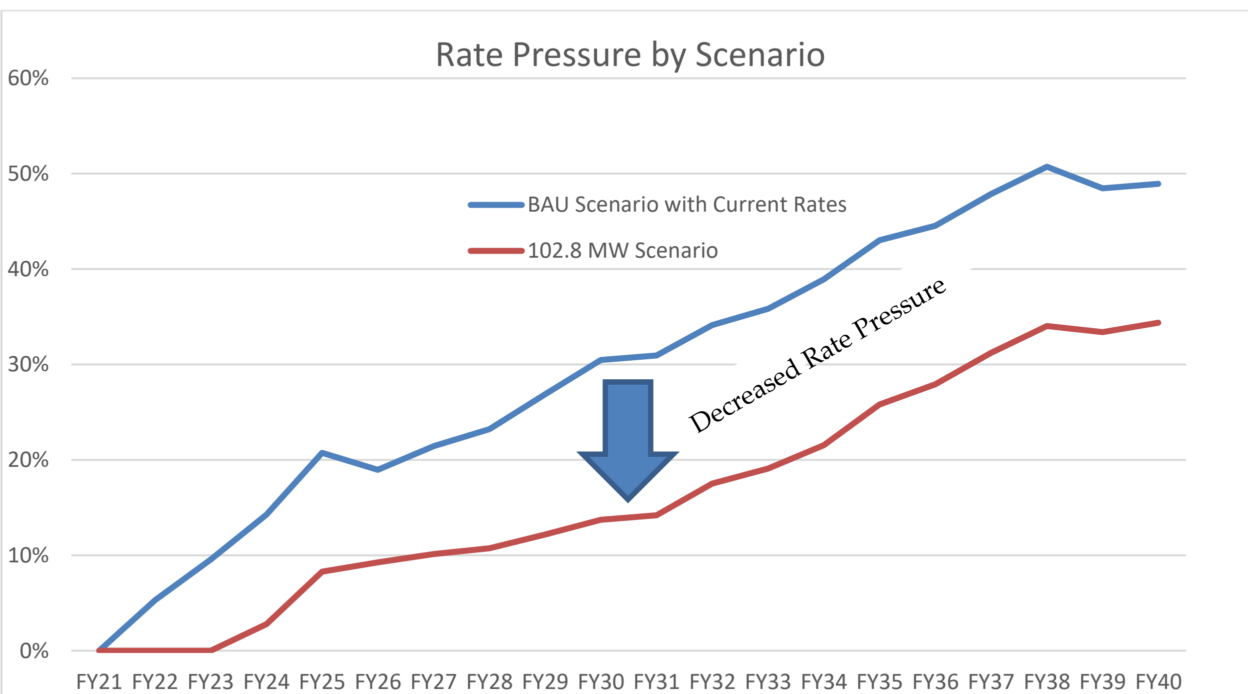
Chapter 6 – Financial Assessment and Potential Rate Pressure

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.

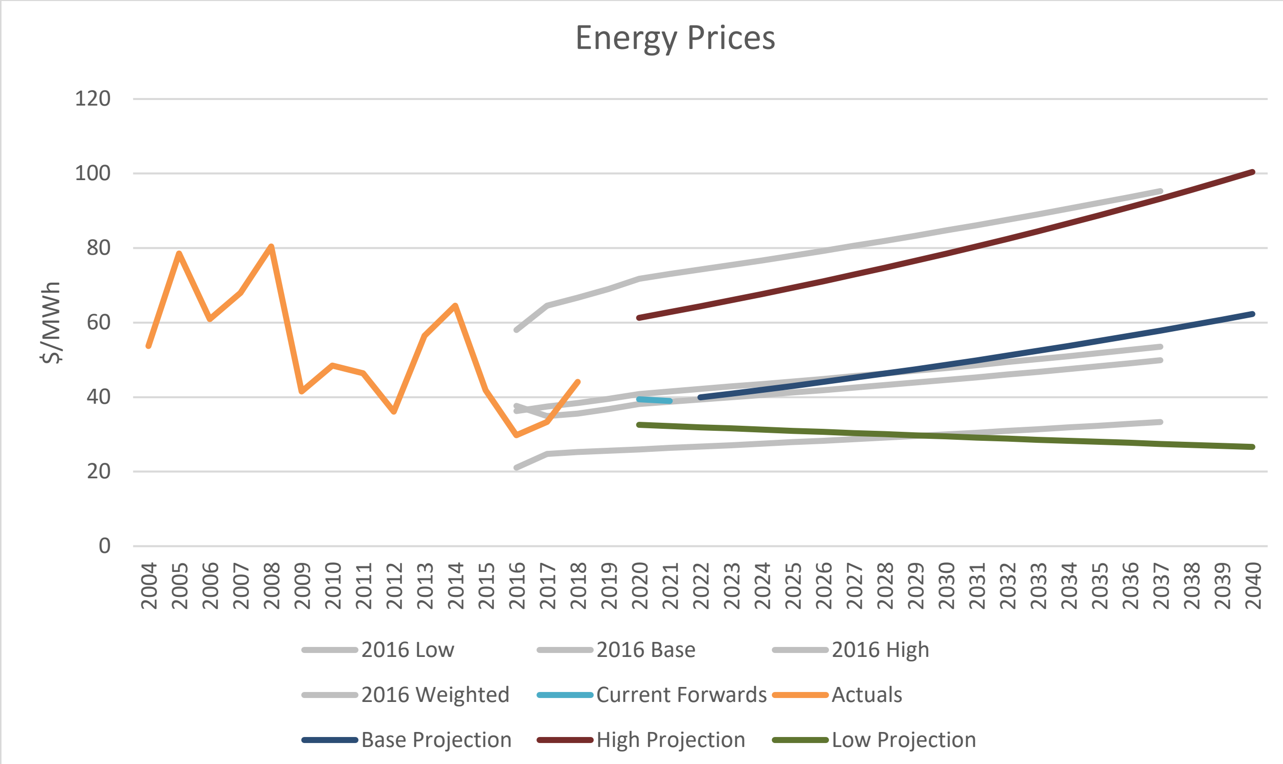
Table 1: Wholesale Energy and Capacity Price Effects on BED's Cost of Service

	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]

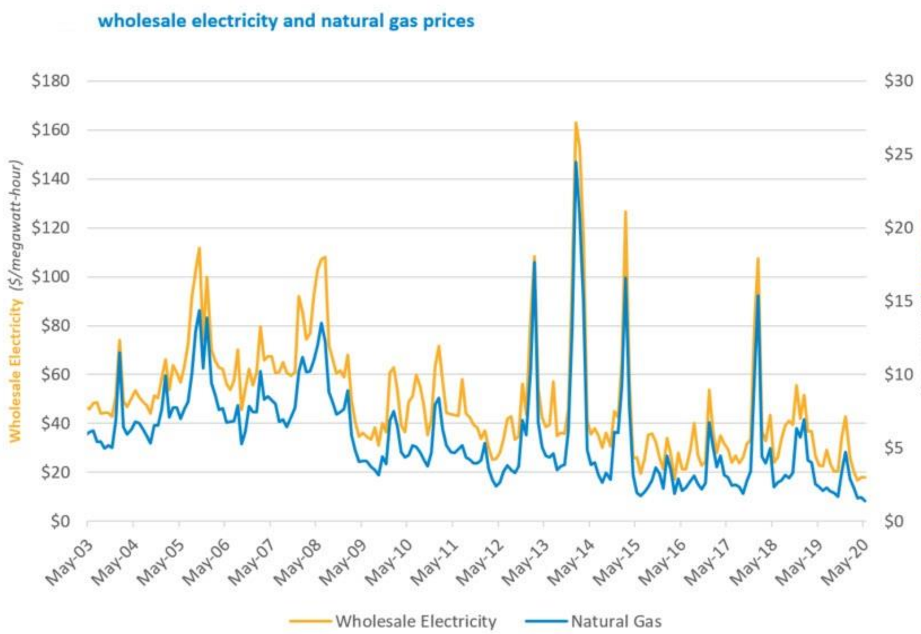
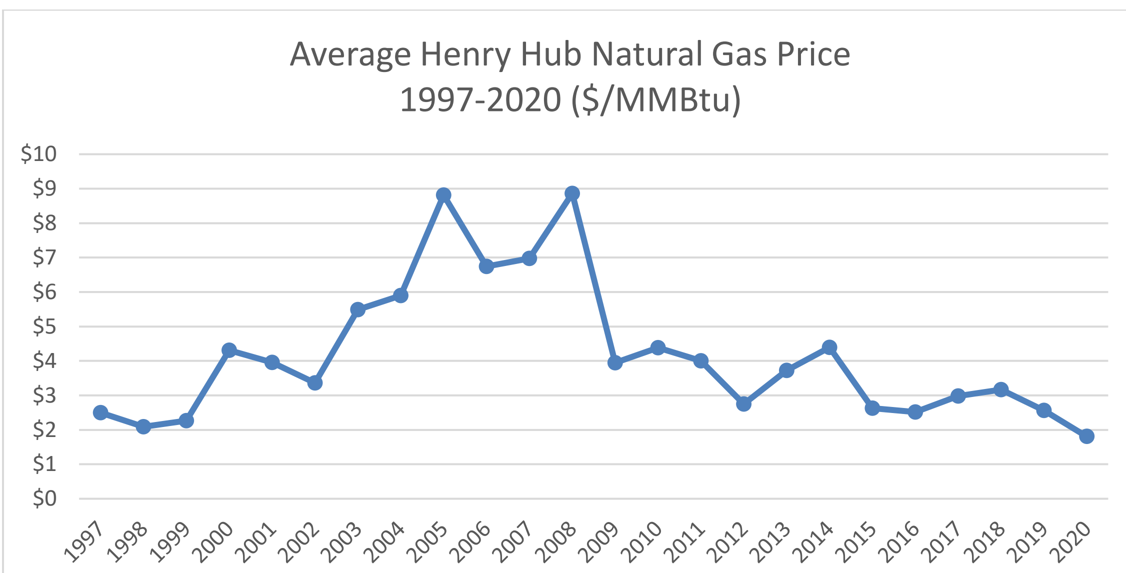


Figure 3.c: Historical Henry Hub Prices



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

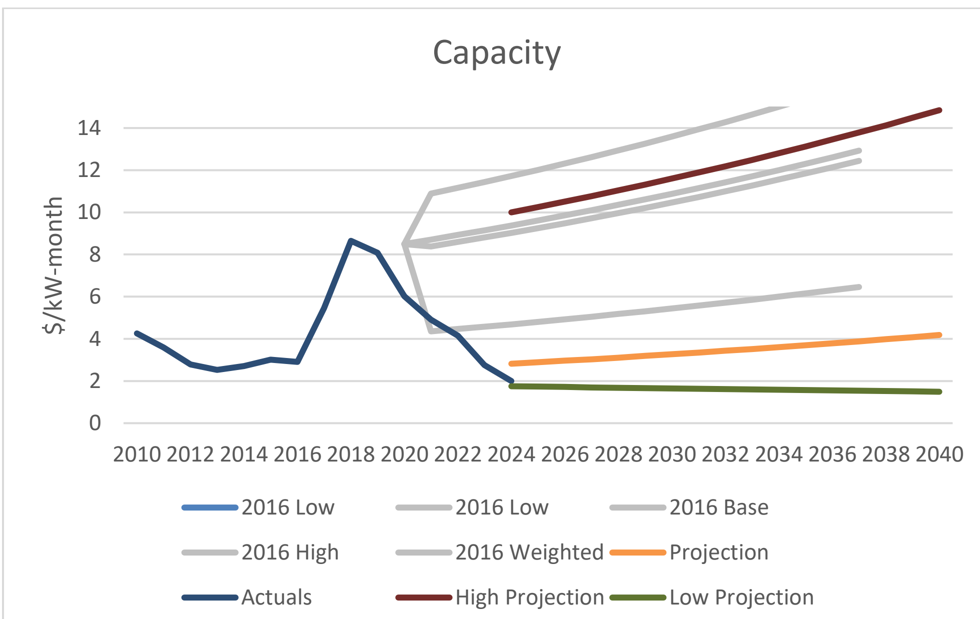
[3] http://isonewswire.com/updates/2020/6/24/monthly-wholesale-electricity-prices-and-demand-in-new-engla.html, accessed July 2020

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).

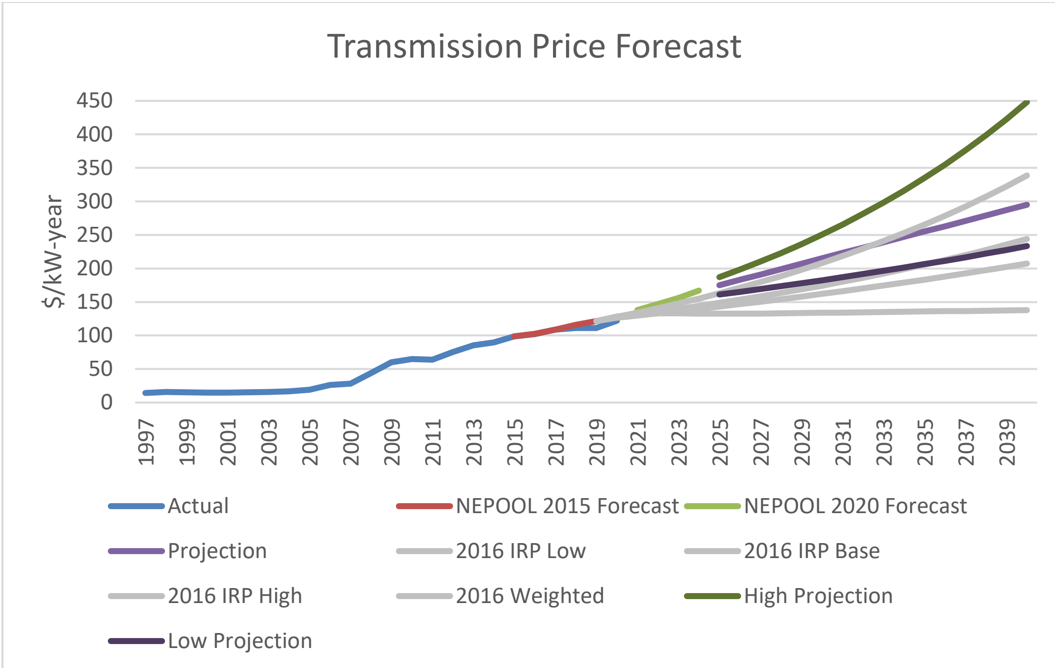
The most recent auction (February 2020) cleared capacity resources at $2.00 per kW-month; capacity prices have now decreased for the last five auctions. Moving forward, BED expects capacity prices to increase at a modest rate over the IRP planning period. This view is primarily a function of future fossil-fuel 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

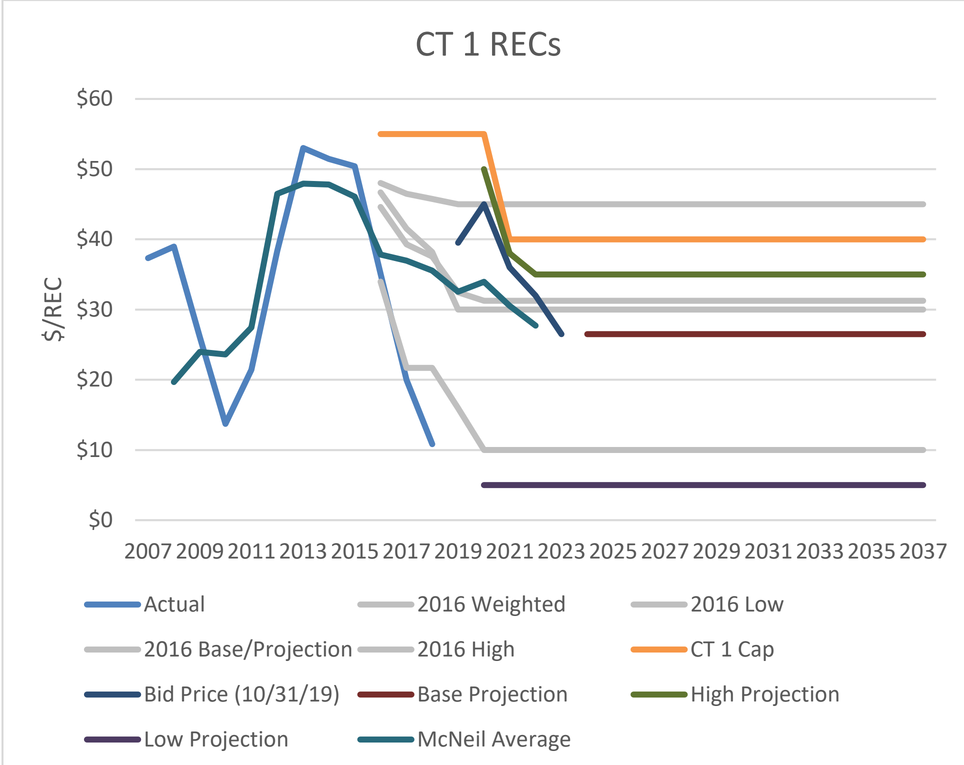


RNS cost drivers are numerous, and include replacing aging infrastructure, more stringent reliability requirements, and network congestion. Complicating matters is the difficulty in avoiding regional transmission costs, even in a future world consisting of greater amounts of distributed energy resources ("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.

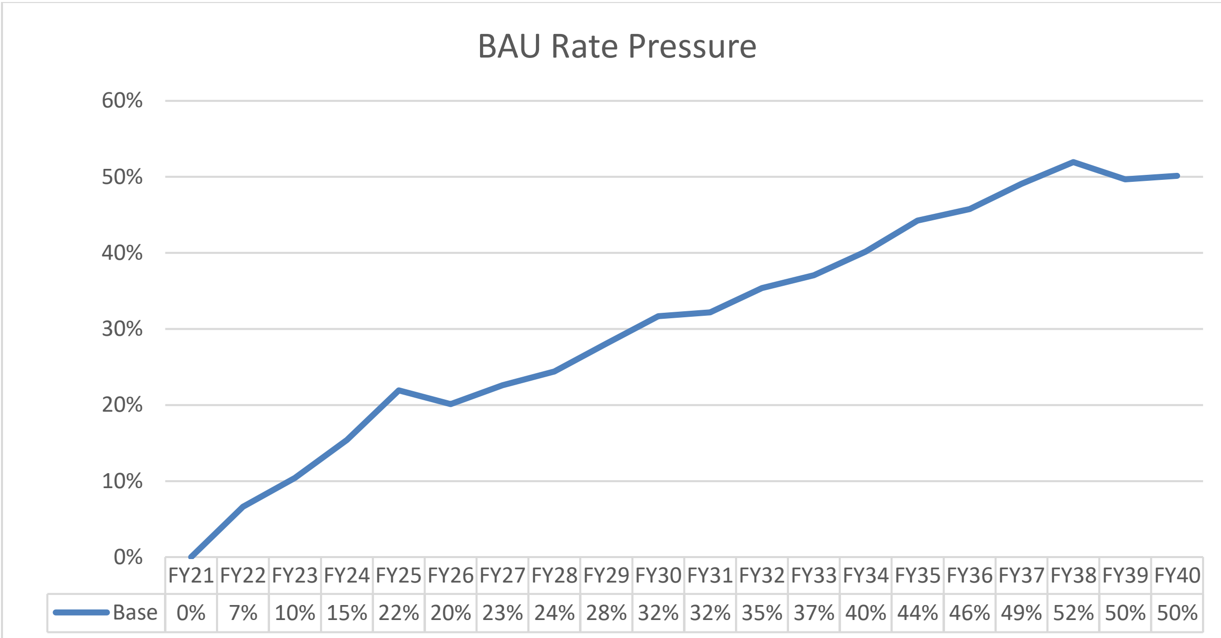
Long-Term Debt Interest Expense

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

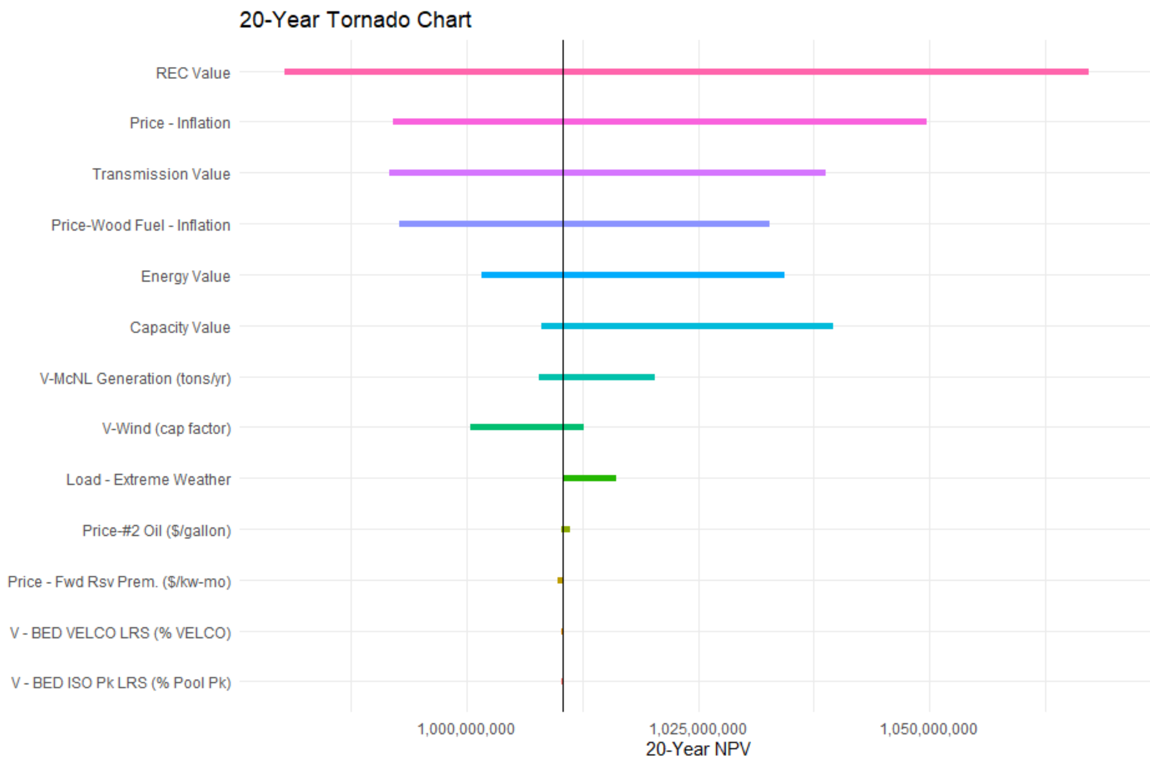


Table 3.a compares the range of risks that individual variables could impose on BED's cost of service.

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

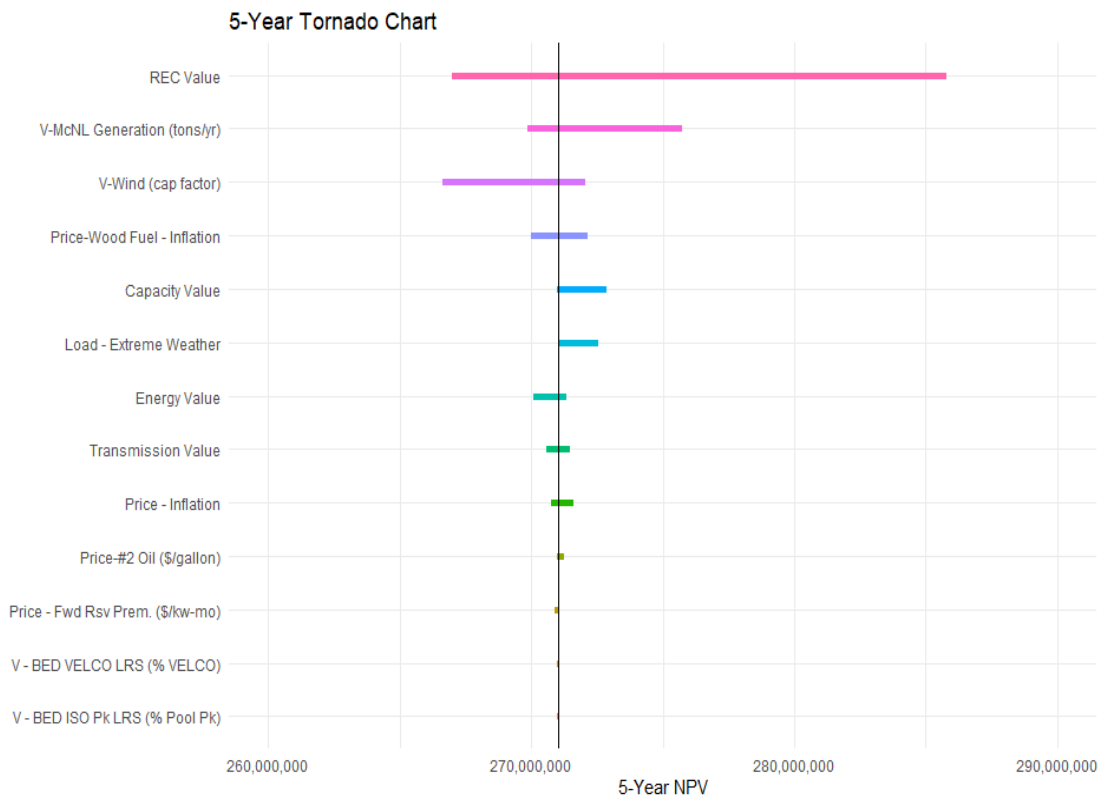


Table 3.b compares the range of risks that individual variables could impose on BED's cost of service.

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

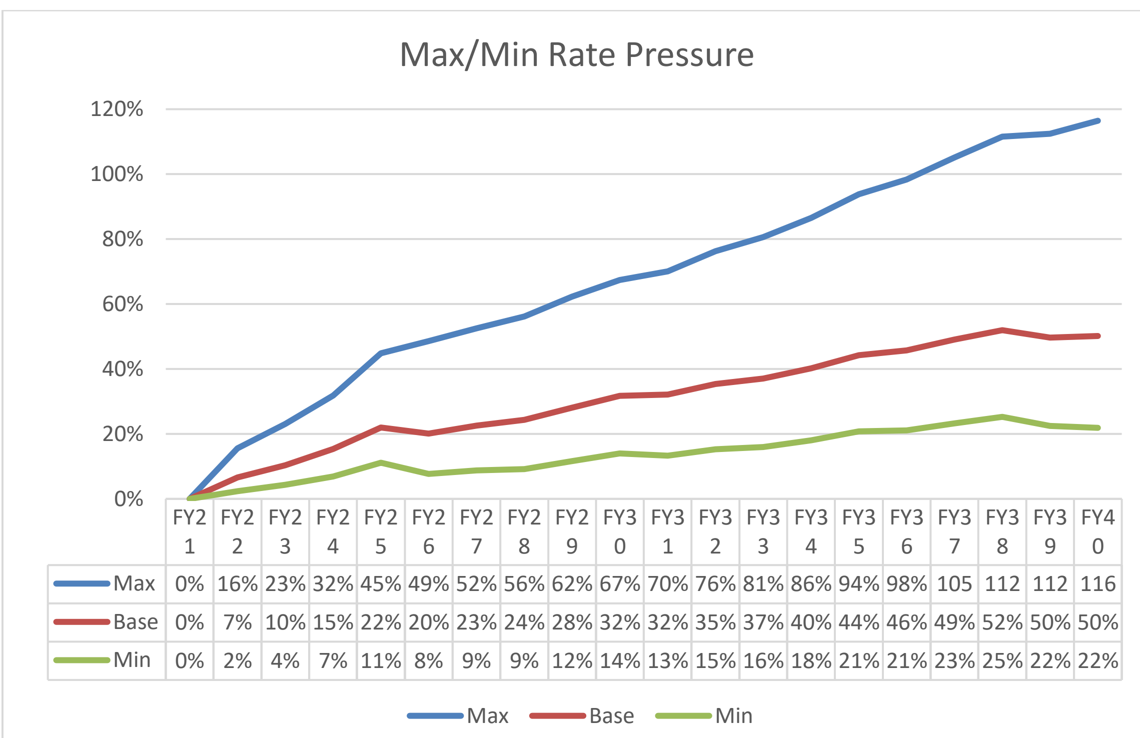
Item	Max ($M)	Min ($M)	$Max-$Min ($M)
REC Price	15	-4	19
McNeil Generation	5	-1	6
Wind Generation	1	-4	5
Wood Price	1	-1	2
Capacity Price	2	-0	2

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.