as fossil fuel fired generators may be cost-effective capacity supply resources but are rarely a cost-effective energy supply resource. Some energy producing resources (typically dispatchable resources) also provide significant capacity, but if the full energy output is not needed or desired, the energy would have to be sold, which leaves a utility vulnerable to wholesale energy market volatility. For the purposes of this alternative analyses, a resource that effectively meets both BED's energy and capacity needs would be ideal. However, renewable resource capacity supply options are limited and require sales and purchases in the fluctuating wholesale capacity market.

Renewable Energy Standard – Tier 1

In addition to meeting locally developed goals, BED's current 100% renewable position provides important benefits with respect to meeting Vermont's RES and avoiding costly alternative compliance payments ("ACP"). Under RES Tier 1, starting in 2017, Vermont utilities were required to source 55% of their energy from renewable resources, increasing annually to 75% by 2032. If a utility is unable to meet this requirement it is subject to an ACP for each kWh it is short of the requirement. Therefore, Tier I renewable resources are a valuable component of BED's portfolio.

Renewable Energy Standard – Tiers 2 & 3

As of 2017, Tier 2 of the RES requires utilities to meet 1% of their retail sales with new Vermont distributed renewable generation with plant capacity of five MW or less. This 1% requirement increases annually up to 10% by 2032. Tier 3 of the RES requires utilities to encourage their customers to reduce fossil fuel consumption by an amount equal to 2% of their retail sales in 2017, increasing annually to 12% by 2032. If BED maintains its 100% renewable position, it can meet an alternate Tier 2 requirement as provided in 30 V.S.A. § 8005(b). For both Tiers 2 and 3, any failure to meet the requirements leaves utilities vulnerable to an ACP six times higher than the Tier 1 ACP of $10. Therefore, resources that meet the Tier 2 or Tier 3 requirements provide significant value to BED.

Resource Access

BED's ability to access a type of resource affects its attractiveness and effectiveness with respect to other resource alternatives. Each resource alternative is assessed for its availability, meaning that BED could access it through typical utility mechanisms and without extraordinary measures or unusual circumstances. Each resource is also evaluated based on whether BED could reasonably expect to have the opportunity to own it (or a portion of it) or conversely, whether BED would have to own it in order to have access to it. In all cases, greater availability is viewed positively.

Resource Cost

Resource cost analysis of a potential resource is composed of an evaluation of any initial and ongoing costs, as well as an assessment of whether the resource is consistent with BED's internally developed goals. In all cases, lower initial and ongoing costs are preferable.

Initial Cost

In most cases, the initial cost is the upfront capital cost associated with purchasing or constructing a resource. These costs are typically financed over a long period of time and are fixed as opposed to ongoing cost which can be variable based on resource output.

Ongoing Costs

Ongoing costs can be fixed and variable. Fixed ongoing costs can include property taxes and standard operating and maintenance costs. Variable costs can include transmission and wheeling fees. Most ongoing costs apply whether the resource is owned or a PPA.

Consistency with BED Goals

BED and the City of Burlington have a long-standing commitments to innovation and the protection of the environment, as demonstrated by its achievement of 100% renewability and commitment to achieve the City's NZE by 2030 goal. To ensure the ongoing achievement of such goals, BED must consider the extent to which each potential resource will BED's goals. While it is not necessarily feasible to quantify this value, consistency with BED's goals may make an otherwise more expensive resource based on initial and ongoing costs more attractive than a lower cost resource. While non-renewable resources will not advance BED's renewability goals, consideration of such resources does, at a minimum, provide a useful benchmark for cost comparison with renewable resources.. Additionally, non-renewable resources provide value as capacity providers provided they are not used for production of any material amount of energy annually (i.e. are being used to serve reliability versus energy needs).

Resource Risk

There are cost risks associated with every generation and supply resource alternative. Some risks, such as variable fuel, maintenance, or capital costs, are easy to quantify while others are more difficult such as potential regulatory changes. BED has completed the following review of known and anticipated risks of each potential resource to assess the most likely financial and societal costs.

Resource Analysis Summaries

Each of the following resource analyses summarizes the resource's effectiveness at meeting BED's goals, and their accessibility, costs and risks.

Resource Environmental and Locational Considerations

BED staff has been working on a draft metric that combines resource direct land use requirements and weighted distance from load metric to include when evaluating competing resource options. This metric does not monetize this value but does reduce it to a numeric value for comparisons. This metric is available in draft format for discussion in future decisions but could use additional development. BED's Strategic Direction calls for expanding local generation and serving energy needs in a socially responsible manner. The majority of BED's energy is now produced in Vermont, and about half is in Burlington. BED continues to work on tools to explicitly calculate the relative merits of power portfolios based on both their location and environmental impacts.

Alternatives Analysis

This section provides a description of each resource followed by a summary of each resource's overall effectiveness, accessibility, and cost. These summaries are used to complete the Generation & Supply Alternatives Matrix located at the conclusion of this chapter which provides an overview of how selected resources compare to one another. This comparative analysis helps to determine which resource options have the greatest potential for meeting the public's need for energy services at the lowest present value costs, including environmental and economic costs.

The following list of potential resource alternatives was developed with the 2020 IRP Committee. To help the committee evaluate and compare resource options, BED assembled the capital cost, fixed and variable operating and maintenance ("O&M") cost and levelized costs using the levelized cost of energy analysis performed by Lazard in 2019,[6] and well as the Battery Energy Study for PacifiCorp's IRP.[7]

Table 3.3: Potential resource alternatives

Plant Type	Net Output (MW)	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-year)	Variable O&M Cost ($/MWh)	Levelized Cost ($/MWh)
Solar-Utility Scale-Crystalline	100	$900-$1,100	$9-$12	$0	$36-$44
Wind-Onshore	150	$1,100-$1,500	$28-$36.50	$0	$28-$54
Wind-Offshore	210-385	$2,350-$3,550	$80-$110	$0	$64-$115
Storage	10	$1,548-$2,322	$0.3-$18	$0	$142-$193
Gas Peaking	50-240	$700-$950	$5.50-$20.75	$4.75-$6.25	$150-$199
Gas Combined Cycle	550	$700-$1,300	$11-13.5	$3-$3.75	$44-$68

In order to evaluate the value of capacity supply options across all types of resources, the 2019 capital cost per kW of each resource was converted into a cost per kW-month value, as shown below. This analysis indicates that the lowest discounted cost resource is any natural gas plant located in New England. By way of comparison, ISO-NE market processes have also estimated that the cost to construct a new natural gas fired power plant would be approximately $11.95/kW-month to build.[8] This cost benchmark is oftentimes referred to as the "cost of new entry" or the CONE value. However, in the most recent forward capacity auction, FCA 14, generation actually cleared at $2.00/kW-month, well below the current CONE value.[9] This data suggests that new generators are able to enter the New England market for capacity at or below today's CONE values. Although wholesale capacity costs may be relatively low at present, BED remains concerned that current low prices may be fleeting. To reiterate, BED's capacity-related price exposure is low for the next 3-4 years due to decreasing cleared capacity market prices. At this point BED's capacity price risk after the currently cleared auctions would be mostly "up side" risk, but the current capacity market structure would reveal price changes with three years warning which would allow for potential mitigation activities prior to incurring capacity charges.

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[6] https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf, accessed August 2020

[7] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2017-irp/2017-irp-support-and-studies/10018304_R-01-D_PacifiCorp_Battery_Energy_Storage_Study.pdf

[8] https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/, accessed July 2020

[9] https://www.iso-ne.com/about/key-stats/markets#fcaresults, accessed July 2020

Table 3.4: Alternative Resources capacity cost evaluation

Plant Type	Capital Cost ($/kW)	Cost ($/kW-month)	Assumed ISO-NE Discount (Nameplate MW to Forward Capacity Market MW)	Discounted (ISO-NE) Cost ($/kW-month)
Solar-Utility Scale-Crystalline	$900-$1,100	$5.77	14%	$41.22
Wind-Onshore	$1,100-$1,500	$7.50	25%	$30.01
Wind-Offshore	$2,350-$3,550	$17.03	36%	$46.99
Storage	$1,548-$2,322	$11.17	100%	$11.17
Gas Peaking	$700-$950	$4.76	100%	$4.76
Gas Combined Cycle	$700-$1,300	$5.77	100%	$5.77

In addition to the resources listed below, BED has access to energy and capacity resources through the wholesale markets operated by ISO-New England. Net wholesale energy and wholesale capacity purchases occur automatically under the ISO-NE market structure and can be viewed simply as a "do nothing" option.

Below BED analyzes a series of resources types: Biomass, Solar, Wind, Storage, Combined Cycle Natural Gas, Traditional "Peaker", and Long-Term contracts.

Biomass

Resource Description

In this analysis, "biomass" refers to using waste wood or sustainably sourced/harvested wood/plant-based materials to generate energy. For the purposes of the alternatives analysis, BED's current share of McNeil is classified as "existing biomass" while term "additional biomass" refers to the procurement of some portion of the 50% share of McNeil not currently owned by BED.

Resource Analysis

Resource Effectiveness

Energy

BED has direct expertise with generating biomass energy at its McNeil facility. For 36 years, McNeil has provided reliable and flexible energy supply resource and participated in the day ahead and real time wholesale energy markets. McNeil's capacity factor ranges from 55-70%, allowing BED to meet approximately 40% of its energy needs with McNeil. For the purposes of this analysis, we increased the share of BED's energy needs produced by McNeil proportionally over time. On a day-to-day basis, however, BED tends to be long on energy when McNeil is running, and short when it is not. Acquiring an additional share of McNeil would exacerbate this issue.

Capacity

McNeil's qualified capacity rating according to ISO-New England's Forward Capacity Market ranges from 52 to 54 MW (full nameplate capacity). McNeil is entered into the FCM as a self-supply resource for BED; providing 26 MW of capacity supply that BED can consistently rely on to meet its capacity requirement.

Renewability

McNeil is equipped with a series of air quality control devices that limit the particulate stack emissions to one-tenth the level allowed by Vermont state regulation. McNeil's emissions are one one-hundredth of the allowable federal level. The only visible emission from the plant is water vapor during the cooler months of the year. In 2008, McNeil voluntarily installed a $12 million Regenerative Selective Catalytic Reduction system, which reduced the Nitrogen Oxide emissions to 1/3 of the state requirement. Due to these measures, McNeil energy qualifies under the Connecticut Renewable Portfolio Standard and each MWh of energy generated creates a Connecticut Class 1 REC. Additionally, McNeil's energy qualifies as renewable under Tier 1 of the Vermont RES.

Resource Access

Availability

While BED has a 50% ownership share of McNeil, the other 50% is shared among two entities: Green Mountain Power (31%) and Vermont Public Power Supply Authority (19%). The three owners meet quarterly and maintain open lines of communication regarding the facility's operations and finances. In that regard, BED has direct and frequent access to the parties who could make additional biomass resources available. BED could discuss options with the joint owners to access a greater share of McNeil's energy, capacity, or both.

Ownership

As noted above, BED has an existing ownership share and a direct relationship with the other joint owners, making ownership of additional biomass possible from an access standpoint.

Resource Cost

Initial Cost

If BED pursued a greater ownership share, there would be potential for significant initial costs related to "buying out" current joint owner shares. This cost would be less if instead BED were to enter into a contract to purchase a joint owner's share of energy or capacity, but not full ownership rights.. However, the price of a buy-out is dependent on the potential seller's interest.

Ongoing Cost

BED has firsthand knowledge of McNeil's current operating and maintenance costs. When compared to other controllable and dispatchable energy supply resources, McNeil's variable costs are relatively high. As BED manages the sale of McNeil's Connecticut Class 1 RECs for both BED and GMP, BED is aware of the importance of REC revenue in helping McNeil remain a cost-effective energy supply resource by offsetting the cost of production. Falling REC prices would essentially make McNeil more expensive to operate. McNeil is also an aging plant and increased maintenance costs and additional capital expenses are anticipated in the coming years.

Consistent with BED Goals

Acquisition of additional biomass would further BED's renewability and sustainability goals by assisting with maintaining 100% renewability, meeting RES Tier 1 requirements, and helping to achieve the City's NZE by 2030 goal.

Resource Risk

Biomass is different from other renewable resources like solar and wind because it requires fuel and generates emissions. Accordingly, the renewability classification of biomass is tied in large part to the sustainability of its fuel as well as its level of emissions. More stringent regulations with respect to fuel, emissions or biomass generally could alter its renewability classification and potentially impact the availability of high value RECs and RES compliance eligibility. With BED already relying on McNeil for 40% of its energy supply, greater reliance on McNeil could increase BED's exposure to the resulting market impacts in the event of such regulatory changes.

Resource Conclusion

The most viable option for BED, if it were to desire additional biomass energy, would likely be to seek to buy out some or all of one or more of the other Joint Owners entitlements. However, this would carry some additional single resource risk and BED does not intend to pursue this at this time.

Potential impacts of acquiring additional biomass resources from McNeil are:

- McNeil is a reliable renewable energy and capacity resource that furthers BED's goals and current RES requirements.
- BED has a high level of access to the resource and could investigate shorter term non-ownership options to avoid high initial costs or a higher share of future capital expenditures. BED could also consider increasing its ownership share of McNeil, if one of the other Joint Owners sought to reduce their ownership share.

Potential risks of acquiring additional biomass resources from McNeil

- In terms of cost, McNeil already has relatively high operating costs, with the potential for its net expenses to increase in the event of declining REC revenue in the future.
- Increased reliance on McNeil would expose BED to greater risk in the event of regulatory changes and resulting REC market impacts.

Solar

Resource Description

For the purposes of this analysis, any solar array where BED would be entitled to some portion of the output is analyzed.

Resource Analysis

Resource Effectiveness

Energy

In northeastern US, stand-alone solar has a capacity factor of approximately 15%. It's relatively low capacity factor means that solar alone would be unlikely to provide a good hedge for energy prices. As BED tends to be long on energy in the winter, and short on energy in the summer, solar has the potential to help BED hedge its energy needs on a seasonal basis.

Capacity

Small solar facilities that are less than 5 MW generally do not participate in ISO-NE's FCM. Passive reductions of BED's loads from solar at times when charges for capacity are set allow smaller solar to serve as a capacity resource. Increased behind the meter solar has shifted the ISO-NE peak to later in the day which has reduced its capacity benefit. Larger solar can also provide capacity, however, ISO-NE's current market rules recognize solar at approximately 10% of nameplate capacity.

Renewability

Solar PV is a Tier I eligible renewable resource. Additionally, distributed generation facilities that are less than 5 MW in capacity are Tier 2 eligible resources. Such facilities that are not net metered[10] are also Tier 3 eligible (BED must retire all net metering RECs to retain its exemption from the remainder of Tier 2). Alternatively, RECs produced by solar resources can also be sold to provide revenue to BED.

Resource Access

Availability

BED has supported development of several solar projects in the City of Burlington. By its nature, solar distributed generation is smaller in scale and requires less land for siting purposes than utility-scale generation. While Burlington is a densely populated area with limited open land, there are further opportunities for solar development on rooftops and brownfields within the City. With additional siting potential and the continued decline of the cost of solar panels, BED views solar PV development as an available resource.

Ownership

BED currently owns two behind the utility meter solar arrays and has experience developing such projects. The City of Burlington owns many buildings and land within the City making BED acquisition and development of additional solar PV arrays feasible.

Resource Cost

Initial Cost

Among the renewable resource options considered, a distributed generation solar PV array has the highest initial cost at approximately $1,000 per kW of installed capacity.

Ongoing Cost

The ongoing costs of a solar array consist solely of fixed O&M costs of $9-12 kW-year. The levelized cost of energy for utility-scale solar ranges from $36-$44 per MWh in the Lazard study, though in practice the range will be substantially larger due to regional variation in capacity factor. Distributed generation resources of less than 5 MW are eligible under Tier 2 and could be applied to Tier 3, helping BED avoid an alternative compliance payment under the RES.

[10] 30 V.S.A. § 8005(b)

Consistent with BED Goals

Solar arrays would be consistent with BED's renewability goals and could directly support its NZE target.

Resource Risk

With a capacity factor of only around 15% in Vermont, the effectiveness of solar as an energy resource is limited. Because ISO-NE is currently summer peaking during daylight hours, solar functions as a reasonable capacity resource, reducing load during peak periods. As more solar resources have come online, the ISO-NE peak has shifted later in the day, moving beyond the time of the greatest solar production. Therefore, there is a risk that the energy and capacity value of solar could decrease over time as more solar is deployed.

Resource Conclusion

While solar has a low capacity factor, particularly in the northeast, solar can serve as a capacity resource by reducing load during the ISO-NE peak or by directly participating in the ISO-NE Capacity Market. Solar PV under 5 MW is also an eligible Tier 2 resource and could help BED meet its RES Tier 3 requirement. In terms of BED's renewability goals and NZE target, solar PV could be a very effective resource. However, given BED's urban landscape and ISO-NE market rules, BED expects that solar development in Burlington will, in large part, be net metered solar on building rooftops. The cost-benefit analysis of solar generation resources that are developed in other utility service territories, are severely hinders by the imposition of transmission (i.e. "wheeling") charges by the host utility, except when the solar generation is directly connected to the high voltage transmission system.

Wind

Resource Description

For the purposes of this analysis, utility scale wind refers to onshore and offshore wind farms consisting of multiple large wind turbines that have a combined nameplate capacity of 10 MW or more. According to ISO-NE, as of 2019 there were 1,400 MW of grid connected wind resources installed in the ISO-NE region with an additional 14,200 MW in its interconnection queue, the vast majority of which is offshore.[11]

Resource Analysis

Resource Effectiveness

Energy

Wind generation is an intermittent resource that can exhibit rapid changes in its production due to weather. Onshore utility-scale wind farms have historically

[11] "2020 Regional Electricity Outlook," page 10, ISO-New England, February 2020.

sustained capacity factors of 25-35% over time. Offshore wind is expected to achieve even higher capacity factors. For example, the Block Island Wind Farm attained a 45% capacity factor in 2019.[12]

Capacity

Due to its intermittent nature, ISO-NE does not define wind as an effective capacity supply resource. Because wind resources are not controllable and, thus, cannot be assumed to be available at times when energy demand is highest, ISO-NE "de-rates" wind generators nameplate capacity when it assigns its qualified capacity ("QC") rating. However, it is worth noting that during ISO-NE's pay-for-performance event,[13] all three of BED's wind resources produced above their ISO-NE's capacity ratings and commitments.

Renewability

Wind is a fuel- and emission-free renewable resource. Wind resources qualify for high value RECs in multiple markets throughout New England and nationally. Wind therefore qualifies as an eligible resource to meet BED's RES Tier 1 requirement.[14]

Resource Access

Availability

There are currently five utility-scale wind farms in Vermont; Searsburg Wind Facility (6 MW), Georgia Mountain Community Wind (10 MW), Sheffield Wind (40 MW), Deerfield (30 MW) and Kingdom Community Wind (63 MW). BED currently purchases energy from Georgia Mountain Community Wind, Vermont Wind, and Hancock Wind for 100%, 40%, and 26% of their respective outputs. As noted above, BED views wind resources favorably on multiple levels (i.e. energy output, cost, renewability, access etc.), but new resources are unlikely to be available at the utility-scale in Vermont.

Ownership

While BED has three existing wind contracts, it does not currently own any utility scale wind facilities. However, as new resources are built in the ISO-NE

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[12] EIA Form 923, https://www.eia.gov/electricity/data/eia923/

[13] As of July 2020, the only pay-for-performance event occurred on Labor Day 2018. More information on Pay-for-Performance is here: https://vimeo.com/257500308, accessed August 2020.

[14] Due to restrictions on facilities 5 MW and greater, large scale wind is not available for Tier 2 or 3 purposes.

region, BED may consider additional purchase power arrangements if warranted.

Resource Cost

Initial Cost

Of the renewable resources evaluated, wind has the potential to provide some of the lowest cost energy on a per kWh basis due to its moderate initial cost and low ongoing costs (i.e. its absence of a fuel cost) . According to the above tables, capital costs range between $1,100 and $1,500/kW for onshore wind. Our research also indicated that the cost of wind turbines has decreased in recent years and is anticipated to continue falling over the next several years.

Ongoing Cost

Compared to other fuel-free renewable resources, the fixed O&M costs of wind can be relatively high. However, on a levelized energy cost basis, onshore wind appears to be among the lowest cost renewable energy resources and is reaching cost parity with combined cycle natural gas generators. Offshore wind costs are also expected to continue to decline as developers gain experience building systems and larger systems reach economies of scale relative to conventional generators.

Consistent with BED Goals

As a renewable and zero emission resource, wind is consistent with and supportive of BED's goals. The existence of wind resources in Vermont and the continued development of new wind resources in New England also suggests that wind resources would continue to be available as a component of NZE aspirations for the City of Burlington. However it should be noted that the effective moratorium on new VT wind resource development will result in a conflict with the desire for resources located as close to BED's load as practical.

Resource Risk

As noted, wind generation production is subject to weather conditions. As a utility increases the proportion of its load met with such intermittent resources, it must consider methods to smooth out intermittency. Increasingly affordable storage technologies could help address the issue in the future, but in the meantime, greater reliance on intermittent resources like wind could increase BED's exposure to wholesale energy prices to supplement BED's energy resources during low wind production periods. In the past, development of utility scale wind in Vermont has faced public opposition so any BED investments in prospective Vermont-based wind resources would likely be subject to permitting and construction delays.

Resource Conclusion

Despite its intermittency, BED views wind generation as a moderately strong energy resource, and a less effective capacity supply resource. Levelized energy costs for wind are becoming increasingly competitive, and offshore wind is beginning to become a cost-competitive resource for helping other New England states reach their respective renewability targets. Additionally, wind generates high value RECs that can generate utility revenue or be used to meet RES Tier 1 requirements.

Storage

Resource Description

Energy storage can take many forms, including several types of batteries, pumped hydro, and flywheels, among others. Storage can be viewed as a unique resource because many of the technologies operate both as a supply resource and a load resource.[15] This analysis discusses a 10 MW of capacity/40 MWh of energy storage ("10 MW/40 MWh"), utility-scale, ISO-recognized lithium ion battery storage system that could replace a fossil-fuel powered peaking unit.

Resource Analysis

Resource Effectiveness

Energy

A battery storage system does not generate electricity, but rather serves as a control device that allows a utility to dispatch its stored energy when needed or to capture and store energy at times of surplus intermittent renewable generation. Further advantages of storage are its ability to respond quickly to rising demand, participate in the day ahead and real time energy markets, as well as provide various grid services such as regulation services.[16]

Lithium ion batteries are considered to have relatively high energy density, meaning the amount of energy capable of being discharged is high compared to its physical volume.[17] While lithium ion batteries are among the most efficient batteries available, with efficiency ranging from 80-93%, losses do occur when energy is stored and later discharged (meaning that storage is not "generation" itself but in fact increases net generation needs). The battery configuration

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[15] "How Energy Storage Can Participate in ISO-New England's Wholesale Electricity Markets," page 3, ISO-New England, March 2016.
[16] "How Energy Storage Can Participate in ISO-New England's Wholesale Electricity Markets," page 5, ISO-New England, March 2016.
[17] "Levelized Cost of Storage Analysis – Version 5.0", Lazard, November 2019.

considered in this analysis is intended to offset a peaker unit, and therefore is not anticipated to serve as an energy supply resource, other than by adding supply during BED's on-peak periods and decreasing supply during BED's off-peak periods.

Capacity

A battery's power density, or its capacity to discharge energy over a specific timeframe (i.e. 1 hour, 1 day etc.) is an important consideration when assessing it in the context of a utility's capacity obligations. While battery storage may not be a net producer of energy, as discussed above, it does have the ability to move energy in time and, as a consequence, can act as a capacity resource for distribution utilities. The battery system considered in this analysis could discharge a sustained 10 MW for four hours. At this time, however, minimal battery storage has cleared as capacity resource in an FCA. To compare battery storage to other capacity supply resources, it is important to consider the cost per kilowatt-month. The battery storage peaker unit is estimated to cost $11.17/kW-month, which is well above both the $4.76/kW-month of a traditional peaker unit and the most recent FCA clearing price of $2.00/kW-month. A battery storage facility, though, could potentially provide value streams by providing frequency regulation or transmission cost reduction.

Renewability

The renewability of a battery storage system depends on the source of energy used to charge the batteries. Because 100% of BED's energy is from renewable resources, a battery storage system located within the BED distribution system would assume that same level of renewability. If BED no longer sourced 100% of its energy from renewable resources, and assuming the batteries were not directly charged from a renewable resource, the storage system would be assigned the same proportion of renewability as the rest of the BED load. However, because battery storage is not an energy generator, it would not help BED meet its Tier 1 or 2 requirements. It could, however, help meet BED's Tier 3 requirements based on reducing the need for peaking generators and emissions during on-peak times.

Resource Access

Availability

Storage technologies are continually evolving. As of February 2020, 2,400 MW of battery storage was proposed in the ISO-NE region,[18] although only 20 MW are recognized by ISO-NE at this time. It does not appear that storage capability from existing facilities is available to BED, but it is likely that BED could acquire access to storage in the future. The siting of such a storage facility within the ISO-NE region, with future availability to BED, appears to be feasible with locating such a resource in Burlington appearing viable as well.

Ownership

While not immediately anticipated, BED's ownership of a 10 MW/40 MWh battery storage system or shared ownership of a larger system is possible in the future. ISO-NE has indicated it anticipates energy storage to become an increasingly important part of the regional power system and has released information on how battery storage units can participate in its wholesale energy markets. BED anticipates battery storage systems to become more prevalent in future years as costs continue to decline.

Resource Cost

Initial Cost

Like renewable technologies, the cost of battery storage has fallen substantially in recent years and continued falling prices are expected over the next several years. At present, at $1,548-$2,322/kW, battery storage is around double the cost of a traditional peaker unit. Note this estimated initial cost appears to be consistent with the ongoing costs estimated for a full tolling storage PPA (discussed inn greater length in the Decision Chapter).

Ongoing Cost

The estimated levelized cost of storing and discharging energy from a battery storage peaker unit is $142-$193 per MWh. This cost is well above all the other supply resource options evaluated apart from gas peaking plants. As noted above, capital cost reductions are anticipated, which will help make battery storage more economical on a levelized cost basis in the future. ISO-NE's external market monitor recently stated that, "storage is becoming the most

[18] "2020 Regional Electricity Outlook," page 14, ISO-New England, January 2020.

economic dispatch technology."[19] The ability for a single battery storage unit to serve multiple functions, such as capacity and regulation, could also improve its economic feasibility, although attempting to capture one value stream may decrease the ability to capture another. BED's evaluation of the economics of storage contained in the technology chapter is predicated on this ability to access multiple value streams.

Consistent with BED Goals

When paired with a renewable portfolio or specific intermittent renewable resources, battery storage may be consistent with and supportive of BED's goals. Battery storage has the potential to smooth out intermittent renewable generation curves, making it possible to rely on intermittent renewable resources for a larger portion of BED's power supply needs.

Resource Risk

Unlike a typical generator, a battery storage system has a finite ability to discharge power before it must be recharged. For the 10 MW/40 MWh peaker replacement storage system, its runtime at maximum power would be four hours. If there were a long duration event, or two back-to-back events requiring peaking capacity, reserves, or emergency back-up, it is possible that a battery storage system would fail to provide the same level of energy output as a fossil fuel fired peaker.

Resource Conclusion

Using battery storage as a peaking unit is economically competitive with a fossil fuel fired peaker unit. But, given the recent clearing prices of the New England FCM, however, it would not be cost effective, in the near term, to install a battery storage system in BED's territory as a new resource (see additional discussion in Decision Chapter). Declining capital costs and the potential for battery storage to fulfill multiple revenue-producing roles could make battery storage a more cost-effective method than a traditional peaker to meet Burlington's capacity needs and net zero goals over time. In addition, where storage can leverage additional value streams such as postponing transmission and distribution upgrades or by providing critical reliability for properties such as the UVM Medical Center or Airport, systems could provide additional value to BED's customers. Storage would be evaluated as an alternative or complement to major transmission upgrades if BED was to see significantly increased loads due to electrification.

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[19] https://www.iso-ne.com/static-assets/documents/2020/06/npc_2020062324_composite_day1.pdf, accessed July 2020

Combined Cycle Natural Gas

Resource Description

The late 1990s ushered in a steady shift to natural gas fired generation in New England. These resources are easier to site, cheaper to build, and generally more efficient to operate than oil-fired, coal-fired, and nuclear power plants.[20] A combined cycle natural gas facility uses both gas and steam powered turbines to produce electricity. The waste heat from the gas turbine is used to generate steam, which then powers the steam turbine. The use of waste heat from the gas turbine increases electricity output without additional fuel use, and therefore increases the efficiency of the facility as compared to simple cycle plants.

Resource Analysis

Resource Effectiveness

Energy

Combined cycle natural gas facilities are viewed as strong energy supply resources due in large part to their efficiency from the use of waste heat. They are controllable and dispatchable facilities and can participate in both the day ahead and real time wholesale energy markets. While historically natural gas generators operated as intermediate resources, advances in equipment allow them to now operate as baseload generators while maintaining the flexibility to quickly ramp up and down to balance intermittent renewable resources.

Capacity

Combined cycle natural gas plants are generally excellent capacity supply resources. As a non-intermittent generator, these units generally operate at a high capacity factor (85-90%) and their qualified capacity values are not de-rated, as would be the case with an intermittent generator. In 2019, 45% of the summer and winter capacity in the ISO-NE region was provided by natural gas generators.[21]

Renewability

The overwhelming majority of natural gas used in energy production in the United States is non-renewable and comes from conventional drilling or hydraulic fracturing ("fracking"). To a much smaller degree, renewable natural gas (also known as sustainable natural gas) is available. Renewable natural gas is

[20] "2020 Regional Electricity Outlook," page 9, ISO-New England, January 2020.
[21] "CELT Report: 2020-2029 Forecast Report of Capacity, Energy, Loads, and Transmission," ISO-New England, April 2020.

a biogas (biomethane) that is purified to a level where it is essentially interchangeable with standard natural gas. Sources of renewable natural gas include landfills, wastewater treatment plants and livestock. While Vermont Gas Systems ("VGS") recently began offering a renewable natural gas option to its customers, utility scale quantities sufficient to meet major power plant demands do not appear feasible at this time and it is significantly more expensive than standard natural gas.

Accordingly, the cost analysis below assumes the use of standard, non-renewable natural gas. As such, a combined cycle natural gas facility would not assist BED with meeting its RES requirements.

Resource Access

Availability

In 2019, natural gas powered facilities provided 49% of the energy in the ISO-NE region[22], but only 5% of the proposed resources in the ISO-NE generator interconnection queue are natural gas fired generators so access to new resources may be limited.[23] While there are no natural gas market participant generators in Vermont, given the number of existing facilities in New England, it is likely that BED could have access to a combined cycle natural gas generator through a purchase power contract ("PPA"). Natural gas is not widely available within Vermont, but Burlington and most residents of Chittenden County are within the VGS service territory and have access to a natural gas pipeline that might power a natural gas generator. In fact, natural gas is already available via pipeline at the McNeil biomass facility.

Ownership

Owning a natural gas generator or acquiring natural gas fired power through a PPA would be inconsistent with BED's strategic vision. Even if BED was not pursuing a NZE strategy, siting a new combined cycle natural gas generator in Vermont would be challenging. VGS' recent pipeline expansion project faced highly vocal opposition from environmental organizations and residents along the pipeline route, making the prospect of further expansion to supply a power generator highly unlikely.

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[22] https://www.iso-ne.com/about/key-stats/resource-mix/

[23] "2020 Regional Electricity Outlook," page 13, ISO-New England, February 2020.

Resource Cost

Initial Cost

Of the resources summarized above, a combined cycle natural gas generation facility has the lowest initial cost per kW, at $700-1,300. Despite its low construction costs relative to other resources, combined cycle natural gas generators have some initial cost risk, due to unplanned costs or delays during the project's estimated three-year development process.

Ongoing Cost

The ongoing costs of a combined cycle natural gas generator are also quite moderate compared to other resource options. The fixed O&M costs are in line with some of the lowest cost renewable resources while there are some variable O&M costs. In terms of its ongoing cost risk profile, combined cycle natural gas was rated as having a high fuel cost risk due to the potential for natural gas prices to spike or to be unavailable due to pipeline constraints in the northeast, particularly in the winter months.

Consistent with BED Goals

As noted above, combined cycle generators using standard natural gas are non-renewable resources, and as such do not meet BED's renewability goals. At this time, utility-scale supply of renewable natural gas would likely be challenging from both a supply and cost standpoint.

Resource Risk

The high proportion of natural gas fired generators in ISO-NE as well as limited pipeline capacity has raised concerns about the availability of natural gas in New England. In its 2020 Regional Electricity Outlook, ISO-NE indicated, "during cold weather, most natural gas is committed to local utilities for residential, commercial, and industrial heating. As a result, we are finding that during severe winter weather, many power plants in New England cannot obtain fuel to generate electricity."[24] Therefore, reliance on a combined cycle natural gas generator would expose BED to risks of higher fuel costs (spiking natural gas prices, oil prices, or high wholesale energy prices) and higher emissions. Additionally, all the New England states have passed their own renewable portfolio standards, which incentivizes utilities increase or maintain their use of renewable resources. It is likely that potential future increases in renewability targets will make non-renewable resources such as a combined cycle natural gas generation less desirable over time.

[24] "2020 Regional Electricity Outlook," page 11, ISO-New England, February 2020.

Resource Conclusion

Combined cycle natural gas plants function as strong energy and supply resources and offer utilities high efficiency and relatively low projected initial and ongoing costs (assuming the fuel is non-renewable natural gas). BED's access to this type of resource is limited by the absence of any combined cycle natural gas plants in Vermont and the general alignment between population centers and pipeline natural gas availability, which limits suitable areas for siting a generating facility. Additionally, because standard natural gas is non-renewable and renewable natural gas is likely not to be a viable option at this time, a combined cycle natural gas facility would not be consistent with BED's renewability goals.

Traditional "Peaker" Unit

Resource Description

Facilities referred to as traditional "peaker" of "peaking" units are fossil fuel-fired simple-cycle generators. The primary fuels used in their operation are oil and natural gas, but other fossil fuels can also be used. Many units can run on multiple fuels to adjust to fuel availability and take advantage of cost differences. Additionally, the potential for these generators to run on biodiesel or renewable natural gas may offer other opportunities. For the purposes of this analysis, a 50-240 MW natural gas conventional combustion turbine has been used to determine the benefits, costs and risks of a "peaker" unit.

Resource Analysis

Resource Effectiveness

Energy

Traditional peaker units are rarely a cost-effective energy supply resource, unless the waste heat can be used. The equipment and design of these facilities is not intended for baseload or even intermediate resource operations. Rather, these facilities are intended to only operate during peak hours or as occasional back-up resources. Therefore, because of their limited operation, fixed costs must be recovered over a small number of hours, which drives the levelized price per MWh higher than generators designed for frequent and consistent energy production. The main source of revenue for these units is the capacity and reserve markets, not the energy market.

Capacity

Peaker units are designed and constructed to serve as capacity resources. Thus, BED could, by constructing a peaking unit, likely meet whatever capacity need it had at the lowest initial cost.

Renewability

Peakers are fossil fuel-fired units and therefore they are not renewable resources. As noted above, renewable gas is now available in Vermont, but not in a quantity or at a cost that would make utility-scale use feasible. As the cost to operate increases, the unit becomes less competitive with other resources and will run less, which would make it an relatively high cost Tier 1 resource, even though the use of renewable gas for a peaker, due to the relatively low energy production, would result in less increased costs than for a combined cycle plant. The cost analysis below assumes the use of standard, non-renewable natural gas. Unless fueled by RNG, a peaker unit would not assist BED with meeting its Tier 1 RES requirement. If such a unit were fueled by RNG the energy price would be high enough that the unit would not run often and thus would not contribute much renewable energy Tier 1 goals.

Resource Access

Availability

BED currently owns a 25 MW peaker generator, known as the Burlington Gas Turbine ("GT")[25] which is located along the waterfront in the City of Burlington. Due to its infrequent operation and moderate size compared to other generating resources, siting a peaker unit is generally not as challenging as other types of resources. In addition to the GT, peaker units are located throughout Vermont and the ISO-NE region. For these reasons, BED views a peaker generator as reasonably available.

Ownership

Multiple "peaker" units are located in Vermont; all of the peaker units within Vermont serve as important capacity resources for the utilities that own them. BED is not presently aware of any plans by any Vermont utilities to sell existing peaker units in the State. Therefore, BED's ownership of another peaker unit would likely be tied to the construction of a new facility in Burlington or a contract with an existing facility outside Vermont. The most recent peaker unit built in Vermont was a facility in Swanton, constructed by the Vermont Public Power Supply Authority in 2008.

[25] The Burlington Gas Turbine can currently only use oil fuel.

Resource Cost

Initial Cost

Compared to the other resource alternatives reviewed, a peaker unit has a relatively low initial cost on a per kW basis. At $700-950 per kW, only the larger combined cycle natural gas generator has an equally low range of capital cost per kW as a peaker unit. This simplicity suggests a relatively low capital cost risk related to project length or delay.

Ongoing Cost

The fixed O&M costs for a peaker are the lowest among the resources reviewed while the variable O&M costs are relatively high. Because capital costs must be recovered over a small number of generation hours, the levelized energy costs of a peaker are quite high and are by the far the highest among the non-renewable resources considered. Although, it is important to remember that a peaker is not intended to serve as a primary energy supply resource. Rather, the ongoing economics of a peaker are tied to whether its cost of operation and upkeep is less than the cost to purchase market capacity or capacity from another resource, which if initial costs are ignored they generally are.

Consistent with BED Goals

As a fossil-fuel powered generator, a peaker is not consistent with BED's renewability goals. However, unlike baseload or intermediate non-renewable resources that produce significant amounts of energy, the magnitude of non-renewable energy generated by a peaker is quite small. The potential exists to use renewable natural gas for peaking purposes, or the output from a peaker could be "greened" using replacement or excess RECs (or other emission offset tools) equal to the unit's annual MWh output, as is currently done with BED's GT.

Resource Risk

Because peakers derive their financial value from the capacity and reserve markets and do not generally generate revenue from energy production, their economics are vulnerable to clearing prices of market auctions each year. A low clearing price could dramatically reduce revenue for a peaker for an entire year with little opportunity or ability for a utility to improve it. Past history has seen extended periods where the capacity market revenues would not support peaking generation or where capacity value was zero, though revisions to FCM structure should moderate price swings through demand curves, and reward peakers' quick availability through pay-for-performance.

Resource Conclusion

Peakers are intended to serve a narrow yet important primary function: the provision of capacity supply to a utility and the grid. In terms of this specific function, peakers are highly efficient and cost-effective. As expected, when compared to resources intended to serve as energy-producers, they do not appear economically attractive for acquiring energy. The current low capacity market prices have made BED's acquisition of additional traditional peaking capacity unlikely in the near term.

Long-Term Renewable Contract (Non-wind)

Resource Description

For the purposes of this analysis, a generic utility scale hydroelectric generator (over 5 MW) is used to evaluate the merits of a long-term renewable resource contract.

Resource Analysis

Resource Effectiveness

Energy

Run of the river hydro is an intermittent uncontrollable resource. BED can minimize its risk of receiving an undetermined quantity of energy by choosing to contract for either a firm or unit contingent PPA with a hydro generator. Additionally, hydro units with storage capability can be excellent providers of capacity under present market rules due to their ability to move the output to different times of the day.

Capacity

Hydro contracts can be crafted to include capacity in addition to energy, however, like other intermittent resources; run of the river hydro is not a strong capacity resource, while hydro with ponding can be.

Renewability

Run of the river hydro is a Tier 1 renewable resource. Additionally, depending on the particular hydro resource, the unit(s) could produce higher value RECs that can be sold by BED (as is the case with the Winooski One facility).

Resource Access

Availability

There are many existing hydroelectric generators of varying sizes and classes throughout Vermont and the ISO-NE region. BED has entered contracts for hydropower in the past and believes hydro contracts continue to be available as a supply resource at least for the near future.

Ownership

This option is intended to evaluate a contract, not ownership.

Resource Cost

Initial Cost

Not applicable.

Ongoing Cost

For the purposes of this analysis, BED assumes the contract price for hydro energy would reflect market costs.

Consistent with BED Goals

From a renewability standpoint, a contract for existing hydro energy is consistent with BED's goals. If the unit is within close proximity to Burlington or within Vermont, such a contract could also be consistent with BED's desire to increase its reliance on local resources.

Resource Risk

Because this resource analysis is limited to additional PPAs for hydropower, it is possible to avoid some of the normal renewable resource intermittency issues by entering into a firm delivery contract. Nonetheless, even with a firm contract, some risk of non-performance remains, which would expose BED to wholesale market energy prices. A defaulting counter-party would be liable for liquidated damages intended to make BED whole (covering any resulting increased energy costs), but there is a risk that a counter-party would not be in a financial position to pay the liquidated damages.

Resource Conclusion

A contract for hydro would allow BED to efficiently match its energy supply resources to its needs. Hydro can also provide capacity supply, although it is quite minimal relative to the energy supplied in run-of-the-river units. Conversely, capacity value can be quite substantial for units with significant ponding capability. In addition, BED's recent hydro purchases have involved multiple assets delivering under one contract. The energy purchased through an additional hydro contract, provided it includes the related RECs, would qualify under Tier 1. Given the number of hydro units throughout Vermont and the ISO-NE area, BED believes hydro is a resource with ample availability. Assuming contract prices are similar to the wholesale cost of energy, a contract for hydropower would be cost-competitive with other renewable supply options.

Long-Term Non-Renewable Contract

Resource Description

For the purposes of this analysis, a nuclear facility was used to evaluate a long-term contract for a non-renewable resource.

Resource Analysis

Resource Effectiveness

Energy

Nuclear generators provide constant baseload energy and are regarded as strong energy producers with a capacity factor in the 80-90% range. Nuclear generators in New England are not well-suited to provide the fast start and flexible output to balance supply changes related to intermittent resources.

Capacity

Due to their reliable nature and consistent output, nuclear generators are strong capacity supply resources.

Renewability

While a nuclear generator does not produce measurable air emissions, its use of non-renewable uranium classifies it as non-renewable resource. If BED wished to retain its 100% renewability, it would need to purchase RECs to cover the purchased non-renewable energy.

Resource Access

Availability

The number of nuclear generators in the ISO-NE region and the share of regional energy supplied by them has been in decline for several years and is expected to continue to decline.

Ownership

This option is intended to consider a contract for energy, not resource ownership because of BED's net zero goals.

Resource Cost

Initial Cost

Under a contract, BED would not be directly responsible for initial capital costs. Nonetheless, nuclear has high initial costs and risks which are frequently reflected in contract terms due to their magnitude .

Ongoing Cost

Similar to long-term renewable options, it is likely that BED's costs would be based on market prices rather than a unit's specific economics.

Consistent with BED Goals

Due to its non-renewable classification, nuclear power is not consistent with BED's renewability and NZE goals.

Resource Risk

If natural gas prices remain at historically low levels, natural gas generators are expected to continue to out-compete nuclear generators in the wholesale energy markets.[26] Thus, nuclear power would expose BED to additional cost risks that could result in upward rate pressure.

Resource Conclusion

As more economically feasible natural gas generation and wind resources are on the rise in the ISO-NE region, nuclear power is on the decline, as two major plants were retired in recent years. While BED could benefit from having access to additional consistent energy and capacity supply, such supply from a nuclear facility would be inconsistent with BED's strategic direction.

Overall Conclusion

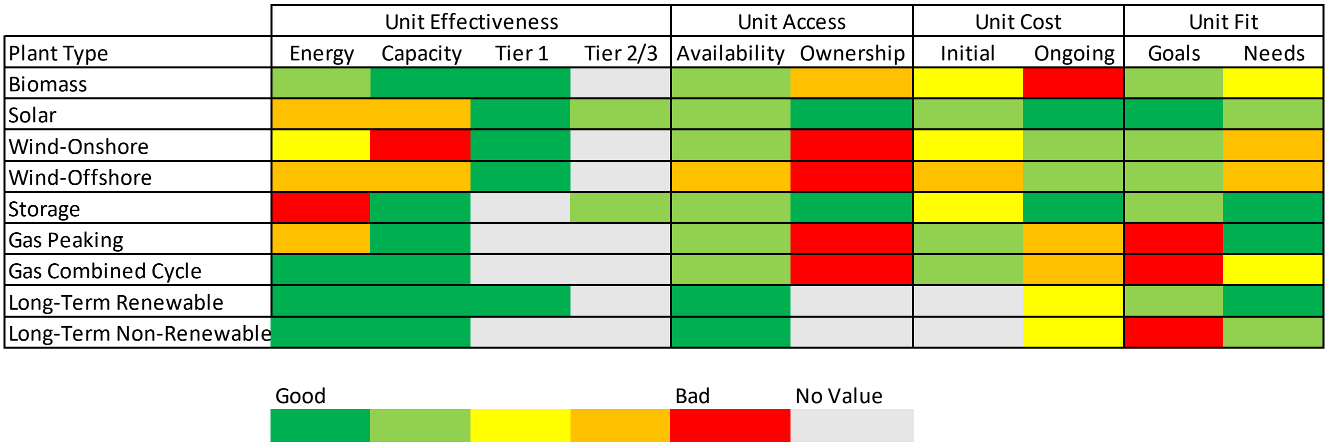
BED currently has a sufficient quantity of energy supply to reliably serve its customers in accordance with 30 V.S.A. §218c. Indeed, BED maintains ownership and/or control over resources that can supply all its energy requirements through 2024. However, because BED's energy comes from renewable resources, BED is substantially short on capacity. This shortfall or capacity gap is a function of ISO-NE's reliability protocols which significantly de-rate resources that are intermittent, such as wind, solar (if ISO-NE recognized) and run-of-river hydro dams.

BED is highly dependent on the continued operation of the McNeil biomass plant to maintain BED's status as a 100% renewably-sourced energy provider. However, the economic viability of the McNeil plant has faced challenges in recent years with the fall in wholesale market energy prices. Furthermore, the plant will likely need additional capital investments to maintain its reliability. As noted elsewhere, BED is researching its options to improve the economic viability of the McNeil plant such as seeking to construct a district energy system using the waste heat from the plant. If a district energy system were to be fully implemented, the efficiency and economic value of the McNeil plant would be enhanced. On the other hand, if McNeil were to be retired, BED would need to acquire cost-effective replacement energy and capacity, which may not be readily available in the short-term.

[26] "2020 Regional Electricity Outlook," page 9, ISO-New England, February 2020.

To summarize the costs and benefits of various resources, BED performed a comparative analysis shown below. Those resources with green shaded boxes have been identified as creating the most benefits in terms of their effectiveness, accessibility, and costs.

Table 3.5: Resource Comparisons



Unit effectiveness is shown as function of capacity factor for energy, market capacity received for the resource as a percentage of the facility's nameplate capacity for Capacity, and whether the resource is eligible for each of the RES tiers under the Tier 1 and Tier 2/3 columns. Unit access is shown based on this chapter's analysis regarding availability and ownership. Unit cost is based on the initial and ongoing costs assumed in each analysis on a per kW basis. Unit fit is based on the description of how the resource would or would not meet BED's needs and goals as described in this chapter.

Chapter 4 – Transmission & Distribution

BED recognizes there is an ongoing shift in the fundamental aspects of power supply and delivery. The one-way energy flow from large scale generation via high voltage transmission lines to local distribution systems that has dominated grid structure for decades is becoming increasingly bi-directional and dynamic. With the growth of distributed generation ("DG") and net metering, the traditional customer role as an energy user is expanding to include being an energy generator and potentially a supplier of other ancillary grid services. Just as the customer role is evolving, so too must utilities and their transmission and distribution ("T&D") systems.

The sections below describe BED's ongoing efforts to provide reliable T&D services as well as future projects that will ensure BED is prepared for the challenges and opportunities of grid modernization.

Transmission and Distribution Description

BED is connected to Green Mountain Power ("GMP") through the 34.5 kV bus tie breaker at the McNeil Plant Substation and to the rest of Vermont through Vermont Electric Power Company ("VELCO") at the East Avenue and Queen City Substations. The East Avenue 13.8 kV switchgear is supplied by VELCO's 115/13.8 kV T1 transformers rated 30/40/50 MVA and T2 transformer rated 30/40/56 MVA. The Queen City 13.8 kV switchgear is supplied by a VELCO 115/13.8 kV, 33.6/44.8/56 MVA transformer. The McNeil 13.8 kV switchgear is supplied by a BED 34.5/13.8 kV, 20/26.7/33.3 MVA transformer. The VELCO transmission system connects all of the utilities in Vermont to each other and also has interconnections with New York, Quebec, Massachusetts and New Hampshire.

BED's sub-transmission system includes approximately 1.5 miles of 34.5 kV line from the East Avenue Substation to the McNeil Plant Substation. This line is jointly owned by BED (40 MVA) and GMP (20 MVA). The line is connected to the VELCO transmission grid at the East Avenue Substation by VELCO's 115/34.5 kV, 33.6/44.8/56 MVA transformer and to GMP's 34.5 kV system by the 34.5 kV tie bus breaker at the McNeil Plant Substation.

BED's distribution system throughout the City is comprised of sixteen 13.8 kV circuits with approximately 135 miles of 13.8 kV lines and 0.8 mile of 4.16 kV distribution taps. BED also owns the 0.9 miles 12.47 kV distribution circuit that serves the Burlington International Airport ("the Airport"). The distribution system is approximately 47% underground and 53% aerial.

BED has 25 MW of on-system generation at the Burlington Gas Turbine and 7.4 MW at the Winooski One Hydro Plant that are connected to the 13.8 kV system. BED also operates, and is 50% owner of, the McNeil Generating Station. McNeil is on the GMP system, but it is connected to the BED system through the GMP 34.5 kV bus at the McNeil Plant Substation.

BED's distribution system annual peak load for year 2019 was 60.40 MW. The substation transformer and generator ratings and coincident peak demands are provided in the table below:

	Rating	**Peak Load**
East Avenue Bus #3 T1 Transformer	50 MW	15.35 MW
East Avenue Bus #4 T2 Transformer	56 MW	8.79 MW
Queen City Transformer	56 MW	21.53 MW
McNeil Transformer	33.3 MW	12.79 MW
Burlington International Airport	-	0.66 MW
	Rating	**Peak Generation**
Lake Street Gas Turbine	24.8 MW	0.00 MW
Winooski 1 Hydro	7.2 MW	1.28 MW

Transmission & Distribution System Planning & Standards

BED's distribution system is operated as an open primary network. This is a system of interconnected primary circuits with normally open switches at the interconnection points. When problems arise on the circuit, back-up is provided to as many customers as possible by other circuits by changing the normally open and closed points on the system. Switching is performed by BED's Supervisory Control and Data Acquisition (SCADA) system or by manual switching when necessary.

The East Avenue, Queen City and McNeil Substation transformer load tap changers ("LTCs") are set to hold voltage at the peak hour between 122.1 V and 124.6 V (set point of 123.4 V and bandwidth of 2.5 V on a 120 V basis) at the substation 13.8 kV bus. The voltage delivered to BED's customers meets ANSI C84.1-2011 Range A during normal operation and ANSI Standard C84.1-2011 Range B during contingencies. The substation transformer LTC voltage settings allow for ISO New England Operating Procedure No. 13 ("ISO OP-13") Standards for 5% Voltage Reduction, primary voltage drop, and 6 volts of secondary voltage drop (distribution transformer, secondary cable and service wire).

Most of BED's trunk lines are rated 600 amps. This is to allow for the switching of loads between circuits, even at the system peak. The loading on the 600 amps main trunk lines is typically kept below 9 MVA during normal operation. This is to allow for the isolation of a fault to a small section of a circuit and switching the remaining sections to adjacent circuits.

The power factor is measured and monitored by SCADA at the substation breakers for the substation transformer and each circuit, and at reclosers and switches along the circuits. BED maintains a 0.98 power factor or higher on its distribution circuits to comply with VELCO power factor requirements and to keep the circuit voltage from dropping below an acceptable level during normal conditions and contingencies. This is implemented by switched and fixed capacitor banks and close monitoring of the VAR load on each circuit.

BED standard wire sizes are as follow:

- Aerial Primary Circuits: #2 Aluminum, 1/0 Aluminum, 4/0 Aluminum, 336 kcmil AAC and 556 kcmil AAC;
- Aerial Secondary Circuits: #2 Aluminum, 1/0 Aluminum, 4/0 Aluminum and 336 kcmil AAC.
- Underground Primary Circuits: #2 Aluminum, 1/0 Aluminum, 350 kcmil Copper, and 1,000 kcmil Copper;
- Underground Secondary Circuits: #2 Aluminum, 1/0 Aluminum, 2/0 Aluminum, 4/0 Aluminum, 350 kcmil Aluminum, and 500 kcmil Aluminum.

BED standard transformer sizes are as follow:

- Pole mounted transformers: 15 kVA, 25 kVA, 37.5 kVA, 50 kVA, 75 kVA, 100 kVA, and 167 kVA;
- Pad mounted single phase transformers: 15 kVA, 25 kVA, 37.5 kVA, 50 kVA, 75 kVA, 100 kVA, and 167 kVA
- Pad mounted three phase transformers: 75 kVA, 112.5 kVA, 150 kVA, 225 kVA, 300 kVA, 500 kVA, 750 kVA, 1,000 kVA, and 1,500 kVA;
- Submersible transformers: 15 kVA, 25 kVA, 37.5 kVA, 50 kVA, 75 kVA, 100 kVA, 167 kVA, 250 kVA and 333 kVA;

Distribution system planning studies are performed to improve system efficiencies and identify the least-cost options to meet future load requirements in a safe and reliable manner. Distribution system planning is performed consistent with the distributed utility planning principles, and planning process under Vermont PUC Docket 7081. In addition to energy efficiency and DG, BED will also be looking at the potential use of battery storage to avoid future T&D upgrades. Distribution system studies are performed when the city peak load forecast, actual city peak, or an individual circuit experiences significant load change. In 2018, BED performed a planning study to evaluate the ability of BED's distribution system to serve future University of Vermont ("UVM") load additions.

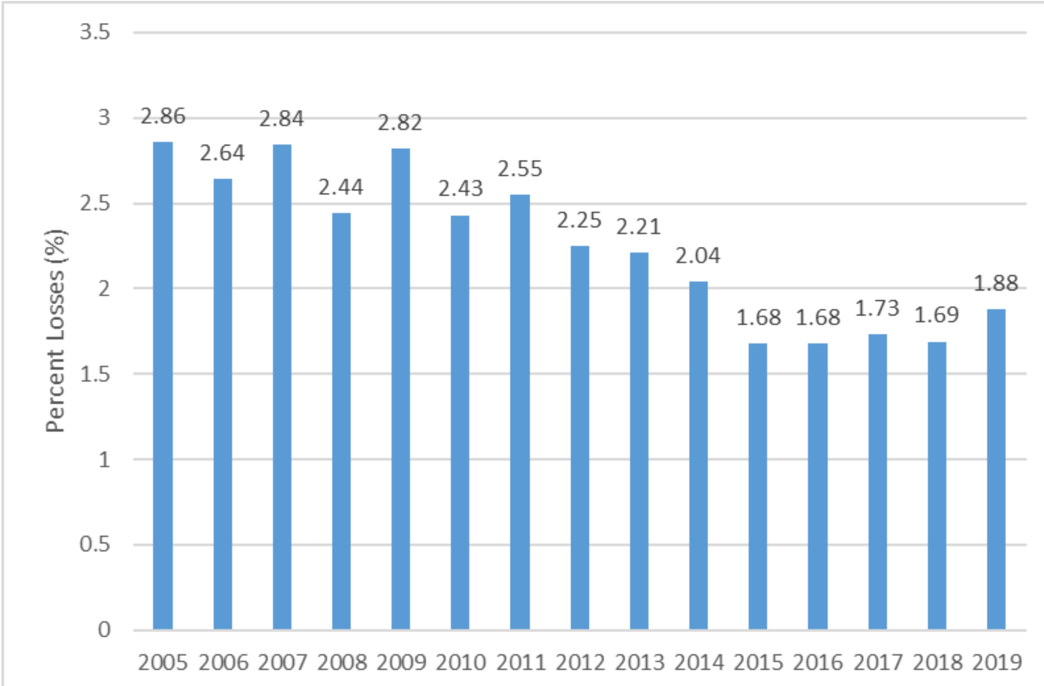
BED performs feasibility and system impact studies to identify the impact of proposed DG on the distribution circuits. The impact studies evaluate the impact of DG on the distribution system at the city peak load hour and also during light load condition and maximum generations under normal system configuration and contingencies.

BED uses CYMDIST software for distribution system analysis, efficiency studies, impact studies and planning studies. The distribution system simulation model is presently updated manually with efficiency gains from CYME Gateway software to convert data from a geographical information system ("GIS") to CYMDIST model. In FY2019, BED completed the integration of CYMDIST with the GIS system to automatically extract distribution circuits and system information from the GIS to the CYMDIST simulation model. This has increased the accuracy of the simulation model and improved staff efficiency by eliminating manual entry of data from one system to another.

Distribution System Efficiency Measures

The movement of power through the distribution system incurs electrical losses due to the resistance of the equipment to the flow of electricity. System losses increase the amount of electricity required to supply the customers' needs. BED has several programs in place and routinely performs analysis to improve system efficiency using methods that are both cost-effective and technically feasible. As a result of BED's system efficiency efforts, BED's total distribution system losses dropped from 2.86 % in 2005 to approximately 1.88% in 2019. Figure 1-0 shows BED's historical distribution system losses.

Figure 1-0: System Losses



Distribution system efficiency measures are evaluated on each circuit and cost-effective measures are implemented. The following efficiency measures are evaluated by BED:

- Optimal locations of capacitor banks;
- Distribution system configuration;
- Phase balancing;
- Single phase to three-phase conversion;
- Increasing distribution voltage level;
- Creating new 13.8 kV distribution circuits;
- Re-conductoring of lines with lower loss conductors;
- Equipment acquisition procedure;
- Transformer/load matching;

Optimal Locations of Capacitor Banks

Capacitor Banks are installed on BED's distribution circuits to reduce the VAR flows, reduce losses and improve voltage. BED maintains a 0.98 power factor or higher on its distribution circuits to comply with the VELCO power factor requirements, reduce losses, improve voltage and be able to serve load with acceptable voltage during contingencies.

Fixed or switched capacitor banks are installed on the distribution circuits. The switched capacitor banks are controlled through the SCADA system, and a few in the field are controlled via stand-alone voltage or VAR controllers. BED's operator remotely opens and closes capacitor banks based on the voltage requirements or circuit breaker preset VAR alarm values to maintain a circuit power factor close to unity.

The optimal locations of existing and new capacitor banks on each circuit are determined using CYMDIST software to minimize losses or improve voltage.

In 2018, BED performed a capacitor bank study to determine the optimal locations for the existing capacitor banks on its distribution circuit. The results of this study showed that the relocation of the existing capacitor banks to new optimal locations is not cost-effective in a 25-year societal-cost analysis.1 (BED depreciates its distribution capacitor banks on a straight-line basis over a 25-year service life).

<u>Distribution Circuit Configuration</u>

Distribution system configurations are evaluated when the City peaks or an individual circuit experiences significant load change. In 2018, BED evaluated balancing the load between 1L1 and 1L4, 2L4 and 3L1, 3L4 and 3L5, 1L2 and 2L5 circuits to optimize losses and improve reliability. The results of this study show that balancing load between the circuit groupings above reduces system peak losses by 31.43 kW and is cost-effective in a 33-year societal-cost analysis(BED depreciates its distribution cables on a straight-line basis over a 33-year service life). One system re-configuration case was implemented in FY2020. Two cases have been re-evaluated due to un-anticipated costs identified after this analysis and are no longer cost effective. The remaining two cases are scheduled for completion in FY2021.

<u>Phase Balancing</u>

Balancing the phase loading on the distribution circuits will decrease line losses and improve line voltages and backup capability. On an annual basis, BED evaluates the loads among the phases at summer peak on each circuit and corrective actions are taken and implemented based on the results of this evaluation. BED evaluates the phase balancing at the substation switchgear breakers for each distribution circuit and going forward at the reclosers and switches located on the distribution circuits.

With BED's distribution system losses of approximately 1.88%, balancing the phases on the distribution circuits is typically done to improve the voltage for normal system operation and during contingencies.

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1 BED depreciates its distribution capacitor banks on a straight-line basis over a 25-year service life.

In 2018, BED evaluated balancing of phases on its distribution system to optimize losses, improve line voltages, and backup capability. The results of this study show that transferring load on Henry Street and Wilson Street from phase C to phase A reduces system peak losses by 2.5 kW and is cost effective in a 33-year societal-cost analysis.[2] This phase balancing was implemented in FY2021.

Single-Phase to Three-Phase Conversion

Single-phase to three-phase conversions are evaluated when the City peak or an individual circuit experience significant load change. Upgrading a line from single-phase to three-phase construction results in line loss reduction. However, the conversion of BED's circuits from single-phase to three-phase construction has not been cost-effective because the potential loss savings from this conversion is low[3] in comparison with high cost of rebuilding BED's aerial and underground circuits.

Such costs may include traffic control during the construction of aerial projects and a $25 per square foot City administrative and excavation fee for placing BED's lines underground within a paved portion of a City street

In 2018, BED evaluated upgrading the highest loaded distribution circuit sections from single to three-phase construction. The results of this study showed that upgrading a section of BED's lines on Canfield Street, part of the 1L2 circuit, from single-phase to three-phase construction reduces system peak losses by 2.3 kW and is cost-effective in a 33-year societal-cost analysis.[4] This upgrade was implemented in FY2020.

Increasing Distribution Voltage Level

As of 2018, approximately 0.9 miles of 4.16 kV taps remained in the City and were fed from stepdown distribution transformers. The 4.16 kV taps are located at Appletree Point, Sunset Cliff and Pearl Street. BED has been working closely with its customers to complete the conversion of these taps to 13.8 kV in the next five years. This conversion plan is contingent on BED obtaining easements from private property owners.

Creating New 13.8 kV Distribution Circuits

Constructing additional 13.8 kV circuits would reduce line losses by reducing the load on an existing feeder. However, creating new circuits on BED's system solely to lower line losses would not cost-effective because BED's distribution losses are extremely low, at approximately 1.88%, while the costs of large main trunk line wires and installing aerial and

2 BED depreciates its distribution cables on a straight line basis over a 33-year service life.
3 Losses on BED's distribution system are approximately 1.88%.
4 BED depreciates its distribution cables on a straight line basis over a 33-year service life.

underground circuits are high.

Re-Conductoring of Lines with Lower Loss Conductors

Upgrading the conductor size of a circuit will result in a lower line resistance and lowering the line resistance will reduce line losses. BED's trunk lines are oversized because BED's distribution system is designed to allow for the isolation of a fault to a small section of a circuit and switching the remaining sections of the circuit to alternate feeds.

In 2018, BED evaluated increasing the conductor size on sections of its distribution circuits. The results of this study showed that reconductoring existing lines was not cost effective in a 33-year societal-cost analysis.

Equipment Selection & Utilization

BED utilizes least-cost principles to select transformers and cables. The specific processes used for transformer and cable acquisitions are outlined below. Other major equipment such as aerial wires, breakers, reclosers, switches, and capacitors are purchased per BED standards, specifications and purchasing process.

a) Transformer Acquisition Procedure

   BED requests quotations for steel metal core and amorphous metal core distribution transformers from multiple suppliers. BED makes purchase decisions according to the standards set out in the Memorandum of Understanding between the Public Service Department and BED dated December 27, 2004 using a distribution transform acquisition program. The Memorandum requires consideration of the initial cost of the transformer, the economic value of the increase in capacity costs, energy costs, VELCO transmission costs, distribution costs and environmental externalities over 25 years[5].Based on these factors, BED then purchases transformers with the least societal costs.

b) Cable Acquisition Procedure

   BED uses a cable acquisition program to make purchase decisions based on 33-year societal-cost analysis. The analysis considers the initial cost of the cable and the economic value of the increase in capacity costs, energy costs, VELCO transmission costs and environmental externalities over 33 years (BED depreciates its cables on a straight-line basis over a 33-year service life).

Transformer/Load Matching

5 BED depreciates its distribution transformers on a straight-line basis over a 25-year service life.

New or replacement transformers installed on BED's system are purchased using BED’s transformer acquisition procedure and sized to match customer load. When BED replaces an existing transformer, a load study is first done to determine the correct size for the replacement transformer. For new transformers, BED sizes the transformers based on coincident peak load estimates from the customer, customer’s engineer or electrician, similar facilities’ loads in the City, and the expertise of BED’s engineers. The residential transformers are not sized to allow every customer connected to the transformer to add electric vehicle, heat pump, or other strategic electrification loads in the future. Depending on the total magnitude of the additional load from strategic electrification, the transformer may need to be replaced. By correctly matching the size of the transformer to the load being served and existing DG while also allowing for a margin of growth, transformer losses are reduced which improves the overall system efficiency.

Advanced Metering Infrastructure (“AMI”) provides BED with information about the energy consumed and demanded, , reactive power or power factor for each customer, along with voltage monitoring and power quality information. This information is stored in BED’s meter data management system (“MDMS”).

BED has implemented a transformer and service point auto updater feature in ArcGIS to integrate customer information with the transformer connecting that customer. This information is stored in the GIS. This information improves staff efficiency by reducing manual processes. Additionally, BED staff are able to easily create load reports on existing transformers and size future transformers using this AMI data. As part of BED’s current strategic information technology project, BED will implement grid analytics software to automatically create transformer load reports using the newly integrated GIS data. BED anticipates this phase of the project will be complete within three years.

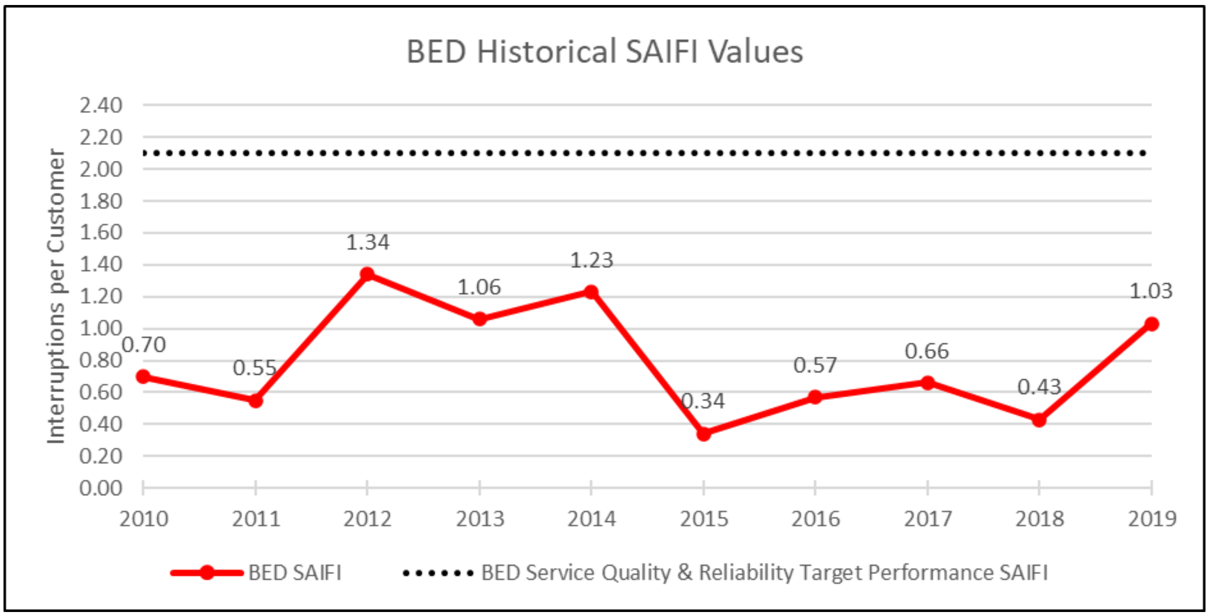
Reliability

BED is committed to supplying the highest system reliability and power quality to its customers that is economically feasible. Like other utilities, BED tracks power interruptions or outages. An interruption of power is considered an "outage" if it is a zero-voltage event exceeding five minutes. There are two types of outages, planned outages and unplanned outages. Planned outages are outages that are initiated and scheduled in advance by BED for purposes of construction, preventative maintenance or repair. Unplanned outages are outages due to unexpected and unscheduled events. BED’s distribution system reliability is measured by the System Average Interruption Frequency Index (“SAIFI”) and Customer Average Interruption Duration Index (“CAIDI”) pursuant to PUC Rule 4.900. These indices

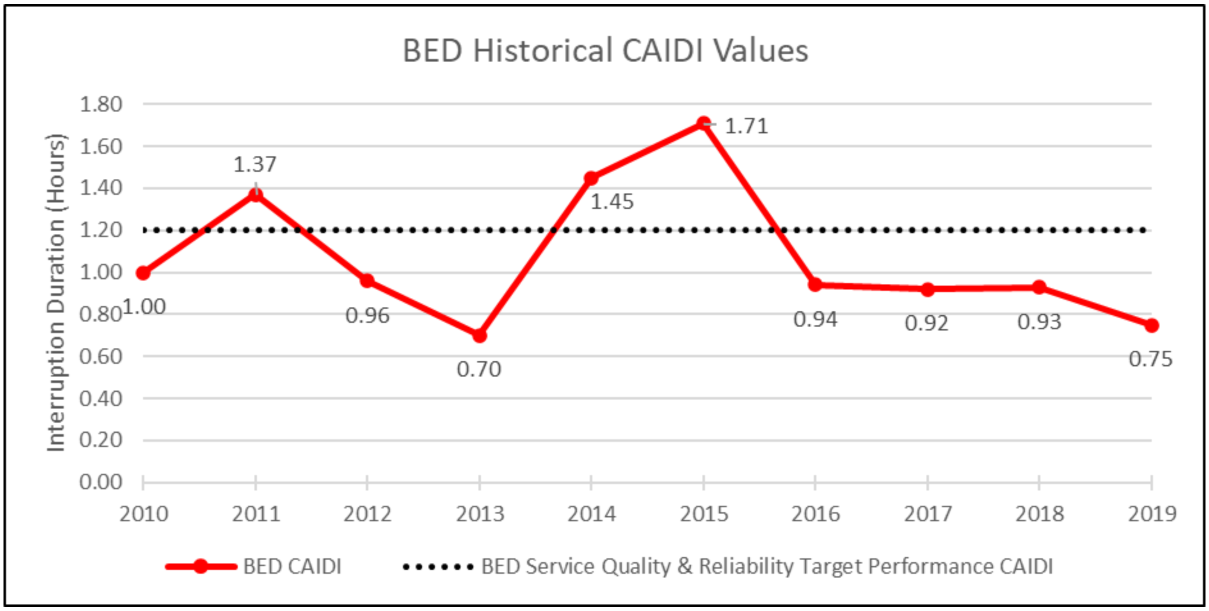
are also impacted by BED's planned outages and include major storms.
Every year, BED analyzes the outage information on its distribution circuits, identifies the worst performing distribution circuits, and updates its distribution action plan to improve the performance on these circuits.

BED's SAIFI for 2019 was 1.03 interruptions per customer, significantly better than the SAIFI service quality and reliability target performance of 2.1 interruptions per customer. BED's CAIDI for 2019 was 0.75 hours, well below the CAIDI target performance of 1.2 hours.

The following Figure 4-0.1 shows BED's historical SAIFI.



The following Figure 4-0.2 shows BED's historical CAIDI.



RELIABILITY IMPROVEMENT PROGRAMS

BED's distribution system is designed to allow for the isolation of a fault to a small section of a circuit and switching the remaining sections of the circuit to alternate feeds prior to making repairs. In addition, BED has several programs in place to ensure that system reliability and power quality remain as high as possible. The following are a few of these programs:

- Distribution System Operating Procedures
- Distribution System Protection
- Wildlife protectors
- Pole Inspection and Maintenance Plan
- Overhead Distribution Inspection and Maintenance Plan
- Underground Distribution Inspection and Maintenance Plan
- Tree wire
- Fault indicators
- Reclosers/SCADA-controlled switches
- Replacement of underground system
- 100- and 500-year flood plains
- Underground Damage Prevention Plan

<u>Distribution System Operating Procedures</u>
BED has created contingency plans for the loss of each 13.8 kV distribution circuit and 13.8 kV substation switchgear. These contingency plans are updated annually and used by BED's dispatch center during planned and unplanned outages to expedite restoring service

to impacted customers.

Distribution System Protection

Adequate distribution system protection is required to avoid and/or minimize hazards to the public and BED's line workers, to prevent damage to electric utility infrastructure, to reduce the number of customers impacted by outages and to allow for prompt power restoration. Any time a protective device is installed on a circuit, BED performs a protection study to ensure coordination between the new and existing devices on the circuit.

BED has the following protective equipment installed on the distribution and sub-transmission System:

- Circuit breakers are installed at each end of the 34.5 kV sub-transmission line.
- Distribution circuit breakers are installed in each of BED's three substations. These are the primary distribution circuit protection and quickly de-energize an entire circuit to protect the substation transformer from damage.
- Reclosers are similar to circuit breakers but are used as secondary protection mainly on aerial distribution circuits and to tie circuits together.
- Underground distribution switches with protective breakers are similar to circuit breakers but are used as secondary protection on underground distribution circuits and also to tie circuits together.
- Distribution line fuses isolate permanent faults to minimize the size and number of customer outages
- Transformer fuses protect distribution transformers and secondary lines serving individuals or groups of customers.
- Current-limiting fuses are installed on distribution taps and aerial transformers. These fuses limit the energy released during a short circuit event and protect the associated equipment from failing.
- Over-voltage arresters are used for protection of all aerial transformers, capacitors, normally open switches, normal open points, and at each end of primary underground circuits.

BED's specific sub-transmission protection strategies include:

- The primary forms of protection for the 34.5 kV line are relays with a high-speed line differential scheme on both ends of the line. Relays communicate with each other via fiber, quickly determine if a fault is within its zone of protection and open the breakers.
- Overcurrent and step-distance relay functions are utilized for backup protection in

case the fiber link between the relays is lost.

BED's specific distribution protection strategies include:

- The loading on each circuit is typically kept below 65% of the circuit's steady state summer current carrying capability during normal operation and below 80% of relay pickup setting at all operating conditions. This strategy establishes adequate cold load pickup capability and allows for the switching of loads between circuits.
- Overcurrent protection includes coordination of circuit breakers, reclosers and fuses. Overcurrent protection is designed to maximize load current, allow for cold load pickup and feeder backup configurations and maintain sensitivity required to keep the system protected from bolted faults.
- BED utilizes the so called "fuse saving" protection method on all of its overhead circuits. This method allows for breakers or reclosers to operate faster than a fuse attempting to clear the fault without causing a long duration permanent outage. The same breaker or recloser recloses after approximately eight seconds, attempting to restore the power to the circuit. In the case of a transient fault (e.g. a squirrel, bird, tree branch, etc.), the fault is cleared at this point and power is restored to all customers. In the case of a permanent fault, the fault is still present and is cleared by the nearest upstream fuse. This method is not used on predominantly underground circuits.
- Most of BED overhead circuits utilize multiple recloser schemes which improve the capability of minimizing outages and back-feeding circuits. Similarly, all BED underground circuits utilize multiple underground switches for the same purpose.
- All BED distribution breakers utilize synchronism check function, eliminating the potential of connecting non-compatible sources and causing a significant outage.
- All new designs for underground systems use protective and/or switching devices at taps from the main line circuit.
- Short circuit analysis is completed using CYMDIST modeling software. This analysis is done to simulate BED protection schemes as discussed above. The results of this study help to confirm fuse sizing and protective device settings.
- Short circuit data is also utilized when analyzing arc flash hazards on the primary distribution system. CYMDIST uses the detailed distribution model to calculate the available arc flash energy at every primary voltage point on the distribution system. This enables BED to coordinate the ratings of safety equipment and personal protective equipment ("PPE") used by line crews.

In year 2018, BED and VELCO completed the installation of phase reactors at the East Avenue and Queen City transformers to reduce the line to ground and three-phase fault current levels on BED’s distribution system. BED then completed a comprehensive protection coordination study of its entire distribution system. As a result of this study, BED is in the process of implementing new protection settings for its breakers and reclosers. This project is expected to be completed by the end of FY2021.

Wildlife Protectors

BED construction standards include the installation of wildlife protectors on all new exposed transformer, capacitor and circuit breaker bushings and arresters. In addition, BED has started the installation of static guard protectors on reclosers, switches and disconnects. Most of the unplanned outages on BED’s distribution system in year 2015 were caused by animal contact. As a result of the new construction standards indicated above, BED’s animal-caused outages decreased from 33 in 2015 to 18 in 2018. .. As of 2019, BED has completed a survey and wildlife protection installations of all distribution circuits.

Pole Inspection and Maintenance Plan

The purpose of BED’s Pole Inspection and Maintenance Plan is to identify poles that are damaged or showing signs of decay in order to take corrective action before the poles fail. BED’s pole inspection plan requires inspection of all wooden distribution and streetlight poles every seven years and tests the poles that are over ten years old. Poles are evaluated and inspected for cracks, split and rot and then tested using industry standard testing practices. All poles that fail the inspection and testing will be labeled as condemned poles and will be replaced.

Overhead Distribution Inspection and Maintenance Plan

The purpose of BED’s overhead distribution inspection and maintenance plan is to routinely inspect and maintain the overhead distribution system. BED’s overhead inspection plan requires inspection of all overhead utility structures every five years. Structures and all BED attached equipment are visually inspected for signs of wear, damage, missing components and any non-equipment issues such as close proximity to trees. BED maintains records of all inspection cycles. Any repairs associated with these inspections are prioritized and scheduled.

Underground Distribution Inspection and Maintenance Plan

The purpose of the Underground Distribution Inspection and Maintenance Plan is to routinely inspect and maintain the underground distribution system. BED’s underground inspection plan requires inspection of all underground utility installations every ten years. This plan proactively identifies and corrects any problems related to underground utility holes or the equipment within them.

Tree Wire

BED uses covered (tree) aerial wire where appropriate to limit the number of faults caused by tree contact.

Fault Indicators

BED installs fault indicators on the aerial and underground distribution circuits to assist the field crews in locating fault locations. The fault indicators are installed at major junctions to allow the crews to identify the direction of the fault.

Reclosers/SCADA Controlled Switches

Reclosers improve the reliability of electrical service for customers who are located upstream of faults by protecting them from downstream faults. The reclosers do so by automatically detecting faults and opening to isolate faulted sections of circuits, thus reducing the number of customers that experience an outage. Reclosers can also be remotely opened and closed by dispatchers to reconfigure the distribution system to quickly restore customers and isolate faulted sections of circuits. Similarly, SCADA-controlled switches allow dispatchers to remotely open and close switches to reconfigure the distribution system. . BED has installed aerial reclosers and SCADA-controlled switches on its main distribution circuits, normal open tie points and on long lateral taps.

To further improve reliability and expedite service restoration, BED plans to replace the following equipment with reclosers and smart switches:

- Replace disconnect 346D with a smart switch;
- Replace manual switches, 227S, 407S, and 917S with smart switches;
- Replace reclosers 112R, 234R, and 252R with SCADA-controlled reclosers.

Replacement of Underground System

Approximately 47% of BED's distribution system is underground. Although underground circuits experience fewer outages than aerial circuits, underground circuits are more difficult to repair which results in outages of longer durations. Aerial circuits are inherently easier to troubleshoot and repair due to their visibility and relative ease of access, whereas underground circuits are not readily visible and often require work in confined spaces such as vaults and utility holes. In addition, some of BED's underground circuits are direct buried. The loss of a direct buried underground circuit will result in long customer outages due to the need for excavation to locate and repair faulted cables (cables in conduit can usually be replaced without the need for excavation). BED's capital construction plan calls for the replacement of underground circuits based on first-hand knowledge of specific problems, age of cable, existing installation (direct buried, availability of spare conduits), type of load, engineering judgment, coordination with Department of Public Works ("DPW") pavement plan or City or State road rebuild projects, and budget constraints. BED's underground circuit replacement work throughout the City will reduce the length of unplanned outages, improve operating efficiencies and coordinate with the City of Burlington's Street Pavement Plan. on

Over the next five years, BED plans to rebuild the old underground system at Farrell Apartments, UVM Living and Learning, UVM Aiken Center, Juniper Terrace, Harbor Watch, and the Airport.

<u>100- and 500-Year Flood Plains</u>

BED's McNeil, East Avenue and Queen City Substations are not within FEMA designated flood hazard areas. This conclusion is based on BED's review of the Vermont Agency of Natural Resources ("ANR") Atlas program using the FEMA flood layers for reference.

<u>Underground Damage Prevention Plan</u>

BED has an underground damage prevention plan that complies with PUC Rule 3.800 and 30 V.S.A. Chapter 86. The plan outlines the State requirements for BED to locate its underground facilities using its underground cable locators upon receiving notification from Dig Safe Systems, Inc. The plan also requires BED to closely monitor its own excavation efforts and manage our damaged infrastructure repairs with an emphasis on employee/public safety and service restoration.

Volt/VAR Optimization

The voltage and VAR flow on BED's distribution system are controlled by the substation transformer LTC controllers, and fixed and switched capacitor banks on the distribution circuits.

The East Avenue and Queen City Substation transformer LTC controllers are owned and maintained by VELCO while the McNeil Substation transformer LTC controller is owned and maintained by BED. The East Avenue, Queen City and McNeil Substation LTCs are set to hold voltage at the peak hour between 122.1V and 124.6V (set point of 123.4V and bandwidth of 2.5V on a 120V basis) at the substation 13.8 kV bus. The voltage at the substation transformer LTC is set as low as possible for the summer peak hour while still providing all the customers on each circuit with ANSI C84.1-2011 Range A voltage during normal operation and ANSI Standard C84.1-2011 Range B during contingencies and meeting ISO OP-13 Standards for 5% Voltage Reduction.

The substation transformer LTCs regulate the 13.8 kV bus voltage for all circuits connected to the substation at the 13.8 kV bus. As a result, all the distribution circuits fed from the substation transformer have the same voltage set point. BED does not use the Line Drop Compensation ("LDC") for voltage regulation because the transformer LTC regulates the 13.8 kV bus voltage of two large generators (Winooski 1 Hydro and Lake Street Gas Turbine) which are connected directly to BED's distribution circuits. The distribution system is operated in a network configuration when the gas turbine is running.

As discussed in the Optimal Locations of Capacitor Banks section, BED remotely controls the capacitor banks. The SCADA system monitors each circuit's VAR flow and will send an alarm to the system operator when the VAR flow is outside of the set points. One or more capacitors are then either turned on or off to return the VAR flow to within the limits. Two of the three large pad-mounted capacitor banks on the distribution system are controlled by SCADA and also by stand-alone voltage controllers. BED has installed stand-alone capacitor bank control units on all aerial SCADA controlled capacitor banks and has connected them to the fiber system. These controllers operate independently on each circuit to control the VAR and voltage.

In 2019, BED and VELCO completed the replacement of the existing transformer LTC controllers at Queen City and East Avenue Substations to allow for multiple voltage set points and a 5% voltage reduction. The new LTC controllers allow BED to operate the distribution system at a lower voltage setting during certain months of the year taking into consideration ISO OP-13 Standards for 5% voltage reduction. Monitoring of the AMI system voltage information will allow for the LTC parameters to be optimally set and provide feedback to BED to assure the voltage stays within required parameters.

With expanded control of the LTCs and monitoring and control of the distribution capacitors, BED can improve the optimization of the system voltage and VAR flow on each circuit.

Grid Modernization/Distributed Generation/Strategic Electrification

BED's 2019 business-as-usual base case 90/10 peak load forecast assumed low increase in installation of electric vehicle chargers and heat pumps which resulted in minimal distribution system load increases. While this minimal load addition may not impact BED's distribution system main trunk lines, it may create line overloads if the load additions are concentrated on a small radial tap. In addition, depending on the number of electric vehicles/chargers and heat pumps being connected to an existing transformer, the total load added may result in an overload on the distribution transformer, secondary wire, and/or service wire and require the replacement of the overloaded equipment. BED's AMI system, in conjunction with the planned grid analytics software, plays a major role in identifying transformers and secondary/service wires that may be impacted by load increases from installation of new electric vehicle chargers and heat pumps.

The distributed renewable generation on BED's system has not yet created reverse power flow issues for BED's distribution system. However, as additional electrification measures are installed and net-metering facilities constructed, depending on the type of connection, the size of the equipment being installed and the total generation on BED's circuits, one or more studies (feasibility, impact, stability, facility) may be required to identify and remedy potential problems with reverse power flow. BED has developed Distributed Generation Interconnection Guidelines that are posted on BED's website, and a solar map to show the DG on each circuit and provide a preliminary screening tool to assess BED's circuit capacity for accepting new distributed renewable generation projects.

NET-ZERO ENERGY PLANS

See the separate chapter on Net Zero for information on distribution impacts when Net Zero activities increase BED's system peak above its current limits (essentially modelling what will be required to serve a load in excess of 80 MW, but not to exceed 102.8 MW). Work expanding this analysis to encompass the load impacts above the 102.8 MW level (i.e. to the potential loads resulting from "full" electrification) is underway.

ADDITIONAL GRID MODERNIZATION

To support a potential future increase in the rate of installations of electric vehicle chargers, battery storage and distributed renewable generation, BED will continue to further modernize its distribution system and internal software platforms. The following are BED's current initiatives to modernize the distribution system:

- GIS integration;

- Asset management system;
- Distributed generation resources;
- Outage management system;
- AMI integration; and
- Distribution automation

Geographic Information System

BED maintains a comprehensive, state-of-the-art GIS and that includes data on the primary distribution circuits, secondary system, service wires, transformers and DG facilities. In addition, customer service points are linked to distribution transformers, significantly simplifying the transformer loading evaluations. The GIS data is also used to track BED's assets, including the quantity and condition of all poles and equipment attached to the poles.

Distributed Generation Resources

BED has developed an online map of existing and proposed DG facilities on each circuit. , The map includes information on the size and type of each facility. Additionally, the map shows each circuit's capacity for interconnection of future DG facilities.

https://www.burlingtonelectric.com/distributed-generation

Through the CYME Gateway software mentioned above, BED is able to extract from the GIS and model every DG resource on its distribution system in the CYMDIST modeling software. This allows for more accurate system modeling and system impact analysis of future DG projects.

Outage Management System

BED maintains an automatic feed to the VTOutages website based on the outage notification capabilities of its Itron AMI meters. That feed went live in November of 2016.

It should be noted that this system is limited compared with a fully featured outage management or distribution management system; meaning, that BED's system is not able to include meters in the outage count where outages are not reported by the AMI system. This situation results from either a mesh network meter being out of communication during the outage ("islanded" without a communication path and thus unable to report), or from the customer having opted out of AMI metering. As a result, the reported information would likely represent a lower number of customers without power, with the relationship being dependent on the size of the outage. For example, if a single meter reports an outage, it is likely that is very close to the extent of the outage. However, if the full system were out, the reported count would be low by the number of non-AMI and "islanded" meters.

<u>AMI Integration</u>

BED has completed the deployment of its AMI meters across its entire service territory by replacing nearly all of the electric meters with AMI meters. The remaining meters on BED's system are 475 Automated Meter Reading (AMR) meters and 267 non-AMI/AMR meters. BED has established a link between meter accounts and the transformer supplying these accounts in the GIS. With this data link and access to the meter data management system MDMS BED engineering staff are able to create load reports for existing transformers and size future transformers as well as develop other reporting tools. This process will be automated with the implementation of the grid analytics software mentioned above.

<u>Distribution Automation</u>

BED's SCADA system allows BED to collect operational and planning data, and remotely control and operate key field devices such as breakers, reclosers, switches, capacitor banks, and transformer LTCs .The SCADA system increases customer satisfaction through reduced service interruptions, less customer down time and improved quality of supply.

BED has replaced all of its substation electromechanical relays with microprocessor-based relays. The protective devices associated with substation breakers, reclosers, and underground switches allow temporary faults to be removed from the system before automatically restoring normal service. In conjunction with fuses, the protective devices give BED the capability to limit permanent faults to the smallest possible number of customers. These devices have greatly increased BED's ability to isolate faults, clear temporary faults, reduce the number of customers impacted by outages and restore service more quickly to customers when outages do occur.
BED has installed reclosers on its aerial distribution circuits to isolate the faulted part of a circuit and improve reliability. These reclosers are also controlled by the SCADA operators.

BED has installed pad-mounted switches with means to automatically transfer critical customer load from a faulted circuit to a different circuit within seconds. In addition, BED has installed pad-mounted switches with protective relays on its underground distribution circuits to isolate the faulted part of a circuit and improve reliability. These switches are also controlled by the SCADA operators.

BED plans to install new and replace/upgrade existing aerial switches and disconnects with reclosers and SCADA-controlled switches as discussed in section 4.1.7. These devices will be able to provide real time information such as amps, kV, kW and kVAR.

BED has installed stand-alone capacitor bank voltage and VAR control units on all aerial SCADA-controlled capacitor banks. These controllers operate independently on each circuit to control the VAR and voltage. The controllers are also controlled by the SCADA operators.

BED also replaced the substation transformer LTCs controllers at Queen City and East Avenue Substations with new ones that allow for multiple voltage set points.

Additional steps toward distribution automation include investigating the deployment of a distribution management system (DMS) and integration with the AMI system as part of the strategic information technology project.

Emergency Preparedness and Response

BED participates in the statewide emergency preparation conference calls. Based on the available information from these calls, BED assesses the appropriate response to an anticipated event and responds appropriately. If additional crews are needed, there are sources available to BED. BED is a member of the Northeast Public Power Association's Mutual Aid program (NEPPA) and as a result has access to numerous municipal utility crews in the northeast. In addition, BED would reach out to GMP and/or Vermont Electric Cooperative ("VEC") to provide aid. In the event that BED's needs are not met through either the NEPPA Mutual Aid program, GMP or VEC, BED would utilize contract crews.

Currently VTOutages is updated automatically when outages occur and during system restorations as described in the Outage Management System section above.

BED currently contacts customers for planned outages using several forms of communication. Customers are contacted directly by using phone calls, emails, letters or the use of door hangers. Customers are contacted well in advance and reminders are sent before the date of the planned outage. In the event of unplanned outages, customers can contact BED during normal business hours for information. After hours calls will be answered either by BED dispatch office or an off-site answering service. Voice messages are used to let customers know that an outage is occurring and that crews are responding. BED also posts unplanned outage information to the BED website and various social media platforms.

Utilities Coordination

BED coordinates pole installations and construction of underground distribution projects with Comcast Corporation, Consolidated Communications Holdings, Inc. (formerly FairPoint Communication, Inc.), and Burlington Telecom. This coordination between utilities cuts costs through sharing of trenching costs, repaving, permit fees, etc. and also expedites the transfer from old installations to new ones.

In addition, BED coordinates its underground construction projects with DPW street paving plans to minimize the City excavation fees when trenching in the road.

Track Transfer of Utilities

BED uses the National Joint Utilities Notification System ("NJUNS") database to track transfer of utilities and dual pole removal.

Relocating Lines to Roadside

In the process of re-building BED's old aerial lines located behind private properties, BED evaluates the feasibility and cost of relocating these lines into the City right-of-way along the roadway and sidewalk areas. Typically, these relocations take many years to complete due to the scope of work, need for securing easements and cost for potentially placing the lines underground.[6]

Vegetation Management Program

The purpose of BED's Vegetation Management Program is to maximize employee and public safety and minimize power outages caused by tree contacts with BED distribution circuits.

BED has adopted a tree trimming program based on outage history, right-of-way requirements and constraints, as well as the associated rates of growth for the particular tree species indigenous to the City of Burlington.

BED has approximately 133 miles of aerial and underground distribution circuits that are divided into three maintenance sectors. Every three years a sector is given priority and our trimming efforts are concentrated in that area. In addition, BED augments its trimming cycle program by identifying specific areas of need through inspection patrols, outage reports, feedback from customers and BED employees, as well as other agencies such as the

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6 Placing BED's lines underground within a paved portion of a City street requires a City administrative and excavation fee of approximately $25 per square foot).

Burlington Parks and Recreation Department.

During our trimming cycles, BED's inspector and tree trimming contractors will document any danger trees outside the right-of-way. BED then works with the City's resident arborist and private property owners to remove these trees.

The City's resident arborist contributed the following information about the various species of trees and their associated growth rates. According to the City's arborist these same growth rates apply to pruned branches of healthy trees. The growth rates, however, do slow whenever the health of a tree is compromised.

Species	Growth Rate	Growth Rate After Pruning (assuming healthy tree)
Ash Species	Fast	Fast
Birch Species	Medium	Medium
Box Elder	Fast	Fast
Cedar, White	Medium	Medium
Cherry, Black	Medium	Medium
Cherry, Ornamental	Fast	Fast
Crabapple Species	Medium	Medium
Elm, Species	Fast	Fast
Hackberry	Medium/Fast	Medium/Fast
Honey locust	Fast	Fast
Hawthorn Species	Medium	Medium
Ginkgo	Slow	Slow
Linden, Species	Medium/Fast	Medium/Fast
Locust, Black	Medium/Fast	Medium/Fast
Maackia, Amur	Slow	Slow
Maple, Amur	Medium	Medium
Maple, Hedge	Slow	Slow
Maple, Norway	Fast	Fast
Maple, Red	Fast	Fast
Maple, Sugar	Medium	Medium
Maple, Tatarian	Slow/Medium	Slow/Medium
Oak, Red	Medium	Medium
Oak, White	Slow	Slow
Pine, White	Fast	Fast
Pear, Ornamental	Fast	Fast
Spruce, Species	Slow	Slow
Willow, Species	Fast	Fast

BED utilizes standard pruning, flat cutting and brush mowing techniques in its vegetative management program. BED has selected these types of vegetative management controls in an effort to minimize our environmental impact as well as comply with the City's ordinance which prohibits the use of chemical herbicides.

BED mainly employs the services of the Burlington Parks Department, qualified independent tree trimming contractors, and its own line workers to carry out its vegetation management program.

The "tree" outages in 2018 were approximately 5% of BED's total outages, the five-year average was 3.4% and the 10-year average was5.4%. BED's vegetation management plan has been successful in reducing the number of outages caused by "tree" contact. BED feels that we have achieved the appropriate ratio of spending to outcome and will continue to budget approximately one hundred thousand dollars per year for vegetation management.

BED maintains a vegetation management tracking database that identifies the employee overseeing the project, the circuit number, the date and location as well as the entity that performed the work.

The following table provides the total miles of BED's distribution system, miles needing trimming and trimming cycle:

	Total Miles		Miles Needing Trimming		Trimming Cycle	
Transmission						
Distribution	135		70.84		3-years	
	FY2017	FY2018	FY2019	FY2020	FY2021	FY2022
Amount Budgeted	$100,000	$105,000	$105,000	$110,000	$110,000	$110,000
Amount Spent	$95,640	$72,381	$105,000			
Miles Trimmed	23.8	22.26	26.4	20.33	24.11	26.4

Studies & Planning

LONG-RANGE PLANNING STUDY

In year 2018, BED performed a long-range planning study to evaluate the impact of UVM's proposed 3,700 kW peak load addition on the distribution system.7

7 UVM Future Load Spreadsheet document dated April 5, 2018.

The results of this study showed the need for an 1,800 kVAR capacitor bank at the proposed multipurpose recreational facility and the upgrade of two sections of primary underground 350 kcmil copper conductor. The cost estimate for these upgrades ($231,399) was provided to UVM as part of BED's review of distribution system impacts from the proposed facility.

List of Capital Distribution System Projects

a) The following is a list of BED's capital distribution system projects that were constructed between FY17 and FY20:
   - Capacitor bank control units
   - Convert GMP's line to BED's circuit
   - Great Streets – St. Paul Street rebuild
   - Install animal guards & replace cutouts on distribution circuits
   - Install animal guards at BED's McNeil Substation
   - Install conduits on St. Paul from Main Street to King Street
   - Install SCADA-controlled motor operator on switch 144S
   - Install SCADA-controlled motor operator on switch 316S
   - Install SCADA-controlled motor operator on switch 426S
   - Install SCADA-controlled motor operator on switch 343S
   - Install SCADA-controlled motor operator on switch 844S
   - Install new SCADA-controlled switch 905S
   - Rebuild 3L4 circuit from Austin Drive to Lakeside Avenue
   - Rebuild Ferguson/Richardson/Wells Street (Scheduled for FY20)
   - Rebuild Harrington Terrace
   - Rebuild Jackson Court
   - Rebuild Manhattan Drive (Pole 1845 to 1979)
   - Rebuild South Street
   - Rebuild system at Curtis Avenue
   - Rebuild system at Redrock Condos
   - Relocate SCADA server room
   - Replace 806S/807S padmount switch
   - Replace 810S/811S/812S padmount switch
   - Replace cables at Franklin Square
   - Replace cables at Redstone - P787 to 806S
   - Replace #2 unshielded copper cables on Church Street (Cherry Street to Main Street)
   - Replace #2 unshielded copper cables on Cherry Street (Church Street to S. Winooski Avenue)
   - Replace distribution system at Edgemoor Drive and relocate overhead from back yards
   - Replace recloser 109R
   - Replace recloser 412R

- Replace recloser 413R
- Replace recloser 805R
- Replace recloser 112R (Scheduled for FY20)
- Install recloser 405R at Pole 58 - Austin Drive
- Replace underground system at Laurel Court
- Switch replacement (721S/722S/743S/702S)
- UVM Lafayette switch replacement (952S, 953S, 954S, 955S, 956S)
- Various street lighting upgrades
- Replace condemned poles
- Utility hole upgrades
- RTU upgrades and replacement

b) The following is a list of BED's capital distribution system projects planned for the next three years:

- Replace switch 731S/736S/760S/761S (Church Street & Cherry Street)
- Replace switch 910S/911S (UVM Votey Hall)
- Relocate aerial circuit on Bank Street (Great Streets Project)
- Replace the underground system at Farrell Apartments (Off S. Williams Street)
- Replace the electrical system on Scarff Avenue
- Replace the underground system at UVM Living & Learning
- Replace switch 821S/401S/727S/349S/233S (Pearl Street & S. Prospect Street)
- Reconfigure 3L4 circuit long span construction
- Rebuild Airport circuit SA02
- Rebuild the aerial circuit at Appletree Point (Pole P3412 to Pole P3434) from 4.16 kV to 13.8 kV
- Install (9) conduit duct bank from UH#173 to UH#175 on Cherry Street
- Install new duct bank and cables on St. Paul Street from Bank Street to Cherry Street
- Replace the electrical system on Lyman Avenue
- Replace switch 322S/323S/324S (Main Street & University Heights)
- Replace switch 303S/307S/308S/309S (Main Street & S. Prospect Street)
- Replace the underground system at UVM Aiken Center
- Replace the underground system on Juniper Terrace (Off Summit Street)
- Rebuild the aerial circuit at Sunset Cliff (Pole P3706 to P3723) from 4.16 kV to 13.8 kV
- Upgrade the manual switch 407S at pole P2001 (Park Street & Pearl Street) to a SCADA operated switch
- Upgrade the manual switch 917S at P1765 to a SCADA operated switch
- Replace recloser 234R
- Rebuild 1L4 along North Avenue between pole P3131(Starr Farm Road) and P3169 (North Avenue Ext)
- Replace switch 305S/325S/326S (Main Street Reservoir)
- Replace switch 817S/912S/913S (Main Street Reservoir)
- Replace switch 724S/725S (College Street)

- Replace recloser 252R
- Replace disconnects 346D with SCADA operated switch
- Replace the underground system at Harbor Watch
- Upgrade manual switch 227S at pole P1980 (Park Street & Manhattan Drive) to a SCADA operated switch

Maintenance & Implementation of System Efficiency

Through the strategies and procedures described above, BED proactively maintains the efficiency of its distribution system. BED's commitment to linking software and equipment together will further enhance the automation of efficiency efforts and will improve our ability to operate the system as efficiently as possible in the future.

<u>Implementation of Distribution Efficiency Improvements</u>

The following summarizes BED's cost-effective efficiency projects and implementation timeline:

- Balance the load between 1L1 and 1L4, 2L4 and 3L1, 3L4 and 3L5, & 1L2 and 2L5 circuits. One system re-configuration case was implemented in FY2020. Two cases have been re-evaluated due to un-anticipated costs identified after this analysis and are no longer cost effective. The remaining two cases are scheduled for completion in FY2021.
- Transferring load on Henry Street and Wilson Street from phase C to phase A to balance the mainline three phase loading. This project was completed in FY2020.
- Upgrading a section of BED's lines on Canfield Street, part of the 1L2 circuit, from single-phase to three-phase construction. This project was completed in FY2020.

Chapter 5 – Comprehensive Energy Services

Introduction

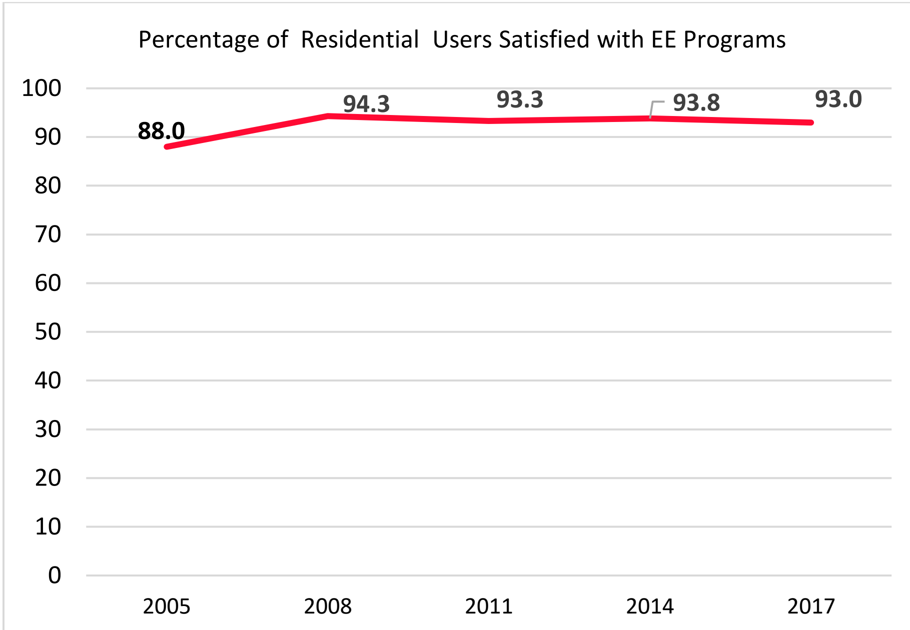
In this chapter, we provide an overview of the importance of BED's energy efficiency programs. We begin with a historical look at the benefits of electric energy efficiency investments, and then discuss how future investments in comprehensive energy services, (traditional electric efficiency and beneficial electrification programs), will help to ensure that BED is prepared to meet increasing customer demand for electricity, while simultaneously meeting the State required reductions in greenhouse gas emissions.

BED's energy efficiency programs are designed to meet the requirements of its Order of Appointment, Vermont's renewable energy standard (Act 56) and the City's NZE initiative as described in preceding chapters. To effectively meet these directives, BED will need to design and implement new customer rates to incentivize customer adoption of beneficial electrification technologies such as EVs and heat pumps, while also lowering the societal cost and impact of increased energy consumption. Simultaneously, BED will need to invest in distribution system upgrades to ensure continued system reliability with increasing customer demand for electricity. BED is well equipped to rise to the challenge of accomplishing these tasks.

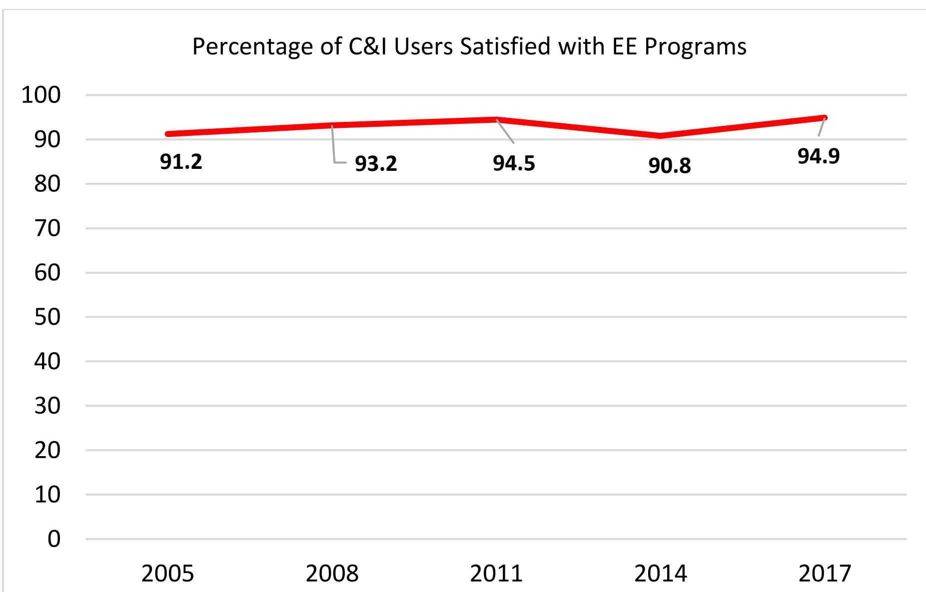
Comprehensive energy efficiency as a valued customer service

To provide the energy services our customers have come to expect, BED will need to continue investing in electric energy efficiency even under a base case scenario. BED also contends that offering only traditional electric efficiency services in the future will be ineffective and inconsistent with the State's Comprehensive Energy Plan. BED must instead provide comprehensive energy services aimed at reducing GHG emissions, source energy reductions and total energy cost savings. By offering comprehensive energy services to customers that include traditional electric efficiency and beneficial electrification services such as incentives for highly efficient heat pumps, EVs, discounted residential EV rates and load controls, BED will be in a much stronger position to meet customer interest in such programs as well as maximizing existing grid capacity to the benefit of all customers.

Continuing BED's tradition of providing electric energy efficiency services is warranted not only because these services generate positive net energy benefits, consistent with 30 V.S.A. §209, but also because customers are extremely satisfied with the services. A recent customer survey poll indicates that 93% of participating residential customers were satisfied with BED's energy efficiency programs.[1]



The same poll concludes that 95% of participating commercial customers were also satisfied with BED's energy efficiency offerings.[2]



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[1] 2017 Burlington Electric Residential Customer Survey, by Spruce Lane Consulting, Dec. 2017.

[2] *Id.*

BED is aware that additional effort is needed to increase awareness and participation in its electric energy efficiency programs. We also acknowledge that barriers still exist to participating in our electric efficiency programs. In past regulatory filings, BED has outlined many of these long-standing barriers which include but are not limited to the following:

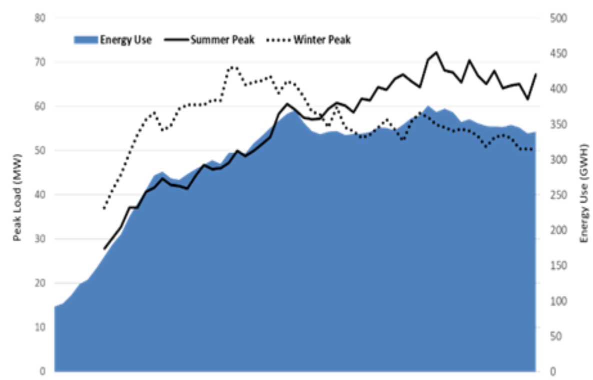
- Most residential and commercial customers rent their building spaces (60% residential, 70% commercial customers);
- 85% of residential rental units are individually metered for natural gas and electric service so tenants pay their utility costs directly creating a split-incentive paradigm;
- A high percentage of customers are connected to natural gas (95% residential, 99% C&I) which costs less to use for heating than electricity;
- 35% of residential accounts are turned over annually so these customers will not benefit from long-term savings from BED's efficiency programs; and,
- Average electricity consumption across BED's residential customer class is already among the lowest in the U.S. at 390 kWh per month.

The aforementioned survey of 439 residential customers confirms that many of the above barriers are still in place today. The same survey indicates that the cost of new efficiency measures (net of incentives) is also a barrier to participation. Some customers view efficiency program participation, particularly our TEPF weatherization program, as being overly complicated despite our efforts to simplify the process to the greatest extent possible. Nevertheless, we are encouraged that many of our customers take advantage of the energy services that BED provides. These include programs that reduce gasoline and natural gas consumption such as electric-lawn mowers, electric bikes, heat pumps, integrated controls, EVs and home-based EV charging.

These added innovative energy services (i.e. Tier III programs) and incentives undoubtedly help to reduce our customers' total energy consumption and bills. Indeed, 63% of residential customers indicated that offering new and innovative services, such as those mentioned above, would be important to them in the future. As BED continues to ramp up its Tier III programs, its energy services staff will need to continue providing customers our original efficiency programs to help customers reduce their electric consumption through efficient appliances, weatherization and lighting controls. However, by combining these efficiency services with demand response services and potentially new rate designs, BED will maximize its ability to influence the times at which customers consume electricity in order to improve BED's system load factor. Improving BED's load factor could produce co-benefits such as decreasing electric rates to the benefit of all customers, including non-participants. More importantly, combining Tier III and electric energy efficiency services under one umbrella service offering allows BED to further advance the value proposition of transitioning away from fossil fuels.

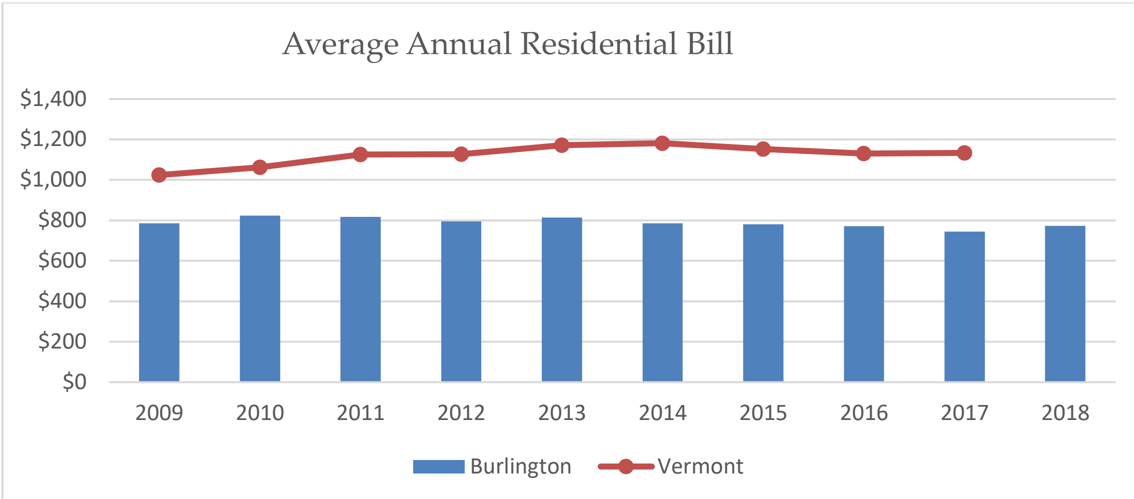
Continuing to invest in electric energy efficiency is also warranted because such investments are a least cost resource that BED can tap into to help improve reliability. Electric energy efficiency investments help to offset anticipated future growth in electric loads and system peak demand as the transformation of the transportation and building sectors unfolds. Thus, continued investment in cost effective energy efficiency, including thermal efficiency and weatherization, should help customers to right-size their heat pump equipment, which reduces electric loads to a greater extent than without added weatherization. Also, increased electric efficiency investments could lower the potential impact of EV's charging in homes and businesses throughout Burlington, including those EV's owned by non-Burlingtonians charging at BED's publicly available chargers.

Historical Results of Electric Energy Efficiency



As noted at the outset of this IRP, BED has been providing energy services for nearly 30 years. Investments in these services have proven effective in many ways. Electric efficiency has helped to flatten load over the past 10 years, allowing BED to defer costly growth-related upgrades to the transmission and distribution T&D system. Efficiency has helped to reduce the need to acquire additional wholesale energy on the spot market or to arrange for the purchase of new power through contracts with renewable energy generators located some distance from Burlington. Thus, continued energy efficiency investments allow for increasing levels of consumers' dollars to be re-invested in Vermont's local economy. Energy efficiency expenditures are made almost entirely locally, typically in the form of professional services, skilled trades employment, and equipment purchases. Not only is the value of the City's building and energy-using equipment improved, but locally retained dollars are "multiplied" many times over by subsequent consumer spending.

Most importantly, BED's energy efficiency investments have significantly contributed to lowering BED customers' electric bills. Currently, BED residential customers have some of the lowest electric bills in the State as shown in the graph below.



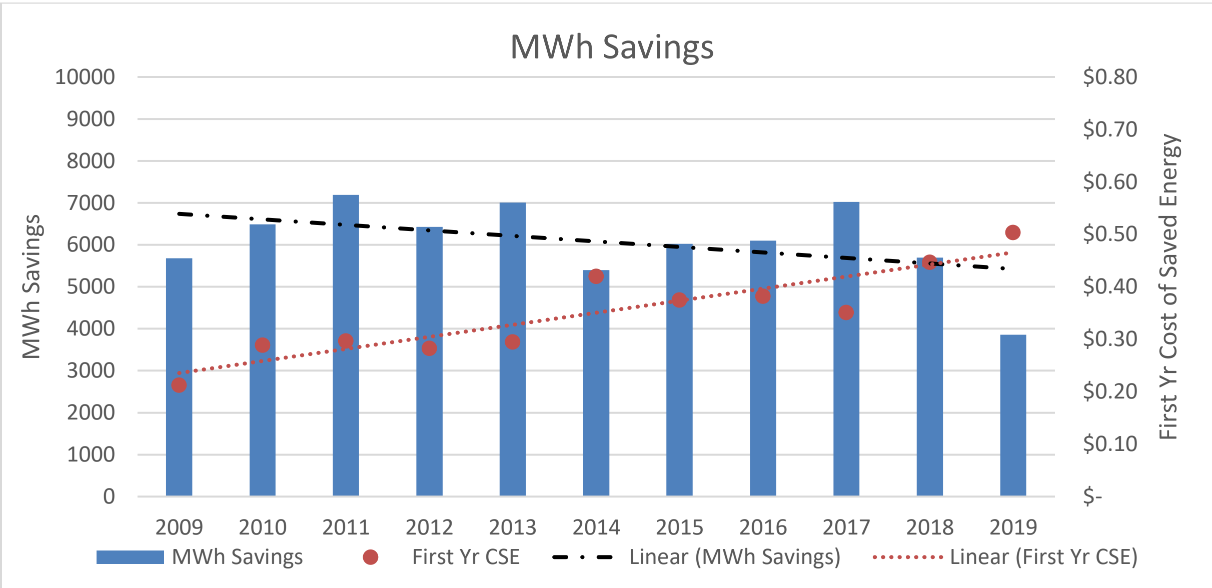
In short, electric efficiency is an effective investment that has been producing reasonable returns for BED and the City for years. And, we expect that these investments will continue generating such returns well into the future through existing and proposed efficiency and Tier 3 programs.

Electric Efficiency Programs

BED provides energy efficiency services and incentives through five main programs: Business Existing Facilities, Business New Construction, Efficient Products, Residential Existing Buildings and Residential New Construction. Ten-year average investments and savings by program are as follows:

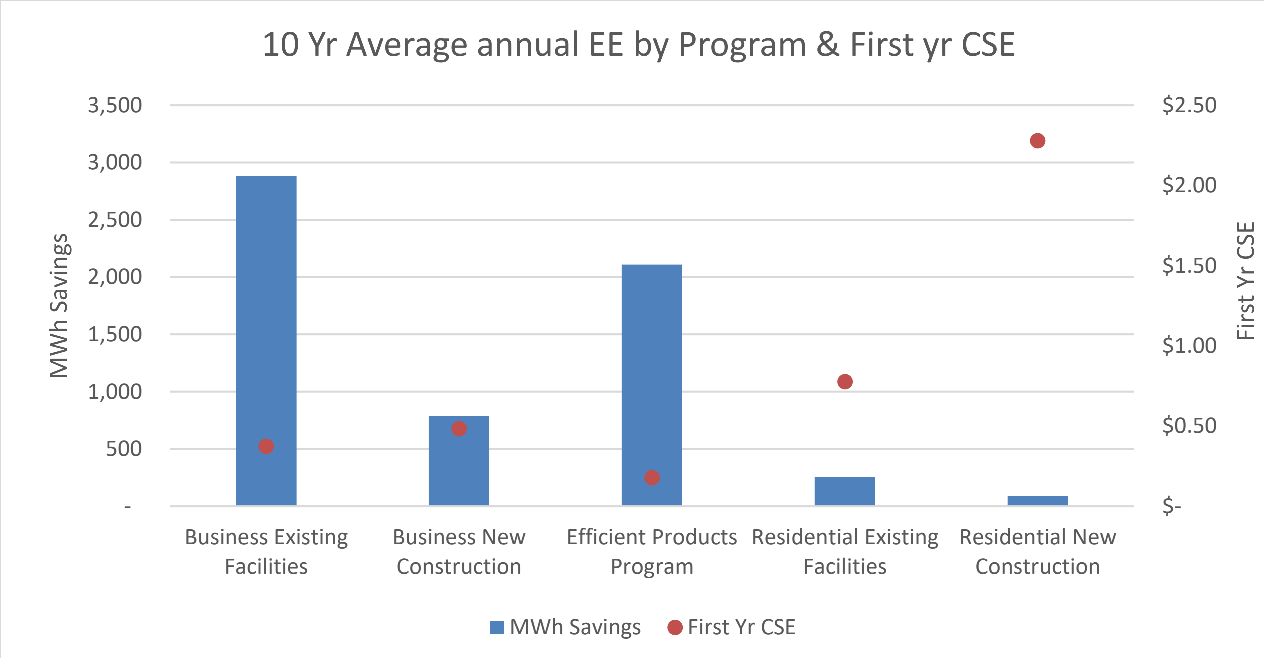
Program	Total Program Costs	Net MWh Savings	BED First Yr CSE (kWh)	BED Levelized CSE (kWh)
Business Existing Facilities	$ 1,088,194	2,884	$0.37	$0.03
Business New Construction	$ 377,690	786	$0.48	$0.04
Efficient Products Program	$ 367,658	2,109	$0.18	$0.02
Residential Existing Facilities	$ 219,064	254	$0.78	$0.06
Residential New Construction	$ 118,529	88	$2.28	$0.07
GRAND TOTAL	**$ 2,171,135**	**6,122**	**$0.35**	**$0.03**

In aggregate, BED's energy efficiency programs have reduced electric consumption by 5,000 to 7,000 MWhs annually. Such savings amount to roughly 1 – 2% of annual retail sales. First year cost of saved energy has ranged from $0.30 to $0.40 per kWh saved. Overtime, however, MWh savings accumulate as efficiency measures remain in place for up to 10-12 years, on average, and even longer for new construction projects. These savings have cost BED roughly $0.03 per kWh ($0.33 First yr CSE divided 12yrs). When compared to the levelized cost of wholesale energy ($0.04 to $0.08/kWh), energy efficiency has proven to be an attractive investment that has contributed to BED's efforts to comply with 30 V.S.A. §218c.



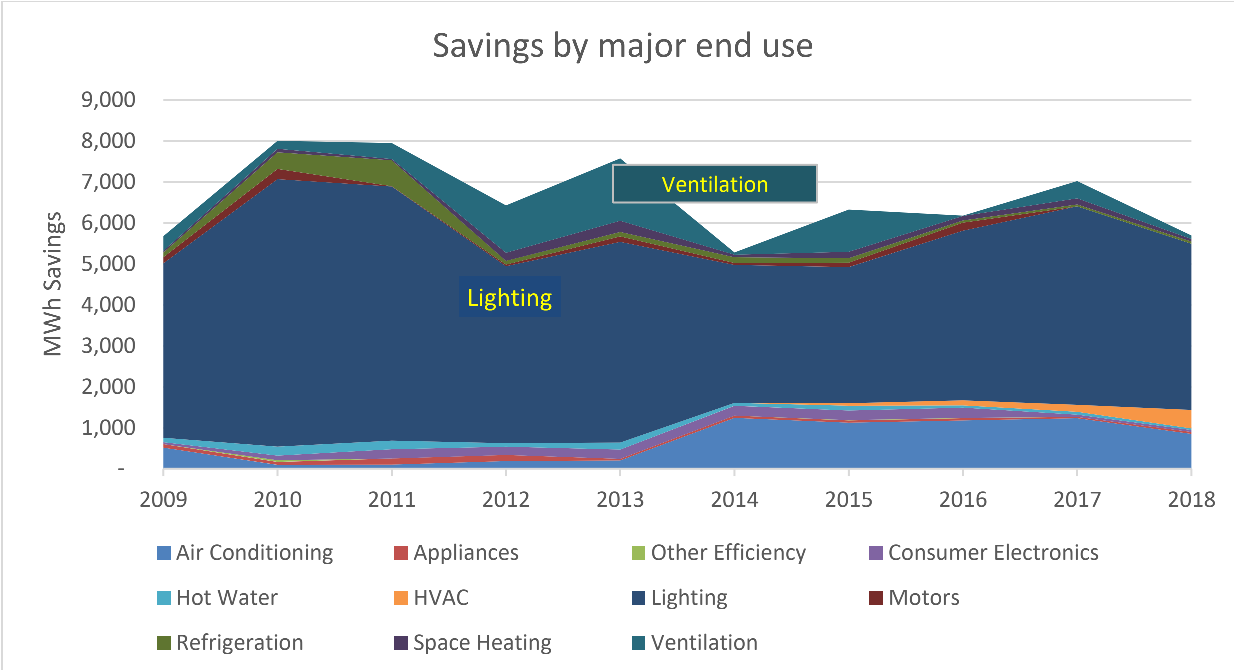
As shown in the above graph, annual incremental energy savings have been decreasing year over year. Meanwhile, the first-year cost of savings has been increasing. These trends are consistent with statewide trends and reflect BED's long history of providing energy efficiency services which has the effect of depleting the reservoir of additional cost-effective electric savings within City limits. Electric energy efficiency resource depletion is a function of cumulative measure adoption over time and market maturity, more stringent building codes and appliance standards and lower energy costs.

By taking a look at individual program results, it becomes clear that the vast majority of historical savings are primarily driven by the commercial sector.



As shown in the graph above, most of the savings have been associated with custom projects for lighting, refrigeration and heating, ventilation and air conditioning (HVAC) equipment within the facilities of our existing business customers. The efficient products program, which is primarily available to residential customers but also small businesses, has also successfully generated low cost electric savings over the past 10 years. Most of these program savings are attributable to retail store price buy-downs on efficient screw-based lamps and through the Smartlight program which provides incentives to lighting installers/contractors (who, in turn, primarily serve small to medium sized businesses) through midstream dealers. On a 10-year average basis, the business programs and the efficient products program have yielded cost effective savings that are less than the cost of avoided wholesale energy.

On the whole, lighting related savings, including controls, have generated most of BEDs savings over the last 10 years.

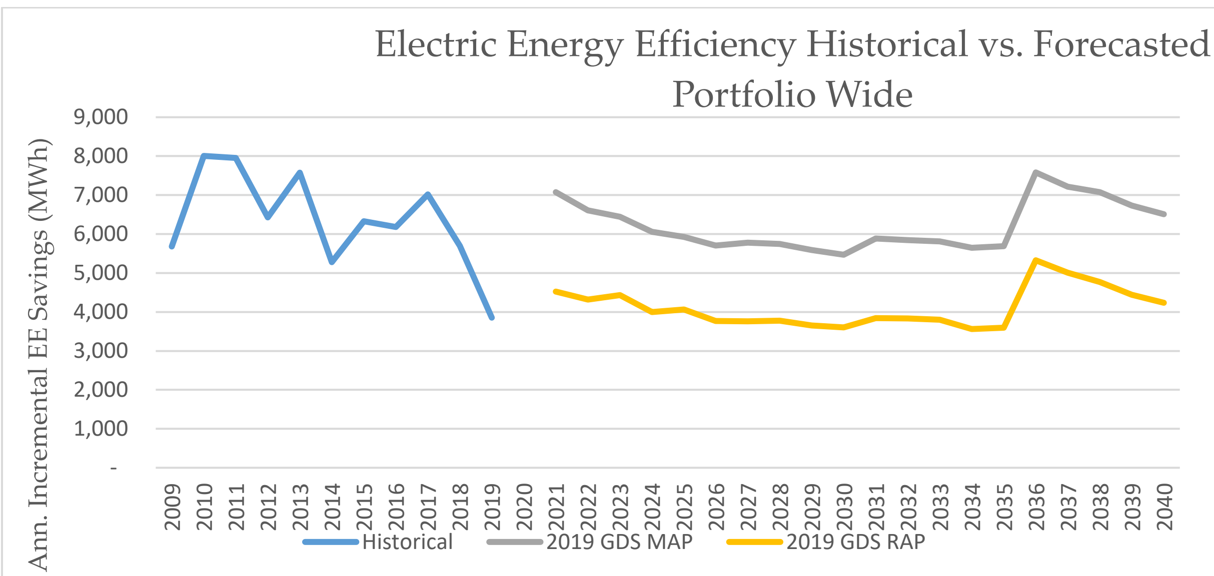


Energy Efficiency as a future resource

Because BED has accomplished the bulk of the available traditional electric efficiency work, it has become increasingly clear over the past two years that the remaining reservoir of cost-effective electric energy efficiency projects is decreasing. BED's long history of providing electric energy efficiency services has encouraged customers to adopt new and more efficient electrification technologies, particularly lighting technologies such as LEDs and, more recently, renewable heating technologies such as air-source heat pumps. So, it has been expected that higher rates of efficiency adoption would inevitably reduce the pool of cost-effective electric savings. Looking forward, some traditional electric savings will undoubtedly persist as new technologies are commercialized, new buildings are developed, and existing buildings are renovated. But questions about the relative size and cost of overall future MWh savings potential remain unanswered at this time.

Such uncertainty should not however dissuade stakeholders from continuing to invest in electric efficiency programs, especially if future investments are combined with beneficial electrification measures. With respect to existing electric efficiency potential, the results of a recent potential study conducted by the Department of Public Service's contractor – GDS Associates – ("GDS Study") indicate that future traditional electric efficiency savings continue to trend lower. Based on GDS' study, future traditional electric realistic potential savings could range between 3,700 MWhs and 4,700 MWhs annually over the next 10 years. Commercial sector savings are still expected to dominate future incremental savings well into the future with savings of approximating 3,300 MWhs to 3,900 MWhs annually – roughly 80-85%of total efficiency portfolio savings. Meanwhile, residential savings are estimated to amount to 600-725 MWhs annually. Because LEDs are becoming commonplace in so many locations, savings generated from BED's efficient products program ("EPP") are anticipated to decrease significantly. However, lighting fixtures, lighting controls and advanced appliances will continue to generate some future savings but not nearly at the level that screw-based LEDs and CFLs have in the recent past. As a result of the community's transition to LEDs, efficient product program savings are expected to be considerably lower in the future.

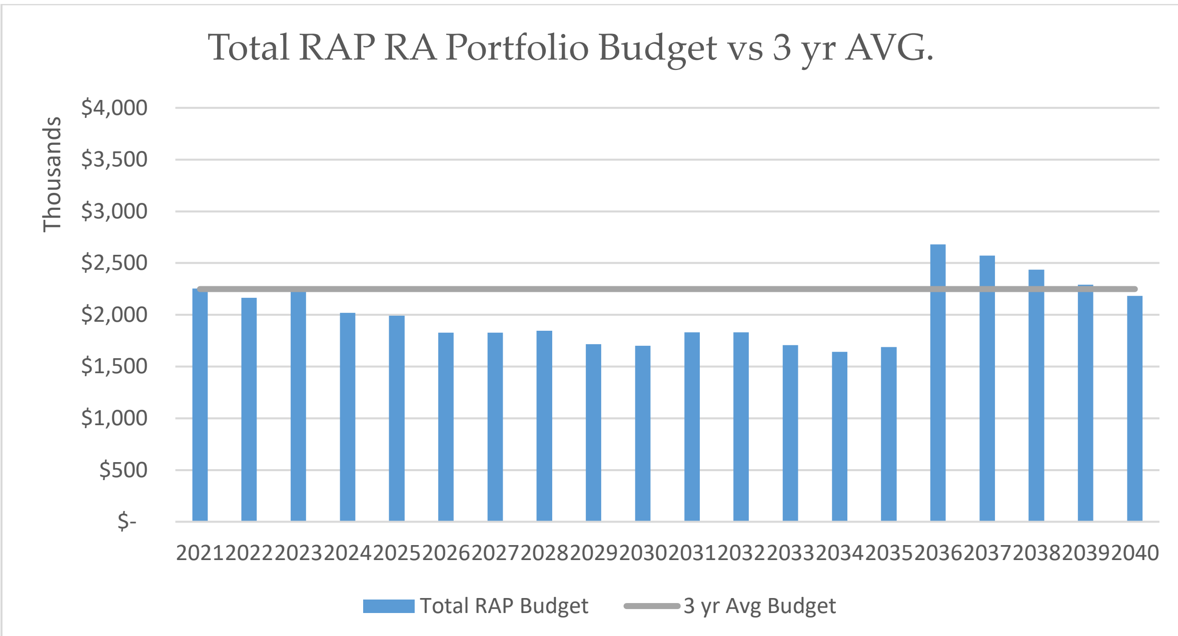
After taking into account the impact of a successful transition to LEDs , future traditional electric energy efficiency savings are expected to be 20 to 40%lower, on average, than a previous 2016 GDS electric efficiency potential study and 30 to 40%lower than average historical savings.



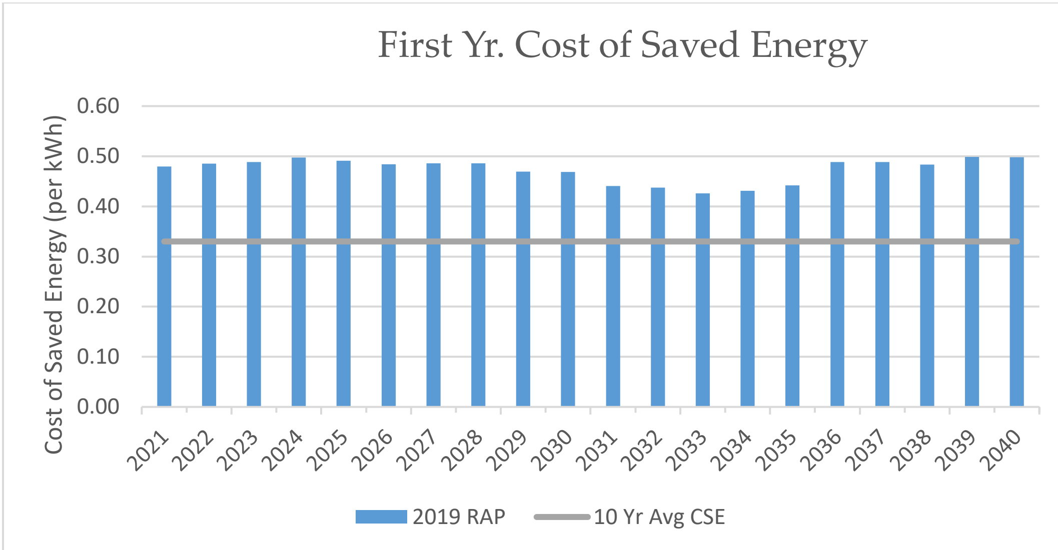
While lighting is expected to contribute less to future traditional energy savings, other types of electrification technologies will become more important. These include the following:

- Heat pumps, including air-to-water heat pumps;
- Thermal shell upgrades coupled with heat pump installations;
- Refrigeration;
- Ventilation and Circulation.
- Motors;
- Heat pump water heaters; and,
- Lighting controls.

Based on the 2019 GDS Study, BED also anticipates that future ratepayer investments in traditional electric efficiency programs will amount to approximately $2.4 million annually (including Development and Support Service (DSS) but not including TEPF) over the next three years, before trending downward in 2024 as new building codes and appliance standards take effect. Such future investments will essentially mirror BED's $2.4 million three-year annual average investment in electric energy efficiency, including DSS, as shown in the Realistic Achievable Potential (RAP) Resource Acquisition (RA) graph below.



With future electric savings decreasing over time and the budgets remaining flat, the cost of those savings is expected to increase. As noted, the 10-year weighted average first-year cost of saved energy is approximately $0.33 per kWh saved, or about $0.033 on a levelized basis. As discussed above, first-year cost of saved energy has been slowly increasing. The reasons for these steady cost increases are many. The primary reason however relates to the fact that acquiring electric savings beyond relatively easy lighting savings typically means that BED needs to motivate customers to buy more expensive equipment or replace existing equipment earlier than the end of its working lifetime. Doing so requires BED to provide greater incentives and additional technical assistance than in the past. BED anticipates that its customers will continue to seek out such additional technical assistance and higher incentives. As the graph below indicates, the GDS Study results confirm our expectations relative to the rise in the cost of first year electric energy savings.



Beneficial Electrification

As noted above, BED is actively assisting customers to achieve the community's aggressive NZE goals. An integral part of this effort includes BED's beneficial electrification programs ("Tier III"), which are designed to encourage customers, in accordance with Vermont's Renewable Energy Standard ("RES"), to replace fossil fueled technologies with new electrified technologies that result in lower greenhouse gas emissions. Both the RES and NZE goals have had a measurable impact on BED's decision-making and planning processes. Since 2017 – the first year of the RES – BED has been implementing a series of programs designed to beneficially electrify two key market sectors: Transportation and building space heating. Our objective for implementing these programs is to transform the local energy market away from fossil fuel consumption and toward efficient technologies powered from renewable resources.

To effectively serve these markets, BED provides customers with technical assistance and financial incentives for the following technologies:

- Electric buses;
- AEVs(new and preowned);
- PHEVs (new and preowned);
- Electric bicycles;
- Advanced residential heat pumps;
- Heat pump water heaters;
- Electric lawnmowers;
- Induction cook stoves;
- Commercial leaf blowers;
- Electric forklifts;

- Commercial variable refrigerant flow heat pumps; and,
- Ground source heat pumps.

Of the measures noted above, electric buses, AEVs and PHEVs and advanced heat pumps are expected to contribute the most to future increases in BED's load requirements and peak demand under the NZE scenario, as noted earlier.[3] However, it is important to reiterate that under a business as usual scenario, BED does not anticipate that adoption of the above-noted Tier III measures by customers will have a material impact – on balance – on BED's future generation and supply resources.

In order to fully assess the range of plausible outcomes that these major transformational technologies may impose upon our generation and supply resources, as well as our ability to effectively serve customers over the planning horizon, BED developed a "mini-model" evaluation tool. The main purposes for conducting the mini-model analyses were to:

- Re-confirm the fundamental economics of the major technology options, which inform our forecasts of customer adoption; and,
- Re-test the economic value of these technologies to BED and society at large.

Mini-Model Methodology

While each technology described below is unique, the outputs of mini-model share a common structure and methodology. Each section begins with a brief description of the technology and the key assumptions that were used in the model to perform two economic tests. The report then summarizes the utility cost test ("UCT") and societal cost test ("SCT") results for each technology. After the UCT and SCT sections, the report provides an assessment of the potential impacts of the technology on BEDs resource requirements and their Tier III implications, i.e. overall costs to BED, GHG emissions reductions and Tier III credits, where applicable. The results of the economic tests and potential Tier III impacts are then used to develop a recommended course of action.

Utility Cost Test

The utility economic cost test is intended to demonstrate whether a particular technology produces a net benefit to BED; either through reduced wholesale costs or increased revenues that exceed marginal costs. Reduced utility costs result from reduced power supply costs, inclusive of energy, capacity, transmission, and ancillary service expenses. Increased

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[3] It is worth noting that VRF and gSHP technologies are currently offered on a custom basis. As such, BED will assess the potential impacts of these technologies as individual projects are presented to BED. While large scale VRFs and GSHP technologies may consume significant amounts of electricity, BED does not anticipate that more than two large VRF projects and one large gSHP project will be completed in the next three – five years. Accordingly, we expect that the impacts of these projects on reliability and the cost to serve customers will be *de minimus*.

utility revenues are generated from additional retail sales, additional wholesale energy sales, or increased renewable energy certificate ("REC") revenue.

Whether a measure produces net benefits for BED depends largely on four key variables that are expected to impose the greatest degree of risk on BED's net present value ("NPV") cost of service. The key variables are the wholesale cost of energy, capacity, and transmission and the forecasted values for renewable energy credits ("RECs").[4] The values for each applicable variable were then grouped together to create a base case scenario, which reflects the mostly likely outcome given our assessment of future wholesale energy, capacity, transmission, ancillary costs, as well as REC values.[5]

Societal cost tests

The societal cost test includes utility costs, as well as the costs that society bears such as illnesses caused by pollution, reduced productivity, and climate related damages. These costs are generally referred to as "externality" costs; or costs that have been attributed to the provision of a service or product that is borne by society at large but is not included in the price of the service or product provided. BED's application of the societal cost test measures the avoidance of such externality costs that are broadly shared by society, such as emissions and other environmental impacts. Externality costs can be avoided by reducing fossil fuel consumption or reducing electricity use generated from a non-renewable source. Reduced societal costs can be attributed to actions by either the customer or the utility. For the purposes of this test, BED adopted a $100/ton of carbon as an avoided externality cost, which has the effect of increasing the value of beneficial electrification and electric efficiency.

As mentioned, none of the beneficial electrification measures noted above are expected to have a material impact under the business as usual scenario on BED's generation and supply resources or on its overall cost of service. Some of the measures, E -bikes, e mowers and e-leaf blowers, for example, consume so little electricity that re-conducting the above noted economic tests for the purposes of this IRP would not have yielded materially different outputs from prior analyses and, as a result, those technologies have been omitted from this analysis as they would not have significantly changed BED's resource requirements. With respect to e- forklifts, induction stoves, variable refrigerant flow heat pumps (VRF) and ground source heat pumps (gSHPs), BED does not currently expect customers will adopt these technologies in significant

[4] For additional discussion relative to these four variables, please refer to Chapter 6.

[5] In the 2016 IRP, BED grouped the four key variables together into four cases: base, low, high and weighted average cases. These cases assumed low, high and most likely (or base) wholesale costs. These costs were then weighed in order to develop a weighted average cost profile. In BED's assessment, wholesale costs are not currently expected to be materially different in the future than the costs that BED developed in the 2016 IRP. Therefore, this IRP includes only the base case costs used in the last IRP.

numbers any time soon. So even if each of these technologies consume relatively large amounts of electricity ,BED does not believe that the cumulative effect of their adoption will materially impact BED's resource plans. Therefore, this IRP also does not include the economic test results of these technologies since system and resource impacts, if any, will be negligible.

Historical results

When BED initially launched its Tier III programs in 2017, there were a limited set of technology offerings to manage. That changed over time as the State's technical advisory group ("TAG") approved new technologies and customer awareness about incentives for electrification technologies grew. As the table below demonstrates, the number of measures adopted by BED's customers has increased from 39 to 305 (omitting BED owned Electric Vehicle Service Equipment "EVSE") as the number of offerings increased.

Count	2017	2018	2019
AEV	33	12	30
PHEV	5	14	19
PreOwned AEV			1
PreOwned PHEV			4
Home EVSE charger			13
Custom			1
E Bike		61	64
Resi Elec Mower			142
HPWH			4
Public EVSE	7	7	8
Workplace EVSE			1
MultiZone ccHP			4
SingleZone ccHP	1	1	22
Totals	**46**	**95**	**313**

It is also worth noting that of the 305 technologies incentivized in 2019, 279 measures were adopted by unique customers. Along with these increases in adoption, BED's program investments have also grown substantially from $44,000 to $128,000, excluding administrative expenses.

Incentives		2017		2018		2019
Production						
AEV	$	40,200	$	14,400	$	38,400
PHEV	$	3,000	$	8,400	$	21,000
PreOwned AEV					$	800
PreOwned PHEV					$	3,900
Home EVSE charger					$	5,200
Custom					$	1,000
E Bike			$	15,250	$	16,000
Resi Elec Mower					$	17,600
HPWH					$	2,400
Public EVSE					$	-
Workplace EVSE					$	1,000
MultiZone ccHP					$	3,450
SingleZone ccHP	$	600	$	375	$	16,250
SingleZone ccHP Add'l Rebate					$	1,200
Totals	**$**	**43,800**	**$**	**38,425**	**$**	**128,200**

To date, the total impact of these new technologies on total load requirements and system reliability has been minimal. So, too, has been the rate impact from providing incentives and technical assistance after net marginal revenues are taken into account, especially since EV customers are strongly encouraged to use electricity during off peak demand periods when wholesale energy, capacity and transmission costs are lower than usual.

Although the load impacts thus far have been minimal, adoption of these measures is helping the City and the State make progress toward their respective clean energy goals. So, it is important to continue supporting these Tier III programs for the foreseeable future. As shown in the table below, estimated lifetime GHG emissions reductions amounted to 1,965 tons in 2017. By 2019, cumulative lifetime emissions reductions have grown to 5,732 tons as new measures were adopted and the older vintage Tier III measures continued to operate in the City and elsewhere.

Cumulative GHG emission reductions	2017	2018	2019
AEV	1,190.4	1,623.3	2,741.6
PHEV	101.0	383.8	848.5
Public EVSE	634.4	634.4	725.0
WorkPlace EVSE			41.1
Ebikes		234.8	246.3
HPWH			23.4
ccHP	39.5	79.0	1,105.7
Cum. Totals	**1,965**	**2,955**	**5,732**

With respect to resource requirements, BED estimates that past technology adoption has increased MWh sales from 145 MWhs to 430 MWhs on a cumulative basis. After considering line losses and reliability, these new electricity sales increased BED's load requirement from approximately 175 MWhs to 516 MWhs over the same time period. Meanwhile, electric efficiency investments have been reducing electric consumption by 7,022 MWhs, 5,696 MWhs and 3,854 MWhs in 2017, 2018 and 2019, respectively.

MWh sales	2017	2018	2019
AEV/PHEV	85.5	143.9	265.4
Public EVSE	56.0	56.0	64.0
Workplace EVSE	-	-	3.6
ccHP	3.3	6.5	91.4
HPWH	-	-	5.3
Total	**144.7**	**206.5**	**429.7**

On top of the energy efficiency impacts, 141 new net metered and group net metered systems, representing approximately 1,995 MWs $_{AC}$ of capacity, were added to BED's system over the past several years. Therefore, electric efficiency investments and net metering have substantially offset the growth in electricity sales attributable to BED's past beneficial electrification programs. Thus, BED anticipates that if electric efficiency and net metering continue to be supported at the same level that they are today, the potential impacts of future beneficial electrification programs on BED's resource requirements are likely to remain static under the business as usual scenario.

The future of beneficial electrification programs

Successfully transforming the transportation and building space heating markets will likely take another 10 to 20 years to accomplish. Accomplishing this goal will, however, require significant additional State and City support to increase public awareness about how existing and future Tier III technologies can supplant fossil fuel driven technologies without inconveniencing customers. BED cannot achieve this extraordinary feat alone. It will need to work collaboratively with many other stakeholders, including State government, City officials, Vermont's distribution utilities and technology providers. Of course, BED will do its part in this statewide effort. Indeed, BED is committed to continue investing in beneficial electrification programs up to the allowable amounts under existing statutes. BED also intends to continue offering comprehensive electric efficiency services to offset the increased loads caused by beneficial electrification adoption so long as the Commission continues to approve efficiency budgets that enable us to acquire all cost-effective electric savings.

In line with our commitment to transform markets, BED fully expects to continue offering beneficial electrification incentives and technical assistance to customers who adopt the following technologies:

	Tier III Projects	No. of Units	Total Budget	2020 Est. yearly MWh Sales	Est. lifetime GHG emissions reductions
Transportation	Electric Buses	2	$150,650	106	1,873
	AEVs & PHEVs (new&preOwned)	200	$290,000	450	3,752
	BED owned EV Chargers	8	$0	64	725
	Workplace EV Chargers	5	$5,800	18	206
	E Bikes	100	$32,000	-	-
Bldgs	ccHP	83	$84,000	271	3,277
	HPWH	50	$34,500	66	293
Other	Electric Forklifts	1	$6,600	-	-
	Electric Commercial Lawnmowers	1	$4,000	-	-
	Electric Residential Lawnmowers	100	$11,500	-	-
	Commercial Leafblowers	5	$1,150	-	-
	Induction Cookstoves	100	$17,250	-	-
Semi Custom	Commercial VRFs	2	$230,000	6	-
	GSHP	1	$115,000	-	-
Totals		**658**	**$982,450**	**981**	**10,125**

As the table above indicates, if BED can successfully implement all of the Tier III measures above in 2020 (and beyond), expenses will increase by about $983,000, inclusive of administrative expenses. Also, electric sales associated with these measures will likely increase by 981 MWhs annually and lifetime GHG emissions will be lowered by over 10,000 tons. In the sections that follow, we provide an overview of the major technologies that are most likely to be adopted by customers in the greatest numbers over the next several years and will therefore have the greatest impact on future resource decisions.[6]

Electric Buses

In terms of their size, length and seating capacity, electric buses are similar in nearly all respects to their diesel-powered counterparts. They, too, are required to pass the so-called Altoona test before the federal government will award a grant to a public transit authority that seeks to purchase one. This rigorous and multifaceted test evaluates the same metrics for both an electric bus and a diesel-powered transit bus. In general, the federal Altoona test assesses the reliability, safety, maintainability, structure integrity, noise, performance (i.e. acceleration, top speed and braking), and fuel economy of all buses. The results of the test conclude that electric buses are much cleaner and quieter to operate. Moreover, fuel and maintenance costs are reported to be substantially less than their diesel-powered counterparts. Indeed, the fuel economy of a 40-foot Proterra electric bus ranges between 17 MPGe to 27 MPGe, whereas a typical diesel bus ranges between 4.00 MPG and 5.00 MPG.[7]

Because electric buses are a new technology, their initial cost can be nearly twice that of diesel buses. Hence, the purpose of BED's electric bus program is to provide as much financial assistance as possible to reduce the high incremental cost of electric buses. BED has designed its semi-custom e-bus program to achieve two fundamental goals: (1) reduce fossil fuel consumption in the City and the GHG emissions associated with such consumption; and, (2) provide Green Mountain Transit ("GMT") the support necessary to acquire additional electric buses.[8] This support comes in the form of a performance-based incentive structure, as further described in BED's 2020 Tier III plan. Importantly, BED's financial incentive is considered by the Federal Transit Authority to be equivalent to local matching funds that are necessary to secure federal grants. Without BED's incentive, GMT would have to seek out additional local funding sources from either the State, the City or other towns in Chittenden County.

As noted in BED's previous IRP, as well as in our Tier III plans, cities and transit operators in recent years have been motivated to procure electric buses to reduce emissions and other smog-inducing particulates. For many communities, transitioning from diesel to electric buses is oftentimes a part of a city's overall sustainability efforts. City residents and commuters

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[6] For more information about the remaining Tier III measures, please refer to the BED's Tier III plan filed with the PUC on 11/1/2019.

[7] See Altoona test report No. LTI-BT-R1406, Penn State Transportation Institute, pg. 134

[8] In February 2020, two battery-electric Proterra buses were delivered to GMT. The buses went into daily operation during the first week of March 2020. Pursuant to its Tier III plan, BED provided GMT a $131,000 performance-based incentive. BED funds, along with a VLITE grant, were combined with other State and Federal grants to purchase the buses.

across the country have also expressed a preference to reduce fossil fuel dependency, as evidenced in increased use of public transportation, carpooling, car-sharing and multi-model transportation. In 2015, approximately 17% of all transit buses were hybrid-electric (i.e. compressed natural gas CNG fueled with electric auxiliary systems) or all-electric or biodiesel worldwide. By 2026, the market share of all electric and hybrid public transit buses is expected to continue increasing at a faster pace to approximately 5-6%compound annual growth rate (CAGR) – about 291,000 units, as battery technology improves, and costs decrease.[9]

Several cities have been operating electric buses for a few years now. They include Dallas, Texas (seven electric buses scheduled for service in early 2017), Indianapolis, Indiana (21 electric buses currently in operation), Seattle, Washington, and Worcester, Massachusetts. Since first reporting about electric buses in our 2016 IRP, several more cities have acquired electric buses and incorporated them into their fleet. Additional cities and regions that have purchased Proterra buses include Pioneer Valley Transit Authority in Holyoke, Massachusetts, Breckenridge, Colorado., University of Montana, Chicago Transit Authority and many others.[10]

Key assumptions

To model the cost-effectiveness of electric buses, BED made several assumptions about their operating characteristics. The variables that have a disproportionate impact on modelling results include the incremental cost of the electric bus, long-term diesel prices (which affect fuel savings), and maintenance savings.

Major Assumptions - Electric Bus (lifetime)			
Customer	Est. Incremental Costs	$	450,000
	Maintenance Savings		$55,081
	Fuel Savings		$106,064
	Measure Life (yrs)		12
BED	Increased MWh sales		52.8
	Net Revenue		$59,000
	Tier III Costs	$	75,325
	Credits		1258
	Net Tier III MWH e Cost	$	35.54
BTV	GHG Emissions reductions		936

As indicated above, the incremental cost of the electric bus was approximately $450,000 greater than a conventional diesel-powered bus. The cost is considerably higher than reported

[9] Fortune Business Insight, *Electric Bus Market Size, Share & Industry analysis, 2019 – 2026. Jan.2020. See:* https://www.fortunebusinessinsights.com/electric-bus-market-102021

[10] For additional information, see; https://www.proterra.com/company/our-customers/

by BED in its 2016 IRP. The reason for this cost increase is related to GMT's decision to purchase a full 12-year battery warranty, rather than risk having to replace the battery in six to eight years. In previous years, BED assumed that the incremental cost of an electric bus without an extended battery warranty approximated $450,000. Despite the higher costs, the accumulated lifetime operating savings (i.e. fuel and maintenance savings) of an electric bus will likely provide for increased cash flow to GMT over time, especially after factoring for grants and incentives. Maintenance expenses are also expected to be $0.19 per mile driven which is lower than maintaining a diesel bus, thus saving GMT $55,081 over the 12-year lifetime of the electric bus.[11] Also, lifetime fuel savings of $106,064 represent the difference between BED's electric time-of-use rate ($0.10/kWh) and the lifetime costs of diesel fuel for a bus that achieves no less than 4.25 MPGs.[12]

For BED, each electric bus travelling 30,000 miles annually will consume about 52.8 MWhs. Presently, GMT has programmed each bus to charge under BED's existing TOU tariff. Such TOU rates will cost GMT $0.10/kWh. However, GMT's contribution toward BED's fixed costs are not anticipated to be much greater than $0.06/kWh, since wholesale energy costs approximate between $0.03 and $0.04/kWh for off-peak power. As such, GMT's cumulative contributions to our net fixed costs are likely to range from $30,000 to $40,000 on a net present value basis over 12 years. Concerning Tier III costs, BED will continue offering generous incentives and support toward the cost of new electric buses, although it is quite possible that future incentives could be less than the current incentive of $65,500 per electric bus driven 30,000 miles annually. For purposes of this analysis, however, it is assumed that the current incentive structure will remain in place for the next several years. Accordingly, BED is assuming a total cost per bus of $75,000, including administrative expenses. After considering net revenues, the cost of Tier III credits is not expected to amount to more than $35 per MWhe.

Utility Cost Test

Under the utility cost test, promoting electric buses is anticipated to result in positive net benefits to all ratepayers in the amount of nearly $40,000 per electric bus over each bus' 12-year lifespan. Benefits flow from increase electric sales of $50,000 to $59,000. Costs increases include energy ($17,000), RECs ($1,000) and ancillary ($1,300). As noted above, GMT has programmed its e buses to charge at nighttime when capacity costs are negligible. Accordingly, the model excludes additional capacity and Regional Network Service Transmission ("RNS") costs associated with electric buses.

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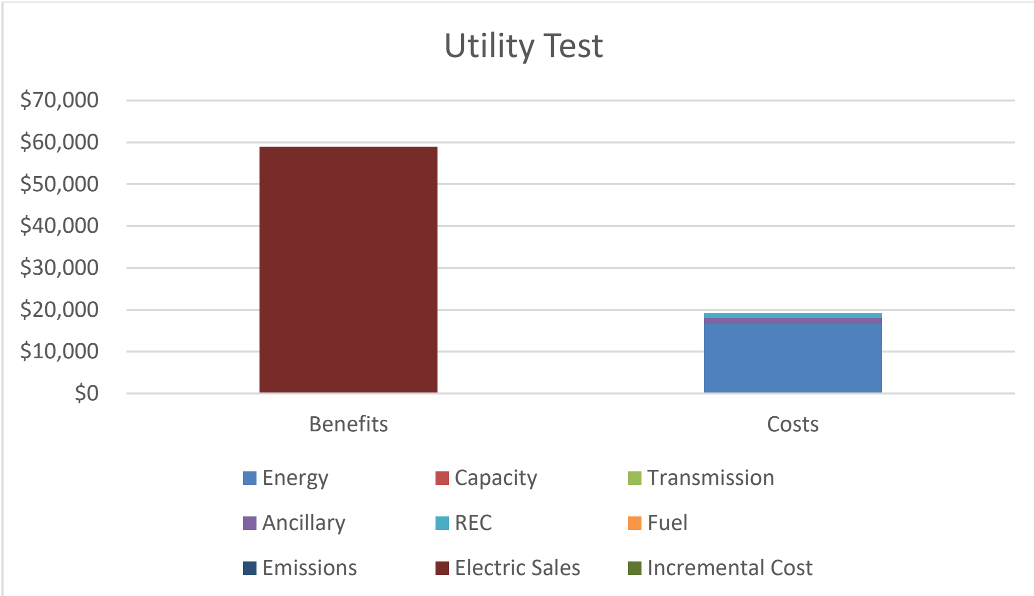
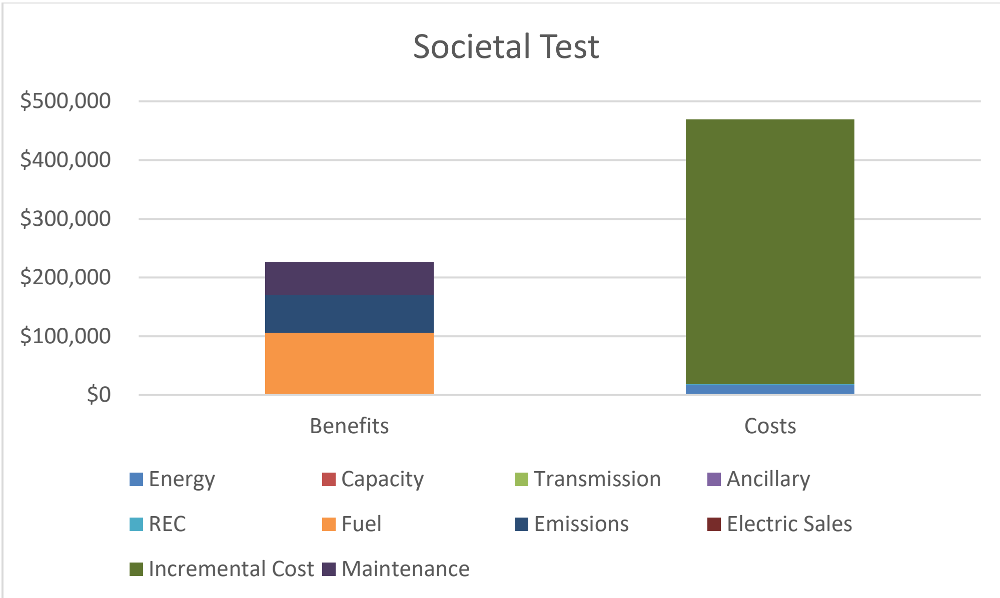
[11] Net present value discounted at 3.5%

[12] Diesel cost were assumed to cost $2.20/gallon and increase by the rate of inflation annually (2.0%).



Societal Cost Test

From a societal cost perspective, an electric bus generates a net present value loss of $242,000 over 12 years. The loss is due to the higher than expected incremental cost ($450,000) of the bus relative to a diesel bus. As noted above, GMT's purchase of e-electric buses is largely funded through federal grants. These grants cover 80% of the capital cost of each electric bus. Were this analysis to include only the costs paid by Vermont's organizations, then Vermont-specific net societal benefits could amount to as much as $117,000 over the 12-year lifespan of an electric bus (these Vermont specific benefits are not shown in the graph below). Additionally, while net societal costs appear to exceed societal benefits based on the specifics of GMT's most recent transaction, BED does not believe this transaction will be indicative of future transactions. In the future we anticipate other factors will help to improve societal benefits over time. First, battery prices, which is the largest component cost of the electric buses, have been trending lower as electric bus manufacturing increases and the technology improves. Second, alternative financing options are just now being explored by regional transit agencies and other stakeholders. Third parties, for example, are beginning to enter the market and offer transit agencies financing terms, such as battery leases, in order to increase the cost competitiveness of e-buses relative to diesel buses. BED is confident that as this financing niche market develops over time, societal benefits will only improve.



Net benefit variables that have been included in the above graphic are diesel fuel savings ($106,000), maintenance expense reductions ($55,000) and emissions reductions ($65,000). In addition to the incremental cost of the electric bus, other net benefit costs include: Energy ($17,000), RECs ($1,000), and ancillary costs ($1,300).

Recommended course of action.

Given GMT's recent success in accessing federal grant funds to purchase electric buses, as well as the level of State and local enthusiasm around electrifying the public transit fleet, BED recommends that it continue to support GMT and its purchase of additional electric buses in the future. Accordingly, BED will continue to offer incentives and technical support. Going forward, BED will also continue to explore options to reduce the upfront capital cost of electric buses. As part of this effort, BED may consider partnering with additional parties to lease the battery – which is the primary cost driver – or to even help GMT through an on-bill financing program.

EVs

Since BED's 2016 IRP, EV technology has rapidly evolved along with BED's customer interest in its AEV and PHEVs programs. Just a few years ago, the number of AEVs and PHEVs offered for sale were limited, their range of travel was relatively short and EVs were cost prohibitive for most Vermonters relative to traditional vehicles. Today, Drive Electric Vermont lists 16 AEVs and 19 PHEVs, prices vary from $30,000 to $85,000 and, the range of travel has increased from less than 100 miles per charge to over 230 miles. These improvements, along with competitive pricing and federal, State and utility incentives are gradually accelerating customer adoption of EV technology in place of traditional fossil fuel powered internal combustion engine ("ICE") vehicles .

While new AEV and PHEV sales are still a fraction of statewide auto sales annually, the future of electrifying Vermonter's vehicles remains bright. Many automotive and electric utility analysts anticipate that as manufacturers continue to incrementally improve battery technology and electric utilities work to make EV charging more ubiquitous, AEV and PHEV sales should increase over time. Such increases in sales will be slow at first but may eventually climb at a faster rate of growth in the latter half of the decade. In VTRANs opinion, new AEV and PHEV sales are expected to reach 15%of annual new vehicle sales by 2025.[13] BED is hopeful that these predictions will come to fruition.

Under its BAU scenario, BED anticipates that the transformation of Vermont's vehicle market will follow national and international trends as more products are introduced. Auto market trends indicate that over the next several years, an increasing number of manufacturers plan to expand their product offerings and increase investments in electrification technologies. According to Electric Power Research Institute (EPRI), Ford plans to spend $11 billion on new EV technology and introduce 40 new (or refurbished) EVs (16 AEVs and 24 PHEVs). General Motors announced 20 new or re-designed AEVs and fuel cell powered vehicles globally by 2023. With a $40,000 manufacturer's suggested retail price ("MSRP"), GMs Chevy Bolt is already a best seller in the U.S. and in Vermont. Hyundai plans to bring 38 new models to the U.S. market by 2025. And, finally, VW announced, in 2018, a $50 billion investment worldwide in AEVs, self-driving cars and other types of electric transportation technologies by 2023. VW expects to build up its AEV manufacturing capacity to almost 15 million vehicles annually by 2025. This increased capacity allows for VW to expand its product line internationally, which is already extensive, to include up to 50 AEV models and 30 PHEV models within the decade.[14]

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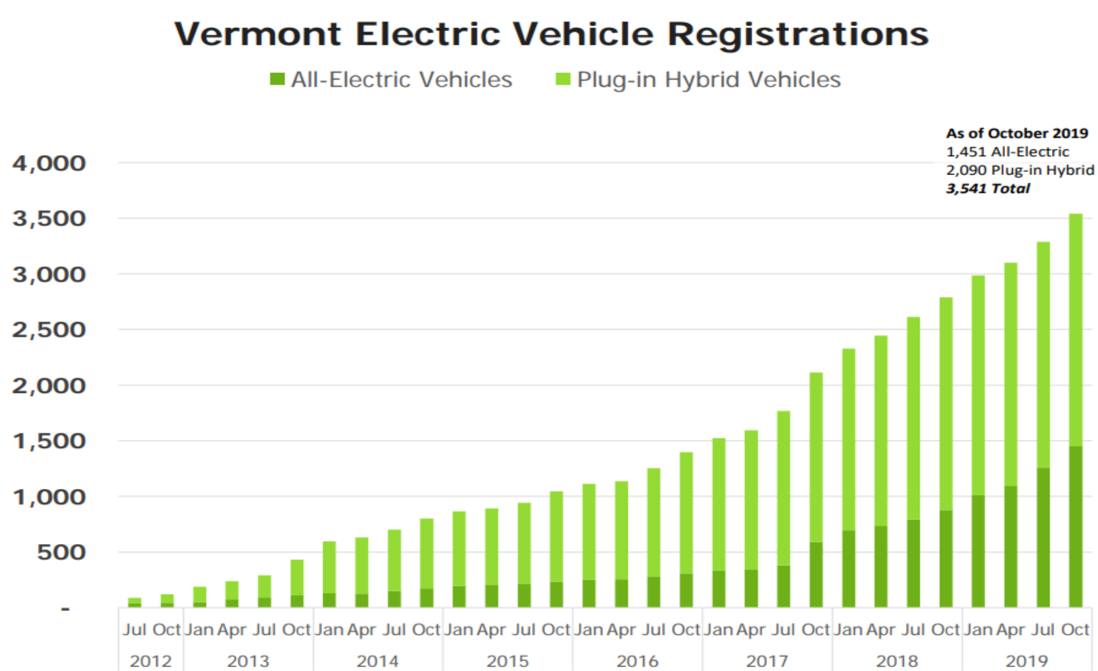
[13] *See:* Vermont Agency of Transportation, *Section 15. 2016 Plug-in hybrid and electric vehicle registration fees*, Legislative report, December 2016.

[14] EPRI, *Consumer Guide to Electric Vehicles,* March 2019.

In Vermont, AEV and PHEV sales have been rising at a steady pace each year since 2012. But in 2017, when the RES took effect, sales growth started to increase at a faster rate.[15] Some of the acceleration in EV adoption was associated with Nissan's temporary $10,000 rebate for older Leaf models in 2017. Other reasons include:

- Increased public education and outreach;
- New products flowing into the State;
- Technology upgrades (i.e. greater range);
- Incentives (federal, state and utility); and,
- Expansion of public and private charging infrastructure.

As the graphic below indicates, the number of registered EVs in Vermont has steadily increased from less than 500 in late 2013 to over 3,500 in late 2019.

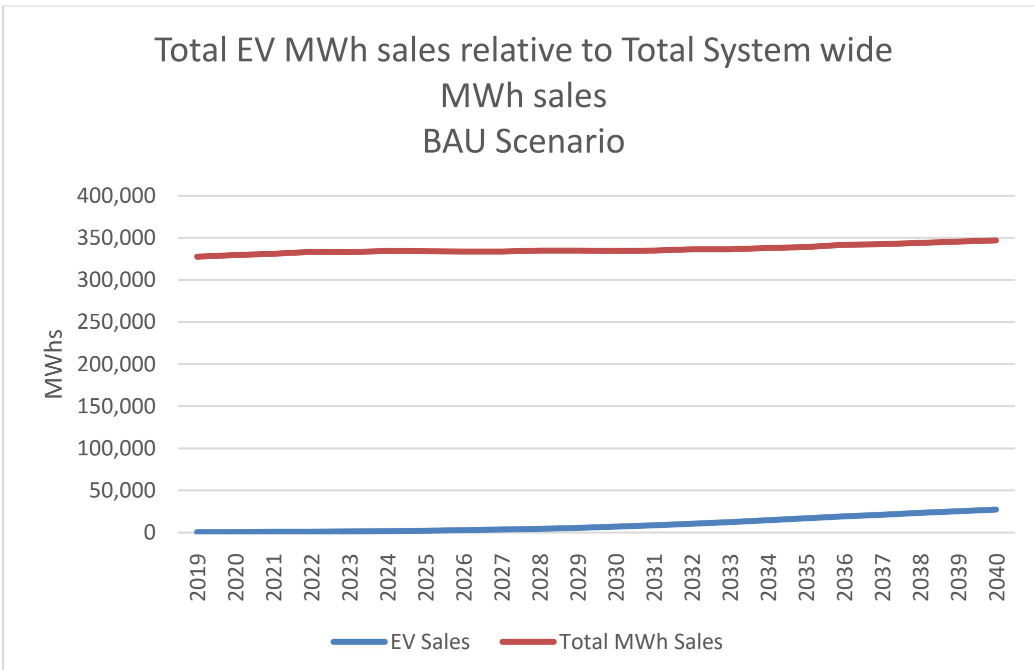


BED intends to continue supporting City- and statewide efforts to shift the automotive market away from traditional, fossil fuel powered vehicles to electrically powered vehicles. Although BED's ability to transform the market is limited, it will continue to work with other stakeholders to encourage adoption of EVs at a faster rate than today. For the next several years, BED will continue to offer incentives for new EVs ($1200+/vehicle) and preowned EVs ($800). BED will also continue to offer financial and technical assistance to customers – both residential and commercial – seeking to install level 2 or 3 electric charging systems. And, BED will

[15] *Courtesy of Drive Electric Vermont, Feb. 2020.*

continue to help raise public awareness about the benefits of going electric through social media, Drive Electric events, and dealership education and outreach.

As noted above, the initial rate of EV adoption under the business as usual scenario is likely to be relatively slow. As the graph below indicates, EV-related MWh sales are expected to increase from approximately 0.21%in 2020 to 2.07%in 2030. Cumulatively, the number of EVs will likely amount to about 2900 vehicles by 2030 across the City, representing approximately 11%of registered vehicles in Burlington. The total load caused by this many EVs is expected to reach about 7,981 MWhs in 2030, and 31,000 by YE2040.[16]



Although some circuits may be affected by increased Burlingtonian EV adoption when several homeowners in the same neighborhood charge their vehicles at the same time, BED does not expect that a BAU transformation of the automotive market will materially impact our resource plans over the next 20-year time horizon. Under the NZE scenario, however, EV market penetration, along with rapid adoption of heat pump technologies, may have a more consequential system impact. For more information about this scenario, please refer to the NZE chapter.

Key assumptions

[16] EV MWh Sales of 6,940 in 2030 times 1.15 reliability and line loss factor; EV MWh sales of 27,317 times 1.15 reliability and line loss factor.

As with other beneficial technologies, the potential impact of EV adoption in Burlington is measured, in part, by our assessment of the benefits and costs of EV ownership for customers, BED and societally. The more cost-effective EVs become over time, the more EVs that will be purchased by Burlingtonians. However, the rate of adoption will be tempered by slow vehicle turnover since most vehicles remain in service for 10-15 years. Thus, replacing traditional ICE vehicles with EVs will be a slow process.

To model the cost effectiveness of AEVs, BED incorporated the following major inputs into its testing procedures.

Major Assumptions - All Electric Vehicle, new & preowned (lifetime)		
Customer	Est. Incremental Costs	$7,000
	Maintenance Savings	$2,122
	Fuel Savings	$7,988
	Measure Life (yrs)	12
BED	Increased MWh sales/year	3.01
	Net Revenue	$584
	Ann. Miles Driven	9,500
	Tier III Costs	$1,380
	Credits	37.69
	Net Tier III MWH e Cost	$21.12
BTV	GHG Emissions reductions	36

For BED, each AEV travelling between 8,000 and 10,000 miles annually will consume about 3.01 MWhs. BED assumes that nearly all AEV owners will elect to subscribe to BED's EV rate credit program, providing such customers with a significant retail electric discount of $0.06 per kWh. Pursuant to BED's approved EV rate tariff, customers enrolled in this program agree to charge their vehicles after 10:00 pm and before 12:00 pm . In return for adhering to this tariff condition, BED customers will be able to charge their vehicles for $0.08/kWh. Under this scenario, BED expects to generate net income of just $0.02/kWh, which will provide a modest contribution to fixed costs. At this lower contribution rate, BED therefore anticipates generating between $60 and $70 annually from each AEV, or about $584 on a net present value basis over the 12-year life of a vehicle (assuming the rate credit program remains effective during this period).

For PHEV's many of the same assumptions are applied to determine their cost effectiveness, as shown in the table below.

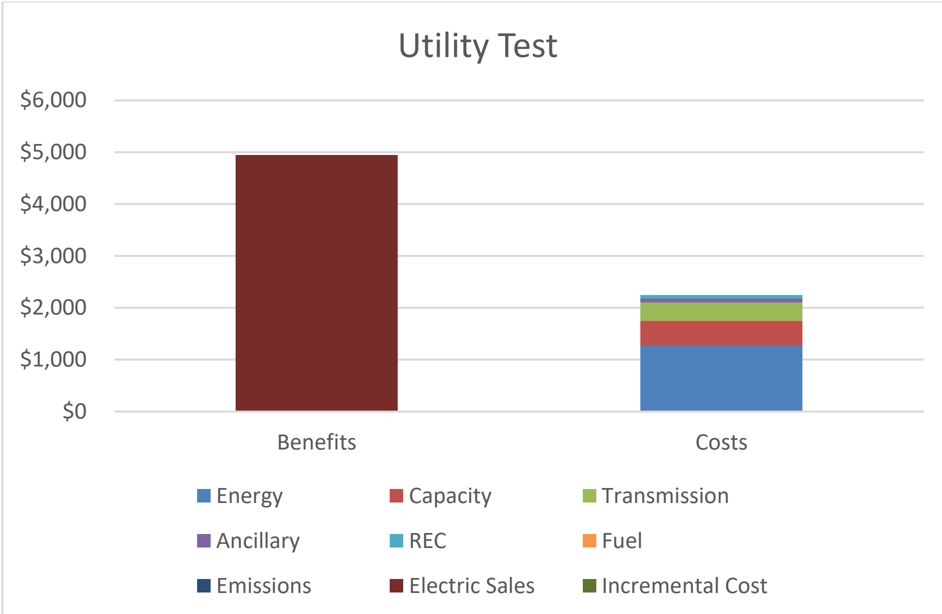
Major Assumptions - Plug In Elec Vehicle (lifetime)		
Customer	Est. Incremental Costs	$4,200
	Maintenance Savings	$1,034
	Fuel Savings	$3,928
	Measure Life (yrs)	12
BED	Increased MWh sales/year	1.596
	Net Revenue	$308
	Ann. Miles Driven	9,500
	Tier III Costs	$1,380
	Credits	28.20
	Net Tier III MWH e Cost	$38
BTV	GHG Emissions reductions	19

Customer Impacts:

As the tables above indicate, new EV owners could easily lower their transportation costs by switching to electrically powered vehicles. AEV owners would experience a simple payback on their incremental investment ($7,000, net of federal income tax credits and utilities rebates) of less than a year in fuel savings alone, especially if they charged in accordance with BED's residential credit tariff. Assuming each AEV owner drives 9,500 miles annually, their gasoline costs of nearly $10,000 (in 2020 dollars) would be completely avoided but their electric costs would increase by approximately $2,300. And, since AEVs require far less maintenance, owners should also experience significant maintenance related savings over time. PHEV owners will also benefit from these savings at a smaller scale.

Utility Cost Test

Increases in the number of EVs charging in Burlington has the potential to generate modest net utility benefits for all customers, even those who do not own an EV. This is so because EVs are load builders and generate incremental MWh sales in excess of the cost to serve them. For customers that take service under BED's existing EV rate, the net benefits are even greater. Under a BAU scenario in which an EV is uncontrolled, utility net benefits are anticipated to amount to approximately $2,700 per AEV (slightly less for PHEVs). If 80%of AEV owners take service under BEDs EV rate, net benefits could increase to approximately $3,500 per vehicle. Utility benefits amount to roughly $4,900 in retail revenues (in 2020 dollars), while costs include energy ($1,300), capacity ($475), transmission ($361), ancillary ($76) and RECs ($60).



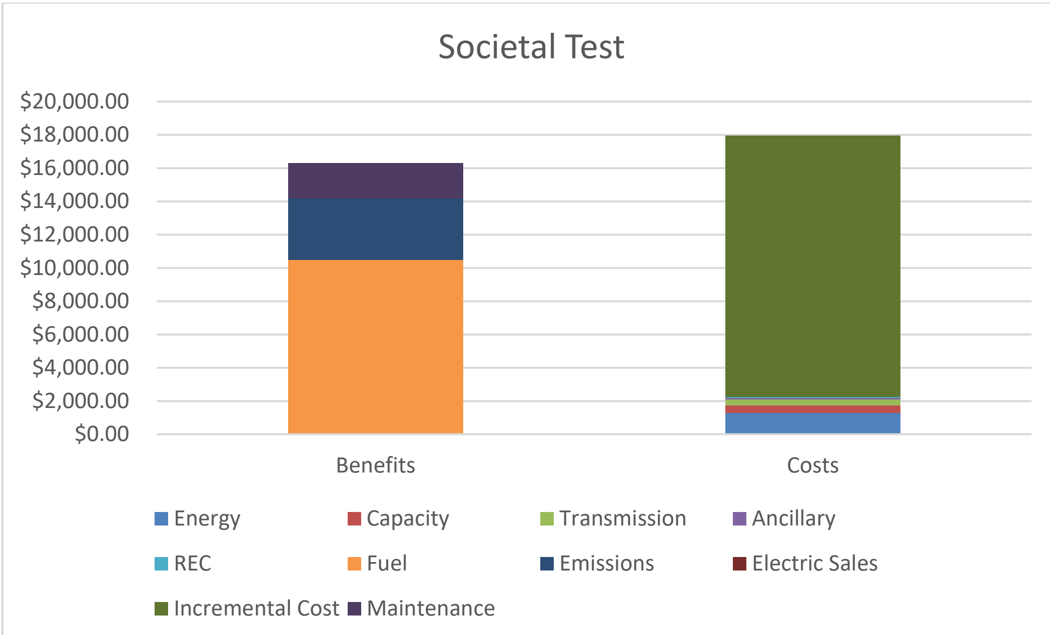
Societal Cost test

Under the net societal cost test, overall costs could amount to more than $1,600 per AEV, resulting in negative net societal benefits. Societal costs exceed benefits due to the high incremental costs of AEVs ($15,700) relative to traditional ICE vehicles.[17] Unlike the customer and utility cost tests, incentives such as the federal income tax credit and utility rebates are considered transfer payments from one group of customers to another. Thus, incentive payments are not factored into the analysis and the full incremental cost of an AEV must be included in the analysis since someone is paying for the higher cost of an AEV (i.e. society at large is through higher taxes and/or utility rates). However, the incremental cost of an AEV is highly speculative and subjective. It depends on the baseline vehicle (i.e. ICE vehicle) that is used for comparison, the trade-in value of an existing vehicle and the type of AEV that the owner is considering for purchase. For purposes of this analysis, the $15,700 incremental value assumes an MSRP of $40,000 for an AEV and a MSRP of $24,300 for a traditional ICE vehicle. In BED's view, prospective? AEV owners would likely be comparing the cost of an AEV to a $30,000 to $35,000 ICE vehicle. If this were the case, then societal benefits would be slightly positive per AEV.

Additionally, the full cost of AEVs is widely expected to decrease over the next few years as the above-mentioned manufacturers introduce new products to the market and battery costs fall.[18] Other societal benefits include gasoline savings ($10,500), avoided CO2 emissions

[17] *See;* 2019 Tier III TAG annual report.
[18] For additional information, *See:* https://theicct.org/sites/default/files/publications/EV_cost_2020_2030_20190401.pdf

($3,686) and vehicle maintenance savings ($2,100). Other incremental costs include energy purchases to serve the AEV load ($1,300), capacity ($475), transmission ($361), ancillary ($76) and RECs ($60).



Recommended course of action

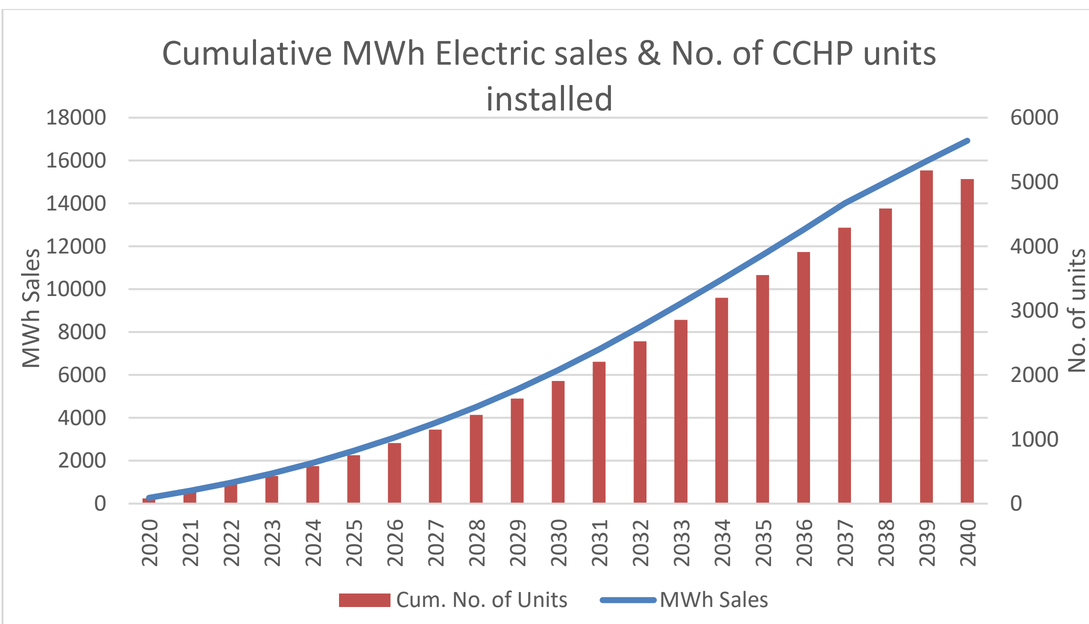
As noted above, BED shall continue to vigorously support local and State efforts to expand the light duty EV market. Primarily, these activities include providing financial incentives to customers, raising customer awareness, engaging auto dealers and public outreach.

Heat Pumps

As noted in its 2020 Tier III plan, BED will continue to support the installation of heat pump technologies in homes and businesses. Such technologies include but are not limited to cold climate heat pumps ("CCHPs") and heat pump water heaters ("HPWH") for residential customers, and variable refrigerant flow pumps, efficient air-to-water heat pumps and even, potentially ground source heat pumps for commercial and residential customers. For purposes of the IRP, BED has modelled the impacts of ccHPs and HPWHs, as these technologies are likely to be adopted by customers in greater numbers and may impose a larger impact on BED's resources than the other beneficial electrification technologies.

BEDs existing CCHP and HPWH programs will primarily target new construction and major rehabilitation projects, as well as "green" customers seeking to dramatically reduce their carbon footprint and disconnect from the natural gas pipeline. Targeting these segments of Burlington's building space conditioning market provides for greater opportunities to offer meaningful financial assistance to customers, as CCHP and HPWHs can be a lower first cost solution compared to installing a traditional fossil fuel boiler and hydronic distribution system. For example, the cost of installing a CCHP is approximately $4,500 compared to $5,500 to $7,000 for a natural gas fired boiler. BED is not aggressively seeking to persuade natural gas customers to augment their existing heat system by installing a CCHP because natural gas customers who install a CCHP will most likely experience higher home heating bills as natural gas heating costs are lower than electric heating costs. BED will instead provide potential retrofit customers, if asked, information about whether a CCHP is the right solution for them given their circumstances and carbon goals. BED will also suggest that customers weatherize their building before installing a CCHP.

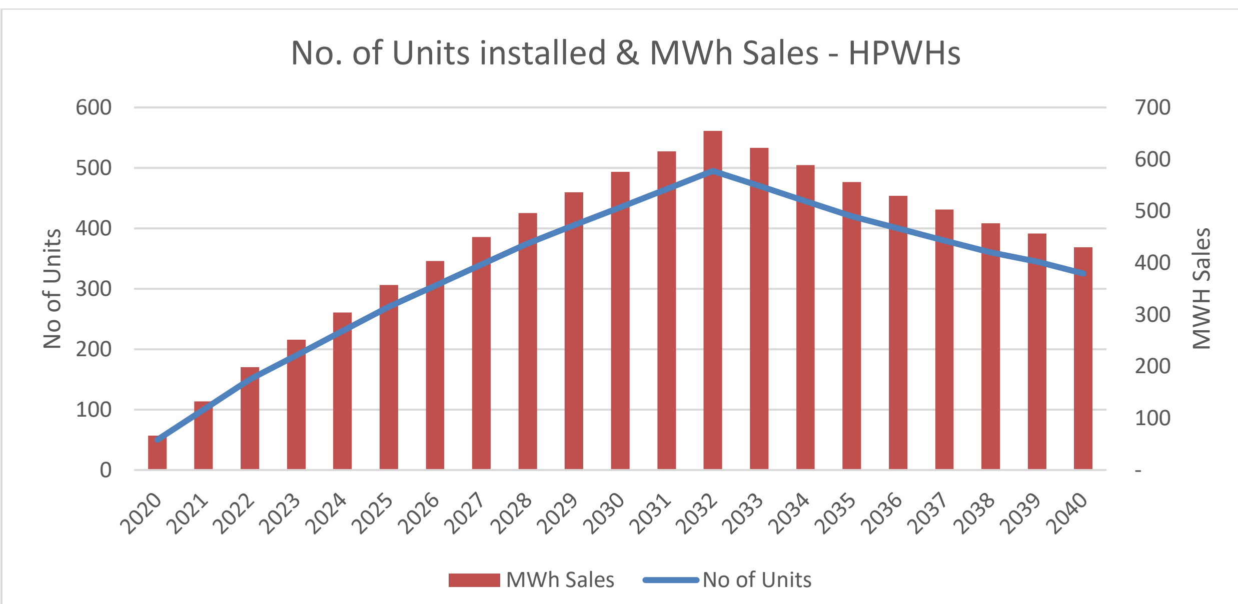
Due to the cost challenges that CCHP and HPWH face related to the low price of natural gas relative to electricity, BED believes that the number of forecasted CCHPs and HPWHs that could be installed in the City will be substantially less than the forecasts of other distribution utilities in Vermont. As shown in the graph below, BED expects as many as 80 to 90 CCHPs to be installed throughout the City in each of the next several years before tapering off in later years. Cumulatively, the number of installed CCHPs throughout the City may exceed 5,000 units by the end of 2040. As CCHPs are installed, MWh sales will of course increase; reaching roughly 17,000 MWhs by the end of2040.



When customers install CCHPs, BED is committed to actively promoting the installation of active controls so that customers are able to effectively monitor the British thermal unit (BTU) output of their heat pump based on internal building conditions and outdoor air temperatures. Such controls, in theory, allow for alternative heating systems (such as electric resistance for newly constructed buildings, or existing natural gas fired boilers in homes) to be used as the primary heat source heat during exceptional cold periods when the newly installed heat pump's output and efficiency are severely compromised. Such controls may also provide BED with the capacity to shift demand from exceptionally high cost periods to lower cost periods to reduce capacity and RNS costs. It is important to note that BED's active control of heat pumps will almost always occur during the summer months to shift cooling related electric loads, as opposed to shifting loads during winter periods when heating needs are critical. Moreover, when customers call BED energy services staff for technical advice, customers will be encouraged to also increase the weatherization of their building as a means to improve comfort and heat pump performance.

It bears noting that customers can also access CCHP incentives through the statewide upstream program administered by Efficiency Vermont and BED. When they do, third party contractors typically install the CCHP equipment and pass along the incentives to the customer. Such incentives are paid to CCHP distributors out of BED's electric energy efficiency budget and passed along to customers.

As for HPWH, BED similarly does not expect that increases in the number of installations will have a material impact on resource planning efforts.



As highlighted in the graph above, total MWh sales may top out at 430 MWh, assuming a cumulative total of 325 units are installed by 2040.[19]

[19] The number of units installed tapers off after 13 years as units are retired from service and not replaced with a new HPWH.

Key assumptions

For purposes of evaluating the impact on BED's resource planning activities, the following major assumptions were made for CCHPs.

Major Assumptions - CCHP	Single head		Multi head
Installation cost	$4,500		$8,000
Ann. MWh Sales (avg.)		3.27	
Ann. Net Rev. (at $0.10/kWh)		$327	
Net Electric Rev.(Lifetime, NPV)		$4,309	
Measure Life	18		18
Avg. COP	2.4		2.4
Avg. FF displacement (%)	40%		50%
Avg. Incentive, incl. Admin		$875	
Avg. net lifetime credits	15		29
MWh e Cost (net)	$ 37		$19

With respect to HPWH, the following assumptions applied to our models:

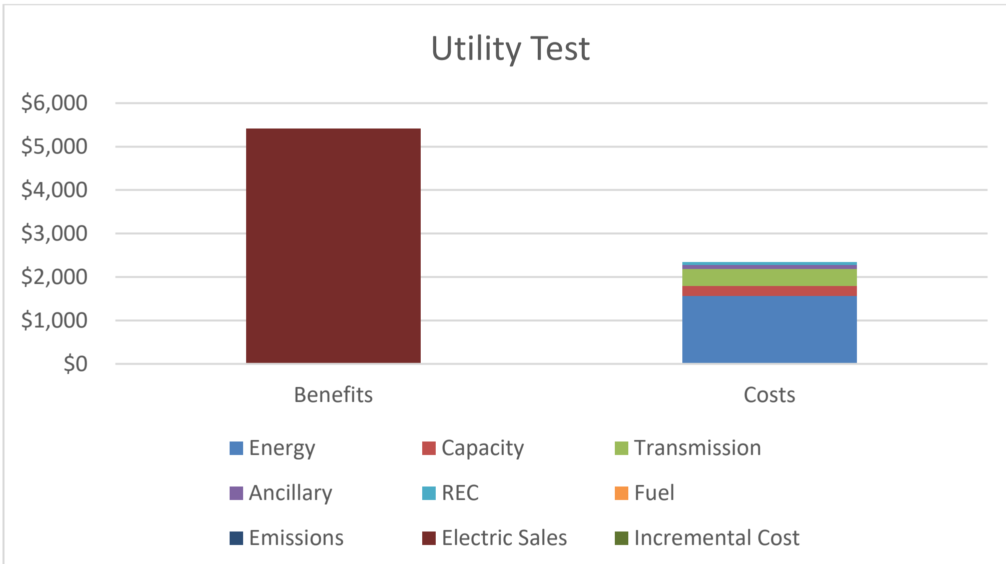
Major Assumptions - HPWH	
Installation Cost	$2,100
Avg. MWh usage (ann.)	1.32
Ann. Net Rev. (at $0.10/kWh)	$132
Net Electric Rev. (Lifetime, NPV)	$1,364
Measure Life	13
Avg. COP	2.05
Fuel Displacement	100%
Avg. Incentive, including Admin	$690
Avg. net lifetime credits	18.96
MWh e cost (net)	($36)

Utility Cost Test

As is the case with increasing EV adoption, an increase in heat pump installations will increase electric loads in Burlington. [20]Thus, they have the potential to generate net utility

[20] It bears noting that the customer, utility and societal cost tests herein reflect the results of our CCHP results. But, BED has also conducted similar tests of HPWH. In the interest of brevity, the HPWH test results have been omitted. Although the amount of the net benefits or costs differ slightly between the

benefits for all customers, even for those who do not install one in their building through downward rate pressure resulting from increasing electricity sales. Based on the above major assumptions, each CCHP installed could generate net benefits of approximately $3,000 (in 2020 dollars) over its 18-year lifespan. Benefits are driven by incremental lifetime electric sales of $5,400 per unit. Utility benefits are offset by increased costs associated with energy ($1,567), capacity ($224), transmission ($395), ancillary ($85) and RECs ($66).



It is important to note however that the economics of the CCHP are very sensitive to a host of important variables including each unit's coefficient of performance COP, room layout, building weatherization, outside air temperatures and fuel prices. Any deviation from the assumptions highlighted above could materially affect the currently anticipated net benefits of heat pumps in Burlington. The same is applicable to the customer's economics, as well as the societal costs test, which is further described below.

Societal Cost Test

Under the net societal cost test, overall lifetime costs exceed benefits by roughly $2,300 per CCHP installed. Total benefits are generated by natural gas fuel savings ($3,000) and avoided emission costs ($1,500). Lifetime costs are primarily driven by the incremental cost of installing a heat pump ($4,500) but also because of the low cost of natural gas in Burlington. Incremental costs can vary considerably and depend on the circumstances related to each building's characteristics and its existing electric systems. For example, if the building's

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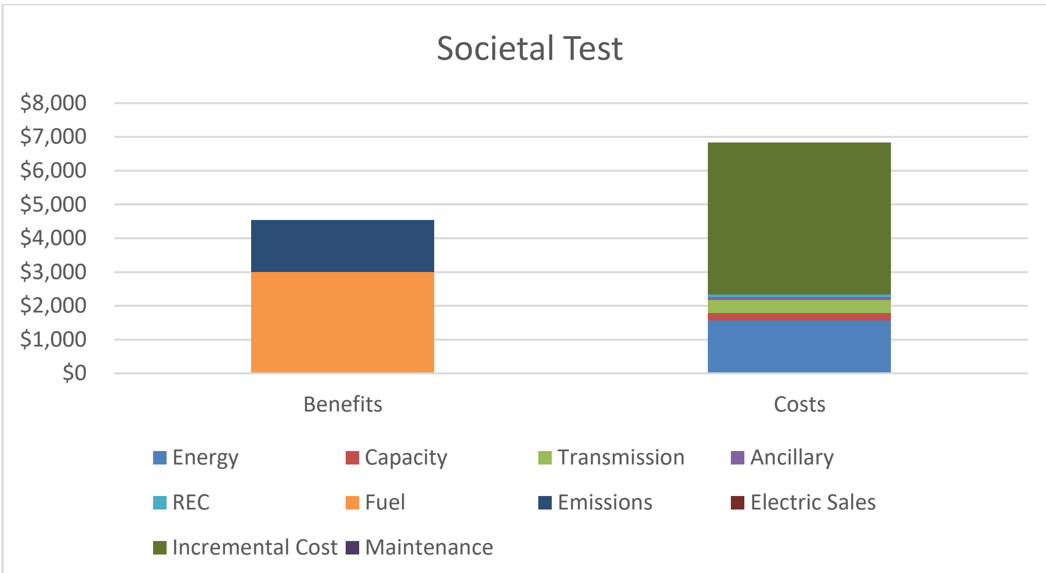
two technologies, the HPWH results are highly similar directional to that of the ccHP results; meaning that HPWH are expected to generate net losses under the customer and societal cost tests, and marginal net benefits under the utility cost test.

electrical junction box needs upgrading, installation costs could easily exceed the average cost of $4,500 per CCHP. Otherwise, installation costs for small single family homes could be significantly less as a single head unit would likely serve the majority of the heating needs of the home. In such instances, the customer would not need to substantially augment the building's electrical system. Plus, the energy savings of a smaller home could be greater than the amounts assumed for modelling purposes.



Other societal costs include energy ($1,566), capacity ($224), transmission ($394), ancillary ($85) and RECs ($66).

Recommended course of action.

Consistent with its NZE, Tier III and EEU initiatives, BED is committed to supporting the aforementioned heat pump programs to the greatest extent possible. Such support includes but is not limited to financial incentives, technical assistance and increasing public awareness about our clean energy programs, in general, and heat pump technologies in particular. All of BED's efforts are designed to address barriers to program participation, as well as to provide meaningful assistance to the State's effort to reach its own clean energy goals.

Conclusion

Although the reservoir of traditional electric energy efficiency project savings may be diminishing due to extraordinary advancements in lighting technologies (and the increase in energy codes and appliance standards), and other electric savings are expected to cost more, investing in traditional electric efficiency in Burlington will provide valuable cost savings for some time to come. The primary reason to continue investing in traditional electric efficiency is to offset the anticipated increase in electric load and peak demand that will likely be triggered by BED's beneficial electrification programs and NZE initiatives. To effectively address these anticipated increases, BED will continue to combine its traditional electric efficiency investments and programs with its beneficial electrification (or Tier III) programs. Combining these services together into a comprehensive, customer-centric energy service offering has multiple co-benefits including but not limited to the following:

- Combining energy services helps to reduce the first-year cost of saved traditional electric savings by spreading overhead costs over more service offerings;
- Customers have expressed an interest in BED combining energy services together as a means to fully address their total energy needs; and,
- Combining energy services helps to alleviate the potential grid impacts of increased adoption of EVs and advanced heat pumps in the City.

Recommended course of action

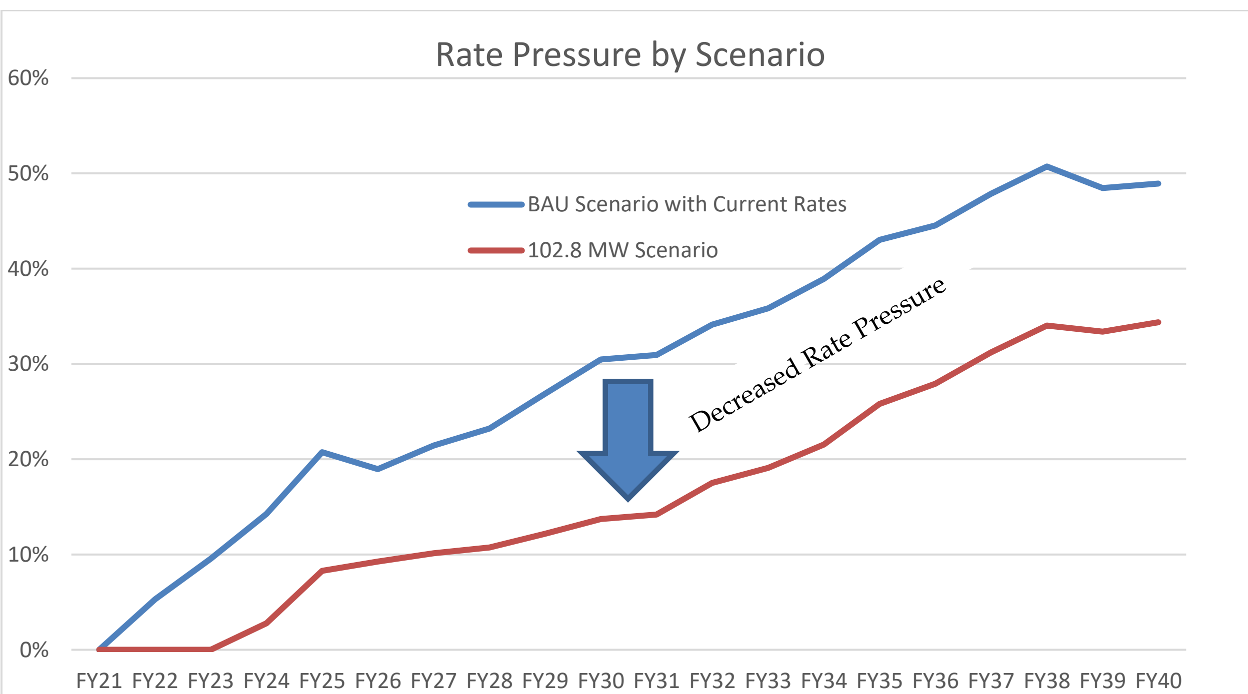
Based on the above, BED will continue to combine traditional electric energy efficiency investments and program services with beneficial electrification services into comprehensive energy services to better serve customers. By combining services together, BED will be able reduce the acquisition cost of traditional electric energy efficiency as well as offset the expected grid impacts that may be triggered by increased adoption of EVs and advanced heat pumps. Pursuing the maximum achievable electric efficiency goals will also help to improve BED's overall resource adequacy needs relative to pursuing a lower electric savings goal based on a budget-constrained potential savings model.

Chapter 6 – Financial Assessment and Potential Rate Pressure

Methodology

A financial analysis model was developed for this IRP to reflect BED "business as usual" ("BAU") costs and revenues over the next 20 years. Also, the IRP Model inputs for the first five years (2021-2025) include more detailed financial forecasts, which BED prepares annually for planning purposes.

The model was used to generate a profile of "rate pressure" over time, which we define as Cost of Service divided by Customer Sales. The use of a rate pressure profile has advantages - over a simple 20-year NPV cost-of-service, as it provides additional information on the timing of impacts and the possible beneficial impact on rates from increases in load which tend to reduce average costs (even though these increases in load do increase total costs). The graph below, extracted from the Net Zero chapter, is an example of looking at the estimated impact on rate pressure of the earlier stages of Net Zero/strategic electrification (see Chapter 8 for a detailed discussion of this graph and the assumptions it represents). It is important to understand that pressure to increase rates generally exists for all utilities due to inflation (both for materials and labor), fuel price changes for energy production, increasing transmission costs, and other cost pressures. Managing these pressures to minimize the need to raise customer rates in the future is one of BED's primary goals.



Even though prior IRPs showed that rate pressures were prevalent through the filing of this IRP, BED has been able to successfully manage the impact of that pressure on rates, as we have not had to raise rates since 2009, . Avoiding rate increases forever is not a realistic goal, however. But understanding the factors that tend to affect rates is a useful exercise to try to manage those factors and to minimize their impact on our cost of service.

Accordingly, BED uses the IRP financial model to establish a "baseline" indication of pressure on rates. Based on what this signal is telling us, we can then attempt to take further action (or not take action) to avoid those rate pressures ultimately requiring an increase in retail rates. As an example, BED can then use the rate pressure metric to evaluate actions such as electrification under net zero (see the Net Zero chapter for additional detail). <u>However, the IRP financial model is not used to estimate when BED might actually need to file an increase in rates due to the uncertainty over future value of key inputs (see later in this chapter for discussion of ranges in key variables and the impact on rate pressure) and due to the differences between the budgeting and rate setting processes.</u>

Five- and 20-year NPV values are however examined to derive tornado charts showing the sensitivity of the financial cost model to changes in key variables. BED has more ability to hedge certain key variables such as Energy and REC prices through purchases and sales in the initial five-year period of the IRP, and the FCM market structure increases capacity price exposure after the first three years. Accordingly, certain very high risks in a 20-year tornado analysis may be of relatively lower concern when the five-year impact on utility costs is considered.

Years 2026-2040 include higher level assumptions that are largely based on inflation. Key variables were stress-tested using tornado charts to represent the potential impact of these variables on our BAU financial model. The financial model was prepared at a high level and is not intended to support a current or future rate filing, which would require known and measurable support and prior local government approvals.

Assumptions

A 20-year forecast is dependent on many variables. These are discussed below, as well as the impact of potential expected changes in those variables on BED's bottom line.

Net Power Costs

BED uses a power cost model based on its one- to five-year budgeting model with assumptions extended for the five+ year period. Many assumptions, such as ISO-NE ancillary costs, are forecast with simple escalation factors. Some variables, however, receive a multi-scenario treatment due to their relative impact on the overall net power cost budget, as described in more detail below.

Meaning of "Long" and "Short" in this IRP

Under the ISO-NE energy market structure, a utility is responsible for buying all of the energy its customers require, and then to offset those costs, it sells all of the energy available from its resources to the wholesale energy market. The same general process applies to the ISO-NE Forward Capacity Market for capacity as well. If BED has excess energy or capacity resources (i.e. "long" energy and capacity) during periods of high wholesale energy prices and demand, the increased load cost tends to be more than offset by increases in revenue from generation. Conversely, in situations when BED is "short" on either energy or capacity and needs to purchase additional energy supply at higher prices to serve loads in the City, additional generation revenue is generally insufficient to offset the higher energy costs. If BED can maintain a balance, in most hours, between generation and load settlement, BED's cost to serve load should not be materially affected by ISO-NE's wholesale energy market prices.

However, if energy and capacity prices change over time, so too does BED's net cost to serve load. Table 1, below, provides a summary of the potential impacts of wholesale prices on BED from the perspective as both a generator and load serving entity. Being long, i.e. a net supplier of a resource, means that high prices generally benefit you, with the opposite being true when you are a net purchaser (i.e. high prices harm a next purchaser). This discussion focuses on energy and capacity, but many of ISO-NE's markets possess a similar dynamic (regulation/AGC, Forward Reserves etc.) and if BED were to make reference to being "long" with respect to AGC it would have similar implications.

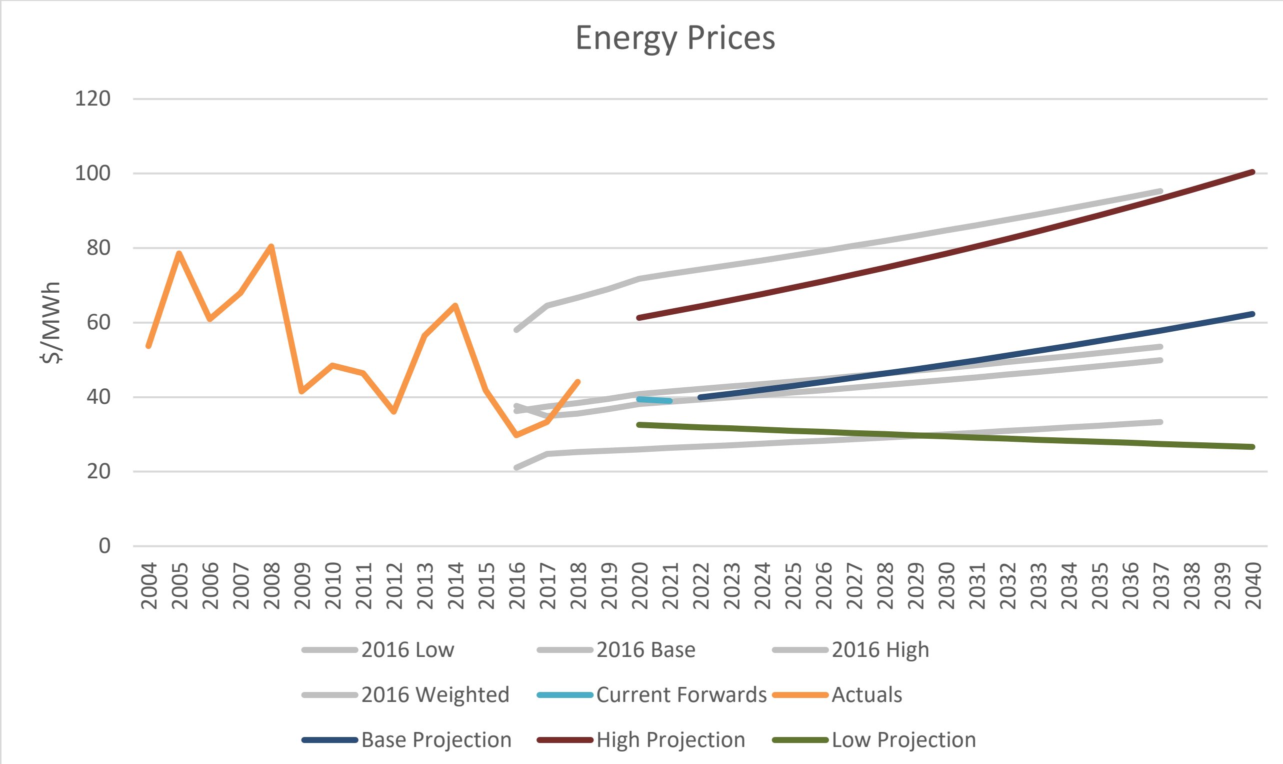
Table 1: Wholesale Energy and Capacity Price Effects on BED's Cost of Service

	ISO NE Wholesale Prices from BED's Dual Perspectives	
	High prices	**Low prices**
Long Energy or Capacity	Benefit (higher net resource revenues)	Cost (lower net resource revenue)
Short Energy or Capacity	Cost (higher net load charges)	Benefit (lower net load charges)

Wholesale Energy prices

Based on our assessment of energy price risk, BED expects future wholesale energy prices to remain relatively stable over time, as shown in Figure 1.a below. The slope of the price increases and the starting point price are similar to the ones in our 2016 IRP.

Figure 1.a: Wholesale Energy Price Forecast



Wholesale electric energy prices are influenced by myriad factors. The single greatest influence on future electric prices in New England is natural gas prices. Between 2000 and 2020, the average share of natural gas–fueled electric generation in New England has increased from 15% to 49%. Generally natural gas electric generators are the marginal unit of production and thus set wholesale electric prices in New England in most hours. This is reflected in the strong correlation between natural gas prices and wholesale electric prices, as shown in Figure 1.b. O

Over this same period, the price of natural gas has gyrated from a low of less than $2/mmBTU to a high of $9/mmBTU in 2008, as shown in Figure 1.c. More recently, spot natural gas prices at the Henry Hub gateway are lower, on average, than they were in 2000, and have averaged less than $2/mmBTU in 2020.[1] The reality of relatively low natural gas prices has not changed since the publishing of our 2016 IRP and is unlikely to materially change by the time BED files its next IRP. Longer term, natural gas prices are expected to increase moderately; therefore, wholesale electric prices are also expected to rise by roughly 2 to 2.5%[2] annually over the IRP period.

[1] See; https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm - accessed July 2020.
[2] This is close to the assumed inflation rate for this period.

Figure 2.b: New England Wholesale Electric and Natural Gas Prices[3]

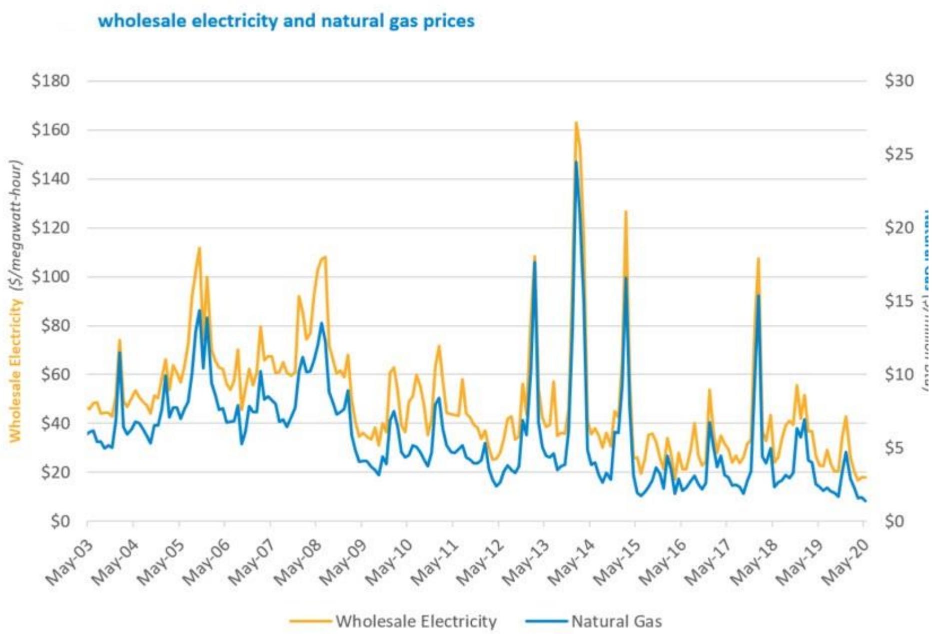
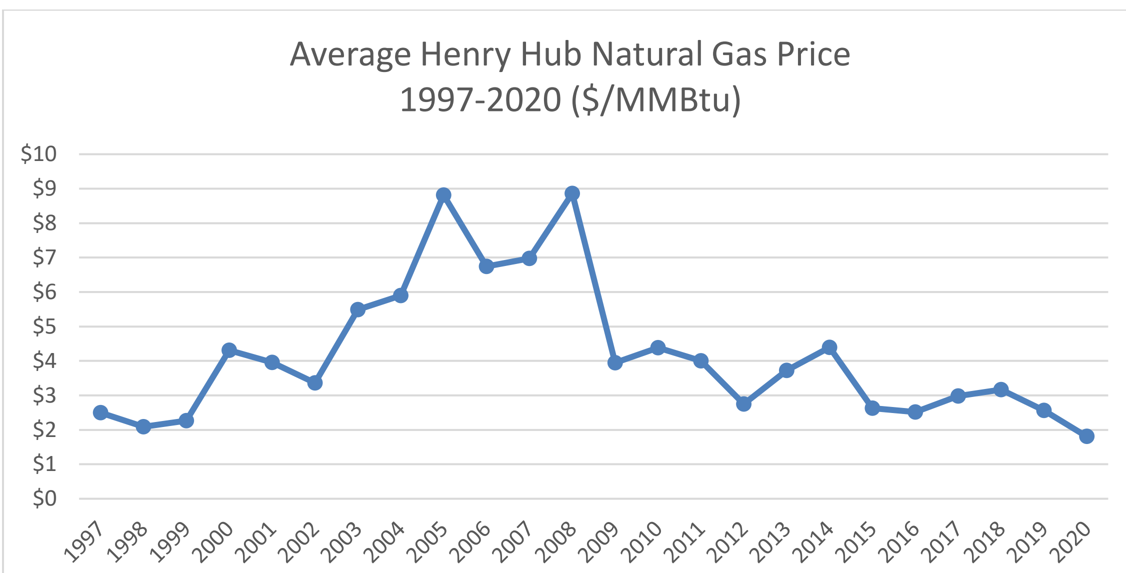


Figure 3.c: Historical Henry Hub Prices



While fluctuations in wholesale energy costs are highly correlated with fluctuations in natural gas prices, they do not line up with BED's net energy costs that are passed onto consumers in retail rates. As BED is both a generator and a load-serving entity, this adds a layer

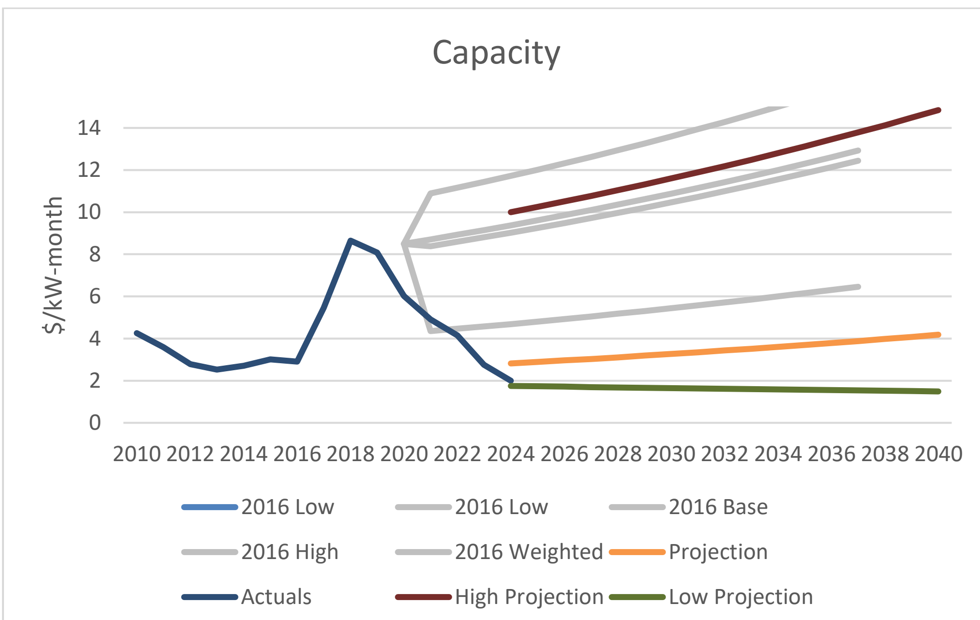
[3] http://isonewswire.com/updates/2020/6/24/monthly-wholesale-electricity-prices-and-demand-in-new-engla.html, accessed July 2020

of complexity to predicting how wholesale energy and capacity prices will impact BED's cost of service. For BED, day-ahead and real-time energy settlements and forward capacity payments represent both revenues and costs.[4] For example, BED earns energy and capacity revenue from its generation resources (i.e. McNeil, Winooski One, etc.) as they deliver energy and capacity to the ISO-NE markets. Energy and capacity, however, also represent costs to BED as a load-serving entity. All things being equal, higher energy prices typically result in additional revenues for BED as a generator when BED has excess resources. However, higher prices also increase the cost to serve BED's load.

Wholesale Capacity Prices

Based on our risk-adjusted weighted-average assessment of capacity price risk, BED also expects future capacity prices to remain relatively stable over time, as shown in Figure 2 below. Additionally, the slope of future capacity prices remains unchanged from our 2016 IRP analysis.

Figure 4: Capacity price forecast



As discussed in the Generation and Supply chapter, BED is capacity short by approximately 30 MWs and will likely remain so over the next several years. A capacity shortfall is not uncommon for Vermont's distribution utilities. Like other Vermont distribution utilities, BED's capacity situation is a function of its energy supply's renewability, and ISO-NE's reserve margin reliability requirements. While its renewable resources may generate sufficient energy in most hours of the year, the capacity value of BED's renewable resources is de-rated in accordance with ISO-NE's market rules. Thus, BED will need to purchase additional capacity

[4] See Appendix B for more detail on Day Ahead and Real Time energy market rules and practices.

above and beyond the amount provided from BED's existing resources (primarily from the McNeil plant and the Gas Turbine).

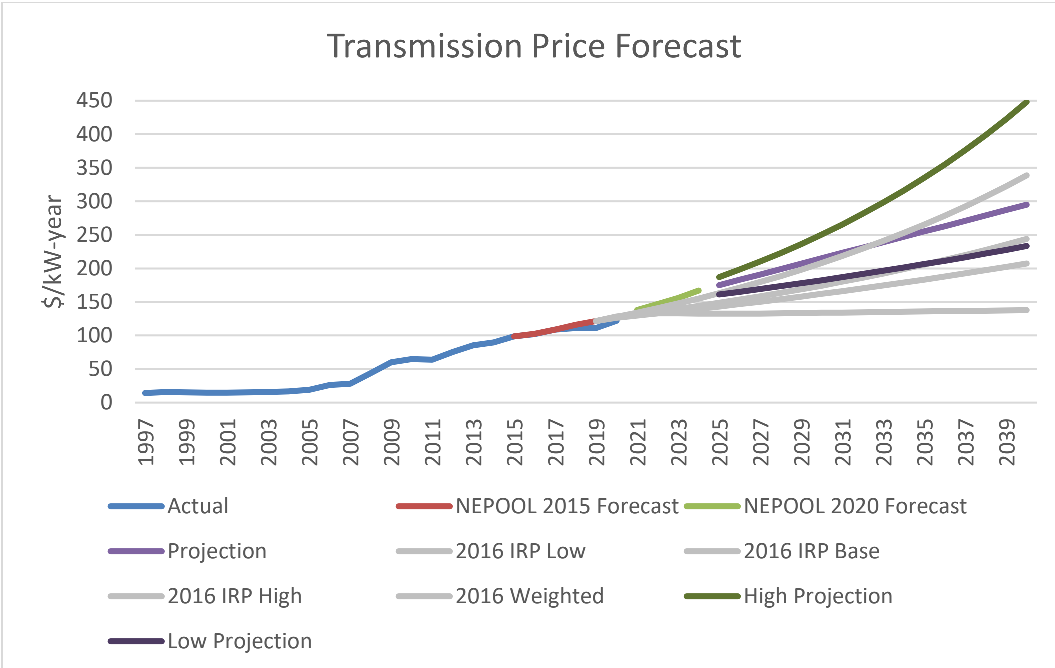
The most recent auction (February 2020) cleared capacity resources at $2.00 per kW-month; capacity prices have now decreased for the last five auctions. Moving forward, BED expects capacity prices to increase at a modest rate over the IRP planning period. This view is primarily a function of future fossil-fuel plant retirements. As existing plants are retired over time, new plants will be built and commissioned. The cost of any such new plants and changes in projected peak demand are the main determinants of future capacity prices. ISO-NE rule changes may also lead to changes in capacity costs and revenue.

As with energy costs, increases in wholesale capacity costs do not necessarily correspond with increases in retail rates because BED earns capacity revenues as a generator. Unlike with its energy, however, BED is unlikely to be able to fully offset potentially higher future capacity costs to serve load with higher capacity revenues since most of its resources are de-rated renewable resources.

Transmission Costs

BED pays for transmission services to wheel energy generated from ISO-NE recognized resources to its customers. Such service is paid under a wholesale tariff, known as the regional network service ("RNS") and is regulated by FERC. Currently, RNS tariff rates are roughly $11 per kW-month. Based on our risk-adjusted assessment of transmission price risk, BED currently projects RNS costs for 2020 to be somewhat higher than our 2016 assessment projected. As shown in Figure 3 below, future RNS costs are expected to increase to $25 per kW-month by 2040. Annually, the rate of RNS increases is estimated at roughly 4%.

Figure 5: Regional transmission costs

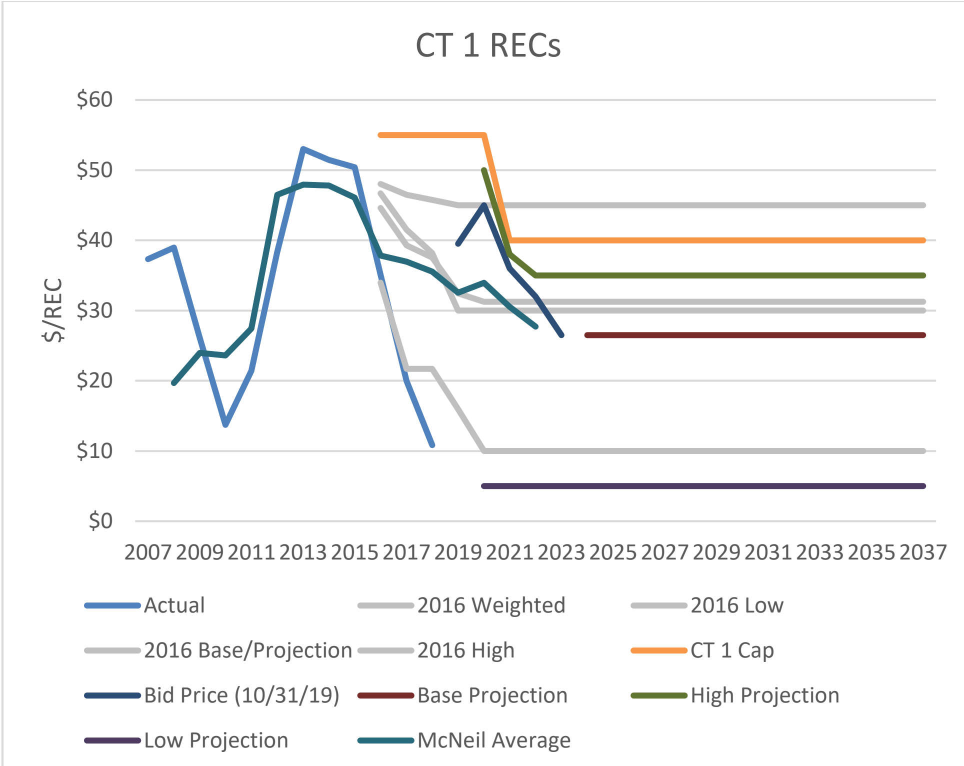


RNS cost drivers are numerous, and include replacing aging infrastructure, more stringent reliability requirements, and network congestion. Complicating matters is the difficulty in avoiding regional transmission costs, even in a future world consisting of greater amounts of distributed energy resources ("DERs"). At first glance, increases in DER assets may initially lower RNS charges, but over time such reduced costs will be offset as ISO-NE increases transmission rates to recoup its investments. Because maintaining a reliable bulk transmission infrastructure is of paramount importance and most transmission costs are socialized across the region, RNS charges are non-bypassable for New England distribution utilities, although they may be shifted between entities subject to the RNS tariff to some extent. Thus, an increase in DERs in Vermont, or elsewhere, will only result in a decrease in future transmission charges (for New England as a whole) if it postpones construction of additional transmission assets.

Renewable Energy Credit Prices

Over the 2020 IRP time horizon, BED anticipates that the price of renewable energy credits ("RECs") will stay at $26.50/MWh after 2024.

Figure 6: REC prices



BED owns the rights to sell or retire RECs[5] generated from the following resources:

Table 2: BED Resources and REC Market Destinations

Resource	REC market sales to…..
McNeil	Connecticut - CT1
Wind: Georgia Mtn., Sheffield, and Hancock	Connecticut – CT1, Massachusetts – MA1, RI New
Winooski Hydro	Massachusetts – MA2 (non-waste)
Solar	Massachusetts – MA1

BED sells high-value RECs from owned generation, and then purchases lower value RECs and retires them. The net proceeds from these REC sales are applied as a reduction to our costs. Put another way, BED's cost of service to customers would be higher than it is today if we did not engage in this type of price arbitrage. REC proceeds are particularly important to the operations of the McNeil plant during this era of exceptionally low natural gas–derived wholesale electric energy prices.

BED's arbitrage strategy has, over the past few years, generated net cash flow of $6.9 million annually. The continued success of this strategy depends on a stable REC market that

[5] 1 REC equals 1 MWh of electricity from qualifying facilities.

consistently displays a generous price differential between high-value RECs (i.e., new renewable solar, wind, and other generators, etc.) and low-value RECs (i.e., older hydro facilities, etc.). Such price differentials, however, are not guaranteed into the future. Higher value REC prices are expected to decline over the next few years and could also continue to swing erratically in value as they have in the past. Meanwhile, low-value RECs are not expected to decline much more and may in fact increase with the implementation of the Vermont RES. In fact, the long-term price of higher value RECs is currently uncertain; hence the wide disparity between the High Projection for CT Class 1 REC prices (a net benefit) and the Low Projection (a net cost), as shown in Figure 4, above.

The price of a REC generally reflects the relative cost of developing certain types of renewable resources as compared to non-renewable alternatives. REC price volatility, however, can also be driven by regulatory uncertainties, demand for power, and the anticipated commissioning of new renewable generation facilities. Higher REC values stem from regulatory mandates requiring utilities to provide more generation from renewable sources or increase the amount of REC purchases, as this creates greater demand for existing RECs and may require development of new renewable resources. On the downside, requirements to purchase more solar power (or solar RECs) relative to other renewable resources have the effect of depressing the value of other RECs, such as those generated by McNeil. Similarly, legislation that weakens or eliminates existing renewable mandates would dramatically lower REC prices.

A few factors have caused recent uncertainty in the markets: the development of Vineyard Wind, a 800 MW offshore wind facility expected to come online in 2023-2024 that will be eligible as a Massachusetts Class 1 resource; a 1,200 MW transmission line connecting Quebec hydro to Massachusetts that would be eligible for their MA Clean Energy Standard requirement and is expected to be complete in the next 3-5 years;[6] and, significant imports of New York wind continuing to be sold to load-serving entities in New England. While the first two developments are significant in the magnitude of new RECs supplied to the Class I market, requirements remain that could delay their completion dates. This has caused these markets to trade at a discount towards the 2023 and 2024 vintages. Anything beyond those vintages is currently traded infrequently, which makes it difficult to gain a reliable evaluation of that market. If these major projects come online in the next 5 years, a considerable decline in Class 1 RECs would likely result, but regulatory changes regarding state Renewable Portfolio Standard

[6] The Massachusetts Clean Energy Standard (CES) provides most of the renewable obligation for compliance buyers in the state. Currently, Class I RECs are being retired against this obligation. The alternative compliance payment (ACP) for this standard is set to 50% of the MA Class 1 ACP, causing new influx of cheaper CES RECs to flood the market.

requirements could then cause a REC price rebound. In the interim, a high degree of volatility can be expected related to news on these projects' progress.

Due to the uncertainty about future REC values, and BED's dependence on REC revenues, REC values represent the single biggest potential impact on future rate pressure. The lack of a readily accessible market for long-term REC sales and the potential for future changes in Vermont's RES make hedging this exposure in the longer term (greater than five-year window) very difficult.

Non-Power Costs

Other Operating Expenses

Operating expenses for the IRP planning period were calculated based on a projected inflation rate of 2%. Using inflation was deemed appropriate for purposes of this high-level long-term financial modeling.

Depreciation

The most appropriate method to forecast the depreciation expense for existing assets is based on remaining life and depreciation expense to date, layering on annual forecasted capital additions, and then calculating the additional depreciation expense for the additions based on their projected date of addition and useful life.

BED used a different approach that BED believes will achieve a materially similar result for the BAU case. As BED does not currently have the aforementioned method of calculating depreciation developed in a financial model, BED took the 2025 forecasted depreciation expense from the financial forecast and escalated it each year at a rate of 2.5%. As BED's weighted average depreciable life of assets is approximately 37 years, this would average approximately $5 million of capital additions each year, which is in line with BED's historical capital spend. The second step of calculating depreciation expenses requires making an adjustment to account for certain assets on a sinking fund basis. This adjustment was done based on the actual depreciation schedules using current straight-line depreciation on those assets vs. the depreciation expense on a sinking fund basis. BED intends to improve the modeling of capital additions and depreciation expense in its next IRP.

Amortization

Amortization expense is largely related to BED's IT Forward project. This was calculated based on planned in-service date and an estimated useful life of 10 years. Additionally, amortization expense is driven by the Winooski One Hydroelectric facility. The difference between the fair market value purchase price and the net book value was recorded as an intangible asset and is amortized over the life of the bond financing.

Dividend Income

For years 2021 to 2025, dividend income was calculated based on actual and forecasted investments in VELCO and Vermont Transco. For years 2026 to 2040, an inflationary increase was applied. For reasonableness, BED used the historical increase in recent years (FY2019 and FY2020) along with the expected increase budgeted for 2021 and forecasted for 2022 and 2023. BED concluded that while applying inflation to dividend income is not a preferred forecasting method, the outcome was deemed reasonable for purposes of this high-level analysis.

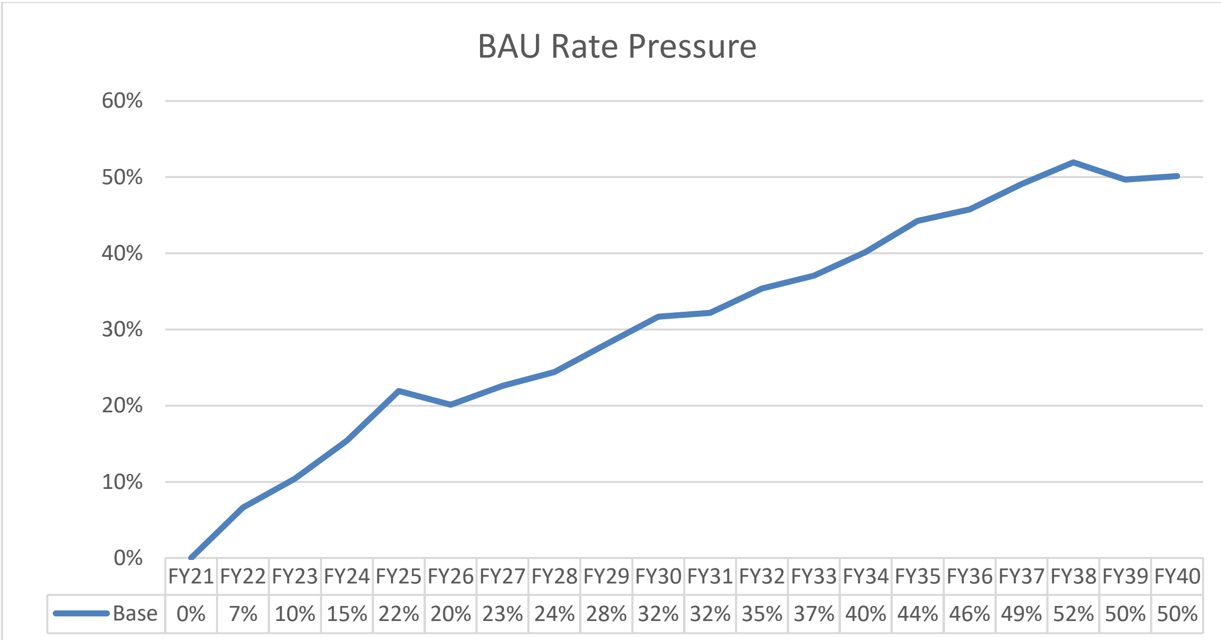
Long-Term Debt Interest Expense

For years 2021 to 2025, long-term debt interest expense was calculated consistent with the payment schedules on current obligations as well as layering on estimated annual issuances of $3 million consistent with historical interest rates. BED does not currently have a 20-year interest expense calculation built into a financial model. Thus, for years 2026 to 2040 we applied inflation to the prior year interest expense. BED evaluated the reasonableness of this calculation and deems it materially sufficient for purposes of this high-level evaluation.

Results and BAU Rate Pressure over time

Figure 5 shows BED's BAU Rate Pressure over time. Rate pressure over time is the cumulative change in average cost of service per KWH served compared to its current level. It could be reasonably expected that under normal circumstances there will be cost escalation over the 20-year period, as inflation over the previous 10-year period (2010-2020) averaged approximately 2%/year.

Figure 7: Rate pressure for Business as Usual (BAU)



This forecast is most useful in comparing rate pressure differences between decisions, and rate pressure and specific annual rate increases are not synonymous. Nor is rate pressure a projection of the need for rate cases over time. As described below, changes in certain key assumptions/variables can result in a material change in rate pressure.

Key Variables Used for Stress Testing

BED evaluates the impact of changes in key variables using "tornado charts" that illustrate the change in a specified result of a model (in this case Net Present Value Revenue Requirement or "NPVRR"). The NPVRR is the net present value (over five or 20 years) of the funds BED must collect from its customers. The tornado chart illustrates the impact of changing each variable from its low to base to high case, with the center line indicating all variables are set as base case levels. For example, in the following 20-year tornado chart, low REC value would increase the NPVRR by $57M. Generally, if the variable reflects an income item or cost offset, the impact of the low value will be to the right (i.e., an increase in NPVRR), and if the variable is a cost/expense, its high case value will be to the right, likewise reflecting an increase in NPVRR.

Evaluation of NPVRR results: 20-Year

The 20-year tornado chart is Figure 6 below. The volatility of the REC market dominates even inflation over the next twenty years in terms of risk to BED.

Figure 8: 20-year tornado chart showing sensitivity of NPVRR to 13 key variables

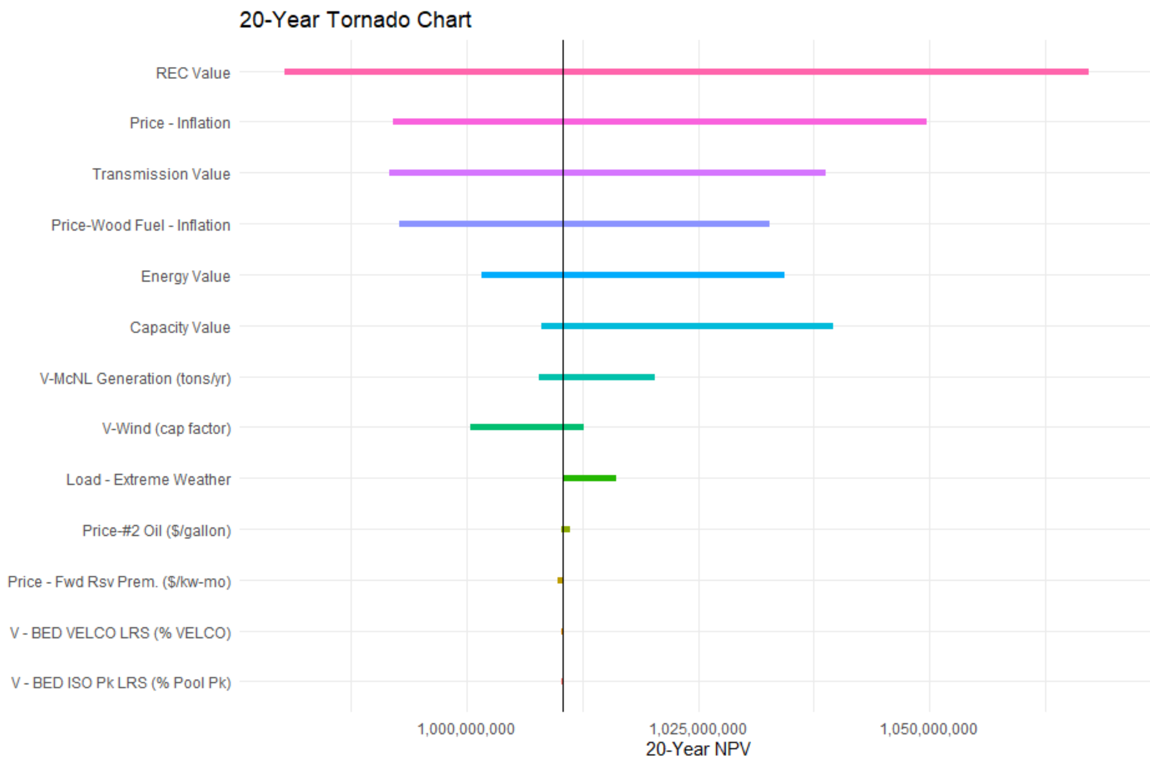


Table 3.a compares the range of risks that individual variables could impose on BED's cost of service.

Table 3.a: 20-Year Minimum, Maximum, and Max-Min Ranges

Price/Rate	Max ($M)	Min ($M)	$Max-$Min ($M)
REC	57	-30	87
Inflation	39	-18	58
Transmission	28	-19	47
Wood	22	-18	40
Energy	24	-9	33
Capacity	29	-2	32

The minimum potential impact of changes in REC values over the next 20 years is a reduction in expense of $30 million, but the maximum impact could be an increase of as much as $57 million, or a difference between these two risk profile scenarios of $87 million. This analysis indicates that based on the ranges assigned to REC prices by BED staff, REC prices will continue to be the single most significant risk that BED faces over time.

Evaluation of NPVRR results: 5-Year

The five-year tornado chart is Figure 7 below. Despite BED's having pre-sold RECs over the next five years, the volatility of REC prices is the largest risk over the medium term.

Figure 7: 5-year tornado chart showing sensitivity of NPVRR to 13 key variables

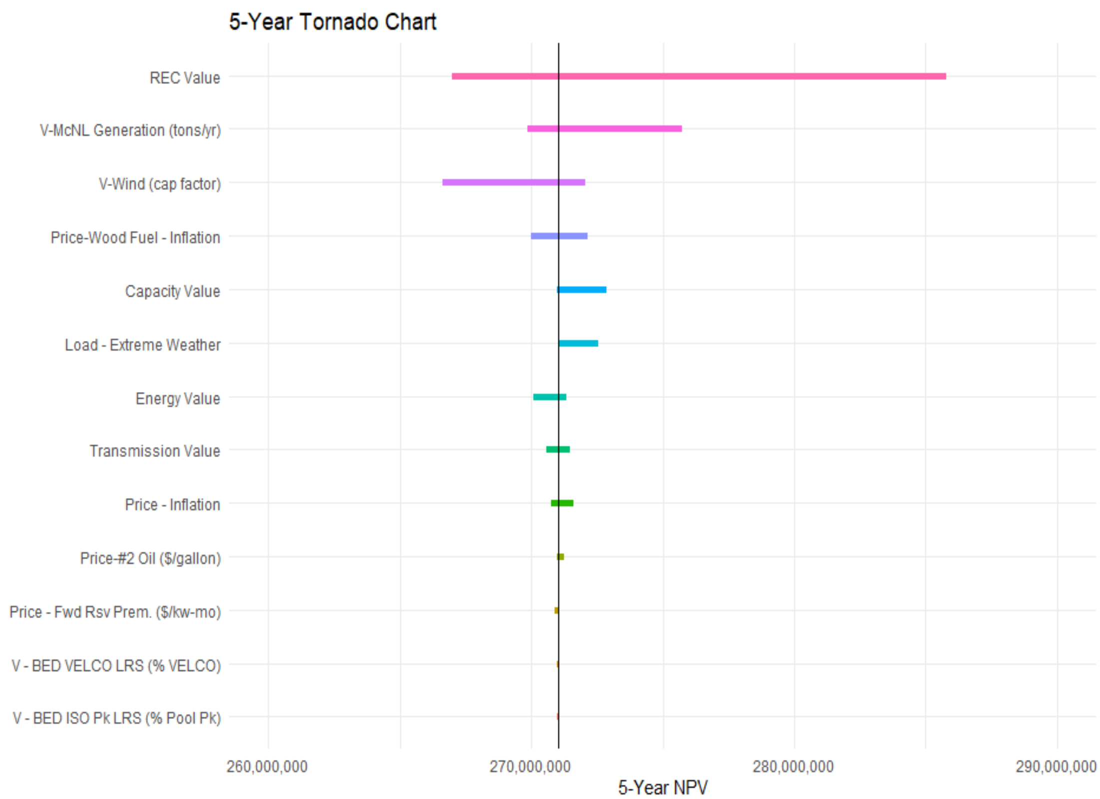


Table 3.b compares the range of risks that individual variables could impose on BED's cost of service.

Table 3.b: 5-Year Minimum, Maximum, and Max-Min Ranges

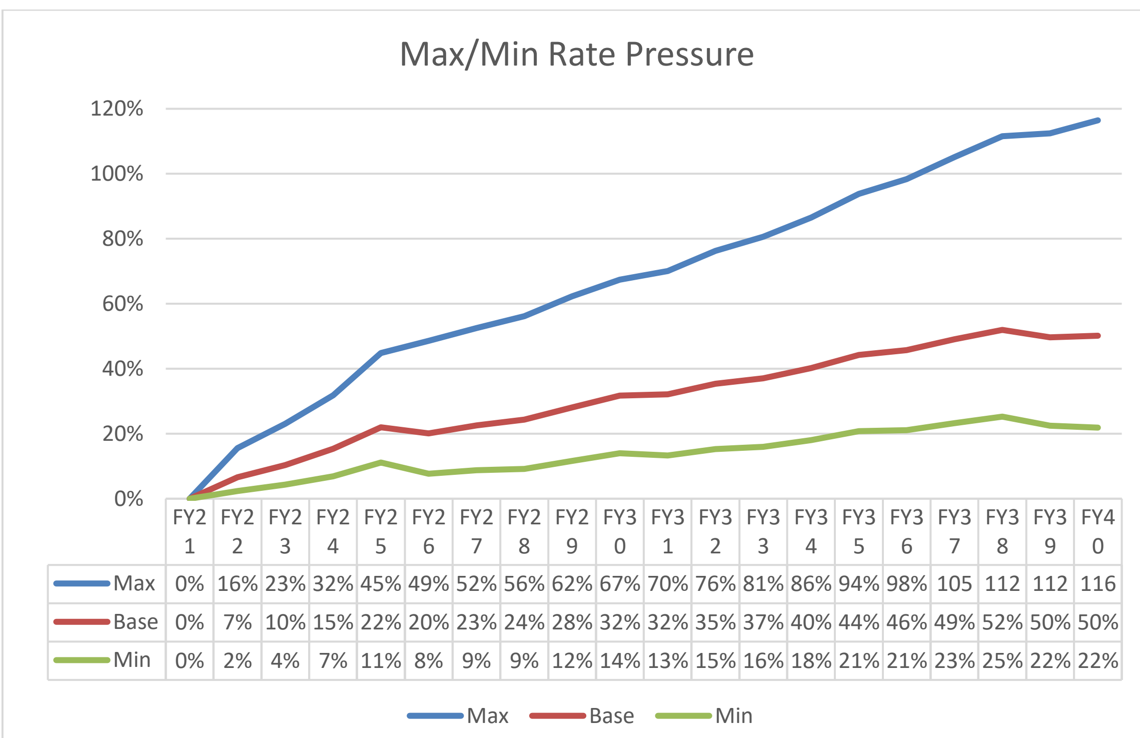
Item	Max ($M)	Min ($M)	$Max-$Min ($M)
REC Price	15	-4	19
McNeil Generation	5	-1	6
Wind Generation	1	-4	5
Wood Price	1	-1	2
Capacity Price	2	-0	2

The minimum potential impact of changes in REC values over the next five years is a reduction in expense of $4 million, but the maximum impact could be an increase of as much as $15 million, or a difference between these two risk profile scenarios of $19 million. This analysis indicates that based on the ranges assigned to REC prices by BED staff, REC prices are the single most significant risk that BED faces in the medium term. In addition, a number of the variables have shifted (or dropped off) compared to the 20-year analysis, showing that over the medium term, energy related risk is less about the price of energy than the quantity of energy captured in this analysis

Results & Range of Potential BAU Rate Pressure Due to Key Variables

Different combinations of key variables will change the pressure on BED's rates over time. Figure 8 shows the potential range of rate pressure outcomes that can result from changes in the assumptions around key variables. The Max line is a forecast of BED's rate pressure if all the tested variables went to the case that would put the maximum rate pressure on BED (whether that is low REC prices or high Capacity prices), and the Min line is the opposite. As shown below, even with the substantial hedging BED currently undertakes, a combination of variable changes could lead to significant continued rate pressure. On the other hand, the lowest potential pressure on rates would result from sustained high REC prices, in which case BED could probably go for an even longer period than it currently has without the need to increase rates. BED, however, considers substantial movement from the base case toward either the min or max rate pressure paths shown below unlikely. In other words, the likelihood of all variables ending up at their best, or all ending up at their worst values (from BED's perspective), and thus achieving either the "Min" or "Max" lines below is significantly less likely than that of achieving something closer to the "Base".

Figure 8: Range of Rate Pressure Scenarios with Best-Case (Min), Worst-Case (Max) and Business as Usual (Base)



	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Max	0%	16%	23%	32%	45%	49%	52%	56%	62%	67%	70%	76%	81%	86%	94%	98%	105	112	112	116
Base	0%	7%	10%	15%	22%	20%	23%	24%	28%	32%	32%	35%	37%	40%	44%	46%	49%	52%	50%	50%
Min	0%	2%	4%	7%	11%	8%	9%	9%	12%	14%	13%	15%	16%	18%	21%	21%	23%	25%	22%	22%

This financial model will continue to evolve, as new information is gathered and as improvements are made to the model, which will be a focus for BED prior to our next IRP filing. This financial analysis is a helpful tool for planning, decision-making, and decision comparison as we look out over a 20-year horizon.

Rate-Related Activities

Introduction

BED is developing several new rate design initiatives with the goal of encouraging strategic electrification that avoids coincident peak demand. These initiatives include expansion of the EV charging rate to commercial customers, exclusion of controlled load when determining a customer's eligibility for the Small General (non-demand billed) rate class, and development of a residential heat pump rate. All three of these new rate initiatives aim to send price signals to customers that encourage strategic electrification, which is necessary for achieving BED's goal of reaching net zero energy.

BED's Net Zero Energy goal calls for the addition of tens of thousands of heat pumps and EVs within the utility's service territory, which are expected to be the largest contributor to peak demand. As discussed in the Net Zero Energy chapter, this additional demand could provide substantial downward rate pressure if this electrification is coupled with load control. BED hopes that rates such as these will further improve the economics of strategic electrification both for BED and our customers.

Commercial Electric Vehicle Rate

BED aims to expand the current residential EV charging rate by adding an option for commercial customers. This rate should increase availability of EV charging at commercial and workplace locations and encourage charging that limits coincident peak demand. It would also increase the number and flexibility of hours available daily for EV charging as compared to the residential fixed EV charging hours. Multifamily apartment "house meters" are also generally on commercial rates, so this expansion would aid home charging for these customers as well.

When left uncontrolled, EV charging increases transmission and capacity peaks and costs. This is especially true with Level 2 charging. Currently, BED has a residential EV charging rate that allows residential customers to charge for $0.08/kWh, the equivalent of paying $0.60 per gallon of gasoline. This rate has been successful in shifting EV charging to off-peak times and avoiding additional capacity and transmission charges. By passing these savings on to the customer, BED can encourage EV adoption in its service territory and reduce costs for all. However, in the commercial sector, EV charging often overlaps with the current residential non-EV charging hours of noon till 10pm. Several other utilities nationwide, including Southern California Edison and LADWP, currently offer TOU rates specific to commercial EV customers to provide low off-peak EV charging.

BED plans to offer three options to residential, small general, and large general customers:

Table 4.a EV Rate Charging Options

Option	Description	Non-EV Charging Hours Annually (Estimated)
Fixed EV Charging	Charger is pre-programmed to only charge during the fixed EV charging hours of 10pm - noon (next day)	3,650 hours (42% of the year)
Flexible Load	BED determines the curtailment period ahead of time and provides at least eight hours of notice.	1,460 hours (17% of the year)
Flexible Real Time	BED controls the charger in real time based on current load and market information.	730 hours (8% of the year)

Both the Fixed EV Charging and Flexible Load options are currently part of BED's tariff. The Flexible Real Time option would be a new option to provide more flexibility for commercial customers. BED's ability to control the charger in real time based on LMP and other factors would maximize the number of hours available for charging, as BED would only need to curtail charging when necessary to avoid high costs (either due to a spike in LMPs or the likelihood of a peak). The customer would be able to opt out of the event, however, they would lose EV charging credit for that month. Advantages of the Flexible Real Time option include:

- Reduced capacity and transmission costs for BED
- Low-cost EV charging for commercial customers
- More hours available daily for EV charging compared to other options
- More daytime charging availability.

The derivation of the EV rate credit amount recovers fixed, hardware/software, energy, and ancillary service costs. With the EV rate credit, the Residential, Small General, and Large General rate classes would all receive a credit to allow them to charge at $0.08/kWh. This would be a kWh credit for the SG class and a kW credit for the LG class, essentially eliminating the demand charge on controlled EV charging for LG customers. BED is hopeful that the rate will go into effect sometime in late 2020 or early 2021.

Small General (SG) and Large General (LG) Rate Amendments

BED aims to amend the SG and LG rates to exclude controlled loads such as EV charging when determining if a customer is moved from the Small General to the Large General rate class. The current rate structure discourages customers from adopting strategic electrification as the added load may force them to move to a demand-based rate. Excluding controlled loads sends a signal to customers to electrify and take advantage of BED's load control programs without the caveat of potentially needing to switch rate classes. Encouraging electrification in this way is important for BED to meet its NZE 2030 goals.

Efficient Electric Thermal Rate

BED is in the process of establishing a cold climate heat pump rate to encourage electrification in the heating and cooling sector. This rate will reduce the cost of electric heating to be more competitive with non-renewable natural gas, although heating with a heat pump is already more cost effective than heating with renewable natural gas. Development of a rate specific to heat pumps should also help mitigate capacity, transmission, and distribution peaks that could occur (and are projected to occur in the NZE30 and NZE40 scenarios) because of added load in the heating sector.

The new heat pump rate will have both similarities and differences to the current EV rate. Both rates aim to reduce coincident peak demand incurred from electrification and added load, however, there are key differences between the heat pump rate and the EV rate. A heat pump has significantly less load control capability than an EV, as it cannot be fully curtailed for long periods of time as an EV charger can. In the case of a dual fuel rate where the customer has a backup heating system, the heat pump would need to be integrated with the existing heating system. Heat pumps require additional load control and metering devices as those capabilities are generally not contained within the heat pump. Finally, heating with electricity is typically more expensive than non-renewable natural gas. The economics are quite different for fueling an electric vehicle as even the retail electric rates are typically less expensive than gasoline.

When performing research in preparation for the development of this rate, it was determined that electric heating rates typically fall into four categories: Whole Home time-of-use (TOU), Separately Metered TOU, Device Controlled, and Dual Fuel.

Table 4.b Heat Pump Rate Options

Whole Home TOU	Customers with an efficient electric heat source qualify for a TOU rate that gives them a discount on off-peak energy used in their home
Separate Metering TOU	Customers receive a discount on off-peak energy used by their efficient electric heat source
Device Controlled	Utility adjusts the heat pump set points during peak times and the customer receives a credit for participating
Dual Fuel	During peak times, the utility curtails the customer's heat pump and a backup heat source is used instead

Many utilities across the country have an electric heating or heat pump rate that is structured like one of these four options, but the device-controlled and dual-fuel rates are less common. Utilities currently deploying device-controlled and dual-fuel options include Otter Tail Power Company, Northwestern Rural Electric Co-op, Connexus Energy, and Minnesota Power. BED spoke with representatives from Northwestern Rural Electric Co-op and Otter Tail Power Company to gain insight into their programs and inform the process of designing something similar in Burlington.

The heat pump rate options that best align with BED's goals are the device-controlled and dual fuel options. BED is hoping to design a rate that offers both options to customers. With the device-controlled option for heat pumps, BED will be able to adjust the heat pump set points based on market and load information. With the dual fuel option, BED will curtail the heat pump during load control events and a backup heat source will be triggered to heat the home instead for the duration of the curtailment.

BED is planning to spend a portion of the 2020/2021 heating season participating in a pilot with Packetized Energy, after which we will design a final heat pump rate.

Chapter 7 – Decision Processes

Objective

Achieving BED's overarching twin objectives (i.e., 218c compliance and helping Burlington transition to Net Zero Energy) in an uncertain world will be challenging. Multiple known and unknown risks about the state of our economy, public health, technology, regulations, and wholesale market prices for energy, capacity, transmission, and RECs must be considered when making decisions. A decision process that adequately recognizes and accounts for a range of future risks when making a decision is critical. In this chapter, we describe our process for evaluating risks and making decisions using Behind-the-Meter ("BTM") storage as an example.

Our objective in providing the example analysis below is to describe to the Commission our analytical methods for identifying and evaluating the known risks associated with a utility-scale energy storage system in Burlington. We then explain how BED would decide whether to proceed with such an investment based on the best available information. After the detailed BTM example, we discuss the decision tree methodology that we would use in the context of a series of choices that may need to be made concurrently.

Burlington's (and Vermont's) goals are currently focused on reducing the many adverse impacts of climate change. However, BED believes that having attained 100% renewability in the energy supply for BED, and with BED's goal of meeting its Tier 3 RES obligation with electrification programs rather than by simply buying RECs, the decisions with regard to climate change will, in large part, be made outside the utility space. Decisions regarding how to address climate change are expected to occur over the next two to three years, particularly if Burlington and Vermont are going to achieve aggressive climate goals. BED will just be one party among many involved in these discussions. BED does expect to need to be able to model potential impacts of new ordinances, statutes, and rules and believes that the work done in this IRP positions us well to do so (see Net Zero Chapter for additional discussion of potential impacts of the early stages of the Roadmap). As noted elsewhere in this IRP, BED is evaluating one plausible, forward-looking scenario: a NZE future. The potential impacts of this scenario are discussed in greater detail in the Net Zero Energy Chapter. The next series of actions required to realize such a future rests largely outside of BED's control. Consequently, BED does not anticipate making any 248 filings soon.

Sample Single Decision Analysis: BTM Energy Storage

To illustrate BED's decision-making process, a sample energy storage purchased power agreement ("PPA") for a 5MW/20MWh Lithium ion battery located in Burlington is analyzed below. Energy storage has long been a resource upon which New England has relied in the form of nearly 2 GW of pumped hydro capacity[1] that has been balancing the grid for over forty years. Recent energy storage price declines for battery storage, as well as an anticipated need for additional storage due to increasing intermittent generation, have led to a revival of interest where numerous customer-sited batteries are being installed and ISO-NE now has 2GW of storage in its interconnection queue. BED has been exploring storage opportunities for several years and has used a recent proposal as a "sample storage project" for the analysis that follows.

Two prices were evaluated. The prices were based on whether the battery would be solely for BED's use (referred to as "full tolling" and carrying a higher price) or would be shared with the developer (referred to as "partial tolling" and carrying a lower price but potentially reducing some value streams and leaving other value streams with the developer). A partial tolling agreement would essentially limit BED to focusing on reducing transmission and capacity costs. Such an arrangement also would require advance notice from the developer to dispatch the battery and inject energy into the grid, thus limiting BED's ability to react to higher than forecasted loads and the battery's value. A full tolling arrangement would allow BED to control the battery in real-time, enabling BED to attempt to capture whatever value stream was most advantageous at that time. Furthermore, unexpected market rule changes that shift value from one value stream to another would likely be easier to adapt to in a full tolling arrangement.

This potential project would be "behind the meter" from ISO-NE's perspective, so ISO-NE would not control it for the purposes of energy dispatch, but it would be "in front of the meter" from BED's perspective as it would not be behind a customer meter. Rules related to the treatment of BTM assets are currently in flux, however, as discussed further below.

The type of tolling, full or partial, affects the probability BED would assign to the storage asset of being able to realize capacity and RNS savings (under current rules). The more hours BED can use the battery, the higher the probability of achieving RNS savings, which are based on a utility's load at the time of the Vermont peak (for Vermont utilities). The probability of achieving capacity savings does not materially change over time (between tolling options), as we assume available dispatch hours would be focused first on achieving capacity savings, which are currently monetarily larger and based on a single annual peak hour. RNS savings[2] would be pursued to the extent that additional energy storage is still available. This would remain true for the foreseeable future because even at very low capacity market prices, the

[1] Bear Swamp and Northfield Mountain

[2] RNS values are based on separate values for each month.

value of 12 months of capacity savings would still exceed the value of one or more months of RNS savings.

Table 1. Assumed Storage Prices and Peak Discharge Likelihoods

Tolling	Price	RNS Likelihood	FCM Likelihood	Notes
Full	$17/kW-month	9/10	29/30	
Partial	$11/kW-month	2/3	19/20	Day-Ahead dispatch; 400 discharge hours per year; discharge must be called either the day before for the next morning or the in the morning for nighttime discharges; BED does not receive any frequency regulation revenues

Project Cost

The bulk of the modeled project costs are associated with PPA, with lesser costs related to the electricity use to recharge the battery (including losses incurred in the charging/discharging cycle, which are assumed at 15% for this project).

Project Value

The value of a battery storage project would depend upon its proposed uses. The value of each use can be further categorized as: the value of a particular use or "value stream," ability to capture that value stream, and the impact on BED's risk profile (due to BED's exposure to risks associated with that value stream). Below, the Transmission, Frequency Regulation, Capacity, and Energy value streams are examined in detail as the primary value streams that can be realized under current ISO-NE market rules. Any particular battery project might, especially in the future, be able to avail itself of additional value streams[3] (and BED would include those in an analysis of a particular project), but the value streams included in this analysis should be available to most projects.

It is important to note that in the case of multiple value streams, consideration is given to the potential that there could be conflicts between what is needed to realize two or more

[3] https://rmi.org/wp-content/uploads/2017/03/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf, accessed August 2020.

value streams. For example, a battery discharged for an anticipated ISO-NE peak hour might not be available to discharge again for a Vermont peak hour that occurred later the same day.

Transmission Value Stream (ISO-NE RNS)

By discharging the battery during the hour of Vermont's monthly peaks, under current treatment of loads, BED would reduce its pro rata share of transmission charges that are based on those peaks because energy discharged locally from the battery would lower BED's recognized demand. The amount of societal value that BED could create through those discharges is less clear because those transmission costs would still be paid by other market participants. If the reduction in BED's load that resulted from battery discharges during monthly peaks postponed the need for development of additional infrastructure, the societal savings could be relevant and material, but the transmission deferral value of a particular project on RNS would be difficult to estimate.

Price/Value

As discussed in the Financial Assessment chapter, RNS transmission costs have approximately quintupled from 2005 to 2020, and the IRP forecasts that they will continue to increase. The current price of transmission ($129/kW-year) is almost equal to the cost of the proposed partial tolling PPA option ($132/kW-year). To the extent that BED is able to discharge the battery during each monthly peak, the transmission savings alone would almost immediately cover the bulk of the project costs provided there are no changes in the load treatment (see risk discussion).

Availability

Transmission savings would be achieved by discharging the battery during the Vermont monthly peak hour. The partial tolling option would require BED to give the developer some amount of advance notice that BED would need to use the battery for discharging and would limit the number of hours that BED can discharge the battery to 400 annually, while the full tolling option would allow BED to discharge the battery in real time and frequently if needed. The availability of transmission savings was then assumed for each tolling option based on our experience predicting peaks relative to the advance notice required and hours available for BED's use.

Since late 2018, BED has been using a model to predict[4] VT and ISO-NE peak load. BED used this model and its experiences to date with its Defeat the Peak program to evaluate the relative desirability of the proposed partial tolling options. It was determined that 360 hours out of the 400 hours proposed in the battery system contract could be used for battery discharge to avoid monthly peaks with 40 hours being reserved for New England annual peaks. In 2019, 8 of

[4] BED ran the model on 183 days in 2019.

12 monthly peaks were contained in the 360 hours, with the highest likelihood of being a peak as calculated prior to the day of the peak. Based on this data, BED assumes that it will be able to coincide battery system discharge with monthly Vermont peaks two-thirds of the time, so for this analysis partial tolling is expected to capture two-thirds of the Vermont monthly peaks. This rate is hopefully conservative relative to actual practice, where BED would be able to examine the probability of a peak somewhat closer to the peak and apply additional data sources and expert judgment (rather than relying on a single model).

Based on our experience with Packetized Energy's virtual battery, full tolling will be able to discharge during 90% of monthly VT peaks. The Packetized Energy program achieved a higher success rate of timing battery discharge with Vermont monthly peaks in part because the batteries operate without restrictions on number or duration of peak "discharges." Consequently, under the Packetized Energy program BED has successfully reduced usage during monthly peaks every month since we began regularly updating our peak events in August 2019.

It is possible that as DERs capable of flattening Vermont's (and the region's) load are deployed, predicting the peak, and when to discharge a battery, will become more difficult. Continued deployment of solar, if not reconstituted, will continue to lower loads when the sun is out, making peak prediction somewhat easier (due to many daylight hours being much less likely to be the peak).

Risk Profile Impact

BED is a buyer but not a seller of ISO-NE transmission services because these charges are assessed under a tariff structure vs. a locational buy-sell market structure (as with energy, capacity, and regulation, among others), so any action that reduces transmission usage and costs will reduce our exposure to RNS price fluctuations. However, a large risk exists that the structure that allows for load reductions to create this value stream will be changed or even abolished. ISO-NE's internal market monitor is currently advocating for "reconstituting" (adding back) BTM generation for the purposes of calculating network load.[5] It is unclear what impact, if any, this will have on BTM storage, but in the worst case, it would the transmission value stream would be eliminated entirely (*as is illustrated by figures 3a-d, the loss of all transmission value would result in the storage option providing no net value to BED under either partial or full tolling*). This represents a key risk to the present consideration of the value of storage.

[5] https://www.iso-ne.com/static-assets/documents/2020/07/2020-spring-quarterly-markets-report.pdf, accessed August 2020.

Frequency Regulation (Automatic Generator Control) Value Stream

Market participants can earn Frequency Regulation (or Automatic Generator Control ("AGC")) revenue by allowing their assets to be controlled on a second-by-second basis by ISO-NE to balance small changes in supply and demand on the grid.[6] BED currently incurs regulation charges based on its share of ISO-NE's hourly load. A BTM storage resource could register with ISO-NE as an Alternative Technology Regulation Resource for the purpose of providing regulation. This value stream would only be available to BED under a full tolling structure due to the battery being in New England and greater than 1 MW.

Price/Value

The price of regulation services is difficult to predict. The increase in intermittent resources could result in additional regulation services being procured by ISO-NE, likely increasing the regulation price. Currently, ISO-NE is procuring less than 100 MW of regulation service on average,[7] and with more than 2 GW of battery storage in ISO-NE's queue, it seems possible that the number of potential suppliers of this service will grow such that the revenue received for providing will fall to the marginal cost of providing it with a battery. If the value of AGC services were to fall to that level, BED and others would not receive any additional net revenues as the value of providing the service would equal the cost of providing it. As shown in Figure 1, the size of the regulation market has remained small relative to the billions of dollars that are exchanged for energy and capacity in New England every year.[8,9]

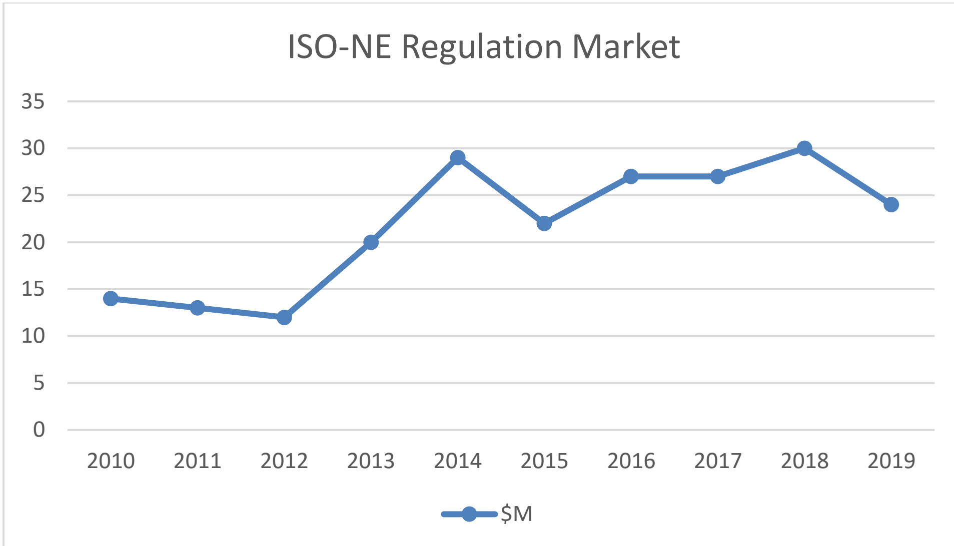
[6] https://www.iso-ne.com/markets-operations/markets/regulation-market/, accessed August 2020

[7] https://www.iso-ne.com/static-assets/documents/2020/05/2019-annual-markets-report.pdf, accessed August 2020

[8] https://www.iso-ne.com/static-assets/documents/2017/04/20170411-webinar-energy-storage.pdf, accessed August 2020

[9] https://www.iso-ne.com/static-assets/documents/2020/05/2019-annual-markets-report.pdf, accessed August 2020

Figure 1. ISO-NE Regulation Market Revenues



The prices assumed in this analysis are a base case based on GMP's Panton battery filing (in Docket 17-2813-PET), a high case of 150% of those values, and a low case starting at the same point as the base case but falling to 0 by 2030. GMP values are used for this analysis given GMP's greater experience in the AGC markets.

Availability

Under a full tolling structure, this AGC value stream would be available to BED whenever the battery was not being used for the other purposes described here; in the partial tolling case it would be unavailable. Using the battery for the AGC value stream may conflict with the battery's use for greater value stream propositions in some cases.

Risk Profile Impact

Deploying a storage asset of this size would reverse and increase BED's exposure to AGC price fluctuations. BED is currently only a buyer of AGC services (i.e., 100% short), having no assets capable of providing those services to the market and is adversely affected when prices for the service increase. With the proposed storage project, BED would become substantially (~300%) long (i.e., a net seller of the AGC service), and therefore adversely affected by falling AGC prices, if it were providing 4MW (5MW * 80% assumed availability) of average service to ISO-NE.

Capacity Value Stream

Under current rules, by discharging the battery during the hour of ISO-NE's annual peak, BED would reduce its pro rata share of capacity charges that are based on those peaks. The amount of societal value that we would be able to create through those discharges is perhaps lower, as the immediate impact would be to shift those costs to other market participants. In the longer term, the reduced load would likely lead to ISO-NE taking actions to "offload" excess capacity in the periodic reconfiguration auctions and less capacity being procured in future FCAs. ISO-NE could adjust future capacity auction procurements, as with EE and BTM solar, by directly modeling the impact of BTM storage in its forecast of required capacity.[10]

Price/Value

Currently capacity represents the second largest value stream available to the proposed storage project (after RNS transmission). The price of capacity has fallen in the last five ISO-NE capacity auctions, but it remains a significant cost driver for BED. Capacity prices are essentially known through May 2024 but could vary substantially in the future.

Availability

BED has consistently been able to identify capacity peaks (i.e., the hour that will ultimately be determined to have been the ISO-NE peak hour for the year) both in its prior demand response program with EnerNOC and its current Defeat the Peak program.[11] For the purposes of this analysis, we assumed that we would be able to time discharges coincident with 19 out of 20 peaks under the partial tolling structure and 29 out of 30 peaks under the full tolling structure. No current discussion is occurring that would remove the availability of the capacity value stream, but as noted above the price is uncertain.

Risk Profile Impact

BED is currently "short" capacity (see Supply Chapter) and will be adversely affected if capacity prices increase in future FCAs, so any action that reduces that exposure will reduce our risk exposure to price increases, provided that BED does not add so much capacity that it becomes a net provider of capacity to ISO-NE (which is very unlikely).

Energy Value Stream

BED could create arbitrage value from an energy storage project by charging during low-priced times and discharging during high-priced times, reducing its net energy charges. This can create value as long as the differences in energy prices between the discharge and charge times are sufficient to justify incurring the energy losses incurred in the cycle. To the extent that discharge times for capacity and transmission might not always coincide with the highest price energy times, there could be some overlap between this value stream and the others.

[10] https://www.iso-ne.com/system-planning/system-plans-studies/celt/, accessed August 2020

[11] http://burlingtonelectric.com/peak, accessed August 2020

Price/Value

Although energy prices vary on a five-minute basis in the ISO-NE wholesale markets, on most days they do not vary greatly, and as a BTM resource this resource would be settled hourly with BED's load. Accordingly, the price assumption is based on BED's existing forecasts of on-peak and off-peak price spreads.

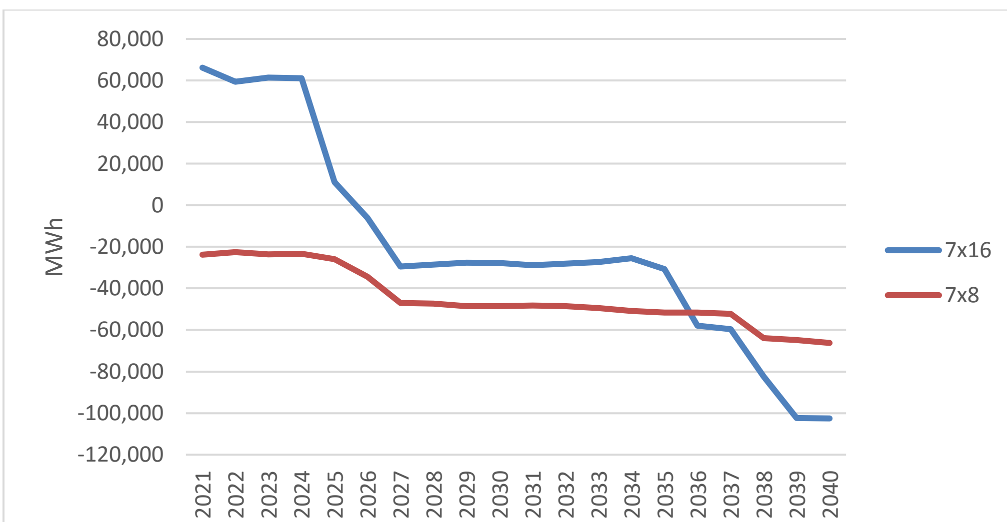
Availability

This analysis assumes that the energy arbitrage would occur around attempting to lower peak costs and, specifically, that on-peak energy usage would be reduced by 400 hours * 5 MW or 2,000 MWh per year.

Risk Profile Impact

As shown in Figure 2, BED is projected to be longer (or less short) in the "x16" hours (7:01am-11pm) than in the "x8" hours (11:01pm-7am) through 2035. As the battery would likely shift load from the x16 hours to the x8 hours, it would exacerbate this issue. That said, given the small net impact to BED's energy position (through round-trip and standby losses), BED is not likely to be taking on significantly more, or shedding much, energy price risk. Additionally, if there are hours with higher and lower prices, a battery can recognize them whenever they occur, not just in the ISO-NE defined "peak" and "off peak" periods.

Figure 2. Energy Position by Time Block



Results

As part of its examination of the storage project, BED performed a cost/benefit comparison of the project at our high, base, and low variable values to the project's costs. This comparison showed that the project would have little impact on BED's NPVRR at our expected prices but would be substantially profitable at higher prices. A series of sensitivity tests were performed, showing that, apart from using the battery for frequency regulation, the project would generally reduce BED's risk to market fluctuations because of the reduction in our capacity shortfall and transmission exposure. Additionally, potential rate pressures were calculated with and without the project, showing the main financial impacts to be in the 2030s due to continued projected increases in transmission prices.

Cost/Benefit

To perform the cost/benefit tests, BED added a storage-specific "mini-model" to our standard IRP 20-year financial model. BED then looked at the value of the project at each of the high, base, and low values for the major value streams identified. This showed the most significant potential value streams of the battery project to be transmission cost reduction as well as frequency regulation market participation and capacity savings. Energy arbitrage is smaller and less likely to be a major driver of the project's economics unless the spread between the highest and lowest prices in a day widens. The cost/benefit analysis also revealed that there is significant risk (both upside and downside) in this project. This risk is driven by both by the different price cases (particularly with regard to capacity) as well as the possibility of the transmission value stream being lost to load reconstitution.

Figures 3a-3d below illustrate the five- and twenty-year cost/benefit analyses. The five-year analysis is presented to consider the impacts during the period where the capacity prices are relatively certain. The effect of the current three-year forward capacity structure can be seen more clearly in the reduced range of potential capacity revenues between the three cases. Note that BED has not been offered a five-year tolling arrangement under a PPA, but one of the theoretical advantages of storage is its modularity and relative ease of deployment (both of which potentially argue against deploying unneeded storage materially in advance of its becoming economical).

Figure 3a. 20-Year Partial Tolling NPV

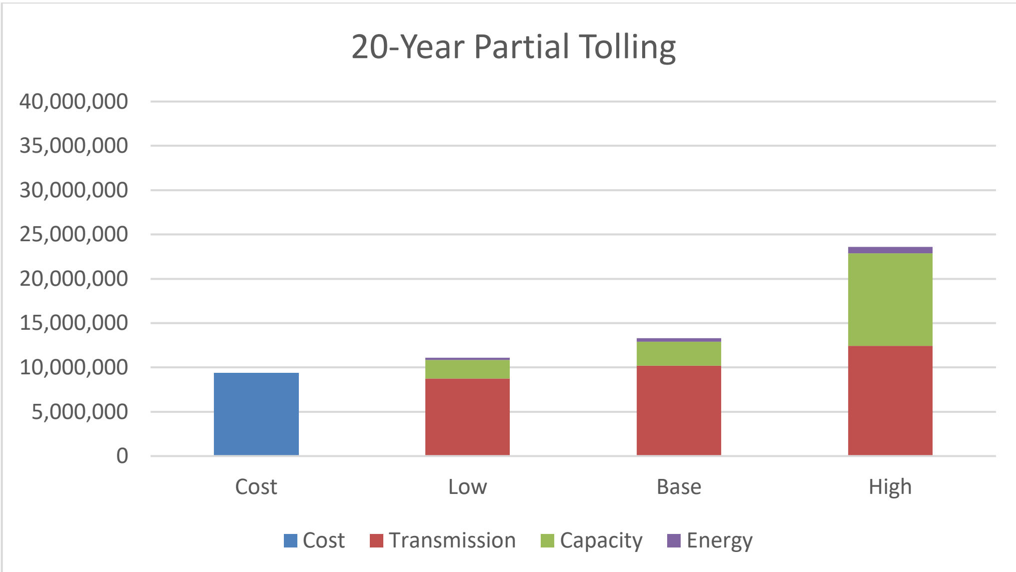


Figure 3b. 20-Year Full Tolling NPV

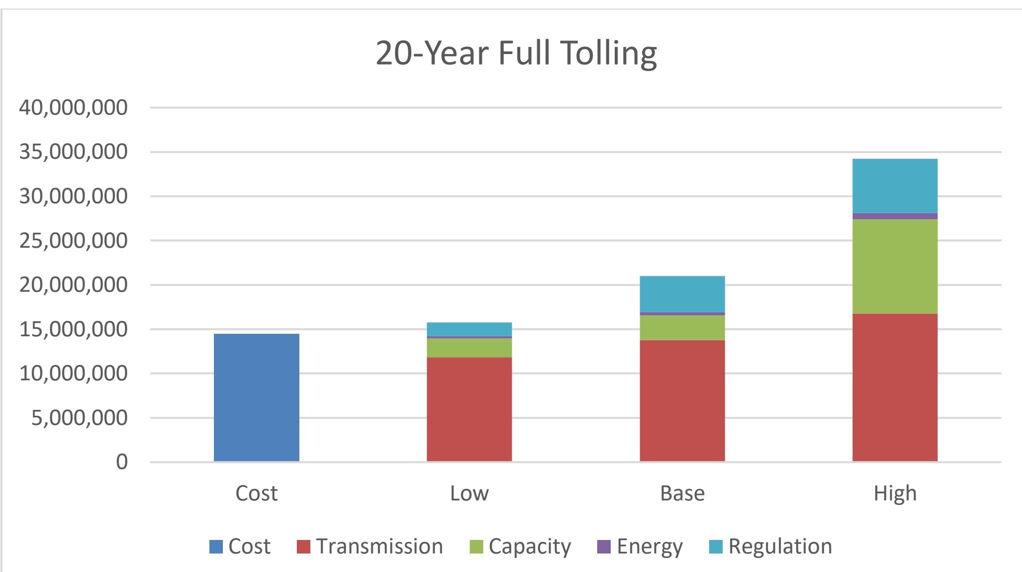


Figure 3c. 5-Year Partial Tolling NPV

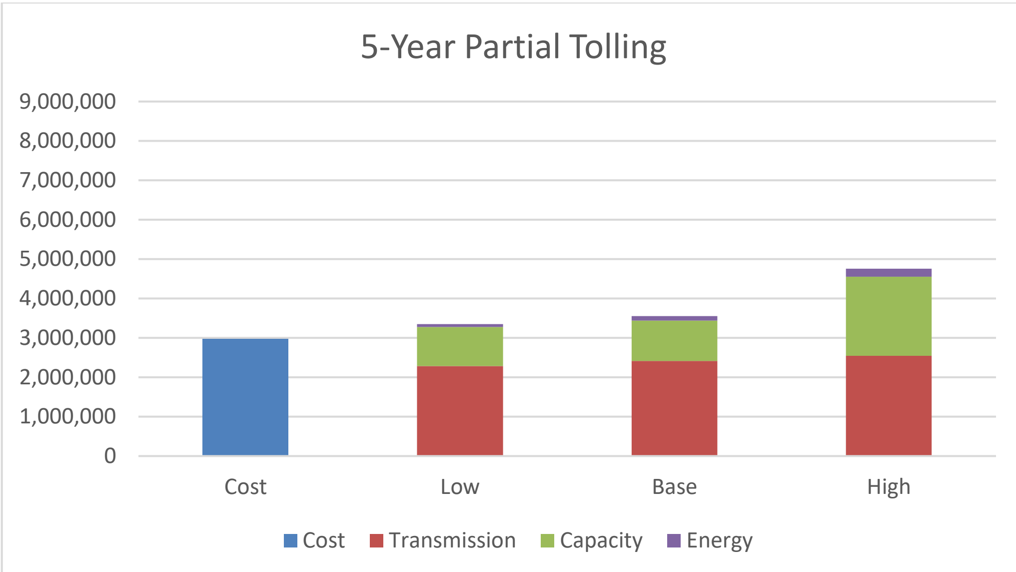
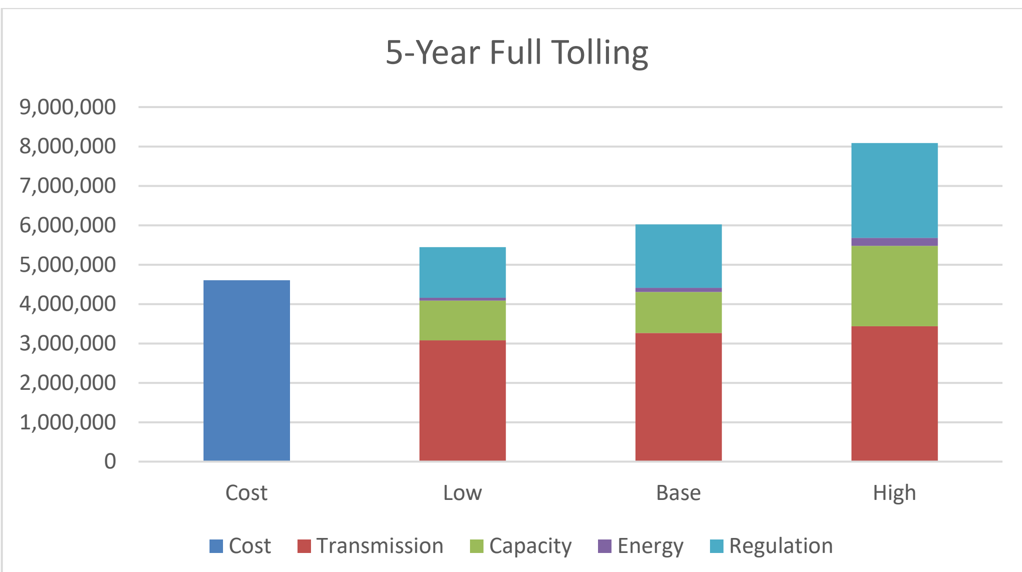


Figure 3d. 5-Year Full Tolling NPV



Sensitivities

To perform the sensitivity tests, BED calculated the NPV of our five- and twenty-year cost of service without storage (i.e., the NPVRR), with a partial tolling PPA, and with a full tolling PPA. The resulting tornado charts (Figures 4a-4f) show a comparison of the NPVs with low, base, and high values for each variable. Based on these charts, it appears that this project would reduce BED's risk of exposure to swings in capacity prices (particularly over the twenty-year horizon) and, if load is not reconstituted as proposed by ISO-NE, it would also decrease BED's transmission price risk. Participation in the project would increase BED's risk to frequency regulation prices and load reconstitution.

Figure 4a. 20-Year Full Tolling Tornado Chart

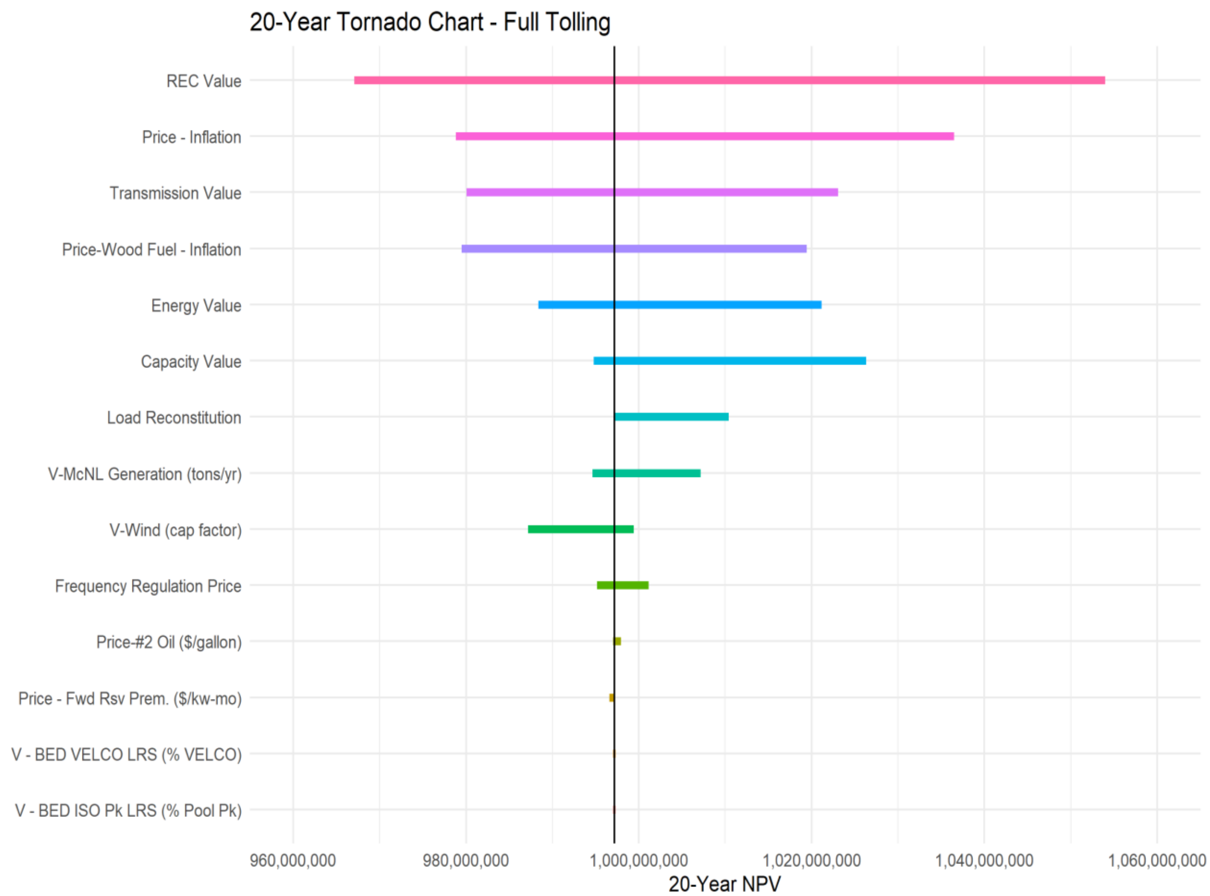


Figure 4b. 20-Year Partial Tolling Tornado Chart

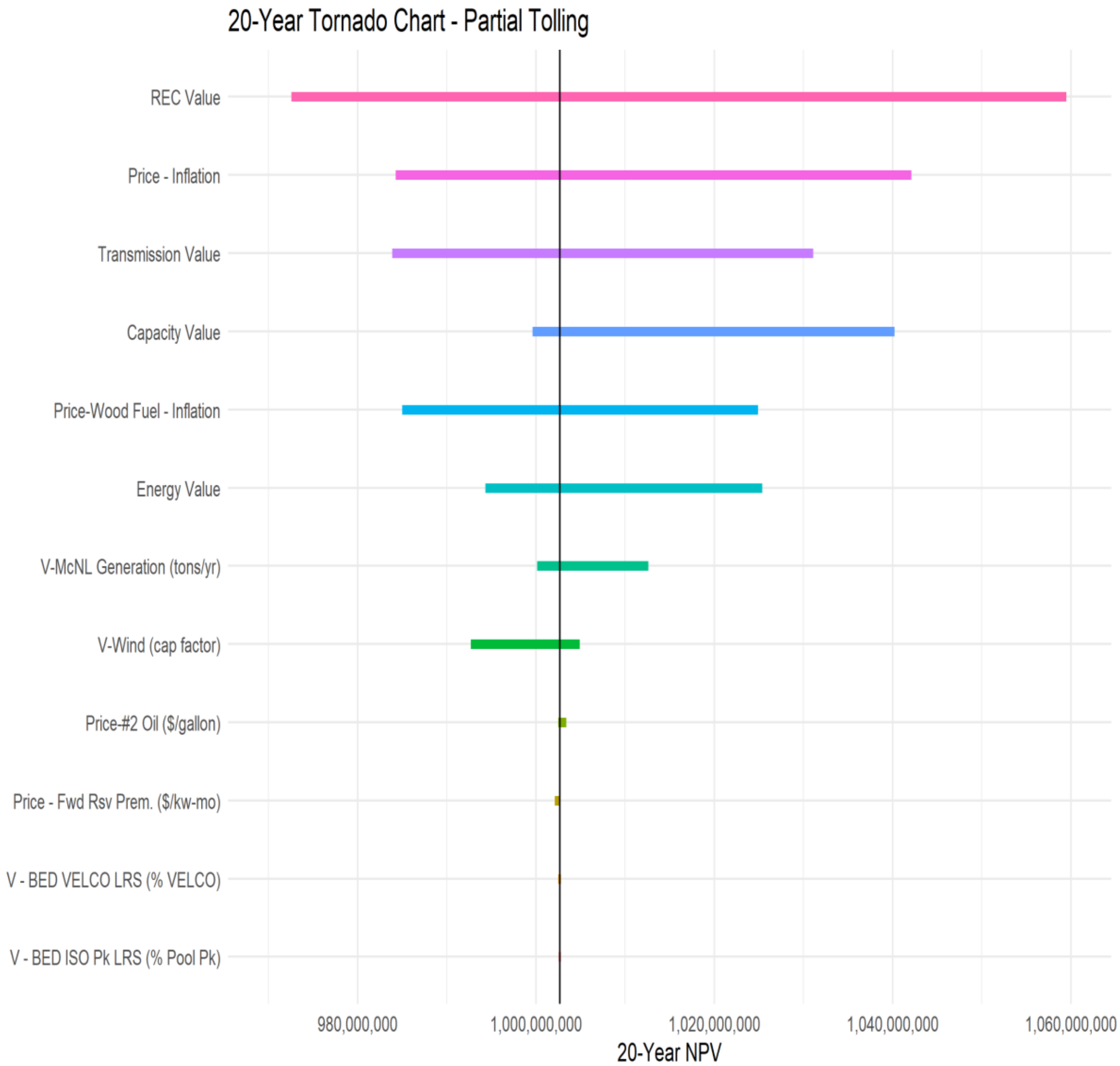


Figure 4c. 20-Year Base (No Storage) Tornado Chart

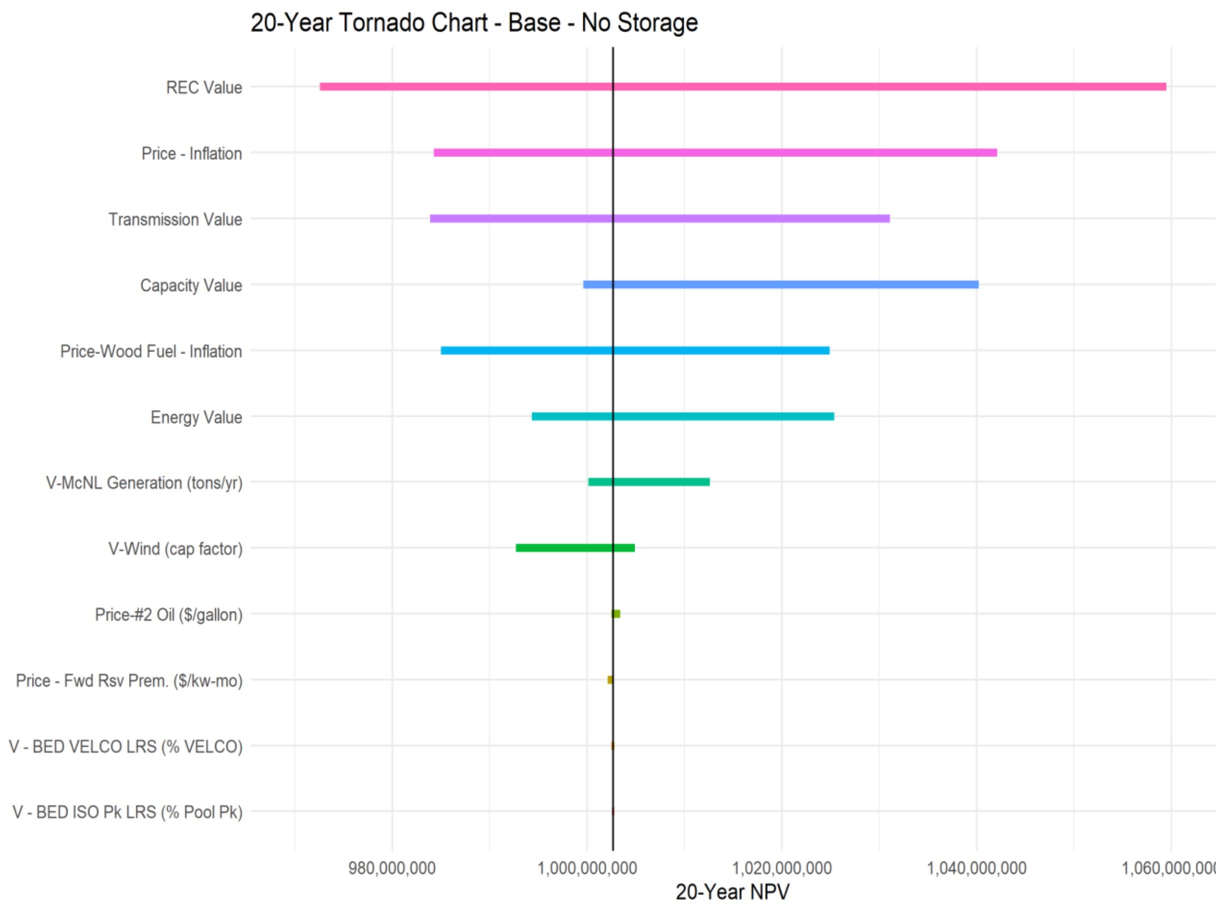


Figure 4d. 5-Year Full Tolling Tornado Chart

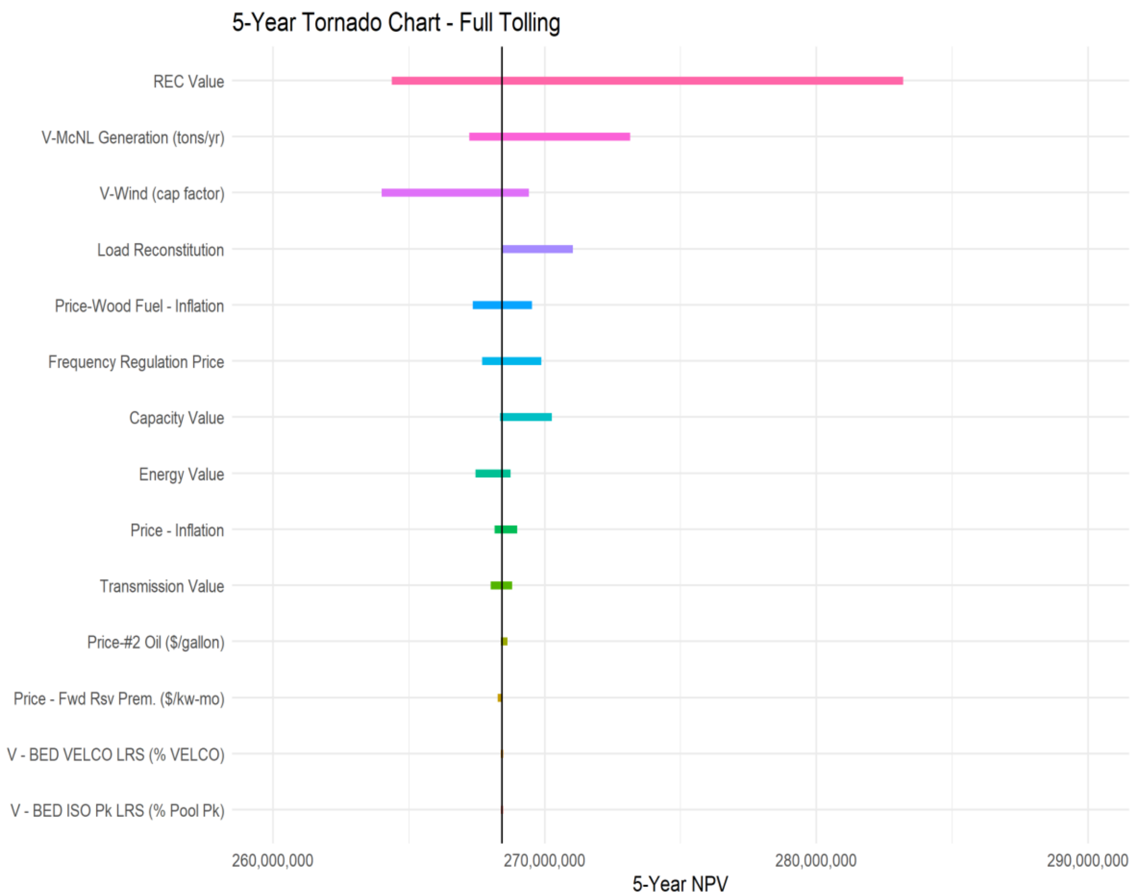


Figure 4e. 5-Year Partial Tolling Tornado Chart

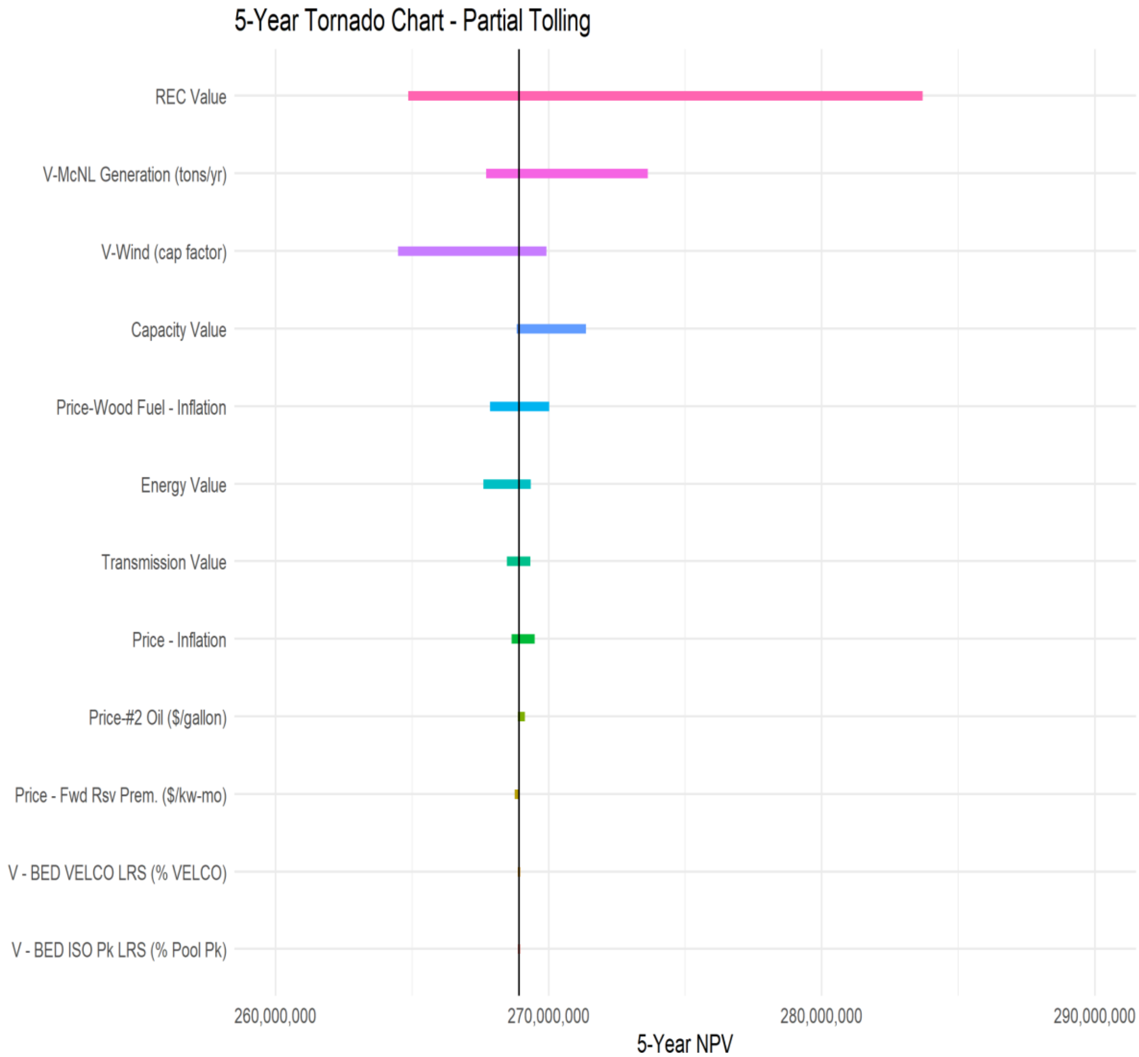
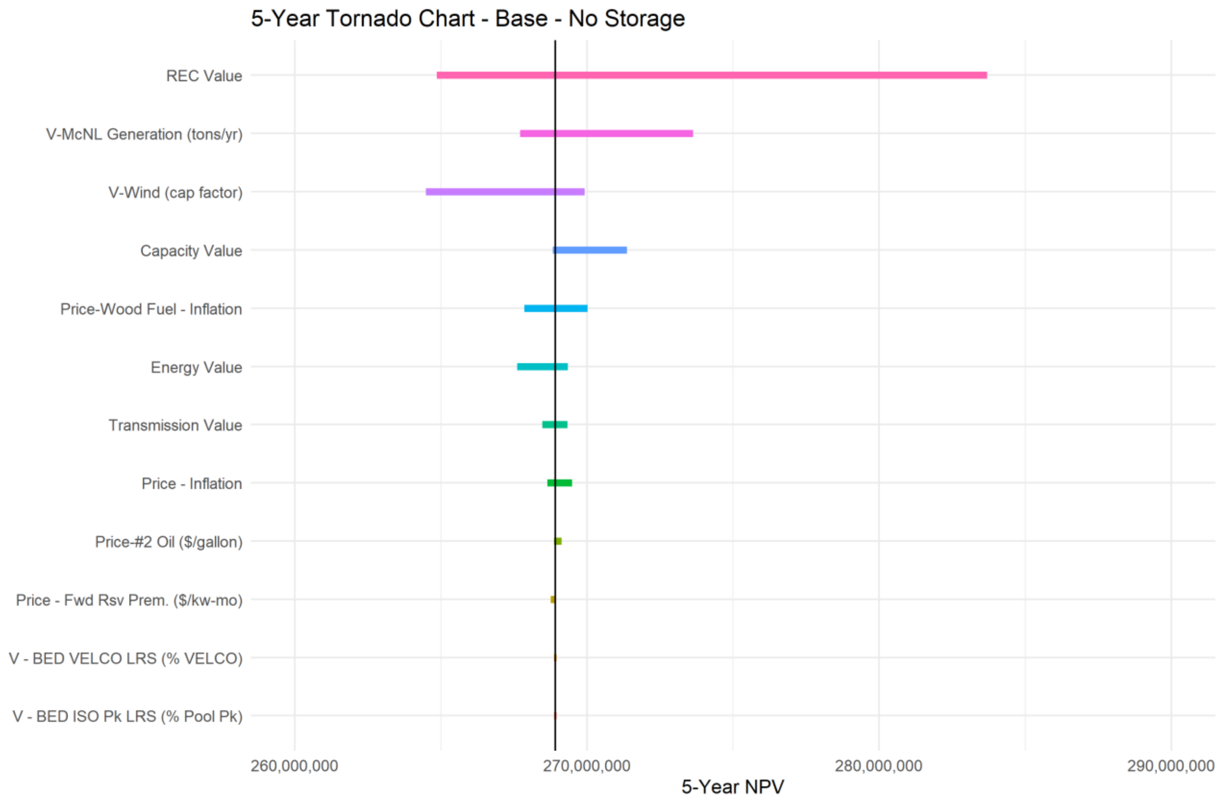


Figure 4f. 5-Year Base (No Storage) Tornado Chart



In addition, as shown below in Table 1, the spread of values between the two PPA options and the "do nothing" option shows a shrinking of transmission and capacity risk assuming no load reconstitution (i.e., no loss of the RNS value stream).

Table 1. Delta between Low Transmission and Capacity Prices Case v. High Transmission and Capacity Prices Case

	5-year	20-year
Base (No Storage)	3,394	87,815
Partial Tolling	2,717	75,760
Full Tolling	2,686	74,508

Tables 2 and 3 provide the range for a larger number of variables and a comparison of the impact of the battery options on those ranges.

Table 2. Delta between High and Low Values NPV by Tolling Case

	5-Year High/Low Delta			20-Year High/Low Delta		
	Base	Partial	Full	Base	Partial	Full
REC Value	18,828,170	18,828,170	18,828,170	86,922,188	86,922,188	86,922,188
Price - Inflation	845,554	829,244	827,724	57,801,366	57,651,138	57,634,299
Transmission Value	866,830	809,266	789,118	47,208,006	44,080,611	42,986,022
Price-Wood Fuel - Inflation	2,174,165	2,174,165	2,174,165	39,926,494	39,926,494	39,926,494
Energy Value	1,737,291	1,284,324	1,284,324	31,040,680	32,773,289	32,773,289
Capacity Value	2,527,518	1,907,459	1,896,581	40,607,084	31,678,950	31,522,316
Load Reconstitution	0	1,933,876	2,610,732	0	9,799,439	13,229,243
V-McNL Generation (tons/yr)	5,915,474	5,915,474	5,915,474	12,509,473	12,509,473	12,509,473
V-Wind (cap factor)	5,426,725	5,426,725	5,426,725	12,217,194	12,217,194	12,217,194
Frequency Regulation Price	0	0	2,170,712	0	0	5,947,869
Price-#2 Oil ($/gallon)	252,179	252,179	252,179	894,709	894,709	894,709
Price - Fwd Rsv Prem. ($/kw-mo)	183,891	183,891	183,891	681,171	681,171	681,171
V - BED VELCO LRS (% VELCO)	90,086	90,086	90,086	281,198	281,198	281,198
V - BED ISO Pk LRS (% Pool Pk)	83,085	83,085	83,085	256,658	256,658	256,658

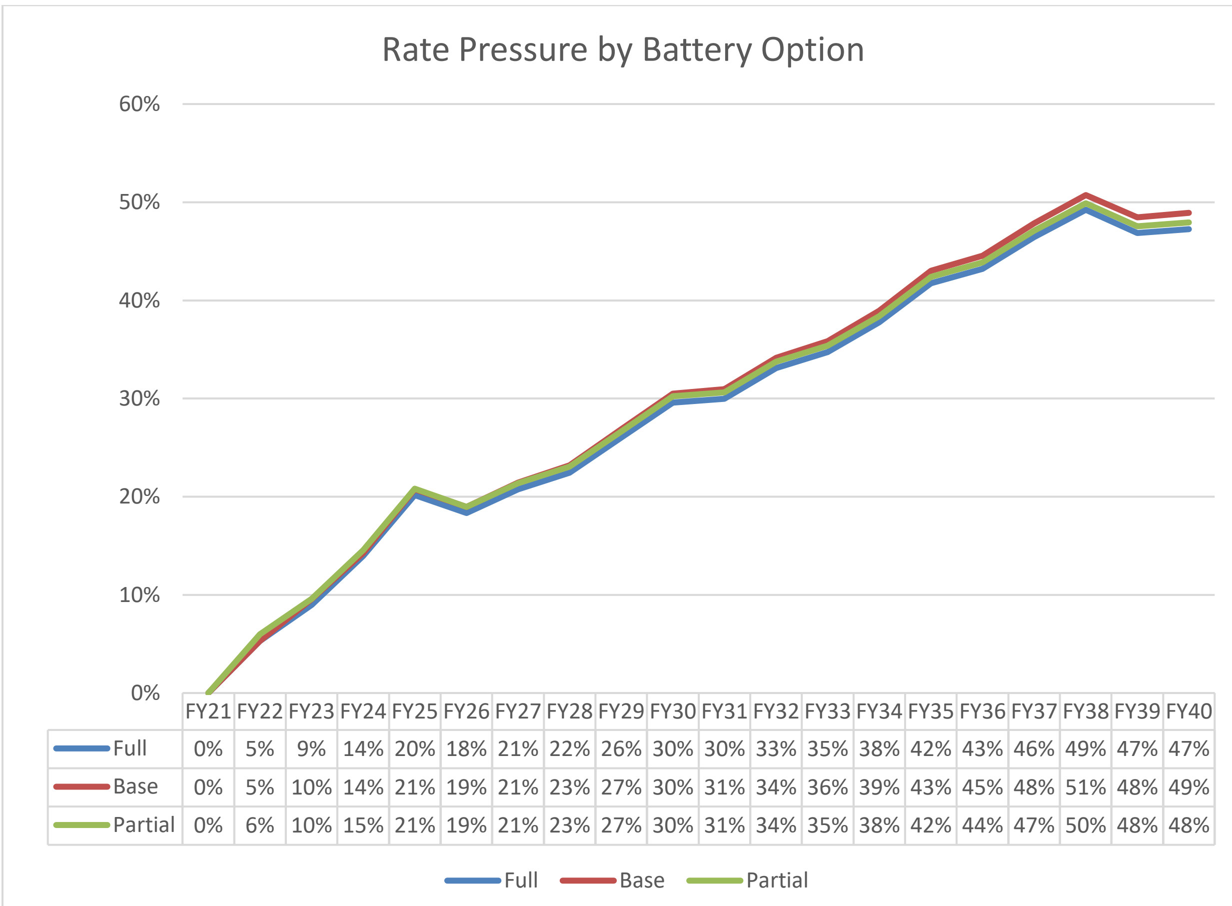
Table 3. Delta between High and Low Values NPV between Tolling Cases

	5-Year High/Low Delta			20-Year High/Low Delta		
	Base to Partial	Base to Full	Partial to Full	Base to Partial	Base to Full	Partial to Full
REC Value	0	0	0	0	0	0
Price - Inflation	-16,309	-17,830	-1,521	-150,228	-167,066	-16,838
Transmission Value	-57,564	-77,711	-20,147	-3,127,395	-4,221,984	-1,094,588
Price-Wood Fuel - Inflation	0	0	0	0	0	0
Energy Value	-452,967	-452,967	0	1,732,609	1,732,609	0
Capacity Value	-620,059	-630,937	-10,878	-8,928,134	-9,084,768	-156,634
Load Reconstitution	1,933,876	2,610,732	676,857	9,799,439	13,229,243	3,429,804
V-McNL Generation (tons/yr)	0	0	0	0	0	0
V-Wind (cap factor)	0	0	0	0	0	0
Frequency Regulation Price	0	2,170,712	2,170,712	0	5,947,869	5,947,869
Price-#2 Oil ($/gallon)	0	0	0	0	0	0
Price - Fwd Rsv Prem. ($/kw-mo)	0	0	0	0	0	0
V - BED VELCO LRS (% VELCO)	0	0	0	0	0	0
V - BED ISO Pk LRS (% Pool Pk)	0	0	0	0	0	0

Potential Rate Pressure

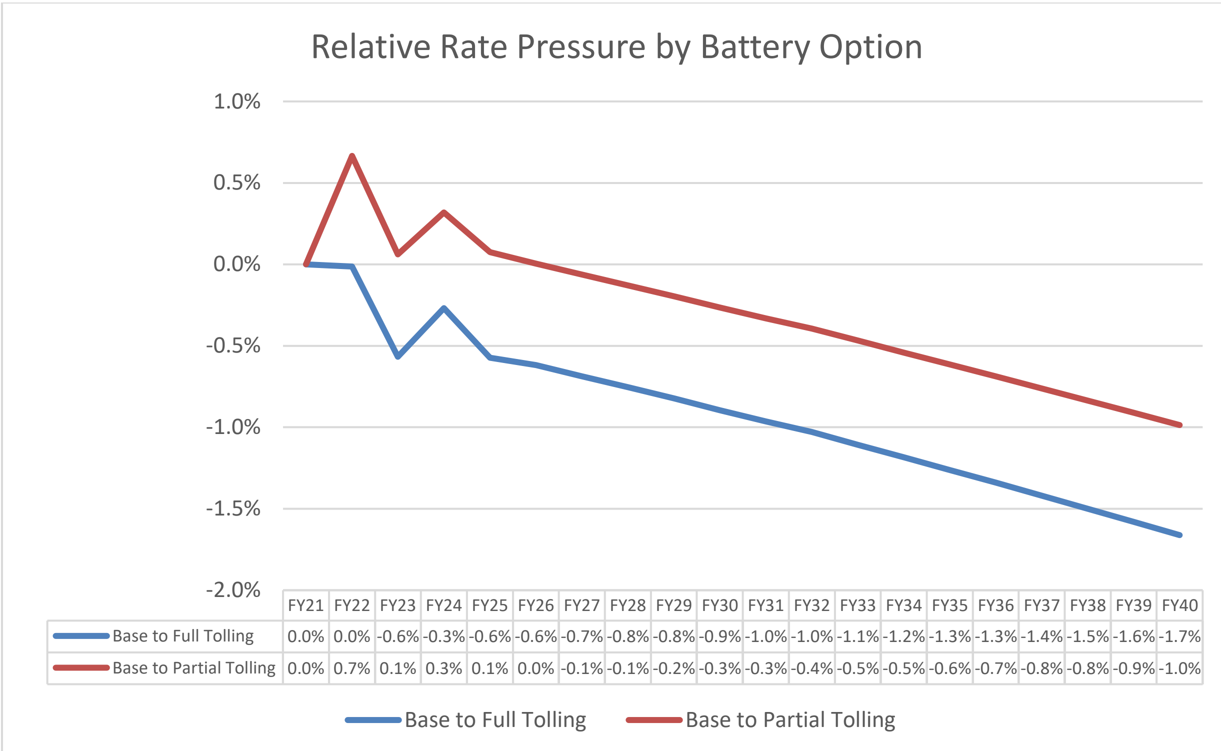
Finally, illustrative potential rate pressures (as well as the difference between those rate pressures) were calculated with and without the project. As shown below, the project will not be the main driver of rates going forward but could mitigate rate pressure in the 2030s under either the full or partial tolling arrangement (see Figure 5b for a more detailed representation of the differences between the lines in Figure 5a). The rate pressure paths shown in Figures 5a and 5b assume continued RNS value.

Figure 5a. Rate Pressure by Battery Option



	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Full	0%	5%	9%	14%	20%	18%	21%	22%	26%	30%	30%	33%	35%	38%	42%	43%	46%	49%	47%	47%
Base	0%	5%	10%	14%	21%	19%	21%	23%	27%	30%	31%	34%	36%	39%	43%	45%	48%	51%	48%	49%
Partial	0%	6%	10%	15%	21%	19%	21%	23%	27%	30%	31%	34%	35%	38%	42%	44%	47%	50%	48%	48%

Figure 5b. Relative Rate Pressure by Battery Option



	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35	FY36	FY37	FY38	FY39	FY40
Base to Full Tolling	0.0%	0.0%	-0.6%	-0.3%	-0.6%	-0.6%	-0.7%	-0.8%	-0.8%	-0.9%	-1.0%	-1.0%	-1.1%	-1.2%	-1.3%	-1.3%	-1.4%	-1.5%	-1.6%	-1.7%
Base to Partial Tolling	0.0%	0.7%	0.1%	0.3%	0.1%	0.0%	-0.1%	-0.1%	-0.2%	-0.3%	-0.3%	-0.4%	-0.5%	-0.5%	-0.6%	-0.7%	-0.8%	-0.8%	-0.9%	-1.0%

Conclusion

As shown above, a single decision can be analyzed in several ways. This analysis of a sample storage project showed that it could have different impacts on BED's bottom line as well as different societal impacts depending on future prices, the availability of value streams, and PPA terms. As the graphs above indicate, a 5 MW storage PPA appears to be a desirable investment (under either a full or partial tolling arrangement) based on currently available information (it results in decreased rate pressure over time) using base case assumptions. It also illustrates that: (i) the full tolling option is generally superior to the partial tolling option, (ii) the partial tolling option actually increases rate pressure in the short term, (iii) the full tolling option does not begin to improve rate pressure until year three of the IRP.

However, there are several uncertainties associated with battery storage systems that we know of that are extremely difficult to model and therefore are not shown in our graphs above. For example, both figure 5a and 5b include the continued value from RNS transmission. Given the above analysis, and coupled with the following considerations not reflected in figures 5a and 5b, BED concludes that it would generally prefer a full to a partial tolling arrangement but at the prices evaluated in this IRP it would probably not proceed with the full tolling option at this time due to:

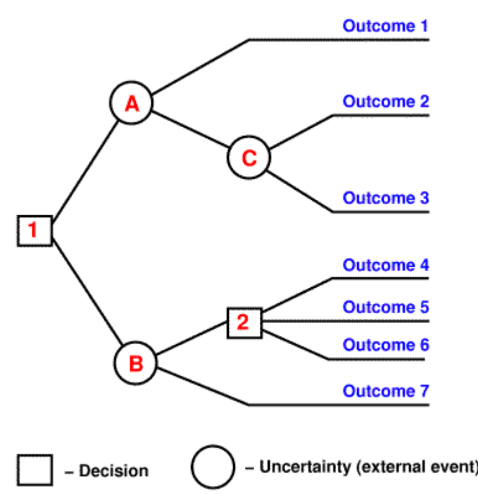
1. Material potential for complete loss of the key RNS value stream (perhaps particularly true for a unit of this size and not located behind a retail meter).
2. Acquiring 5 MW of AGC capability would make BED a material supplier of AGC services relative to its needs, and hence exposes BED to decreasing regulation prices in New England.
3. The concentration of benefit deriving from periods where the FCM price is not known (i.e., three-plus years in the future) coupled with the relative ease and scalability of storage, which argues against installing storage capability prematurely.

Due to these risks, BED's decision making process leads us to the conclusion that postponing decisions related to battery storage is a prudent course of action at this time.

That said, between the 2016 IRP and this one, energy storage systems have made gains in terms of their economics. Thus, BED's decision processes will continue monitoring the applicability of these systems in its service area, especially since the price of battery storage is expected to continue to fall. Also, if ISO-NE clarifies the rules pertaining to RNS value streams such that they are reasonably assumed to continue, or if the FCM market were changed in a beneficial manner, or future FCM clearing prices begin to increase, reconsideration of this conclusion would be warranted.

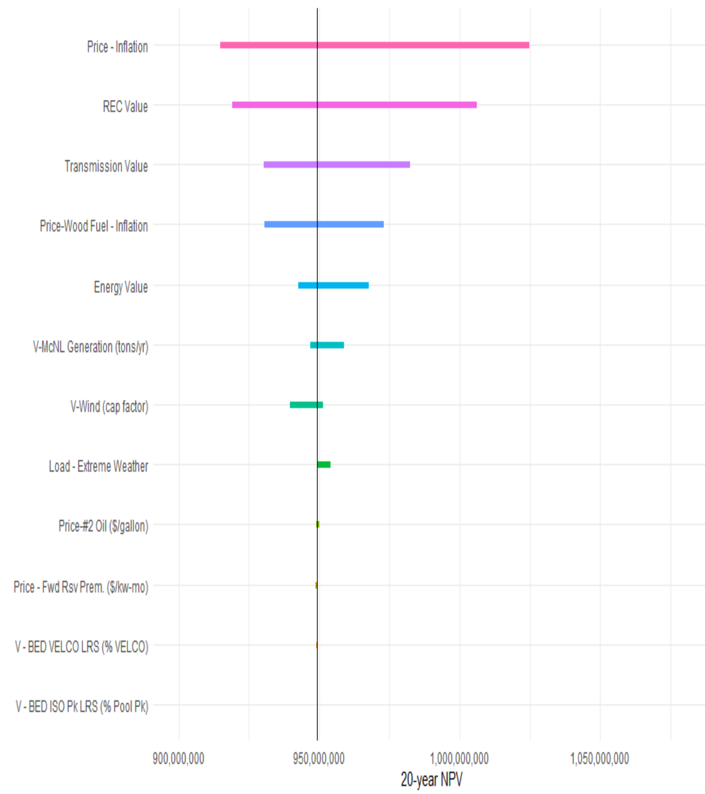
Decision Tree Methodology

On occasion, BED will want to evaluate multiple competing decisions at the same time. A decision tree analysis is a reliable business tool that allows for systematic processing of several input variables or risks that must be evaluated to reach conclusions and make decisions. At its most basic level, a decision tree analysis is a stepwise evaluation of known variables that could materially affect a business's operations if they are not appropriately managed. The diagram to the right highlights such steps, the sequential interactions between decisions and risks, and the plausible outcomes that may follow.



At the start of a decision tree analysis, input variables and other external factors that could impose material risks on decision outcomes are identified.

BED uses tornado charts to further inform its decision tree analyses by graphically highlighting how known risks could impact our cost of service, or net present value of our revenue requirement ("NPVRR"). As shown in the example graphic below, known risks are listed along the vertical axis and the 20-year NPVRR is highlighted along the horizontal axis. The color-coded bars display the range in probability of occurrence of select risks and their corresponding range of impact on BED's NPVRR. In this example, wood fuel inflation is the fourth highest-risk factor because the likelihood of it occurring in the future is speculative (i.e., the wider the bar, the wider the range of probability of occurrence). Similarly, the range of potential impacts caused by higher-than-normal escalating wood prices on BED's NPVRR is considerable. Through this process of charting individual risk profiles and their potential NPVRR impacts, BED can assess the sensitivity of our NPVRR to various known risk factors. Knowing how sensitive NPVRR is to such risks will inform the selection of a preferred path forward with any future resource procurement decision.



Next, BED assigns a probability of occurrence between 0 and 1 based on the best available information. This risk assignment process is typically performed by management and staff responsible for developing project plans. After each team member assigns their probability of occurrence to a specific risk, a range of potential outcomes for the risk can be determined. For example, one team member could assign the likelihood of higher than forecasted inflation (e.g., 5%) a score of 0.90. Another member could assign the same risk a score of 0.10, indicating that higher than forecasted inflation is unlikely to occur anytime soon. This assignment process reveals that inflation not only has the potential to materially impact operations, but the range of such impacts could potentially swing by 80% in one direction or the other. Such a wide range in probability of occurrence also means that inflation is a high-risk factor that needs to be tracked and managed carefully over time.

To reflect BED's decision-makers' view of risks facing BED, input variables are then weighted to arrive at a weighted-average risk profile. If, for example, two staff members assign the risk of high inflation a score of 0.90 and four staff assign a score of 0.1, then higher than forecasted inflation rates have a 36.67% chance of occurring over the planning horizon. By weighting known risks in this manner, management can gain better insight into the impact on BED of the potential future states that are of the most concern. For example, a consistent weighting of the high energy value by BED decisionmakers would indicate concern that the current energy market conditions are not sustainable. This "weighted case" does not replace, but is additional to, the other cases as a point of discussion along with any non-monetary and risk related considerations. These steps of this iterative process are repeated until a reasonable decision path comes into view.

The step of creating a "weighted" case was omitted in the above storage analysis only because of time constraints. Given the range of results and the very real potential for loss of the RNS value stream to rule changes in the near future, creation of a weighted case would not have been likely to change the conclusion reached.

To summarize, the decision tree process leading to the development of BED's tornado charts follows a series of key, iterative steps. These include:

- identifying, evaluating, and modeling key input variables;
- assigning probability of occurrence scores to key input variables, and calculating their weighted average expected probabilities;
- conducting NPVRR sensitivity analyses;
- identifying and examining answers to key questions that may impact BED's overall mission;
- evaluating plausible scenario outcomes; and
- refining decision tree scenarios and re-evaluating outcomes, as needed.

Conclusion

BED considers any major decision through many "lenses." This chapter walked through a sample decision and described the decision tree process for evaluating multiple simultaneous decisions. At this point, BED continues to pursue its Net Zero Energy goal but does not have any major decisions regarding that Preferred Path to evaluate.

Net Zero Energy Roadmap Implications

In 2018, the City of Burlington announced its goal of becoming a Net Zero Energy ("NZE") city by 2030. BED subsequently adopted this goal as its strategic direction, and in September 2019 published a *Net Zero Energy Roadmap for the City of Burlington* ("Roadmap") that outlines specific pathways and recommendations for Burlington to accomplish its goal.

Net Zero Energy is defined as reducing and eventually eliminating fossil fuel consumption in the building and ground transportation sectors by substantially increasing energy efficiency and then switching the remaining fuel to renewably sourced electricity.

The Roadmap provides a comprehensive assessment of the total annual energy consumption in Burlington under business as usual ("BAU") conditions,[1] and describes two alternative scenarios and timelines for achieving a fossil fuel free community: one by 2030 ("NZE30"); the other by 2040 ("NZE40").

BED's involvement with the City's NZE efforts actually began several years ago with securing renewable energy resources. These efforts continue to this day, as BED focuses on meeting its Tier 3 obligations under the RES with electrification programs (rather than lower cost RECs) to the greatest extent possible. Fully decarbonizing the heating and ground transportation sectors will require significant future investments by BED (and other stakeholders) in programs, measures, distribution upgrades, load control capability, and technical assistance. The level of annual investment is expected to be orders of magnitude greater than the current funding directed at BED's energy efficiency utility (approximately $2.2 million annually) and beneficial electrification programs (approximately $0.996 million in 2021 and growing).

Although BED is a leading participant in the City's NZE efforts, the goal cannot be achieved by BED's actions alone. Additional efforts to support NZE will include potential City policies aimed at requiring additional weatherization in existing buildings, and strategic electrification work in new buildings. Partnerships with other City Departments as well as key external partners such as Champlain Valley Weatherization Services, VGS, Green Mountain Transit, and others will play an important role. In some cases, federal or state policy changes may be required. A state policy example is S. 337, which is currently under review. If enacted, S. 337 would provide BED (and other authorized efficiency utilities) with additional flexibility to

[1] A copy of the full Roadmap report is attached and can also be found at: buringtonelectric.com/nze

redirect existing electric efficiency funds toward greenhouse gas reduction initiatives. Still other potential policies identified in the NZE Roadmap that are not directly in BED's control include pricing carbon, developing a transit plan, and changing land use patterns. BED is actively engaged with local, state, and federal officials regarding activities and potential funding to advance Net Zero Energy, but we have not scoped additional funding sources or amounts needed beyond those identified in other chapters of this IRP. Therefore, for the purposes of this IRP, BED assumes that adoption of beneficial electrification technologies, such as electric vehicles and heat pumps, will not occur at a significantly different pace than our BAU scenario until specific policies are enacted. Instead of planning for a NZE30 or a NZE40 future, BED assumes that adoption of beneficial electrification measures will mirror national treads to ensure resource adequacy and reliability are maintained, pursuant to 30 V.S.A. §218c. The BAU modeling outputs do serve, however, as the starting point for evaluating the potential impacts associated of a Net Zero Energy future, which we further describe below.

This chapter provides a high-level assessment of the potential implications of achieving the initial stages of the Roadmap. Specifically, this chapter discusses:

- Roadmap assumptions and outputs;
- Expected distribution system impacts at 102.8 MW;
- Expected power supply requirements at 102.8 MW;
- Preliminary revenue impacts at 102.8 MW; and,
- Whether the sum of the above would tend to increase or decrease BED's average cost per KWH of providing electric service ("Rate Pressure")

Net Zero Energy Roadmap Overview

Reaching the NZE goal by 2030 will require a paradigm shift in how Vermont designs clean energy programs (either with aggressive incentives, state mandates, or both, etc.). Achieving the goal also will require some modification of Burlingtonians' current energy consumption habits. At a minimum, successfully attaining NZE depends on:

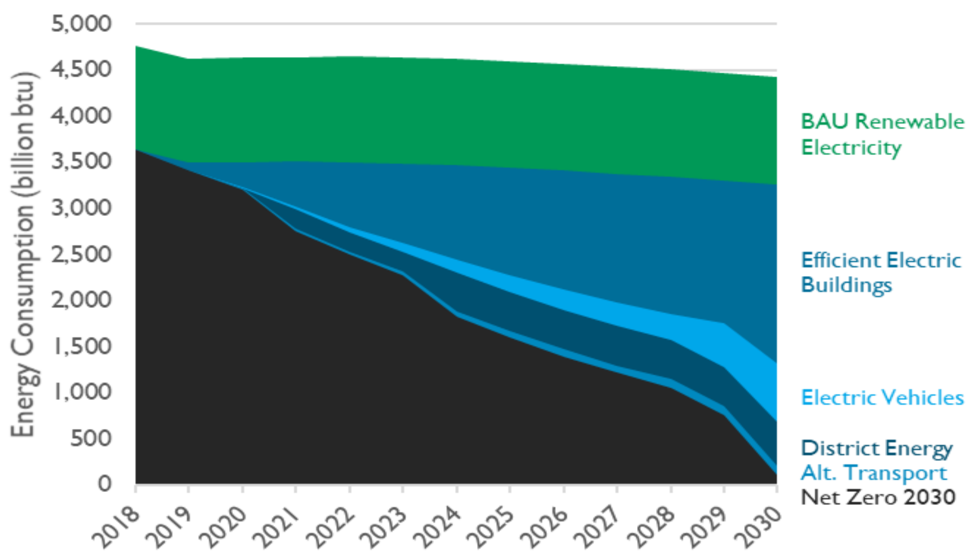
- Substantial reductions in energy use through accelerated and integrated energy efficiency, particularly in the thermal sector;
- Widespread active and passive demand response to limit system impacts to the greatest extent possible;
- Expansion of the distribution system's capability to serve new loads reliably, prior to those loads coming online;
- Comprehensive citywide planning for all new construction projects and major renovations, including renovations of historic buildings to avoid retrofit needs at later dates;

- Widespread adoption of beneficial electrification technologies, such as heat pumps and electric vehicles;
- Maintaining our 100 percent renewably sourced electricity generation portfolio; and,
- Stakeholder support and engagement among all of BED's partners.

In short, the NZE goal requires an "all-hands-on-deck" effort to fully transform two large market sectors that are fundamentally important to the state and local economy: building thermal energy needs and transportation. The main tools that BED can currently leverage to work toward accomplishing the NZE goal are the Renewable Energy Standard, especially our Tier 3 obligations, as well as our EEU programs.

To provide guidance to the community and other decision-makers on how Burlington can attain NZE, BED commissioned the aforementioned report to establish a citywide total energy consumption baseline. This baseline consumption, which amounts to over 4,500 billion BTUs, including renewably generated electricity, serves as the starting point toward the NZE goal. The Roadmap identifies the energy uses that need to be de-carbonized and the implementation "trajectories" required to accomplish the goal by different dates.

Figure 1 Total Energy Consumption



By determining the amount of decarbonization that is needed by generic end use, the Roadmap provides insight into how Burlington can begin the process of reducing fossil fuel consumption by switching to renewably sourced electricity or reducing energy consumption. As Figure 1 demonstrates, fossil fuel consumption (black shaded area) is replaced over time with clean electricity (green and blue shaded areas). To successfully "bend down" the fossil fuel consumption curve, the Roadmap directs Burlingtonians onto four pathways to NZE: efficient electrically heated buildings; electric vehicles; district energy; and, alternative transport. Each pathway includes a set of goals, which are explained further below. The magnitude of the potential fossil fuels savings by pathway is shown in varying shades of blue in the graph above. It should be noted that for transportation sector purposes, only trips by Burlington residents are counted in the Roadmap, although there will be a secondary focus on reducing fossil fuel use by visitors and commuters to the City. As loads are converted from fossil fuel in each sector, that energy will need to be powered by increasing the current amount of renewably sourced electricity (depicted in green in Figure 1).

Pathway 1: Efficient Electric Buildings

Customers will need to dramatically shift from traditional heating systems (i.e. hydronic boilers and hot air furnaces fired by fossil fuels) to new advanced heat pump technologies for space conditioning and domestic hot water.

Air-source heat pumps ("ASHPs"), also referred to as cold climate heat pumps ("CCHPs"), are currently the main technology in Vermont capable of providing sufficient heating capacity, except during extreme cold temperature events (below 0°F). With current technology, Vermonters typically maintain their existing conventional heat source to ensure their building is safe and comfortable during such extreme cold weather. A significant number of CCHPs have been installed throughout Vermont in the past several years and are currently providing customers with more than adequate heat as well as new cooling capabilities. It is expected that the number of CCHP installations will continue increasing, even under our BAU scenario. But in this scenario, their adoption is more rapid, as further discussed below.

While residential heat pump adoption rates have steadily increased in Vermont, the customer's economics for installing a CCHP in Burlington are challenging. Within BED's territory, more than 95% of customers have natural gas heat systems. Because natural gas prices are at all-time low levels, it costs less to heat with natural gas than with a CCHP at present retail electric rates. Therefore, most BED customers will not achieve energy cost savings by switching from natural gas heat to a CCHP system (though for customers wishing to decarbonize their heating load, CCHP technology does compete favorably with the cost of heating with renewable natural gas). It should be noted, however, that many customers may be interested in CCHPs not only for heating, but also their efficient cooling capability.

Although making the economic case for CCHP adoption in Burlington has challenges, the NZE30 modeling outputs would require installation of heat pump technology in all new buildings by the mid-2020s.[2] To facilitate extensive heat pump adoption among existing

[2] In addition to the most widely adopted CCHP technologies, other heat pump technologies include ground source heat pumps ("GSHPs"), water-to-water heat pumps, air-to-water heat pumps, and variable refrigerant flow ("VRFs") heat pumps for commercial applications.

building owners without an increase in the price of natural gas (either intrinsically or due to an explicit carbon adder), BED would need to do one or more of the following:

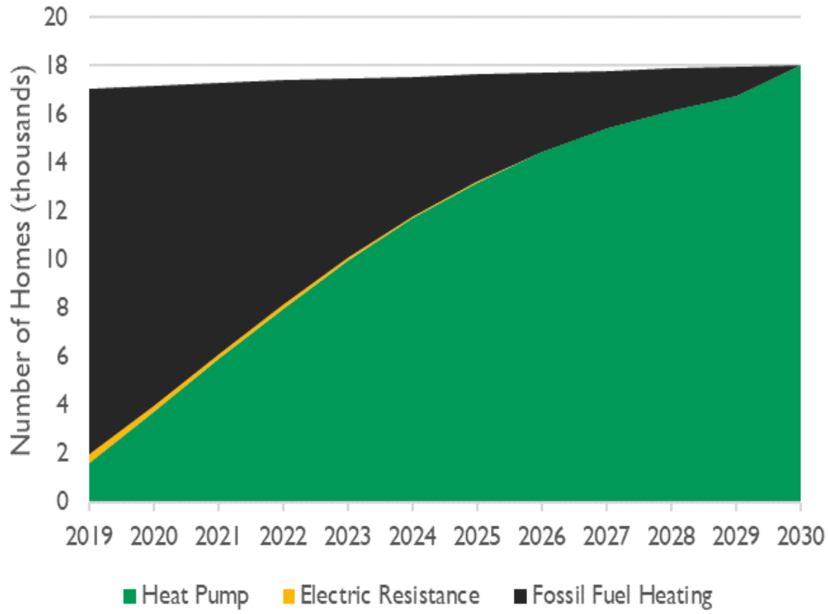
1. Substantially increase incentives above those currently permitted under the Vermont RES (which BED is piloting through its Green Stimulus program)
2. Take action to encourage such conversions at the City government level
3. Offer reduced electric rates for CCHPs, particularly those that are load controlled. [3]

Over the next 2 – 4 years, BED will need to closely monitor changes in the pattern of electric use over time and the City's progress toward heating all buildings and domestic hot water with heat pumps. BED will have to keep tabs on the number of annual and cumulative heat pump installations and simultaneously encourage building owners to increase the thermal efficiency of their buildings by weatherizing the building shells, air sealing, and, in some cases, replacing windows and/or doors. Research into end-use metering and load control options may support special CCHP rate options. Having the capability to control heating and cooling loads from CCHPs – especially to the extent that buildings are probably weatherized – will minimize the impacts of heat pumps on our distribution system and resource requirements.

As Figure 2 below indicates, the NZE30 model anticipates that nearly 10,000 residential heat pumps would need to be installed by 2024, and 18,000 by 2030. Today, there are only 225 advanced heat pumps installed in Burlington, well short of the NZE targets. BED believes NZE progress may come in a non-linear fashion, and depending on technology and policy, the pace of growth may change substantially during the next ten years. This happened with solar adoption, for example. The NZE goals indicate that nearly all households in the City, including those residing in apartments, condominiums, and single-family structures, would need to install CCHPs.

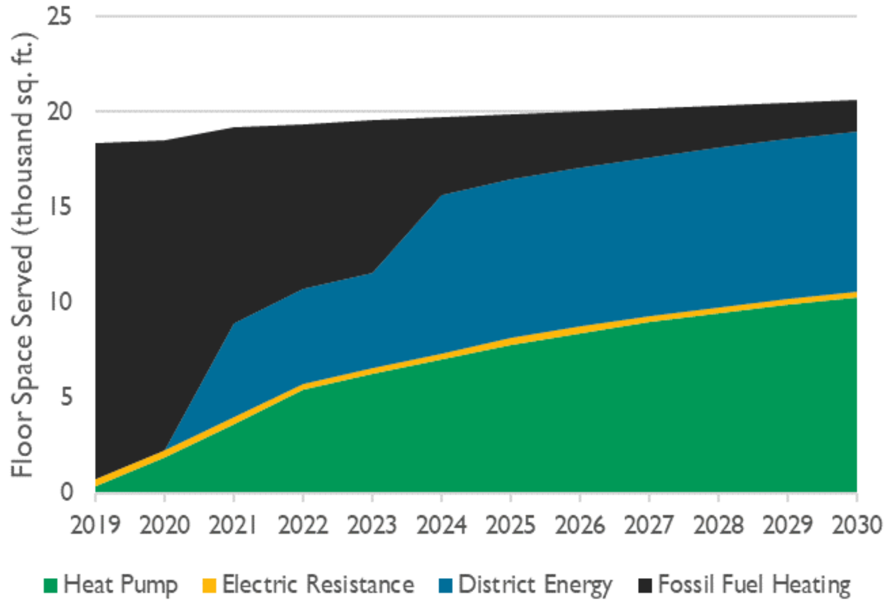
[3] However providing CCHP rate credits would have the effect of reducing the benefits of widespread beneficial electrification on rate pressures. For more information, see Chapter 6.

Figure 2 Residential Households with heat pumps



In the commercial building sector (Figure 3), the NZE30 scenario assumes that an increasing amount of floor space will convert to heat pump technology (mostly VRFs, although GSHPs could also be a viable option) even if their existing boiler systems remain in place. In this scenario, heat pumps will serve as the primary heating system and existing heating equipment will back up heat pumps only during extreme cold weather. Also, the NZE30 scenario assumes that a district energy system will be in place and eventually expand to provide heating to substantial portions of the City's large buildings (e.g., UVM Medical Center).

Figure 3 Commercial Floor Space heated with heat pumps

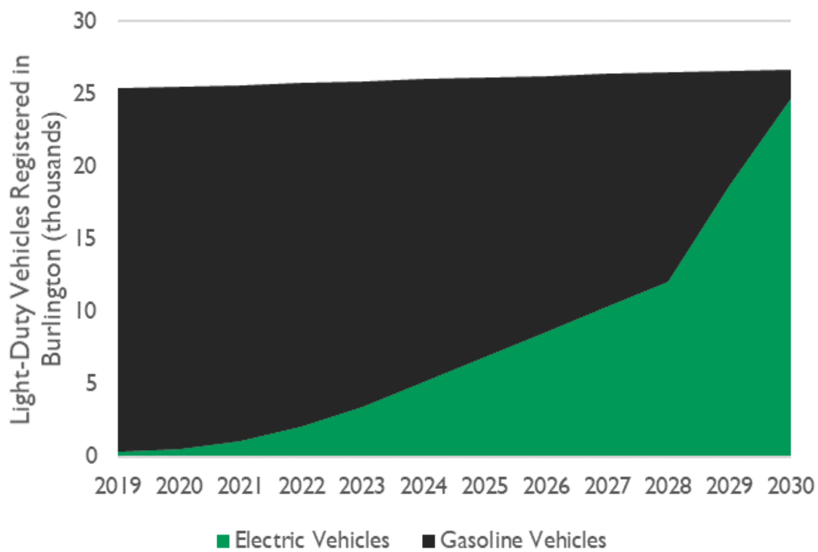


Pathway 2: Electric Vehicles

The electric vehicle ("EV") pathway also aims to achieve aggressive goals for the City. Today, there are approximately 24,000 light-duty vehicles registered in Burlington. Under a BAU case, by 2030 we expect this number to increase modestly as the City's population grows. To achieve the NZE30 goal, the Roadmap assumes that almost all of the light-duty vehicles in Burlington are converted to electric vehicles by 2030.[4] As shown in Figure 4, the rate of EV adoption needs to be brisk to achieve this goal, particularly after 2022, and would require Burlingtonians to convert from existing internal combustion engines ("ICEs") in significant numbers before the end of their expected useful life (12 to 14 years). Under NZE30, the model assumes that nearly 5,000 vehicles registered in Burlington will be electric by 2024, an increase from approximately 500 today. By 2029 and 2030, nearly 10,000 additional ICE vehicles will need to be replaced with EVs. In a typical year, about 1,500 new vehicles are registered in Burlington. BED existing Tier 3 incentives are unlikely to result in this level of accelerated adoption alone, but improving EV technology, increased access to used EVs, and improved charging infrastructure are expected to be of material assistance.

Figure 4 Electric Vehicle Adoption curve

[4] While other vehicles in the City may also be converted to electrically powered motors such as e Buses, transit buses, and others, this section focuses on light-duty passenger vehicles as they are expected to have the greatest impact on BED's load requirements.



Pathway 3: District Energy

The district energy system ("DES") pathway details how large customers[5] can reduce natural gas consumption by partially converting their buildings to steam based on the thermal energy produced from sustainably harvested biomass. In the Roadmap, this pathway consists of diverted steam-based energy and recaptured waste heat from the McNeil Generation Station being distributed via new pipelines to the University of Vermont ("UVM") Medical Center campus and ultimately expanding to serve other buildings. Ultimately, the Roadmap modeling outputs assumes that the DES could potentially reduce natural gas consumption by 475 billion BTUs annually, or about 15 percent of total fossil fuels consumed for building heating. The diverted steam would be used for space heating, domestic hot water, and potentially other thermal processes. The initial buildout of a DES would need to begin no later than 2021 in order to meet the NZE30 goals, and one or more large customer(s) would need to agree to become an anchor tenant to justify the significant upfront capital investment needed to build the system.

Once the capital investment is made, the DES could eventually be expanded to connect with other customers in the vicinity of the steam pipeline system or to integrate additional renewable thermal sources of energy. As is the case with CCHP, the economics of a DES are challenged by the very low price of natural gas today. On the positive side, a biomass-based DES appears to be a cost-competitive method of decarbonizing compared with other options, particularly for large customers. BED has received (and intends to seek additional) grant funding to offset DES engineering study and capital costs. Such studies are necessary to provide potential DES customers with the cost certainty necessary to gain their financial commitment

[5] In the early years of development, it is assumed that only large institutional customers would connect to a DES.

and move the project forward. It is also important to note that VGS has been fully engaged in the DES project as a key partner.

DES would potentially have significant impacts on BED not in terms of new or additional electric load, but in terms of impacts on the McNeil Generating Station (e.g., improved efficiency, changed operational cycles, and potential revenue diversification).

Pathway 4: Alternative Transportation

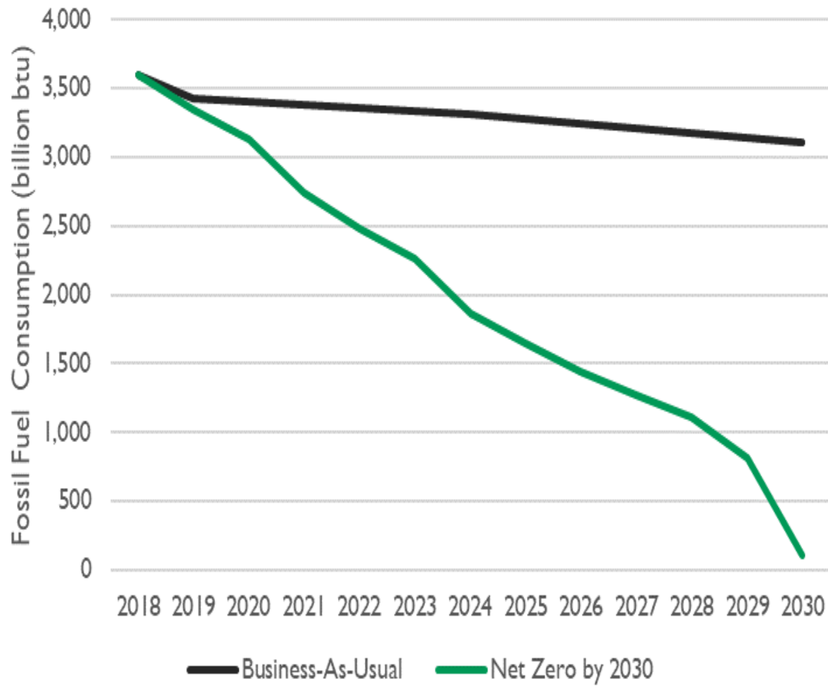
The last major pathway BED and the City will need to pursue involves alternative transportation modes and related behavioral changes. If achieved, this pathway is expected to result in a 5 percent reduction in fossil fuel consumption. The alternative transport pathway assumes that, given increased multi-modal transportation options for commuting to work and other destinations, Burlingtonians will drive a personal vehicle less often. Such options include biking, taking public transit, carpooling, and/or walking.

This pathway is not expected to have dramatic impacts on BED, unlike the DES, EV, and CCHP pathways.

Load and Emission Impacts

Net zero energy does not mean zero energy consumption. Instead, NZE means that as our customers' fossil fuel consumption trends downward over time, their energy needs that are not met by increased efficiencies and/or are replaced with renewably sourced electricity as the City's preferred energy source. Thus, the region below the black line in Figure 5, which represents BAU consumption of fossil fuels, is replaced with renewably sourced electricity. The model also anticipates that the total amount of energy consumed will decrease to a little more than 3,000 billion BTUs because of increased efficiency in the building and transportation sectors.

Figure 5 Fossil Fuel only consumption



Under the NZE30 scenario, the increase in electricity consumption will notably impact BED's existing operations and require upgrades to and modification of certain aspects of its operations to ensure continued reliability. Should the City successfully reach NZE using the Roadmap pathways, the net impact on BED's load requirements would be an increase to roughly 550 GWh from 340 GWh, and peak demand may go from the current 65 MW to 140 MW, as shown in Figures 6 and 7. However, the timing of these load impacts is uncertain, largely because many aspects of achieving NZE by 2030 (or 2040), such as implementing complementary policy actions, are beyond BED's control. Perhaps more uncertain is the progress, if any, that the rest of New England might make toward NZE, and the impacts on the wholesale electric market and transmission systems that total decarbonization would cause.

Therefore, BED selected a load threshold of 102.8 MW and the load shape and timing associated with decarbonization activities to achieve that threshold to understand the early effects of progress toward the Roadmap. 102.8 MW was selected as a load level that would stress the distribution system past its current capability of serving roughly 80 MW load, along with a shift to a winter peak. Additional engineering analysis is in process to understand the upgrades needed to serve the full load outlined in the Roadmap, but these analyses are sufficiently complicated to require additional time to perform.

Again, the graphs below do not represent actual forecasts of specific load occurring by a specific date. The analysis in this chapter does, however, conclude that the rate impacts of distribution upgrades required by load increasing to 102.8 MW during the early stages of the Roadmap are not adverse, although distribution system investment will be needed. Additionally, increases in load may actually work to reduce average costs and rates, as discussed below.

Figure 6 Renewable Electricity sales

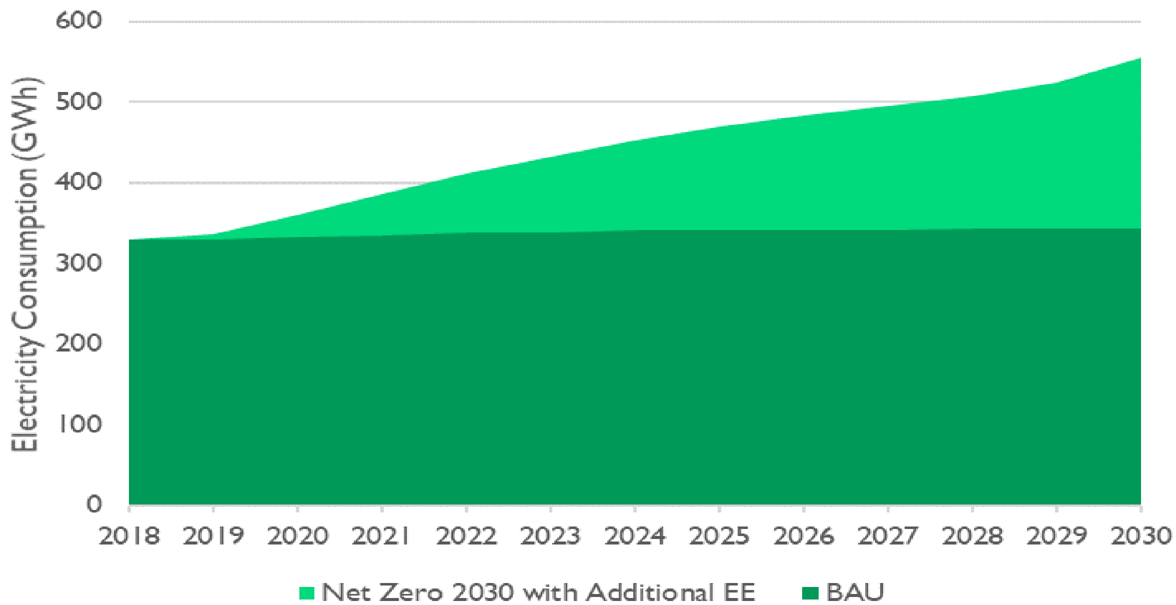
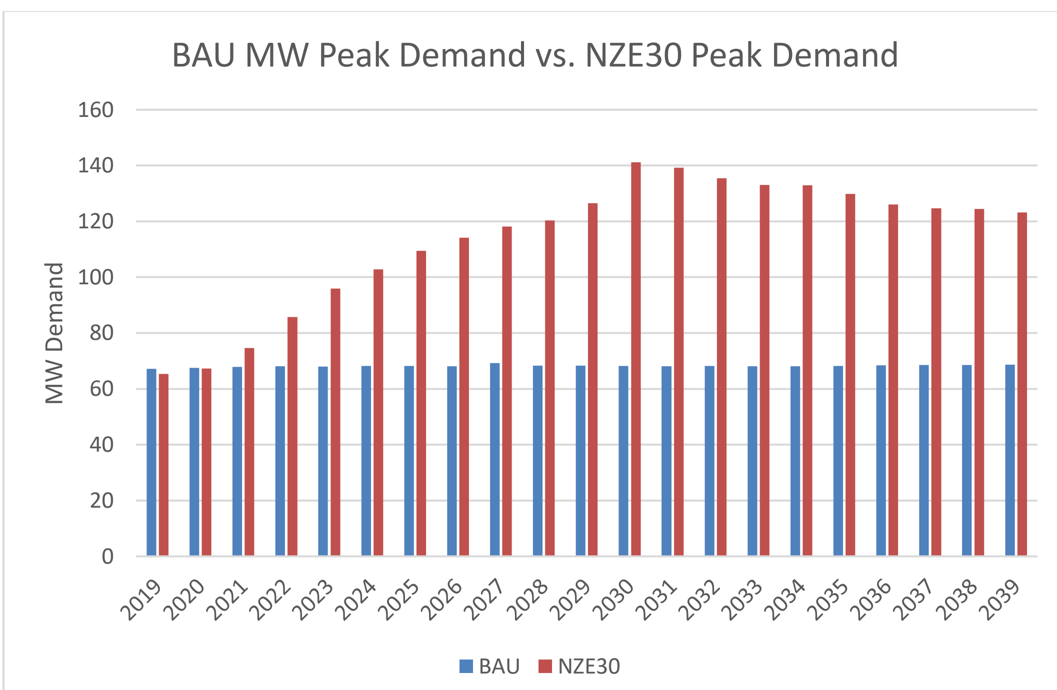
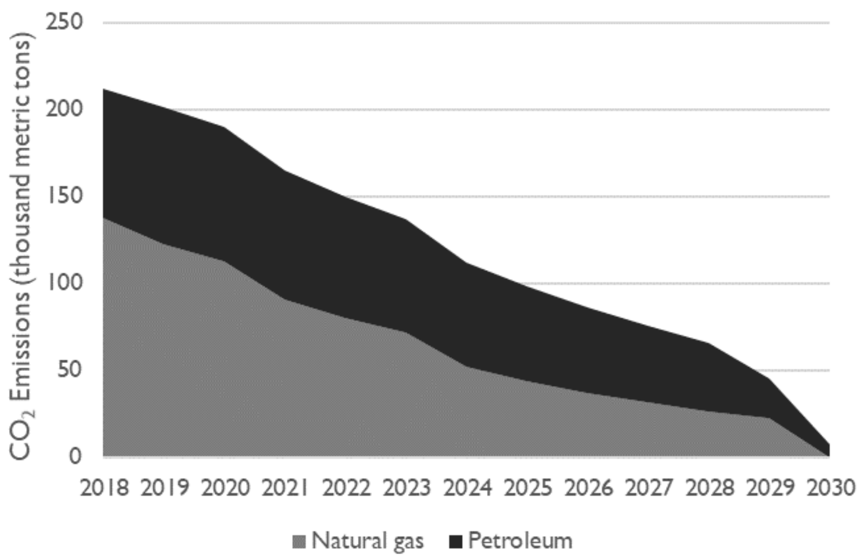


Figure 7 Peak Demand



The NZE30 projections of reduced fossil fuel consumption and lower GHG emissions will provide significant societal and economic benefits to customers and those benefits have not been quantified in this preliminary analysis. As shown in Figure 8, NZE30 may reduce GHG emissions by approximately 200,000 tons. Reductions of this magnitude will undoubtedly contribute to improvements in regional air quality and public health.

Figure 8 GHG Emissions reductions



Potential Distribution System Impacts

BED's NZE30 Roadmap highlights that as load grows with adoption of beneficial electrification measures, so does the potential for system-wide distribution impacts. This cause and effect relationship is illustrated in Figure 7 above, which shows an estimated peak of 102.8 MW in January 2024 and an estimated peak of 140 MW by January 2030. As peak demand grows, BED will need to make additional investments in its distribution system (ahead of loads actually occurring) to ensure continued reliability. However, absent policy directives to achieve NZE goals, BED does not anticipate that an increased demand for power will materialize suddenly. Furthermore, BED is currently not on the trajectory shown in Figure 7.

BED will be able to verify the actual pace of increased demand in electricity by monitoring the rate at which its customers adopt beneficial electrification technologies and the corresponding changes in BED loads, to determine at what point upgrades will need to commence. Selecting 102.8 MW as an initial load level for analysis provides BED insight into the subset of investments needed to fully prepare for NZE30 achievement (by setting an analysis level that cannot be served reliably by BED's existing distribution system – see T&D Chapter). Setting an initial evaluation load level also sheds light on the general economics of achieving

NZE from an electric utility perspective in terms of incremental power costs, retail revenues, and whether the combination of these impacts appears to result in upward or downward rate pressures.

To determine whether distribution system upgrades would be necessary to reliably serve a peak demand load of 102.8 MW, BED analyzed its existing distribution system as it is constructed today and explored four contingency scenarios. In each scenario, one of four main distribution substations serving the City was taken offline at a time: the McNeil substation, East Ave #3, East Ave #4, and the Queen City Substation. If one of these distribution substations were to be disabled unexpectedly, circuit loading and voltage levels would exceed engineering limits. The effect of such conditions, were they to occur, could cause large areas of unserved load in the event of an outage, as well as poor power quality across much of the distribution system.

By modeling the effects of one substation outage at a time, BED's engineering staff is seeking to determine what system upgrades are required to mitigate issues and provide reliable service to BED customers at increased load levels.

The following upgrades were identified to address the circuit overload and voltage issues. It is anticipated these projects will take four to seven years to complete depending on labor staffing levels and the availability of capital funds for this purpose in the context of the complete scope of BED's capital budget (i.e., NZE projects plus other projects not related to NZE).

Project Description	**Project Type**
Upgrade 2L5 Cable from 350 CU to 1000 CU	Upgrade to Existing
Buell St - Convert to 3-Phase	Upgrade to Existing
Heineberg Rd upgrade to 556AL	Upgrade to Existing
Starr Farm Beach – Convert to 2-Phase	Upgrade to Existing
Ethan Allen Pkwy convert to 2-Phase	Upgrade to Existing
Convert Ethan Allen Pkwy northern area to 3-phase and balance the loads	Upgrade to Existing
Upgrade Secondaries/Services and Transformers	Upgrade to Existing
Extend 1L2 to North Avenue & transfer load from 1L4 to 1L2	New Installation
Install 4-Way Padmount or Submersible Switch at Starr Farm Rd & North Ave	New Installation
1L2 extended to Starr Farm Rd 4-way switch and then to Barley Rd	New Installation
Extend 2L1 Circuit to pick up load off 1L1 Circuit	New Installation

Transfer load between 1L1 to 1L4 - Install 556 AL from Staniford Road to North Ave - Install 556 AL from Woodbury Road to North Ave - Install 556 AL from Woodlawn Road to North Ave - Install SCADA controlled switch connecting 1L1 and 1L4.	New Installation
Create a new 2L8 Circuit	New Installation

Modeling results with these upgrades indicate that voltage limitations and thermal loading conditions across the distribution network would remain within appropriate engineering parameters at the 102.8 MW of peak demand, and that consistent, reliable service could be maintained.

Based on the best available information at the time of writing, the total estimated cost of the above infrastructure upgrades ranges between $19 million and $24 million (estimates were prepared using 2019 figures for labor, material, and overhead costs). This estimate is based on using existing personnel to complete the work over the seven-year span and not hiring external contractors.

While this analysis presents a solution at the 102.8 MW level, BED will continue evaluating the potential implications of the NZE load forecast of 140 MW in 2030. It is anticipated that the conclusion of the 140 MW analysis may require upgrades at the substation and/or sub-transmission level.

It is important to note that under the fully realized NZE30 scenario, BED anticipates that there will be several newly identified system upgrades required to support loads beyond the 2024 threshold that are not included above. However, these new potential upgrades will be considered starting from the solutions found in this interim analysis. Once an engineering solution has been developed that adequately supports the forecasted NZE30 load, any additional system upgrades will need to be reviewed in consideration of the projects required at the 102.8 MW load level so that the upgrades previously built would not need to be upgraded again in the latter half of the current decade. Through this iterative process, BED will be in a position to better plan what the distribution system of 2030 will need to look like to support a NZE city and what upgrades it will require along the way without undertaking upgrades that will be superseded in too short a period of time.

Power Supply Requirements

Maintaining a 100 percent renewably sourced electric generation portfolio remains the centerpiece of BED's clean energy strategy and is necessary to decarbonize Burlington's energy needs. The strategy will require BED to procure more renewable energy to serve the energy needs associated with the 102.8 MW load levels (an additional 119 GWh or a 35% increase over current needs). While such an increase in energy requirements may be significant for BED, it isn't significant relative to the amount of renewable electric energy generated and wheeled throughout the New England system.[6] And, because BED's new energy procurements are so small relative to the total renewable wholesale energy market, we do not expect energy prices to materially increase relative to current prices because of Burlington's NZE efforts. Indeed, BED has already conducted informal discussions with an existing hydroelectric supplier about potentially procuring additional power supplies. That supplier has indicated a willingness to provide such additional renewable power supplies to BED at competitive wholesale prices. Accordingly, for purposes of this NZE analysis, BED assumes that up to 120 GWhs of additional power (inclusive of line losses and reliability reserves) will be available at an average wholesale cost of $41 per MWh.

With respect to capacity, transmission, ancillary, and REC costs, BED similarly assumes that the need for these additional resources is *de minimus* relative to the amount of resource availability throughout the region. As a result, the wholesale cost of such services is expected to be similar to current costs, or to follow similar trends in the case of transmission costs for the analysis in this chapter. Combining all expected wholesale energy costs (i.e. energy, capacity, transmission, ancillary, and RECs) will naturally increase BED's cost of service in the aggregate by a material amount. BED's conclusions regarding the ability to implement the early stages of the Roadmap contained in this chapter are predicated on these assumptions.

Preliminary Rate Impact Conclusions

The NZE30 pathway results in both significant forecasted costs and net revenue improvement for BED. This is illustrated below by showing first the forecasted incremental costs associated with the NZE30 pathway, then the translation of those incremental costs to $/kWh, and finally the impact on the projected rate path of the NZE30 pathway.

Incremental Costs ($)

Figure 9 illustrates the expected annual costs associated with serving the Roadmap loads at 102.8 MW. In order to generate relevant IRP model outputs, the timing of the loads was aligned with the NZE30 pathway for costing purposes through 2024 (i.e., to the 102.8 MW level) and the BAU growth rates were used for the remainder of the IRP horizon. This methodology yields a load slightly higher than 102.8 MW in the outer years of the evaluation, but not by a magnitude large enough to change the conclusions in this section.

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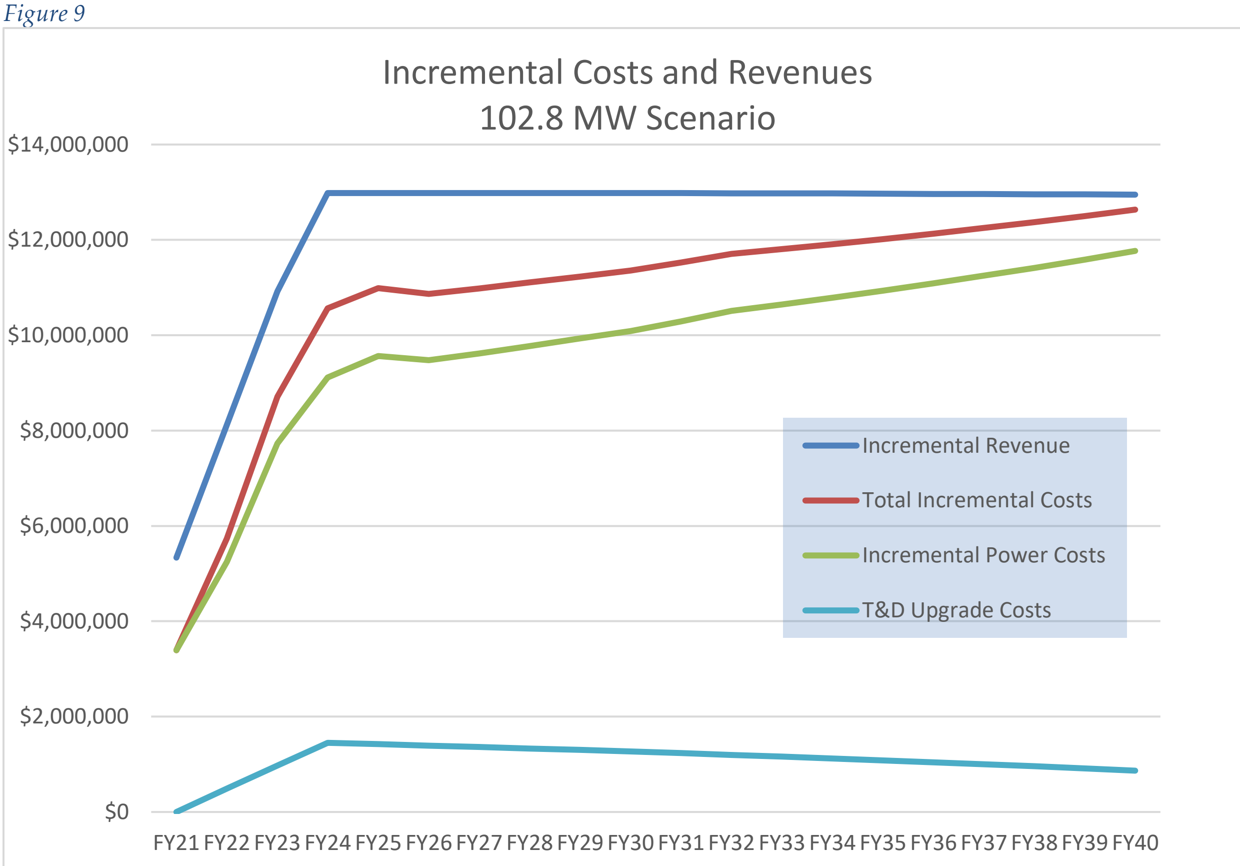
[6] According ISO-NE, 11,149 GWh of renewable and 8,788 GWh of hydro was generated in 2019. *See;* https://www.iso-ne.com/about/key-stats/resource-mix/

T&D capital costs were converted to annual costs through a 25- to 33-year depreciation schedule and a 20-year bond issuance that is consistent with the expected life of the proposed upgrades and BED's current borrowing practices.

Figure 9 indicates that the combined cost to serve the incremental load associated with the 102.8 MW Scenario (the carrying cost of the expected distribution upgrades and incremental power and transmission costs) is lower than the projected revenues under existing rates (assuming no discount to CCHP rates but including BED's off-peak EV charging rate) for the full 20-year period. This would be true at BED's base case projections of wholesale power costs, even if BED had no increases in rates in the next 20 years. It is also informative to note that at the 102.8 MW level, the costs of upgrading the distribution system are far less significant than the wholesale power costs. The review of required T&D upgrades to support loads greater than 102.8 MW will indicate if this relationship changes materially as load levels increase. Excess revenues over the incremental costs to serve provide a contribution to BED's existing fixed costs, which can help to reduce rate pressure, provide some discount to CCHP rates without adding to rate pressure, or a combination of the two.

Figure 9

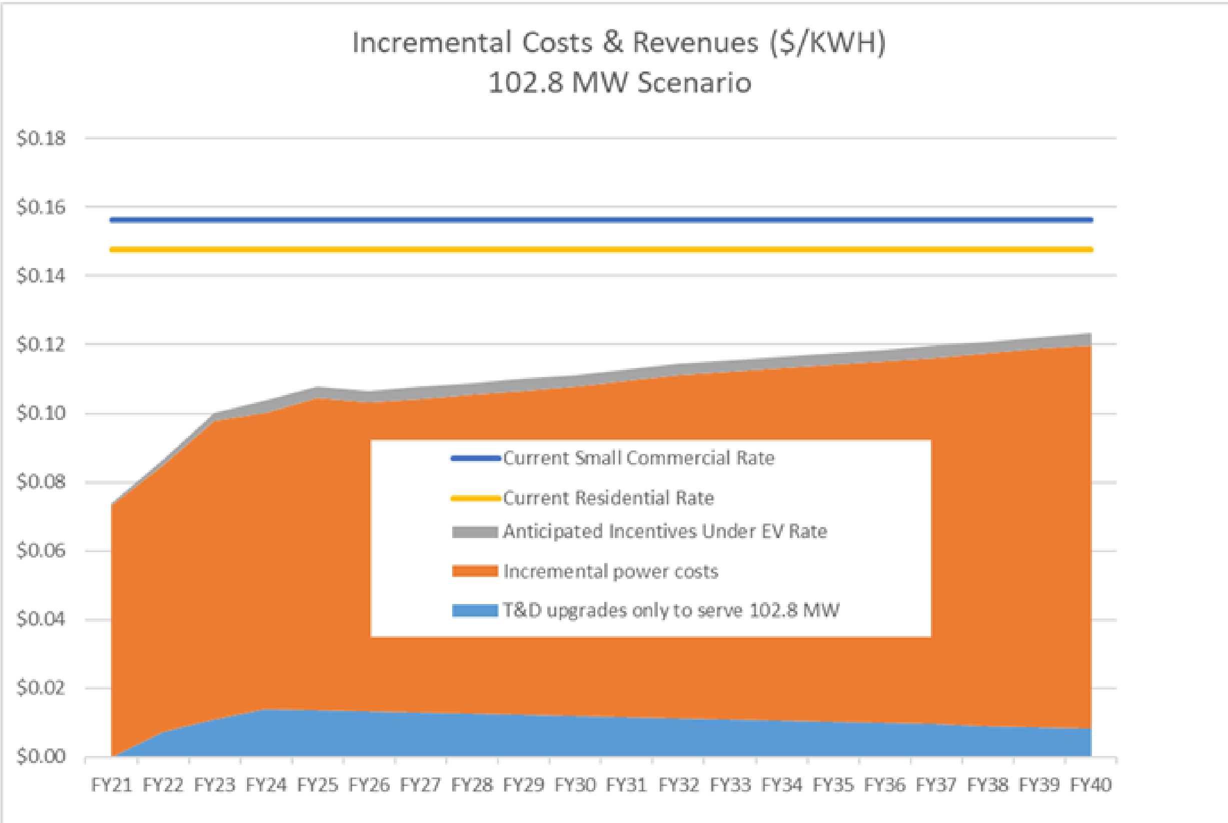


Incremental Costs ($/kWh)

Figure 10 restates the information shown in Figure 9 in terms of cost per kWh to reflect the incremental impacts of both total costs and load. This shows a similar relative magnitude of costs, with the wholesale costs being the majority, rate incentives being significant, and the costs of upgrades being much less significant. For comparison purposes BED has added two lines showing BED's current energy rates for Residential (RS) and Commercial (SG) customers. (Because industrial rates include a demand charge, they are excluded here for simplicity.)

The "T&D Upgrade Costs" area of the graph shows the impact of the distribution upgrades required to serve approximately 102.8 MW of load, depreciated and bonded appropriately. The "Incremental Power Costs" area again shows that the incremental wholesale power and transmission costs are the largest component. Finally, the "Anticipated Incentives Under EV Rate" area shows the impact of offering rate incentives for much of the forecasted load increase related to the number of EVs in the City at the 102.8 MW load level. (Note: this is shown in Figure 10 as an incremental cost for comparison to the existing retail rates on a per KWH basis but is shown in Figure 9 as a reduction in expected revenues). The combined incremental cost to serve the 102.8 MW load is below existing retail electricity charges for the residential and commercial classes over the IRP horizon, provided that new CCHP load is served under the existing rates.

Figure 10

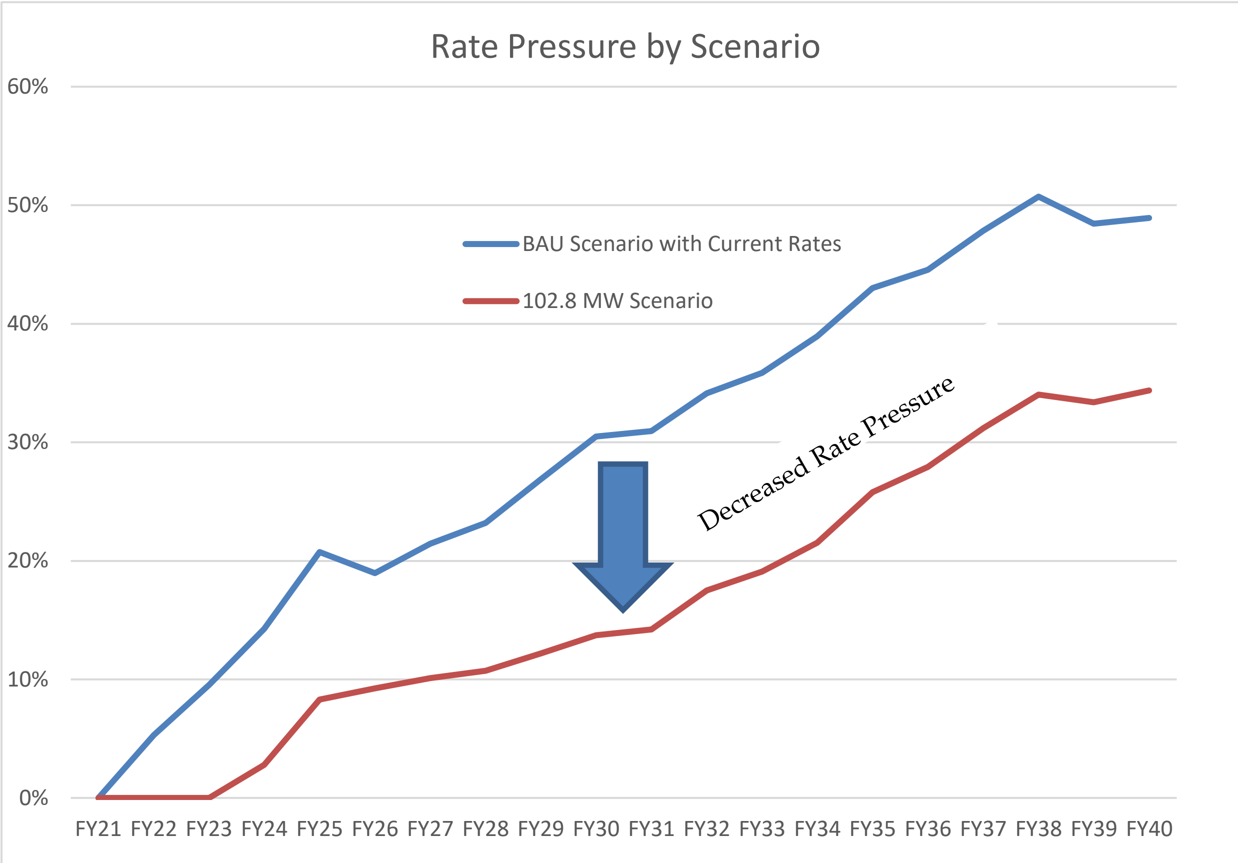


Rate Pressure

Figure 11 compares the change in average cost of service per kWh of retail load ("rate pressure") under the BAU case versus the same change under the 102.8 MW Scenario (using current rates for residential, commercial, and the EV incentive, but without discounting the rate for CCHP sales). The BAU path assumes rate incentives for EV charging as well, but for less electrification of vehicles.

Figure 11 shows decreased rate pressure due to additional electric loads associated with the 102.8 MW scenario after allowing for the incremental costs to serve those loads as described above.

Figure 11



Conclusions

Given the assumptions discussed in this chapter, the 102.8 MW Scenario model outputs indicate that the early stages of electrification toward NZE30 would result in significant increases in electric loads that BED would be required to serve. The model further indicates that BED would change from a summer-peaking utility to a winter-peaking one as more heat pumps are installed (however, BED does not assume NE would change to a winter peaking region in this analysis). Due to these increases and shifts in our energy delivery requirements, BED would expect to incur additional distribution infrastructure costs to reliably serve these loads and that these capital costs would be material as the load exceeds the current capacity of BED's systems.

Future increases in costs are mostly driven by the costs associated with meeting the energy, capacity, and transmission costs related to the increased load under the 102.8 MW Scenario. The need to reinforce sections of the distribution system, and associated costs, to reliably serve increased demand are far less significant. As an offset to these increased costs, new heating, cooling, and transportation loads would also result in additional retail revenues generated from adoption of these beneficial electrification technologies. The cost to serve the expected increases in our load requirements from the Roadmap does not include costs of expanded beneficial electrification programs to meet NZE goals. The annual MWHe requirements of Tier 3 do not come close to the load "trajectory" identified in the Roadmap for decarbonization by 2030 or even 2040. It is expected that non-utility actions may be the largest component in resolving that gap and achieving NZE

In order to implement NZE, at whatever its final deployment rate ends up being, material investments related to beneficial electrification programs will be needed and electric consumption will increase dramatically. BED will need to act to limit peak load impacts wherever possible, while also working with customers to increase the overall energy efficiency of their buildings and ground transportation needs. BED will also need to anticipate when increases in demand for power will occur and have in place a distribution network capable of reliably supporting that demand when it occurs. Power and transmission resources will also need to be secured in time, although the existing wholesale market structure makes the timing of additional resources less critical than that of the needed distribution system upgrades.

BED believes that the primary impacts of the early stages of the Roadmap are:

1. Changes in load level and load shape
2. Increased distribution investments to serve a load level of 102.8 MW
3. Increased costs related to wholesale power costs and transmission
4. Increased retail revenues associated with the new load

BED has not assumed:

1. Material increases in capital costs associated with load control. Any incremental BED costs associated with load control will need to be considered when rates for load-controlled service are established.
2. Material increases in O&M costs (distribution maintenance, customer service, etc.). To the extent that some of the distribution upgrades represent early replacement of existing infrastructure, some O&M costs may be reduced slightly.
3. Incentive costs associated with BED's existing Tier 3 plans (not considered incremental costs of the 102.8 MW scenario in this analysis).

BED has performed this preliminary economic impact of the 102.8 MW loads using the original T&D project cost estimates (converted to annual carrying costs) and using the base case IRP assumptions for wholesale power costs and transmission. For the purposes of this evaluation, BED assumes that the 102.8 MW load level would occur in 2024 and load will grow only slowly thereafter. The analysis is informative and allows for a comparison of the base case rate path to the rate path of the 102.8 MW Scenario with the load shapes assumed in the Roadmap.

BED's analysis shows that the loads associated with the 102.8 MW load level, the costs of associated distribution infrastructure, and the power and transmission costs related to those loads can be served not only without creating rate pressure, but in fact reduce rate pressure by providing additional contributions to existing fixed costs, provided that:

- The assumptions are reasonable
- Electric rates are not materially discounted for CCHP loads without generating additional savings in the costs assumed.

This analysis serves as BED's current basis for modeling the effects of Net Zero Energy actions. It is not definitive without further analysis (currently underway) to verify that the above conclusion would hold true through the full magnitude of load changes envisioned in the Roadmap, although the relatively small proportion of costs associated with the T&D upgrades needed for the 102.8 MW scenario provides for some optimism.

Chapter 9 - Planning Priorities and Action Steps

Based on its Strategic Plan (see Appendices) and the preceding analyses, BED has prioritized the following actions for the next three years. At this time, it appears that none of the contemplated actions would require BED to file Section 248 permit before the next IRP is scheduled to be filed.

Distribution/Operations

In line with our base case (BAU) load projections, the Engineering and Operations group's priorities will continue to focus on normal capital replacement and improvement activities in support of system reliability and efficiency (i.e., the BAU assumes that energy load is not anticipated to exceed 80 MW). Change in peak load levels and load shapes will be monitored to determine how Burlington is proceeding in terms of strategic electrification. If actual load growth begins to accelerate faster than our base case assumptions, the Operations team will begin to implement a series of distribution upgrades that were discussed at length in the NZE chapter. Currently, we anticipate that, should load begin to increase as a result of customers adopting beneficial electrification measures in larger than expected numbers, BED would need between 4 and 7 years to implement the identified distribution upgrades necessary to serve a peak load of 102.8 MW. Please refer to the NZE chapter for more details on the analysis and projects identified.

Generation & Supply – Generation

Over the near-term, BED's Generation team will be focused on maintaining or improving the reliability of existing generating assets through its maintenance programs.

Concurrently with ensuring the reliability/availability of its existing generating fleet, BED is seeking opportunities to improve the efficiency of our resources and provide additional value streams. As in past IRPs, the McNeil Generating Station continues to be a key component of our energy portfolio. As such, any efficiency improvements at McNeil have the potential to affect BED's cost of service. One efficiency project that is being evaluated is the potential use of heat from McNeil for thermal energy in a District Energy System (DES). Another efficiency project is a pilot initiative that seeks to automate combustion air volume in the boiler based on real-time conditions reducing fuel consumption per MWH produced.

Beginning in July 2020, BED modified its wood purchasing policy (see McNeil economics appendix) to attempt to improve the alignment of wood supply and wholesale market conditions and to provide wood suppliers with demands for wood they could plan for with some confidence. McNeil is experimenting with using a blend of base load, seasonal, and on-demand wood contracts with specified volumes by supplier, and with future volume offerings being based on the demonstrable deliveries under the agreements in prior periods. This policy will need close monitoring and adjustment for the first several years to make sure it is functioning as intended for both BED and its suppliers.

BED currently limits itself to owning generation assets inside the City of Burlington, and it is unlikely that any significant owned generating assets will be developed in the period covered by this IRP. If such an opportunity did present itself, BED would rely on the tools and decision processes developed for this IRP to evaluate the potential impact of those resources.

This IRP includes an attachment with an independent study of the impact of McNeil's operation on the Vermont economy as required by the MOU and Order in BED's 2016 IRP, along with BED comments on that report.

Generation and Supply – Power Supply & Planning

As noted in the Generation and Supply Chapter, BED is entitled to sufficient energy supplies to meet our customer needs and BED's RES obligations over the next three years, unless load levels unexpectedly accelerate due to Net Zero Energy activities.

Modifications or extensions of existing renewable contracts are possible either to smooth the changes in costs associated with contract end dates (so-called "blend and extend" contracts) or to take advantage of currently low market prices.

A possibility does exist, largely due to changing cost-side economics, to engage in a PPA for storage capability in the next three years. BED does not currently anticipate owning such a device at this point, as any decision to acquire such services either through outright ownership or through a purchase power arrangement would require section 248 approval. If BED does decide to pursue such an asset, BED would rely on the economic analyses and decision-making framework described in this IRP.

BED would continue to engage actively in any legislative or regulatory proceedings to maintain both its existing exemption to the RES Tier 2 and to the Standard Offer (provided the renewability tests continue to be met) and its ability to sell and replace RECs not specifically required by the Vermont RES in order to limit rate pressure.

BED intends to develop new Tier 3 programs and will continue prioritizing meeting its RES Tier 3 requirements with end-use electrification programs to the greatest extent possible. BED will seek to design programs to ensure all programs are equitable and accessible to all customers.

Energy Services

BED's Energy Services staff is focused on delivering comprehensive energy solutions aimed at reducing the consumption of all fuel types in the City. Consistent with 30 V.S.A. §209(d) and 8005a(3), the Energy Services group's main priority is to continue providing customers with technical assistance with their energy-related needs and incentives for making energy efficient choices. This responsibility extends beyond traditional electric efficiency services and includes technical assistance relative to beneficial electrification measures (i.e. EVs, EVSE, ccHPs, and more). As in the past, Energy Services staff will help customers address their building weatherization/thermal needs by coordinating services with VGS, where appropriate, or providing incentives through our weatherization partners to customers heating their buildings with nonregulated fuels or electric resistance technologies.

Since Energy Services is the primary point of contact for customers seeking answers to their energy questions, they also provide critical input into program designs and implementation strategies. Similarly, Energy Services staff will continue to seek out new opportunities for additional Tier 3and other efficiency programs that increase customer benefits and support the City's Net Zero Energy transformation. Energy Services is also the Team managing BED's Green Stimulus Program and hopes to be able to learn from the program how increased incentives might impact program participation rates, relative to the increase in utility costs.

While the level of energy efficiency investment is determined through the DRP process, BED staff shall seek to align deployment of efficiency measures with key avoided costs and externality assumptions between the DRP and IRP processes for consistency of decisions over time. Energy services will remain actively engaged in the Act 62 PUC docket and the S337 legislative processes that may result in increased flexibility for deploying/prioritizing existing EEU funds based on greenhouse gas reductions.

Customer Care/Engagement

The work and expertise required of BED's Customer Care team will continue to increase with movement toward attaining our Net Zero Energy goals through strategic electrification. Therefore, achieving the twin goals of maintaining the required metrics under BED's SQRP and simultaneously providing exceptional customer care will be a continuing challenge. BED is fortunate to have a top-notch Customer Care team capable of absorbing additional challenges and we are unique among Vermont's distribution utilities in that our Energy Services team (or energy efficiency utility) partners with the Customer Care team to serve our customers. Nevertheless, the first contact most customers have with BED generally is with a member of the Customer Care team and, accordingly, maintaining BED's excellence in responding to customers during these exciting times of change and progress in the utility industry will be a key focus.

Finance/Rates

BED will continue to closely monitor its financial performance inclusive of operational and capital budgets, credit rating factors, and other key financial indicators over the next three years and will focus on improving its long-range financial forecasts to inform planning and decision-making. Further, the team will be focused on process documentation, process improvement, and creating efficiencies as part of a planned replacement of our Financial Information System.

Rate design improvements are likely in the next three years, but a wholesale rate re-design would not occur until a rate filing was needed and the cost of service approved, at the earliest. All of the rate changes discussed below will require local approvals before they can be filed, and State approvals before they can take effect.

Potential improvements in rate design being explored currently are:

1. An expansion of BED's existing residential EV charging rates to BED's remaining rate classes. The existing structure is easily "portable" to the other energy-only class (Small General Service), but extension to demand-based rates such as Large General Service (LG) and Primary Service (PS) is more problematic. TOU rates during the off-peak period of any of BED's TOU rates are sufficiently low to be consistent with the net of credit rates for EV charging under the residential EV charging rate.
2. A change to the criteria under which customers are moved from the energy-only SG rate to the energy- and demand-based LG rate. As many customers view demand rates as "penalty" rates (which may or may not be true based on load factor of the customer), BED does not want load increases from strategic electrification, where the load increase is off peak, to drive such conversions.
3. A possible CCHP "end use" rate to create some load control capability for this key technology and potentially improve the economics of CCHPs in comparison with natural gas–fired heating systems.

Information Systems

A primary focus of the IS department over the next two to three years is expected to be the conversion of core utility and business systems to more modern platforms under BED's "IT Forward" project. This project will replace several of BED's core business systems as well as provide for new functionality. This project is expected to represent a material time commitment from all divisions of BED. Other near-term priorities include provisioning a new data center, enhancing BED's cybersecurity capabilities, completing upgrades to our AMI/smart grid infrastructure, and developing an integrated information and operational technology plan that supports BED's strategic objectives.

Safety, Risk Management and Facilities

BED's Center for Safety strives on a daily basis to achieve and maintain a professional, courteous and well-trained staff that provides high quality support and services to our customers and coworkers.

As such, some major IRP related goals/projects over the next few years are to:

- Assist as needed in electrification programs involving lawn and power equipment, snow removal, fleet vehicles, biodiesel conversions, etc.

- Help facilitate 3rd party contractors' R&D projects within BED and/or with our customers towards installation/testing of control devices on electric water heaters, heat pumps, boilers, etc.

- Continued capitalization of projects such as radiant flooring, insulating buildings, HVAC improvements, a truck bay air system, etc., towards achieving our NZE goals.

Research/Pilot Efforts

Through research activities, particularly in conjunction with the DeltaClimeVT programs that we intend to continue supporting, BED will continue to explore the capabilities of new devices and systems to control load or minimize wholesale market costs. Current pilots underway or in development include:

1. A pilot project with EVMatch, an electric vehicle charger software company that enables smart chargers to be reserved and processes financial payments.
2. Continued partnership with Packetized Energy to deploy control devices on electric resistance water heaters and smart electric vehicle chargers under the Electric Vehicle Charging rate and expansion of these offerings to include a pilot project of submetering and controls for heat pumps.
3. A pilot project in conjunction with BED facilities staff and Medley Thermal to explore the possibility for price-dispatchable electric load in the form of electric boilers located in parallel with fossil fuel boilers. A demonstration of this technology at BED's Pine Street location is the primary focus for this pilot since company property avoids the rate implications during the pilot phase.

4. A pilot project with ThermoAI to optimize the efficiency of the J.C. McNeil Generating Station through learning algorithms. This includes data accumulation and simulation of the biomass plant to determine the potential for fuel savings; use of the algorithms to make suggestions for operational adjustments like air intake; and allowing the trained algorithm to make supervised adjustments to the facility's combustion operations.
5. A pilot project in conjunction with BED, VGS, and WexEnergy to test the thermal savings from their product, Window Skins. This product is a lightweight, transparent plastic window treatment that increases the insulation of windows. BED will be working with VGS to select a building in Burlington to install Window Skins and run measurement and verification analysis to determine the thermal savings achieved.

Net Zero Energy

As discussed in the Chapter of the same title, BED will be intently focused on activities that advance the City's NZE vision. In the near term, the most significant actions will involve engaging with the City's leadership and elected officials as they work to establish new policies and regulations related to heating and transportation in Burlington. Similar types of engagement will extend to the State government level, as the existing body of statutes, ordinances, rules, and regulations are not likely to result in a complete transition of the current fossil fuel–centric economy to Net Zero Energy without significant modifications. BED also plans to focus on ensuring that our strategic electrification programs are accessible to all BED customers by prioritizing equity in our program design, improving our customer outreach and education efforts, and continuing to work with external partners that provide unique value and opportunities to advance Net Zero Energy at a more rapid rate and greater scale.