Executive Summary

Introduction

Energy is the engine that drives the modern economy. It provides the means for industry, commerce and communities to thrive. Vermonters rely on energy for mobility, lighting, to heat and cool buildings, and to keep the technologies of everyday life running non-stop throughout the year. Without energy our quality of life suffers, and the economy grinds to a halt. But energy consumption comes at a cost.

To ensure that the financial and environmental costs of energy consumption are mitigated to the greatest extent possible, the City of Burlington Electric Department (BED) adheres to a comprehensive decision-making framework for evaluating cost effective resource options that can reliably serve the needs of its customers; be they strategic electrification platforms, energy efficiency, advanced demand response initiatives, customer – sited and utility – scale distributed energy resources, traditional owned - generation or purchase power agreements. This framework requires in-depth research on a plethora of complex technical and policy related issues. It necessitates the collection of a vast amount of data; and an ability to assimilate that data into actionable knowledge. Above all else, the framework demands a clear-eyed assessment of the risks BED will face over time.

To incorporate a range of views about its risk exposure, BED sought out the opinions of others in the community. In early 2016, an IRP committee was established. The committee, comprised of two members of the public, two Burlington Electric Commissioners and three BED staff members, met ten times to discuss important econometric modelling variables, identify risks and quantify the potential impacts of BED's risks. At the conclusion of these meetings, the IRP committee selected a "preferred pathway" that should lead to a collection of resources (i.e. portfolio) capable of delivering cost effective energy-related services. The committee also identified three key risks associated with the preferred pathway (and others) that could have the potential to materially impact BED's costs, if they are not properly managed. As described further in the following chapters, the three top risks include: the value of renewable energy credits, wholesale energy prices and capacity.

Although BED's resource decision-making framework helped to inform the IRP committee's selection of a preferred resource portfolio, which is discussed at length in the Preferred Path chapter, this plan should not be construed as a request for approval of the specific action recommendations contained in the plan. Similarly, this plan neither seeks approval to make a capital investment nor expend additional operating funds to pay for expenses. Indeed, this IRP is merely a description of BED's processes for identifying and evaluating a range of plausible pathways that could lead it to a specific resource procurement decision that would be consistent with 30 V.S.A. §218c and BED's strategic plan. The preferred portfolio/pathway, as described herein, however, does highlight BED's aspirational goals and is indicative of the organization's direction.

The IRP also provides some historical context about BED's operations but its main focus is forward – looking. It lays out a foundation on which future decisions can be made and reflects the organization's commitment to serve the energy needs of its customers in a safe, reliable, affordable and responsible manner.

Several main themes can be detected in this IRP. Such themes are a reflection of BED's 10 year vision to:

> *Transition Burlington to a "net zero energy city" across electric, thermal, and transportation sectors by reducing demand, realizing efficiency gains, and expanding renewable generation, while increasing system resilience.*

The main themes threading throughout the IRP include efforts to:

- Maintain BED's focus on helping customers make the most efficient use of their electricity purchases;
- Maintain BED's status as a 100 percent renewably – sourced provider of electricity;
- Provide safe, reliable electric services;
- Ensure that electric bills remain affordable;
- Transform energy markets through strategic electrification initiatives; and,
- Strengthen and harden infrastructure.

Turning BED's vision into reality will require a customer-centric approach to every initiative BED launches as well as an action plan, as described herein, to take advantage of opportunities as they arise. BED staff will need to focus on effectively managing risks. Also, new green technologies must be thoroughly evaluated, and if found to be cost effective for customers and society; fully embraced. Market actors will not only need to be fully informed of BED's services platform but inspired to promote that platform for the benefit of their customers. Partnerships will need to be forged, cultivated and sustained for the long term. But, most importantly, BED must continue its role as a trusted member of the Burlington Community.

Purpose of Integrated Resource Plans

Pursuant to 30 V.S.A. §218c, each regulated electric company is required to prepare a least cost integrated plan (also called an integrated resource plan, or IRP). In accordance with State statute, such a plan shall:

> *"…meet[ ] the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental*

and economic costs, through a strategy combining investments and expenditures on energy supply, transmission, and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs. Economic costs shall be assessed with due regard to:

(A) the greenhouse gas inventory developed under the provisions of 10 V.S.A. § 582; (B) the State's progress in meeting its greenhouse gas reduction goals; (C) the value of the financial risks associated with greenhouse gas emissions from various power sources; and (D) consistency with section 8001 (renewable energy goals) of this title.

In this context, BED has used this IRP process to demonstrate how the underlying methodology and decision-making tools it used to evaluate options for balancing supply and demand will help the organization make the best possible decisions over the longer term. BED contends that its IRP meets the above-noted statutory requirements for the following reasons:

- It identifies key input variables and risks that could impact BED's operations (see Appendix B and Decision Tree Chapter);
- Describes how BED will manage risks (see action plan);
- Documents how BED can meet the energy needs of its customers, after safety concerns are addressed, at the lowest present value life cycle costs (see preferred path chapter);
- It incorporates environmental and economic costs (see Main econometric modelling runs); and,
- It describes BED's strategy for future investments and expenditures in strategic electrification (see technology chapter), energy supply (see generation and supply chapter), T&D capacity and efficiency(see T&D chapter), and comprehensive energy efficiency programs (see EE chapter).

Lastly, 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 frameworks, methodologies and tools will allow for a greater degree of flexibility in the future so that it can seize upon opportunities as economic and technological conditions in the industry change.

Utility facts

While reviewing this IRP, it may be helpful to keep the following facts in mind. Such facts provide context to the decisions the organization has made in this IRP and why it continues to pursue a set of compass coordinates that reflect the community's environmental ethos.

- The City of Burlington Electric Department (BED) was established in 1905 as a municipal utility to lower the cost of energy for residences and the city's street lights.

- The total population of Burlington is approximately 42,200 and it is widely considered the economic, cultural and educational hub of Vermont as many Vermonters and tourists commute into the City to work, shop, and attend events.

- BED's service area spans approximately 13 sq. miles, including the Burlington Airport.

- BED currently serves 20,590 customers – 16,760 residential customers and 3,830 commercial customers.

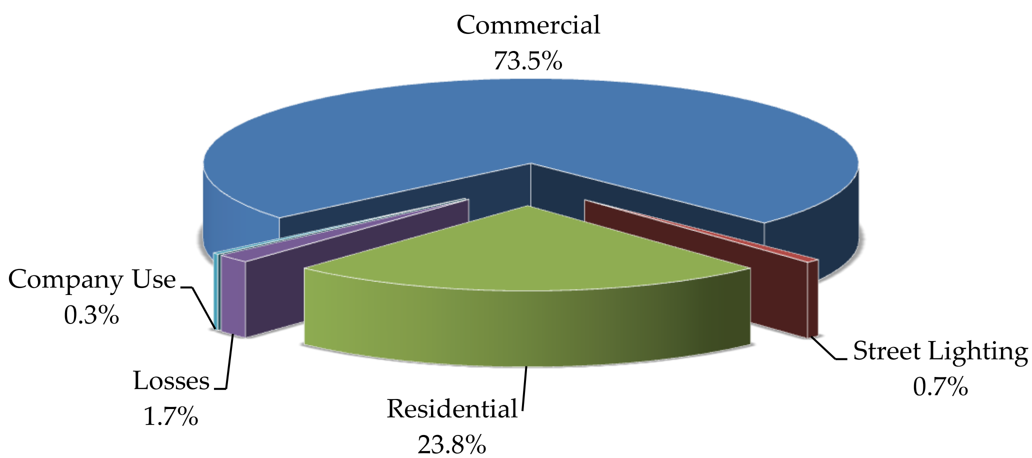
- BED revenue bonds $27.6MM) and general obligation bonds ($46.8MM) are rated A3 by Moody's Investor Service, up from Baa1 (December, 2016). The upgrade was attributed to improving Debt Service coverage, liquidity, a diverse renewably based resource mix, and a diverse local economy.

- The McNeil Biomass Plant (50 MW) commenced operations in June, 1984. BED is the majority owner (50%) and operator of the facility. In 2008, state-of-the-art pollution control equipment was installed. The equipment reduced local NOx emissions and allowed for the sale of high value renewable energy credits. With the proceeds from REC sales, BED was able to achieve a 2 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 percent of its electrical needs from renewable resources was achieved.

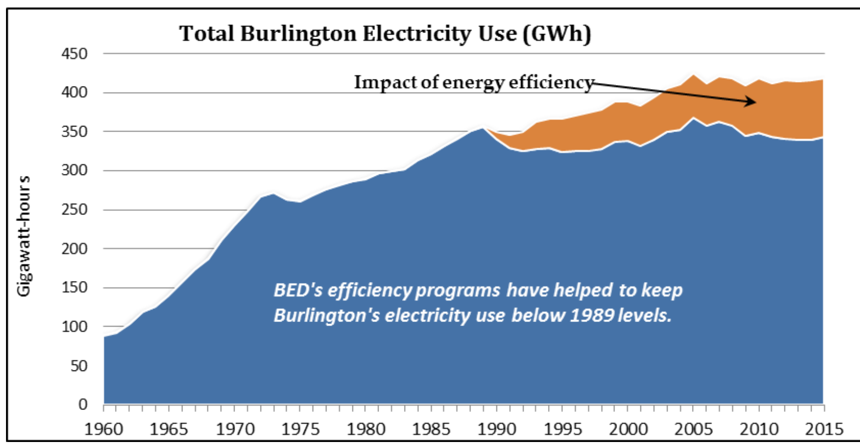
- During 2015, customers consumed roughly 343,146 MWh at their premises, plus distribution losses. Commercial customers account for the largest share of electricity use in the City, as shown in the graph below.

Figure 1: Electricity consumption by sector



- The top 20 commercial accounts account for nearly 50 percent of the City's total energy load.

- Residential customers consumed in 2015 about 81,000 MWhs, roughly the same amount as in previous years. 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.

- Investments in Energy efficiency over the 20 years have helped to essentially flatten load growth.

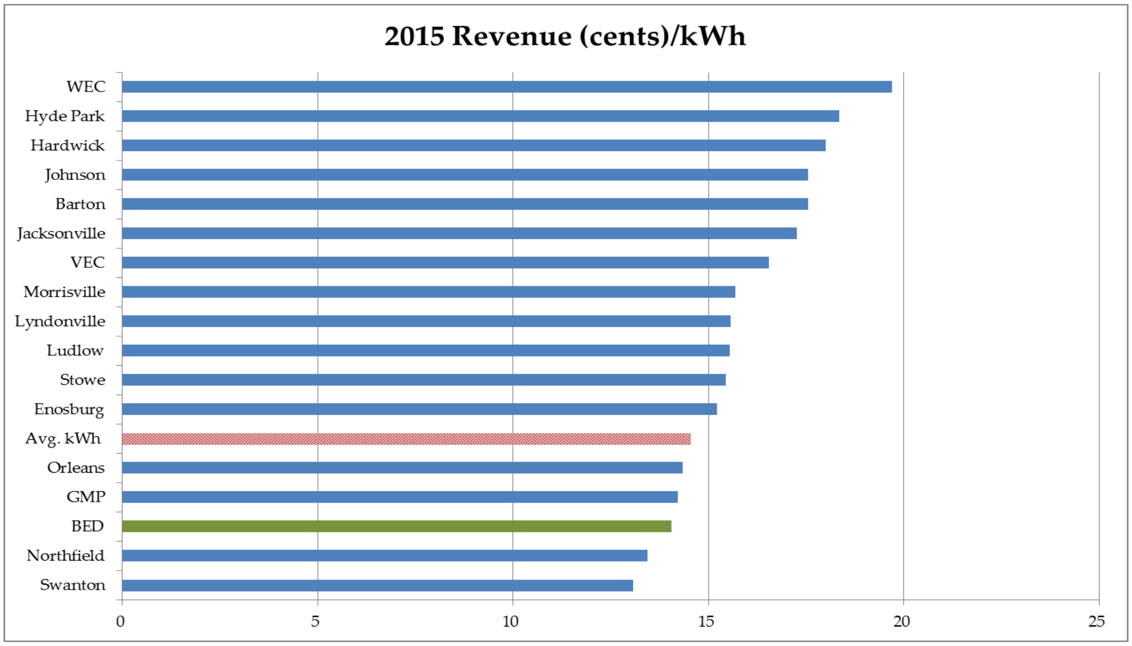
- Approximately 11,000 residential customers consume less than 500 kWh per month.

- 60 percent of residential customers rent their homes.

- 70 percent of the commercial customers lease their building space.

- Because a high percent of its customers are college students, 35 percent of BED's accounts turnover to new customers each year.

- BED collects the third lowest level of revenues (proxy rate) per kWh consumed.



Organization of the report

BED's 2016 integrated resource plan is comprised of eight chapters:

- Demand for electricity
- Technology options
- Energy Efficiency
- Generation and supply
- Transmission and distribution
- Decision Tree analysis
- Preferred plan
- Implementation plan

In the sections below, a brief summary is provided on each section.

Demand for electricity: Long term energy and peak demand forecasts are essential inputs into the planning process. The output from these analyses informs BED's management about the range of total energy and capacity that will be necessary to provide reliable electric service. For this IRP, energy and capacity forecasts were based on statistically adjusted end use models that relied on historical data related to regional economic growth, weather patterns, seasonality, housing and business formation and customer usage and behaviors.

Similar to prior forecasts, the 2016 long range forecast is a composite forecast of BED's major rate classes (i.e. residential, commercial & industrial and street lighting). Estimates of system losses and company-wide usage were also considered. Over the current planning horizon, BED anticipates that total energy use will increase 0.25 percent annually, while peak demand will increase by only 0.08 percent, as shown in the table below[1].

Table 1: Energy and Peak Demand forecasts

	2016	2021	2026	2031	2036	CAGR
Residential	83,680	85,468	83,605	83,597	84,894	0.07%
Com & Ind	259,881	273,071	272,132	274,269	276,364	0.31%
Street Lighting	2,547	2,572	2,509	2,460	2,416	-0.26%
Total Energy Use (MWh)	346,108	361,111	358,246	360,326	363,674	0.25%
Peak Demand (MW)	66.9	68.2	67.4	67.6	67.9	0.08%

The 2016 forecast contrasts with the 2012 IRP forecast as current expectations of future load growth are substantially lower than prior forecasts. In 2012, overall energy use was anticipated to grow 0.95 percent (CAGR), while peak demand was anticipated to increase by 0.97 percent (CAGR). Previously, the commercial and industrial sector was expected to contribute the most to load and peak demand growth. Now, the expectation for overall load growth is considerably less than in 2012. Much of the forecasted decrease in energy sales is attributed to increased penetration of net metered PV systems, increased energy efficiency (particularly from LED lighting and controls) and a continuation of prior years' trend away from energy intensive commercial and industrial activity.

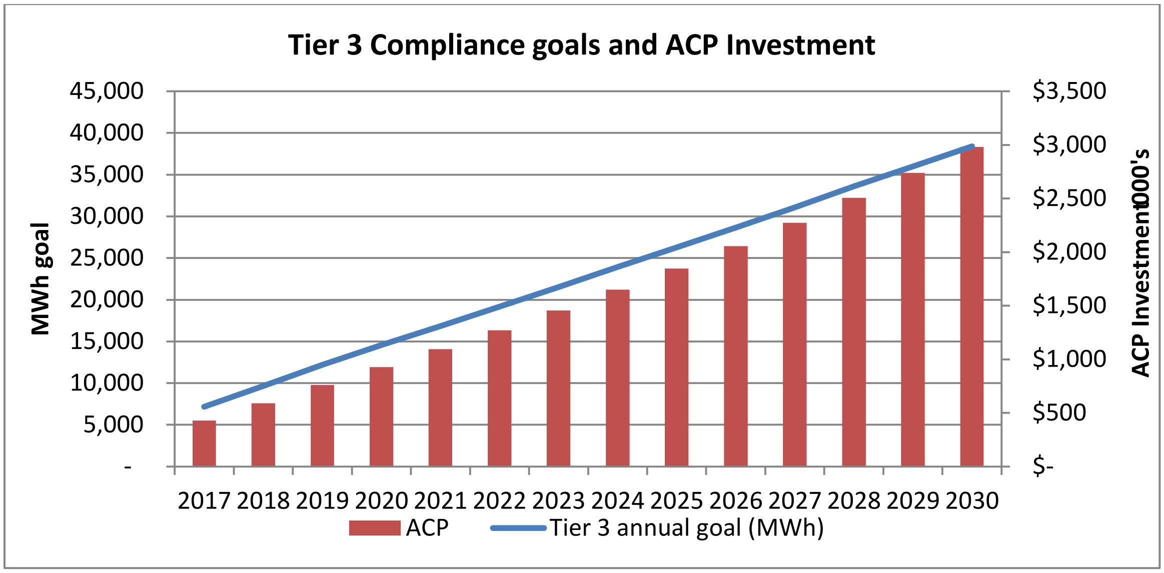
At this stage of the analysis, the forecasts did not reflect the potential impacts of strategic electrification (Tier III) activities. Following the review outlined in the technology chapter, adjustments were incorporated into the forecast to reflect the anticipated energy and demand impacts of the current Tier III plan on future loads, before this modified load forecast was used for future analyses.

Technology options: 30 V.S.A §8005 (a)(3)(B) stipulates that each distribution utility serving more than 6,000 customers shall achieve Tier III credits equal to or greater than 2.0 percent of their annual retail electric load in 2017. Thereafter, a distribution utility's annual Tier III MWh credit goal shall increase by two-thirds of a percent until having reached 12 percent of its retail

[1] The initial forecasts did not include the potential impacts of energy transformation (RES) projects.

electric sales on or after January 1, 2032. Annual spending for Tier III eligible projects shall be capped at the alternative compliance payment (ACP). For 2017, the ACP has been set at $60 per MWh. After 2017, the ACP shall increase annually by the rate of inflation using the consumer price index. For BED, the unadjusted, aggregate annual MWh goals and budgets are shown in the graph below:

Figure 2: Tier 3 Compliance



The passage of 30 V.S.A §8005, commonly referred to as the renewable energy standard (RES), as well as technological advancements in several technologies, has prompted BED to consider modification to its current business model. In addition to seeking out customer-centric methods and practices that would reduce electrical loads through energy efficiency, BED is also in the process of launching strategic electrification programs. Under the RES, BED is now encouraging its customers to adopt new technologies designed to reduce fossil fuel consumption and lower emissions of greenhouse gases associated with such consumption. In many cases, this new initiative will, in theory, result in increased load on the distribution system, higher electric bills for participating customers but, importantly, lower energy costs overall.

BED is currently operating under the assumption that its Tier III goals and budgets would apply at least through 2020 – the year in which the Board will conduct a review of all Tier III programs in Vermont. Afterwards, the goals and budgets may be modified. To achieve its Tier III goals, BED has begun to plan for and implement a series of programs that are intended to help customers reduce their fossil fuel consumption. Thus far, these programs include the following technologies:[2]

[2] Tier III credits and budgets are not cumulative in 2020, but are instead incremental.

Table 2: Energy Transformation programs

	2017				2018			
Tier III Measure	No. of Units	MWh Credits	Total Budget		No. of Units	MWh Credits	Total Budget	
Electric Bus	2	2,428	$	145,680	3	3,642	$	222,890
Electric Vehicle	40	1,518	$	91,080	50	1,898	$	116,158
Electric Vehicle Supply Equipment	12	414	$	24,840	19	656	$	40,147
High Performance Heat Pumps	40	2,830	$	169,800	49	3,467	$	212,180
PassivHouse	0	-	$	-	0		$	-
Total		**7,190**	**$**	**431,400**		**9,663**	**$**	**591,376**
	2019				**2020**			
Tier III Measure	**No. of Units**	**MWh Credits**	**Total Budget**		**No. of Units**	**MWh Credits**	**Total Budget**	
Electric Bus	2	3,642	$	227,348	4	4,856	$	309,194
Electric Vehicle	72	2,733	$	170,605	80	3,037	$	193,373
Electric Vehicle Supply Equipment	25	863	$	53,872	15	518	$	32,982
High Performance Heat Pumps	70	4,952	$	309,124	76	5,377	$	342,367
PassivHouse			$	-	2	755	$	48,073
Total		**12,190**	**$**	**760,949**		**14,543**	**$**	**925,989**

In addition to the above technologies, BED staff also analyzed the potential for customer sited PV and battery storage to serve as distributed energy resources. Except for battery storage, all of the above-noted technologies were deemed to be cost effective from both the utility's perspective and society's; meaning that deployment of such technologies would result in benefits that are greater than the cost of deployment. In many cases, the benefits were in the form of avoided fuel costs, increased electric sales from renewable sources and externality costs associated with greenhouse gas emissions.

Deployment of the above noted technologies is expected to have a marginal impact on energy and peak load requirements. Indeed, as a result of Tier III activities, energy sales are only expected to increase by 9.6 percent – on a cumulative basis - above the base case scenario, while peak demand will likely increase by 2.1 percent. At the same time that the Tier III programs are driving up energy and peak loads, the Tier III program will also improve the system's overall load factor (this is predicated on the requirement that Tier III measures incorporate best demand control practices). Absent any Tier III obligation, BED would have anticipated that its load factor would remain static over time at around 60 to 61percent. But with the implementation of the above noted programs, and perhaps others, BED is now expecting the load factor to increase to 65 percent over time. This improvement is viewed as a net benefit, and could help to offset other operating costs.

Figure 3: Tier III Energy Impacts

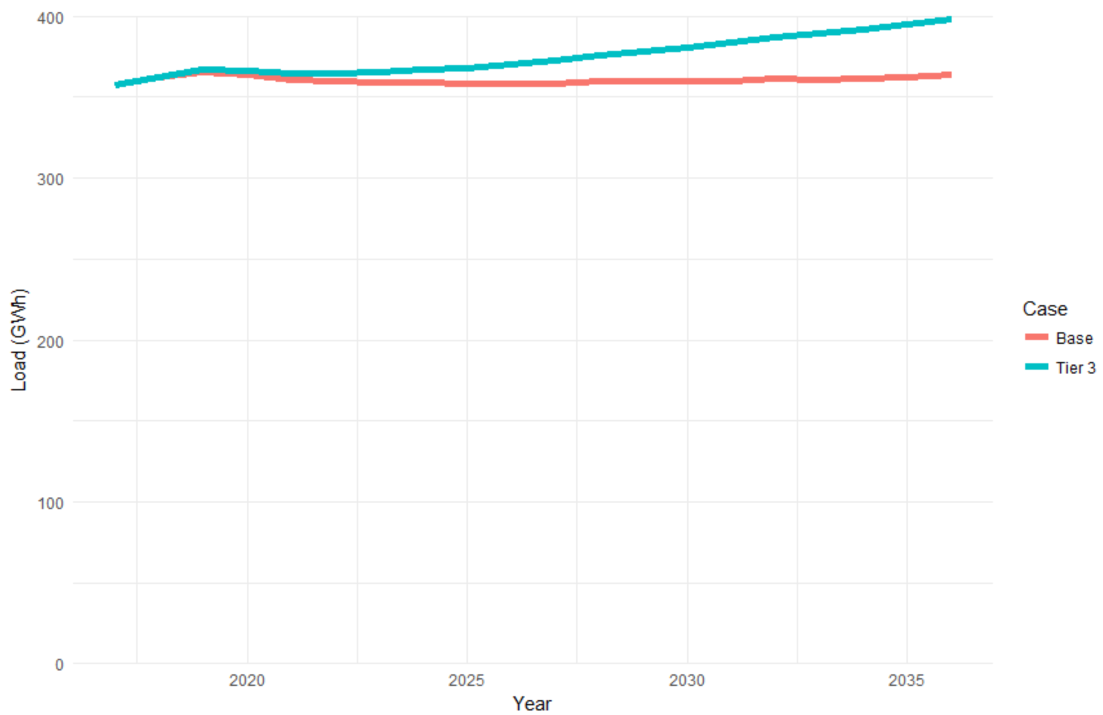


Figure 4: Tier III Demand impacts

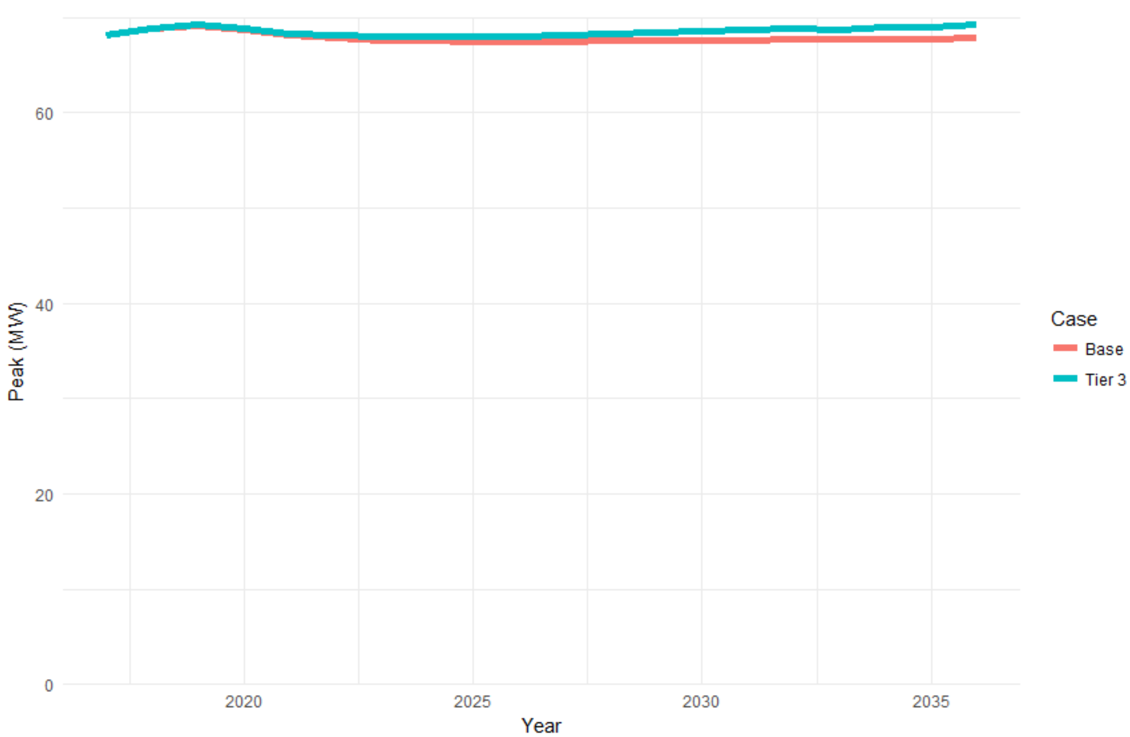
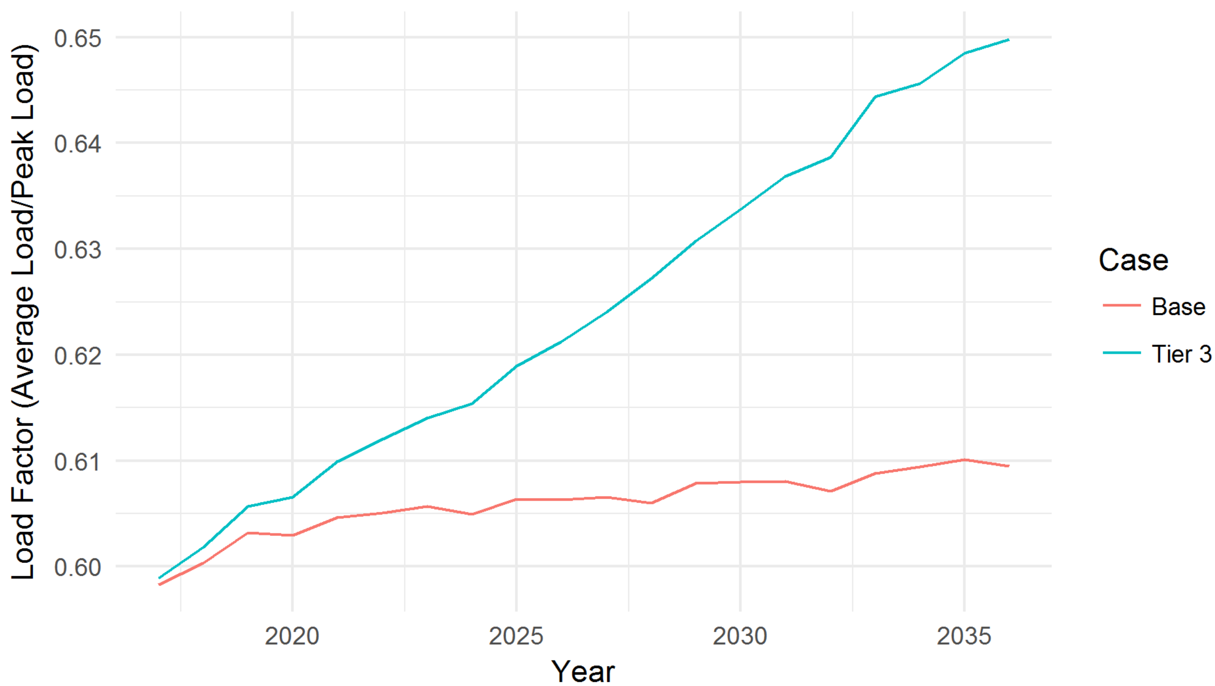


Figure 5: Load factors



Energy Efficiency: Since 1990, BED has provided customers with energy efficiency services and incentives. Over time, these services have had a dramatic impact on citywide energy consumption by essentially flattening load growth despite increased economic activity, new housing starts and population growth. In more recent years, investments in energy efficiency, which are funded through a volumetric energy efficiency charge on customer's bills, have amounted to approximately $2.9 million annually. Such investments have resulted in savings of between 6,000 and 7,000 MWh annually – as much energy as a 1,000 new homes consume every year. In the past, energy efficiency investments have proven to be a low cost resource; indeed, the levelized cost of energy savings has historically been less than $0.03 to $0.05 per kWh.

BED provides energy efficiency services and incentives through 5 main programs: Residential existing homes (including low income residences), residential new construction, efficient products, business new construction and business existing facilities. Investments and savings for these programs since 2010 are as follows:

Cumulative (2010 - 2015)	Incentives	Total BED investment, incl incentives	Participant Costs	Total investment	Net, MWh saved	First yr cost (BED only)	MWh Yld	Levelized Cost
Business Existing Facilities	$ 4,069,904	$ 6,745,953	$ 4,018,980	$ 10,764,933	17,570	$ 0.384	$ 26	$ 0.032
Business New Construction	$ 1,042,864	$ 1,724,778	$ 3,064,166	$ 4,788,944	4,433	$ 0.389	$ 26	$ 0.032
Efficient Products Program	$ 1,435,815	$ 1,939,258	$ 1,844,654	$ 3,783,912	14,227	$ 0.136	$ 73	$ 0.011
Residential Existing Facilities	$ 440,661	$ 1,295,009	$ 443,774	$ 1,738,783	1,671	$ 0.775	$ 13	$ 0.065
Residential New Construction	$ 224,678	$ 615,610	$ 44,758	$ 660,368	481	$ 1.280	$ 8	$ 0.051

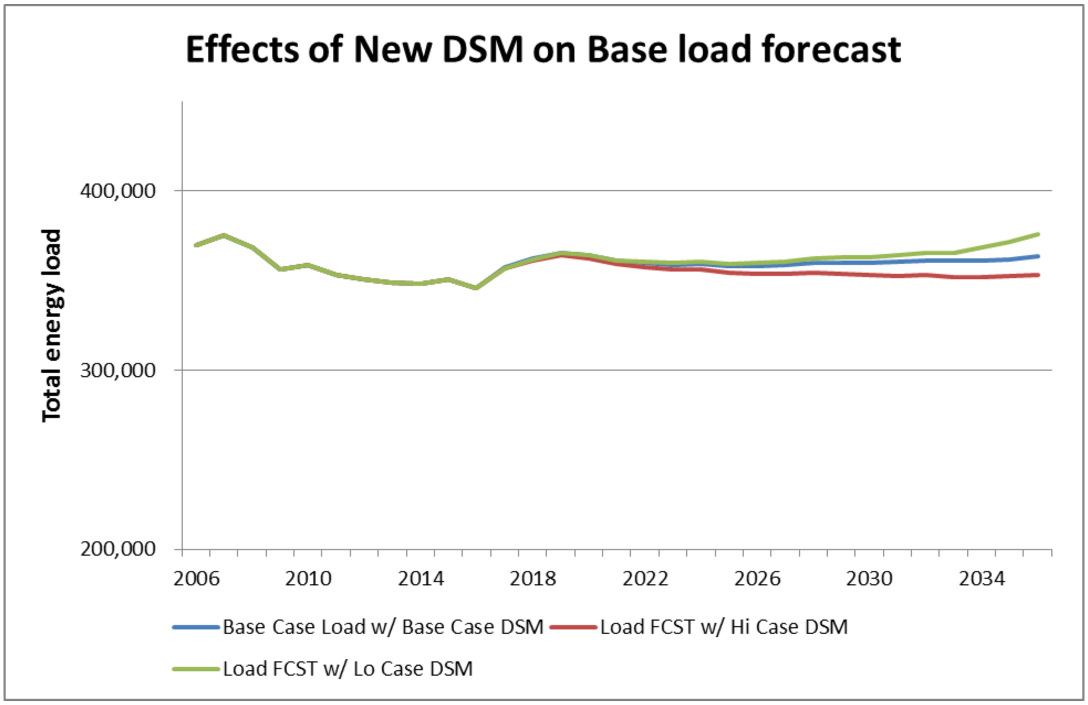
Past energy efficiency investment results however are not indicative of the future potential for new incremental savings. Advancements in new technologies and building designs have led to significant increases in building codes and appliance standards. The effect of this upward shift in codes and standards has been a reduction in the potential for new, low cost energy efficiency savings. To capture this phenomenon, BED constructed a model to forecast the potential to further reduce energy consumption through energy efficiency (EE) under three scenarios. A summary of the scenarios is follows:

1. High case EE – This scenario represents the status quo and assumes that current budgets are increased 5 percent annually. Similarly, BED assumes that under this scenario, MWh yields would remain unchanged. In other words, BED would be able to acquire the same amount of energy efficiency per $10,000 invested that it has in the past. However, because the budget is increased over time, the amount of the annual MWh savings increases. The effect of the budget increase is to decrease the total forecasted energy load relative to the base case EE scenario.
2. Base case EE – under this scenario, lighting savings were de-rated by 2 percent annually through 2023. In 2024, lighting has been de-rated even further by 20 percent to account for the full implementation of EISA[3], which is expected to increase the efficiency of baseline lighting products and decrease the amount of potential savings. Losses in lighting savings, however, are partially offset by new efficiency acquisitions in heating and cooling end uses and large commercial new construction projects. In addition to reductions in lighting savings, budgets were increased 5 percent in years 2016, 2017 and 2018; thereafter, budgets increase 1 percent annually.
3. Low case EE – under this scenario, base case EE assumptions apply with respect to lighting de-rates and new efficiency opportunities (i.e. HVAC and commercial new construction projects) but the current budget is reduced by 20 percent in 2018, and kept at this level through the year 2020. Starting in 2021, budgets are reduced 1 percent annually. In addition, the MWh yield is de-rated 2.0 percent annually, meaning that for every $10,000 invested in energy efficiency the amount of MWh acquired is less.

The graph below reflects the impact of each energy efficiency scenario on base case energy forecasts through 2036. The solid green line represents the low DSM/EE case scenario (i.e. less efficiency savings available to reduce total load). With lower cumulated savings, the total energy to be delivered to customers is expected to increase. The solid red line indicates

[3] EISA stands for the Energy Independence and Security Act of 2007. Signed by President Bush, EISA is intended: to move the United States toward greater energy independence and security; increase the production of clean renewable fuels; protect consumers; increase the efficiency of products, buildings, and vehicles; promote research on and deploy greenhouse gas capture and storage options; improve the energy performance of the Federal Government; and increase U.S. energy security, develop renewable fuel production, and improve vehicle fuel economy.

aggressive DSM/EE efficiency programs will remain in place and reduce total load in the later years. The solid blue line is indicative of the base case DSM/EE scenario and results in a relatively flat load growth scenario over time.

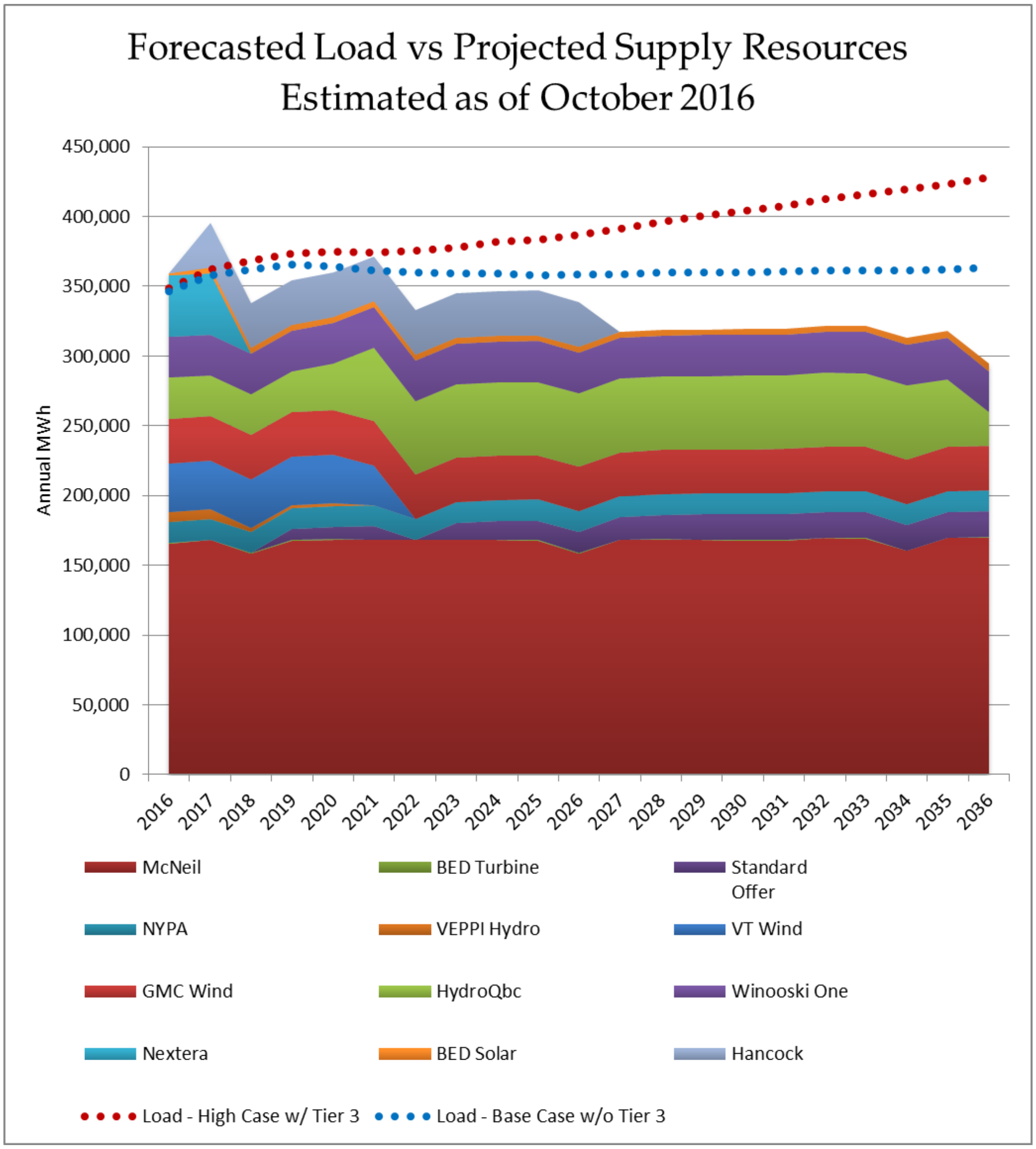


Generation and supply:

After forecasting its energy and capacity needs, net of energy efficiency impacts, BED evaluated typically available power supply resources (both owned generation and contracted) to serve the future electricity needs of the City. The main objective of this analysis was to assess the cost effectiveness of a host of different generation resource types capable of reliably generating electricity so that a portfolio of supply resources could be assembled for further analysis (see Decision tree chapter). The generation types – new and existing – evaluated included wind, solar, combined cycle natural gas turbines, additional biomass, battery storage, hydroelectric, active demand response resources and wholesale energy purchases.

During times when the need for energy and capacity exceeds available resources, distribution utilities, including BED, must consider alternatives to close the supply gap to ensure reliable service is maintained. For BED, the energy gap in most years is currently expected to be relatively narrow, as shown in the graph below.

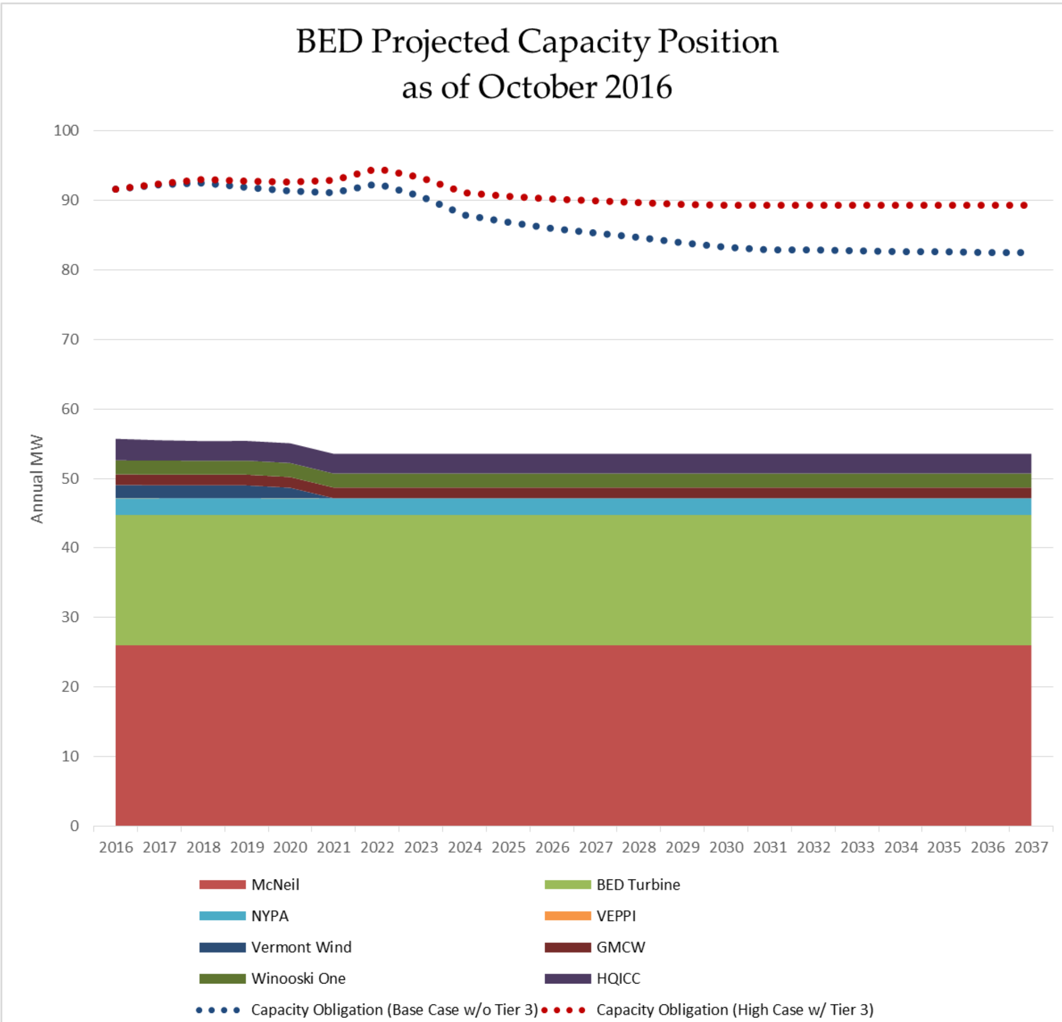
Figure 6: Energy supply resource position



The above-captioned gap in energy supply should not be viewed with alarm or as an insurmountable problem. Indeed many of Vermont's utilities are similarly situated or have larger gaps than BED. To close the forecasted supply gap, BED has several options. It could do one or a combination of the following: enter into additional competitive renewable power purchase contracts, build new generation facilities, increase investments in energy efficiency or purchase wholesale energy on the spot market, when necessary. As a result of its analyses, BED is currently pursuing a strategy that allows it to keep its energy option open for the near and intermediate term. An energy "open options" strategy provides for an ability to react quickly to new opportunities as they arise and to evolving market conditions.

Although BED accepts narrow and transient gaps in its energy supply as a daily operational drill, closing the gap has become routine and customary. Capacity shortfalls, however, are more of a challenge. Current estimates indicate that owned and contracted generation resources are capable of providing two-thirds of the City's actual capacity requirement. As shown in the graph below, the capacity shortfall is expected to persist well into the future.

Figure 7: Capacity resource position

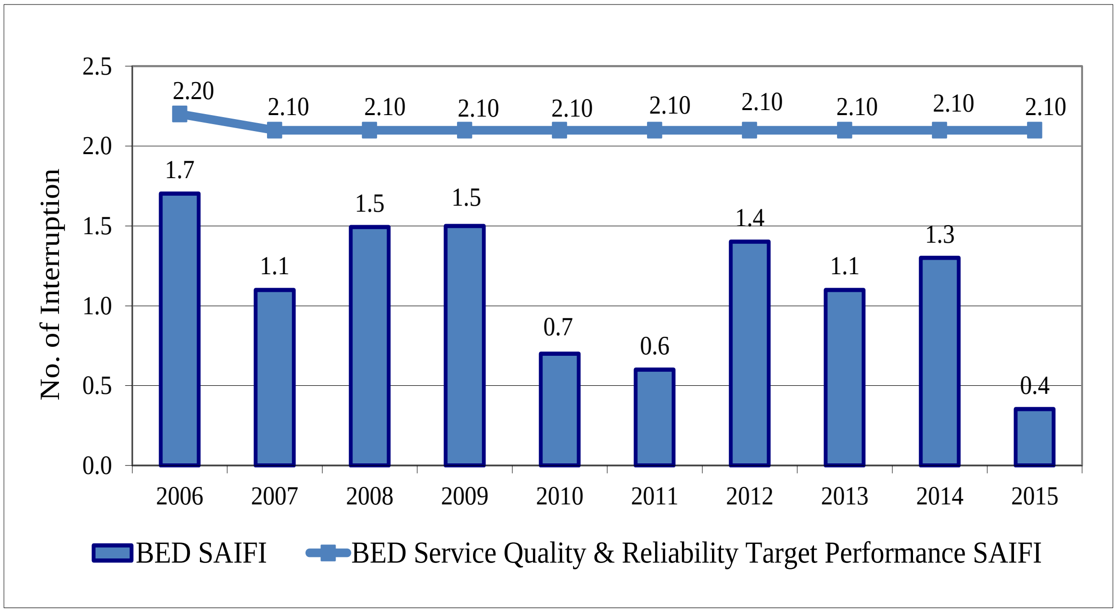


This capacity shortfall position is largely a result of the low capacity rating assigned to most renewable resources, the fact that the new Hydro Quebec resource does not include any capacity assignments per ISO - NE, and the need to maintain capacity levels above peak loads for reliability. It is also not unique to BED. In fact, most distribution utilities in Vermont are probably in a similar position and they too are required to pay market rates to regional generators for their capacity to reliably serve the needs of customers. To make up for the capacity shortfall, BED has several options. It could continue to purchase additional capacity on the wholesale market; contract for capacity with another generator, build and own additional generation, and/or increase investment in active demand response programs.

Transmission and distribution:

BED is committed to providing the highest level of reliability in the most cost effective manner. And, recent investments in the transmission and distribution systems have yielded benefits. As shown in the graph below, the number of system interruptions has declined over time.

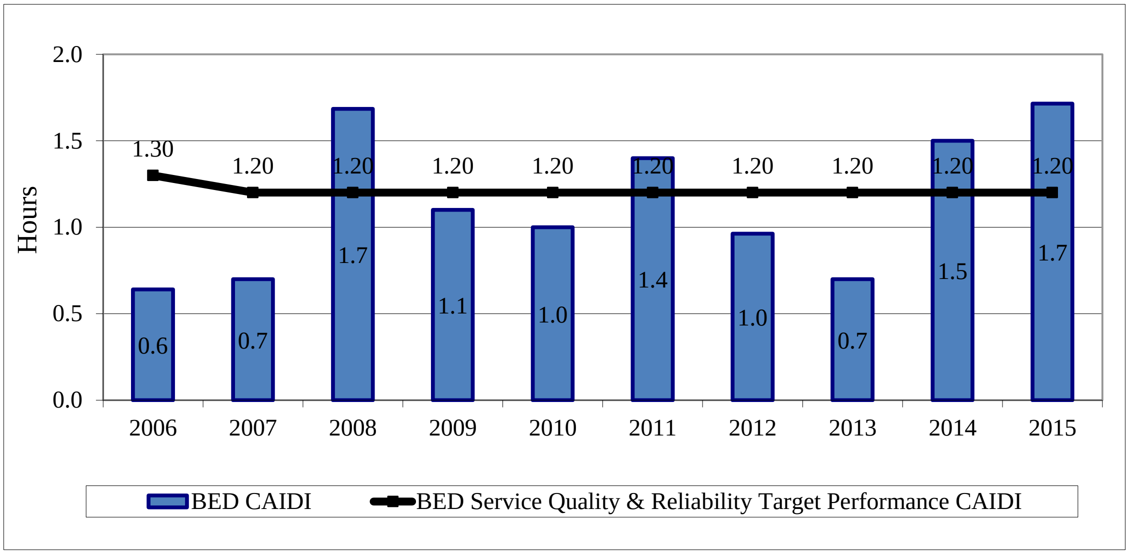
Figure 8: SAIFI metrics



As the graph illustrates, BED's System Average Interruption Frequency Index (SAIFI) for 2015 was 0.4 interruptions per customer, significantly better than the SAIFI Service Quality and Reliability target performance goal of 2.1 interruptions per customer.

Although investments in the distribution infrastructure have resulted in few interruptions per customer, the duration of customer outages when service events do occur still needs improvement. As the next graph demonstrates, BED's Customer Average Interruption Duration Index (CAIDI) for 2015 was 1.7 hours, which is above the CAIDI target performance of 1.2 hours.

Figure 9: CAIDI metrics



Fluctuations in both the SAIFI and CAIDI metrics are primarily driven by weather-related events. High wind and icy conditions materially impact the number of service interruptions and the duration of such outages. With additional investments in reliability programs and advanced infrastructure, BED will continue to make strides in achieving its objectives of providing safe, reliable and cost effective services.

Decision Tree analysis:

To identify a preferred resource portfolio that would adequately balance costs and risks, a sensitivity analysis was conducted of 9 case studies under base case, low case and high case scenarios. This analysis included an evaluation of 21 variables, and an assessment of whether such variables could materially increase (or decrease) BED's cost of service. During the course of the analysis, BED staff found that some of the input variables imposed a greater degree of risk on its operations than others; meaning that the difference in the net present value cost of service between the high case and the low case scenarios was significant; e.g. more than $10 Million. Of the 21 input variables, renewable energy credit values imposed the greatest risk ($135MM) followed by energy prices ($38MM), McNeil generation output ($23MM) and Capacity prices ($19MM).[4]

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[4] At the outset of the IRP process, transmission pricing was originally considered a high risk variable that needed to be monitored and managed. Upon completion of the sensitivity analysis, BED staff determined that while transmission pricing is a significant cost and therefore has the potential to impose risks on BED's customers; transmission pricing does not vary significantly between plausible portfolio options. The range assigned to transmission did have an effect on the analysis of certain technology options however.

A summary of the nine case studies are summarized below:

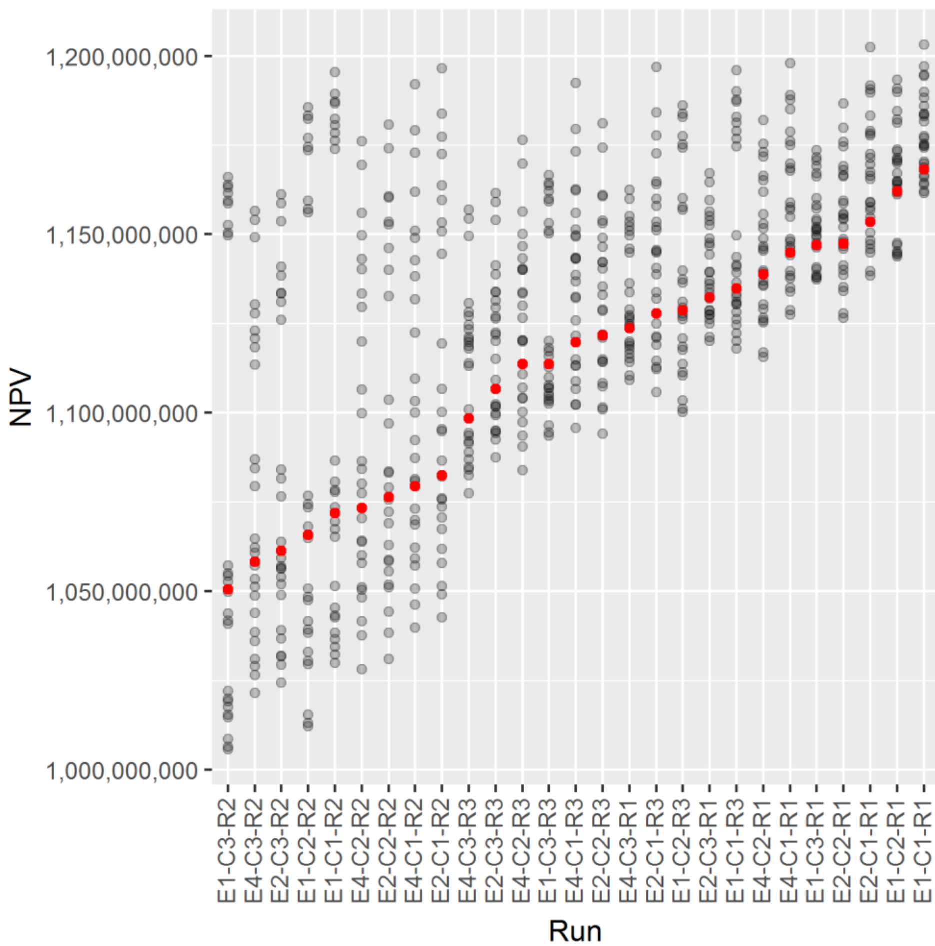
Energy Case code	Short Name	Summary description	Primary Risk
E1	Additional wind	New wind resources have the effect of increasing energy costs, even with continued REC arbitraging, as the forecasted price for new wind is greater than the combined values of energy and RECs. E1 contributes toward efforts to maintain 100% renewability claims.	Increase in risks associated with RECs and no material improvement in capacity shortfalls.
E2	Extend Hancock Wind	Similar to E1, above, although economics are slightly improved as new contracts would not go into effect for 11 years.	Same as above.
E4	Energy options open	BED postpones entering into new energy contracts over the short and intermediate term and investigates new sources of RE generations as opportunities evolve.	Wholesale energy prices increase; new renewable energy projects are unavailable when needed.

Capacity Case code	Short name	Summary description	Primary Risk
C1	Build Peaker	Build (or contract for) a peaking unit sufficient in size to close the current and future capacity shortfalls. Fossil Fuel resources would result in loss of 100 percent renewability.	Large scale transmission projects (i.e. VT green line or Clean Power Link) could undermine plant economics, if capacity prices fall due to capacity oversupply.
C2	No new capacity action	BED postpones entering into new capacity contracts over the short and intermediate term and investigates new sources of capacity as opportunities evolve.	Wholesale capacity prices rise, causing increased retail cost of service (but also higher capacity revenues for McNeil and GT turbine).
C3	Active	BED initiates DR programs	Programs are unable to

	Demand Resources	for residential and commercial customers with goal of acquiring up to 10 MWs of capacity at a price that is less than current wholesale capacity prices. Program would have no effect on energy prices or REC values.	achieve goals or sustain customer DR through the regional peak demand hours (alternatively BED is unable to accurately predict the peak demand hours). Consequently, capacity expenses are unchanged.

REC Case code	Short name	Summary description	Primary Risk
R1	Hard Stop	Discontinue REC arbitrage immediately	Could result in at least a 10% rate increase (at IRP REC price assumptions) resulting in customer dissatisfaction and the potential for greater levels of upward rate pressure.
R2	Arbitrage RECs	Continue to sell high value RECs and buy low value RECs to continue claims of 100% sourced electricity.	High value RECs decrease resulting in reduction in arbitrage opportunities. Lower revenues would need to be recovered through other means, including possibly higher rates.
R3	Soft landing	Initiate volunteer green pricing program whereby subscribing customers would pay higher electric rates in exchange for RECs.	Low subscribership would require BED to continue arbitrage practices.

Each case study was then combined into a series of 27 plausible resource portfolio options. To evaluate the sensitivity of each option to the input variables, a scatter plot was constructed. As highlighted in the graph below, the NPV cost of service (vertical axis) of each option ranges from a low of approximately $1.0 Billion (cumulative) to a high of $1.2 Billion.



The location of each dot along the vertical axes is a direct result of the impact of each potential combination of key variables on the potential outcome. This means that the dots shown in the area above the red dots generally reflect low REC values, and high values for energy, and capacity and transmission. They also represent higher interest rates, higher wood fuel prices and higher than expected load growth – to name a few of the other variables studied. If all of these factors were to occur at the same time, BED's cost of service would be higher than current expectations. The dots located in the area below the red dots generally reflect the opposite values. The red dots in the graph represent the IRP committee's overall average weighting for each of the critical values (i.e. RECs, energy, capacity and transmission) and the middle range of all the other variables BED Staff evaluated. The red dot NPV values therefore represent the likely outcome based on the group's consensus and BED staff expertise.

Based on its sensitivity analysis, the four least cost resource options are as follows:

Pathway	Total NPV Cost of service (billions)	Range (millions)	Lowest NPV (billions)	Highest NPV (billions)	Path description
E1-C3-R2	1.051	160	1.005	1.166	Add wind - demand response - arbitrage RECs
E4-C3-R2	1.058	134	1.021	1.156	Energy Options open - demand response - arbitrage RECs
E2-C3-R2	1.061	137	1.024	1.161	Extend Hancock wind - demand response - arbitrage RECs
E1-C2-R2	1.066	173	1.012	1.185	Add Wind - demand response - arbitrage RECs

Preferred plan:

Upon completion of its analyses, the IRP committee and BED staff selected E4-C3-R2 as the preferred decision path. Referred to as the "energy options open – active demand response – arbitrage RECs" pathway, E4-C3-R2 is the second least cost pathway under the utility cost test and the fifth least cost pathway under the societal cost.[5] However, E4-C3-R2 reduces some exposure to high side risk (particularly on the REC front). The E4-C3-R2 pathway is expected to result in the following outcomes (the following information can also be generated for any decision tree branch as well):

[5] The societal cost test includes an implied carbon cost adder for non-renewable MWhs or the residual mix of generation for which there are unclaimed RECs that BED would have to purchase on the wholesale energy markets to maintain reliability and its claim of renewability.

Table 3: Preferred Path outcomes

Year	Rate Pressure	Net Power Cost	Cost of Service	Retail MWh	$/kWh	Renewable	Non-Renewable MWh	Societal Cost
CY17	0%	$24,875,239	$58,276,612	343,965.79	$0.169	112%	0	$0
CY18	2%	$27,114,288	$61,462,134	353,344.99	$0.174	94%	27,450	$1,114,488
CY19	9%	$30,853,414	$65,875,579	358,492.46	$0.184	98%	15,455	$627,462
CY20	10%	$30,734,016	$66,484,651	360,218.86	$0.185	99%	9,254	$375,721
CY21	11%	$30,657,929	$67,162,583	358,181.88	$0.188	103%	0	$0
CY22	6%	$27,481,931	$64,894,237	357,698.60	$0.181	92%	34,704	$1,408,977
CY23	14%	$31,029,563	$69,112,920	358,171.30	$0.193	96%	23,323	$946,920
CY24	17%	$32,160,506	$71,007,348	359,642.78	$0.197	96%	23,530	$955,298
CY25	19%	$33,078,040	$72,749,339	360,137.77	$0.202	95%	23,849	$968,286
CY26	22%	$34,371,733	$74,879,582	361,725.72	$0.207	93%	34,022	$1,381,288
CY27	23%	$34,499,136	$75,862,528	363,990.72	$0.208	86%	58,187	$2,362,375
CY28	26%	$36,120,087	$78,358,300	367,255.35	$0.213	86%	59,748	$2,425,763
CY29	29%	$37,630,347	$80,769,130	369,494.21	$0.219	86%	61,574	$2,499,894
CY30	32%	$38,926,439	$82,984,663	371,559.55	$0.223	85%	63,627	$2,583,266
CY31	35%	$40,288,088	$85,292,666	373,822.23	$0.228	84%	66,245	$2,689,563
CY32	37%	$41,660,310	$87,634,983	377,080.91	$0.232	84%	67,087	$2,723,712
CY33	38%	$41,439,302	$88,628,926	378,759.85	$0.234	84%	68,601	$2,785,206
CY34	41%	$42,591,392	$91,020,119	381,435.30	$0.239	81%	79,091	$3,211,081
CY35	44%	$43,832,775	$93,531,052	382,908.24	$0.244	82%	76,694	$3,113,788
CY36	46%	$44,655,037	$95,645,365	385,805.90	$0.248	76%	103,285	$4,193,374
Total		**$703,999,572**	**$1,531,632,719**	**$7,323,692**	**$0.209**	**90%**	**895,726**	**36,366,461**
NPV		**$484,553,076**	**$1,058,366,849**					**$22,841,032**

Selection of this option path is expected to produce total NPV costs of $1.058 billion over the planning horizon. On a nominal basis, retail rates would likely increase from $0.17/kWh to $0.25/kWh, on average across all customer classes. However, adjusted for general inflation, retail rates are not anticipated to be demonstrably different than they are today – assuming all other expectations remain unchanged.

Although E4-C3-R2 is not the least cost pathway, its selection is reflective of several positive attributes; namely the preferred pathway: allows for a greater degree of flexibility and is the second lowest NPV cost of service; has a better risk profile; and, will likely result in a lower probability of future rate increases compared to most of the other decision pathway options.

Implementation plan:

To ensure that BED sets a long term course direction that would be consistent with the anticipated outcomes of E4-C3-R2 and its overall strategic plan, BED established an implementation plan that focuses on:

1. Delivering best-in-class customer service that is consistent with 30 V.S.A §218c;
2. Energy efficiency;
3. Strategic electrification and energy transformation projects;
4. Modernizing and hardening infrastructure;
5. Maintaining its status as a 100 percent renewably-sourced electric energy provider;
6. Cost – effectively addressing its capacity challenges;
7. Implementing active demand response programs; and,
8. Managing risks.