Chapter 3 - Technology Options

Vermont's Renewable Energy Standard (RES) is having a direct and measurable effect on BED's decision-making processes. Because the RES encourages utilities to deploy eligible strategic electrification technologies that have the potential to reduce fossil fuel consumption and lower GHG emissions, BED intends to promote strategic electrification measures in two key market sectors: transportation and building space heating. The fundamental objective for entering into these sectors 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 is evaluating the following technologies:

- Electric Buses
- All Electric Vehicles
- "At-Work" electric vehicle chargers
- Cold climate heat pumps – mainly new construction/major renovations
- Passive House
- Solar PV - behind-the-customer meter
- Battery Storage

To help inform the IRP of possible future scenarios and to improve on the accuracy of the load forecast for this IRP, BED estimated the magnitude of the impact caused from deployment of the above-noted technologies on future energy loads and peak demand. To this end, a "mini model" was developed for each technology to assess a range of plausible outcomes. The overarching goals of the mini-model analyses were:

1) To understand whether any of the technology options fundamentally did not make economic sense from a cost perspective at this time. Each technology was tested based on its sensitivity to variables, which impacted its value and/or cost to BED and its customers. The economic tests included the societal impact of each technology option.
2) For any technologies that were found uneconomic at this time, BED sought to identify key issues and other metrics that it could monitor in order to determine if and when the economics of a particular technology have sufficiently improved to warrant action.

Mini-Model Methodology

While each technology described below is unique, the report outputs all share a common structure and methodology. Each technology model begins by briefly describing the technology and the key assumptions that were used in the model to perform various economic tests. The report then describes the technology's economics from the perspective of the customer, utility

(BED), and society. Report summaries also include an assessment of the RES's Tier III implications, where applicable. The results of the economic tests and potential Tier III impacts were then used to develop a recommended course of action. The mini-model analysis summary concludes with an estimated deployment rate based on the results of the economic tests, the Tier III analysis, and the recommended course of action.

Economic Tests

The economic tests from the perspective of the customer, BED (utility) and society differ from each other as each test evaluates costs and value streams in a unique manner. Additionally, the economic tests differ from technology to technology. The individual mini-model reports, provided below, describe the specific technology measures, and their use, costs and benefits. This information is intended to provide an overview of the primary issues BED considered in its evaluation of the measures and the general approach used to evaluate net benefits. It is important to note that some benefits for certain technology options are difficult to quantify and measure. While these benefits are not included in the economic tests, where they exist, they have been noted in the mini-model summaries.

Customer Test

The customer economic test is intended to demonstrate whether a particular technology would ultimately reduce a customer's out-of-pocket costs (both capital and operating costs). This test essentially considers the net savings, if any, from substituting fossil fuel consuming equipment with hyper-efficient electric-powered technologies, i.e.; replacing a traditional internal combustion engine with an all- electric vehicle. In most circumstances, the test considers only market opportunities as opposed to early retirement/retrofits. This means that customers elect to purchase and install eligible measures when their existing equipment reaches the end of its useful life.

Utility Test

The utility economic 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 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 to BED depends largely on four key variables that were expected to impose the greatest degree of risks on BED's net present value (NPV) cost of service. The key variables are the costs of energy, capacity, and transmission and the forecasted values for renewable energy credits (RECs). Appendix C to this report includes a detailed description of the key variables and how BED evaluated their potential impacts.

However, some of the key variables are not expected to have a meaningful impact on the cost of service. For example, implementation of a Passive House program is not expected to result in increased costs or revenues as certified Passive Homes typically consume a third (or less) of the energy of code-compliant homes. Thus, BED should not expect to experience any impacts. The values for each applicable variable were then grouped together to create four specific cases that each technology option was tested against. These cases are high case, base case, low case, and weighted case.

Societal Test

The societal cost test includes the utility cost inputs and the costs that society bears as well. The societal cost test is intended to measure the avoidance of costs that are broadly shared by society, such as emissions and other environmental impacts. Such costs can be avoided by reducing fossil fuel use or reducing energy use if the energy source is non-renewable. Reduced societal costs can be attributed to actions by either the customer or the utility.

RES Tier III Implications

As noted, the energy transformation (or Tier III) provision of the RES stipulates that utilities must support strategic electrification projects. To meet their Tier III requirement, utilities may undertake actions and programs that encourage customers to reduce their fossil fuel consumption and lowers GHG emissions attributable to that consumption. Such encouragement, however, is constrained. Any actions taken by a utility shall not cost more than the alternative compliance payment of $0.06/kWh (in 2017), inclusive of administration expenses.

Recommended Course of Action

The recommended course of action, included in each of the technology summaries below, is based on the results of the aforementioned economic tests. For those technologies with net positive economic test results, actions to advance the deployment of that technology were recommended. When these economic tests proved to be negative, the recommendation is to postpone any further actions and to monitor developments affecting the technology. However, the best course of action is less clear when the results of the customer, utility, and societal economic tests diverge from one another. When the customer economics are weak, it is BED's responsibility to offer a cost effective incentive to encourage market transformation. As a municipal utility, however, BED is obligated to clearly communicate when a technology does not produce positive customer economics, even if there are significant utility and/or societal benefits. In all cases, the conclusion and recommended course of action for each technology is based on current circumstances and the best available data. BED acknowledges it will be important to monitor technology advances and, possibly, dynamic retail rate pricing regimes to inform future plausible courses of action, when warranted.

Estimating the Rate of technology deployment

Estimating the deployment rate of the technology options is an important output of the mini-model analyses, as the saturation levels of certain technologies will likely impact BED's load forecast. The pace of technology deployment will undoubtedly be influenced by the existing economics of each technology for those covering the initial capital investment and the ongoing operating costs. The availability of a Tier III incentive to reduce the initial capital cost or improve the ongoing operational economics will also influence the deployment rate of technologies.

Cold Climate Heat Pumps

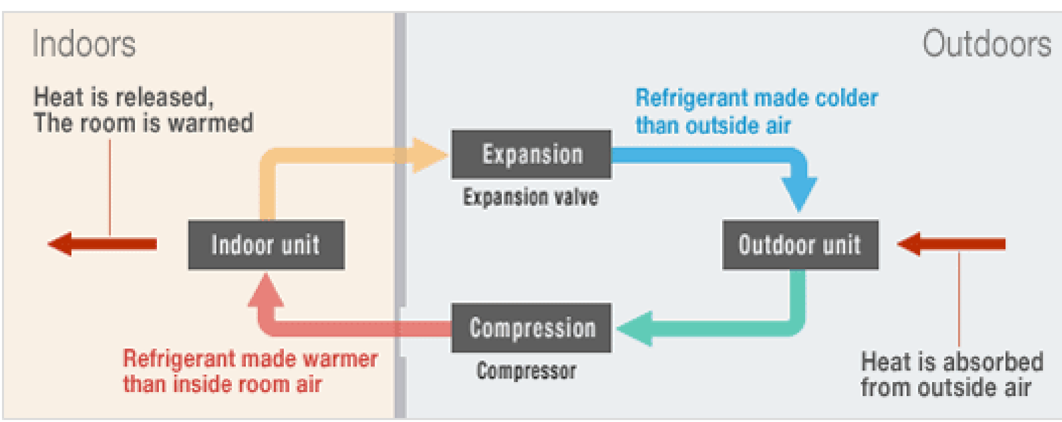
Technology description

Heat pumps are well-known and fully-tested technologies that have been successfully installed in buildings and appliances for several decades. They can be found in air conditioners, refrigerators and freezers, domestic hot water tanks, clothes dryers and space conditioning equipment (e.g. heating in winter, cooling in summer). Heat pumps also come in various types: air-sourced, water-sourced and ground-sourced pumps; meaning, heat pumps transfer energy from one air mass to another, from a mass of water to air, and/or from the ground to air.

This section focuses on air-sourced heat pumps used for space conditioning. These units are commonly referred to as ductless heat pumps or mini-splits.

Ductless heat pumps are commonplace in more temperate regions of the country than Vermont. These more traditional heat pumps have never been widely adopted in New England because their effectiveness to deliver heat decreases substantially as outside temperatures drop below 20°F. But recently, heat pump technology has improved. So-called cold climate heat pumps (ccHPs) can now move "heat" to indoor living spaces as long as the temperature outside is at least 0°F.

Instead of generating heat by burning fuel, cold climate heat pumps transfer heat more efficiently than traditional ductless heat pumps via a refrigerant that flows through multiple variable speed compressors and expansion valves. This transfer of heat is illustrated in the graph below.[1]



Improvements in new cold climate heat pumps are primarily a function of advances in refrigerants (known as R410A), multiple variable speed/flow compressors, ductless heat delivery and controls. These advancements have led to improvements in efficiency relative to

[1] See Mitsubishi Electric, http://tinyurl.com/h6llt6p, last accessed on 4/11/2016.

traditional heat pumps, as well as corresponding reductions in the operating cost per MMBTU. As shown in the table below, the per MMBTU cost of operating a ccHP under current retail costs is considerably lower than propane fueled boilers and electric resistance base-board but 4-10 percent higher than the cost of Natural gas, oil, and wood. This table does not include the purchase cost of the heating system.

Fuel (unit)	BTUs/unit	System Efficiency	$/unit	$/MMBTU
Fuel Oil, gal	138,200	85%	$ 2.04	$ 17.37
Kerosene, gal	136,600	80%	$ 2.61	$ 23.88
Propane, gal	91,600	80%	$ 2.40	$ 32.75
NG, ccf	100,000	85%	$ 1.40	$ 16.47
Electric,kWh	3,412	100%	$ 0.15	$ 43.96
Electric, HP	3,412	240%	$ 0.15	$ 18.32
Wood, green cord	22,000,000	60%	$ 227.14	$ 17.21
Pellets, ton	16,400,000	80%	$ 294.00	$ 22.41

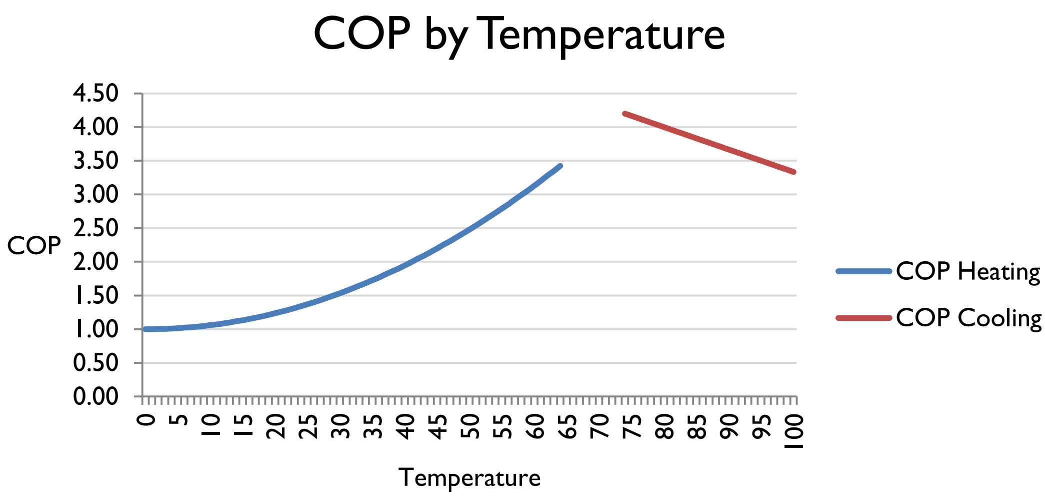
Source: DPS May 16 Fuel Report

Key assumptions

For the purposes of this analysis, the following basic assumptions were used to estimate the net impacts of ccHPs:

Basic ccHP Assumptions	
Ann. Heat load (MMBTU)	90
Installed Cost	$4,500
Incentive	$300
Fuel displacement (%)	60
Coefficienct of Performance (%)	240
NG/ccf	$1.40
Propane	$2.40
Heating oil	$2.04
kWh rate	$0.15

In addition to the assumptions above, BED modeled the energy consumption and demand of ccHP units based on their coefficients of performance and outside temperatures in order to evaluate their potential impact on utility operations and costs. Using weather data for Burlington from 1995-2015, BED assigned a COP for each degree of temperature and then calculated the energy consumption and demand of the unit based on the assigned COP. When outside temperatures were less than 0°F or between 65°F and 74°F, BED assumed that ccHPs were shut down. The graph below demonstrates how outside temperatures affect COP.



Modeling results

Customer economics

The economics of ccHPs are highly sensitive to the unit's coefficient of performance[2], the retail price of fuels, and customer operations. Indeed, relatively small changes in any of these variables can have a material impact on whether customers actually save money by installing a ccHP for heating their home or business. For example, at today's low fossil fuel prices and assumed average COP (i.e. 240%), customers connected to the natural gas system, should not expect to save money using a ccHP for space heating (even if the cost of the ccHP is ignored). But if the COP of a ccHP improved to 250%, then the cost of operating it relative to a NG boiler with an AFUE of 85 percent would be slightly lower (however the payback for the capital cost of the ccHP would be excessive). Similarly, modest changes in fuel prices affect customer economics. At $1.60/ccf of natural gas, using a ccHP with a COP of 240 percent would cost less to operate than an NG boiler. But at $1.40/ccf, natural gas boilers with an 85% AFUE would be less expensive than a ccHP. As shown in the table below, some fossil fuel prices, such as natural gas, have remained relatively low over the past 12 – 18 months and have thus undermined the customer economics of ccHPs.

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[2] Coefficient of performance: is defined as the ratio of heat output to the amount of energy input. For example, if a ccHP delivers 13,500 BTU/hr and consumes 1.6kW, its COP is 2.47 = (13,500 BTU/hr) ÷ (3412*1.6kW). This means that for every unit of energy consumed (input) by the ccHP, it produces 2.47 units of energy (output).

Fuel Source $$/MMBTU	15-Jan	Feb-15	Jan-16	Feb-16	May-16	Trend
Electric Resistance	43.46	43.46	43.46	43.96	43.96	
Propane	37.25	31.90	34.06	34.39	32.75	
Pellets	22.41	22.41	22.42	22.41	22.41	
Kerosene	31.23	28.43	23.67	21.78	23.88	
Electric HP, High Eff	18.32	18.32	18.32	18.32	18.32	
Wood	17.21	17.21	17.21	17.21	17.21	
Fuel Oil	25.73	23.82	18.20	16.82	18.45	
Nat. Gas	18.55	17.91	17.42	16.00	16.47	

Source DPS fuel reports

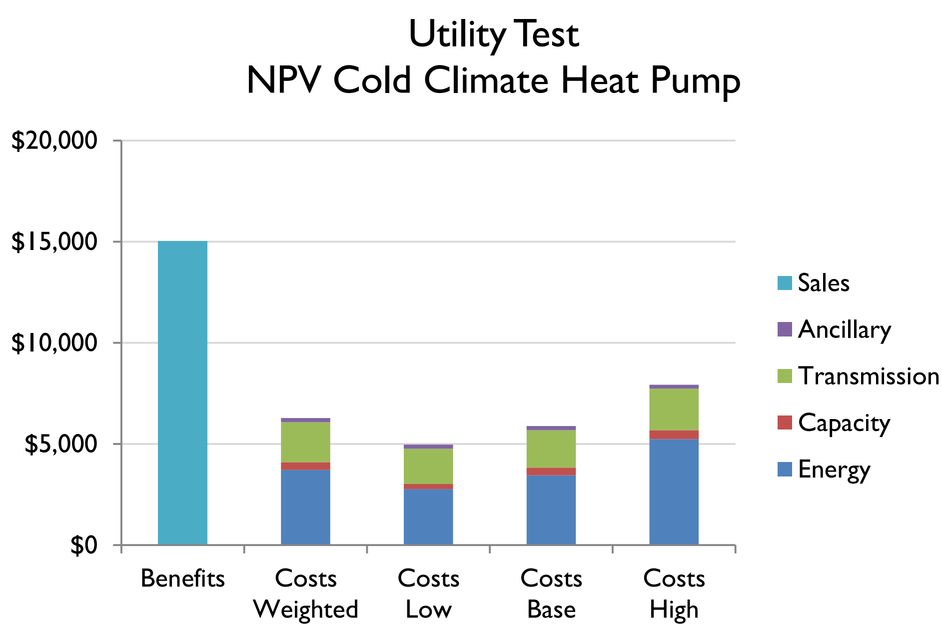
Note: All fuels assume average efficiency (AFUE) levels of 80 - 85%

As noted above, ccHPs essentially shut down when outside temperatures fall below 0°F. Moreover, the performance of ccHP's drops precipitously as outside temperatures near 0°F and they become much less efficient. Consequently, customers will need to maintain their existing system for supplemental heat during cold spells. However, the cost of heating with a ccHP in combination with an existing natural gas boiler, for example, will exceed the cost of heating the building with only the customer's existing boiler and this conclusion does not include the cost associated with installing the ccHP. The following table illustrates the estimated cost to heat a typical single family home using a ccHP in combination with other fuel types based on current fuel prices. In this example, the ccHP is assumed to contribute 60 percent of the required heat.

	CCHP	NG Boilers	Oil	Propane	Kerosene	Electric, kWh	Pellets	Wood, green
House BTU load - delivered	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000	90,000,000
BTU per unit of fuel	3412	100,000	138,200	91,600	136,600	3,412	16,400,000	22,000,000
Total consumption	26,377.49	900	651	983	659	26,377	5	4
COP/AFUE	2.4	0.85	0.85	0.8	0.8	1	0.8	0.6
Price per unit	$ 0.15	$ 1.40	$ 2.04	$ 2.40	$ 2.61	$ 0.15	$ 294.00	$ 227.14
cost per MMBTU	18.32	16.47	17.37	32.75	23.88	43.96	22.41	17.21
Total cost	$ 1,649	$ 1,482	$ 1,563	$ 2,948	$ 2,150	$ 3,957	$ 2,017	$ 1,549
If ccHP can displace:	0.6	54,000,000	54,000,000	54,000,000	54,000,000	54,000,000	54,000,000	54,000,000
Remaining BTU served by existing system	0.4	36,000,000	36,000,000	36,000,000	36,000,000	36,000,000	36,000,000	36,000,000
total ccHP cost		$ 989	$ 989	$ 989	$ 989	$ 989	$ 989	$ 989
Total FF cost		$ 593	$ 625	$ 1,179	$ 860	$ 1,583	$ 807	$ 619
Total heating cost		**$ 1,582**	**$ 1,614**	**$ 2,168**	**$ 1,849**	**$ 2,572**	**$ 1,796**	**$ 1,609**
Savings $ (costs)		**$ (100)**	**$ (51)**	**$ 779**	**$ 301**	**$ 1,385**	**$ 221**	**$ (60)**
Savings %		-6.7%	-3.3%	26.4%	14.0%	35.0%	11.0%	-3.9%
Plus GMP lease								
Total savings		$ (100)	$ (51)	$ 779	$ 301	$ 1,385	$ 221	$ (60)
Avg Install Cost		4200	4200	4200	4200	4200	4200	4200
Simple payback (yrs)		n/a	n/a	5.39	13.97	3.03	19.01	n/a

Utility Cost test

As noted above, to determine the benefits and costs of ccHP, BED first developed a model that estimated the energy consumption of ccHPs based on historical weather/temperature conditions and their assigned COP. BED then compared the average expected usage of ccHPs by month, assuming monthly average temperatures, to ISO-NE energy prices and the Vermont and ISO-NE peaks to determine the energy, capacity and transmission cost impacts. For example, during the month of January, BED assumed that, on average, a ccHP would consume 1.77 kWh per hour based on historical average January temperatures of 22°F and average heating COP of 1.39 (exclusive of the hours when the ccHP is shut down). This analysis suggests that while ccHP consumption and demand is correlated with system energy and peak demand, ccHPs still pass the utility cost test as shown in the graph below. ccHPs pass the utility cost test due to their efficiency and because, on average, the anticipated cost to serve ccHPs in Burlington would be lower than current retail rates, provided however BED would not have to build additional distribution infrastructure to serve increased loads caused by ccHPs over their lifetimes.

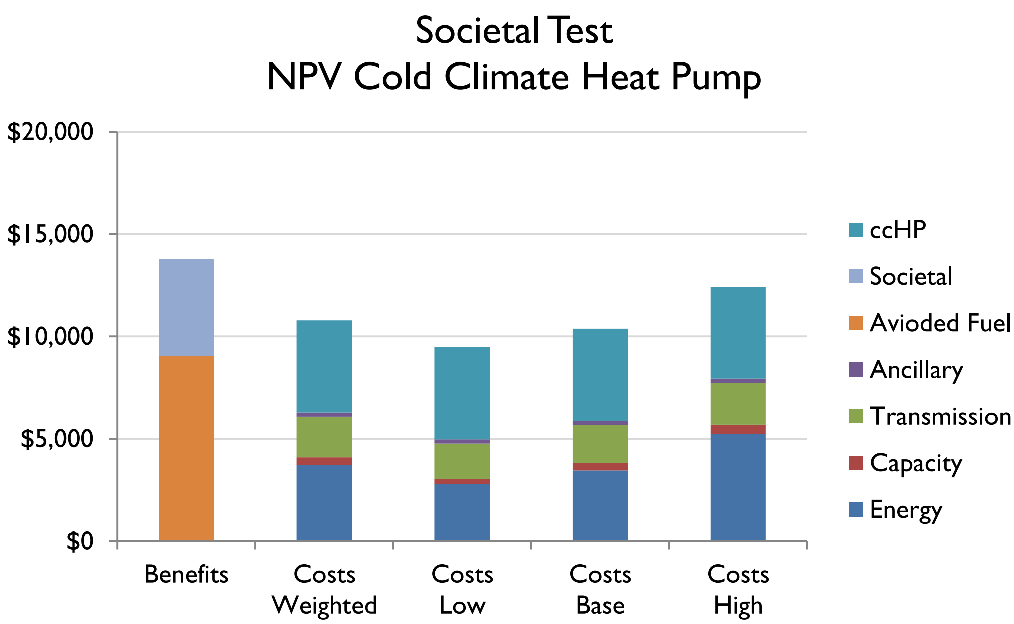


The above analysis indicates that ccHP technology represents a highly profitable technology for utilities to deploy. In fact, every ccHP installed would generate up to $9,000 in positive utility benefits over the ccHP's lifetime under the base case scenario.

The utility cost test, however, is independent of customer economics, and indicates that a utility could choose to incent ccHP technology without causing rate pressures even if this technology were not ideal for a particular customer. This harkens back to the "too cheap to meter" days of utility economics when utilities advocated additional sales as a way to reduce average retail energy rates. It also indicates that utilities could theoretically lower the retail rates for serving a ccHP to make the technology more economically attractive to customers as will be discussed in the section on recommended actions.

Societal Cost test

The installation of ccHPs also creates positive societal net benefits under all scenarios, as illustrated in the graph below due to the avoided emissions from fossil fuels. Under the base case scenario, societal net benefits would amount to approximately $3,300 over the lifetime of the unit. However this screening result is dependent on the inclusion of societal costs.



In addition to the customer's fuel savings (shown in the graph above as Benefits), the societal cost test evaluates other net benefits that may accrue to society due to the installation of ccHPs in homes and businesses. Since ccHPs displace fossil fuels, society in general potentially avoids a host of risks associated with fossil fuel consumption. Such risks impose costs on society, either directly or indirectly, but are not fully reflected in retail fuel prices. These risks include but are not limited to price volatility, transporting and storing fossil fuels and environmental harms (i.e. climate change, hydraulic fracking, etc.). Installation of ccHPs will also lower CO2 and other GHG emissions that are known to impair health and increase health care costs. Since health care costs are essentially shared across the economy, society would benefit by reducing emissions and improved health. For the purposes of the societal cost test, BED assumed that every ton of CO_2 emissions that was avoided results in a societal benefit of $95 per ton.

Tier III implications

Pursuant to 30 V.S.A. §8005, BED is permitted to provide incentives for measures that reduce fossil fuel consumption and greenhouse gas emissions. Since ccHPs have the potential to do both, incentives to customers ranging from $3,000 to $4,000 per ccHP may be possible. However, since ccHP are uneconomical for customers based solely on operating costs, providing an incentive where natural gas or wood is used, appears to be imprudent at current fuel prices. To make ccHP economical for customers, utilities would not only have to subsidize the up-front cost of ccHPs but they would also need to provide incentives toward the ongoing heating costs.

Recommended course of action

Evaluation of the customer economics of ccHP's yields very interesting results. For the majority of customers in BED's service territory (who are connected to the natural gas pipeline), ccHP technologies could actually increase space conditioning costs at current fuel prices.[3] On the other hand, at today's energy costs, BED and other VT utilities are financially motivated to encourage customers to install ccHPs based on retail revenue economics and Tier III requirements. This inherent conflict presents BED with a challenge.

The challenge that BED is facing is that natural gas prices are so low that ccHPs cannot compete in the space conditioning market yet there are both regulatory and industry pressures to encourage ccHP adoption. Irrespective of these outside pressures, BED has elected to limit the promotion of ccHP, since incentives toward the purchase of a ccHP would not change the fact that customers would most likely incur higher operating costs under current retail electric rates, fuel prices and ccHP operating characteristics. Rather than broadly market ccHPs throughout the City, BED will instead target the customers using propane and electric baseboard resistance for heating purposes. Additionally, BED will continue to promote ccHPs in the new construction market, where developers want to reduce the up-front cost of new homes and apartments.

For customers currently using wood or natural gas, BED recommends that it continue researching whether reliable and cost effective ccHP's will become commercially available over the next few years and whether such new versions are advanced and efficient[4] enough to yield a reasonable economic return for customers. In the meantime, BED will forego incentive offers for

[3] Space cooling benefits, if any, derived from ccHPs do not offset space heating costs for natural gas customers.
[4] i.e. COPs substantially greater than the annual 240% now assigned to ccHPs.

customers using wood or natural gas as their primary heat source until such time that BED can offer specific end-use rates to improve customer economics, identify appropriate units, or fuel prices for wood and natural gas increase.

As a municipal utility, BED does not want to actively encourage deployment of technologies that are uneconomic for the customer, even though promotion could result in benefits for the utility. In addition to monitoring natural gas prices and technological developments, BED will also explore alternative electric rates focused on new technologies such as ccHPs. In BED's view, it is theoretically possible, based on the utility cost-test methodology for the utility to reduce retail rates for ccHP's (and other similar technologies). However, end-use targeted rates that are based on societal goals (as opposed to cost to serve) have not been deployed in Vermont, and providing a rate that targets a specific technology would require the ability to isolate that load from remaining uses at the location for billing purposes.

Further research exploring the potential issues mentioned above and discussions about these end-use rates with State regulators will be key next steps.

Deployment pace estimate

Approximately 10 percent of residential and 5 percent of small commercial customers heat their buildings with a non-natural gas fuel. As such, the pace of deployment will be slow, but perhaps not anemic, especially if a number of newly constructed homes and rentals are built in the near future absent an active BED program for retrofits. For example, BED's EEU incentivized 43 units in 2015 (one project included 22 units). At an assumed annual 6.6 MWh of energy usage per year these 43 units would result in load growth of less than 0.08%.

Given the current low cost of natural gas and the slow pace of ccHP installation, distribution impacts should remain minimal for the near future. In addition, BED will have the opportunity to ameliorate the impact of ccHP installations through the use of additional incentives for weatherization and dynamic rate designs.

Based on the above analysis, BED does not anticipate that significant numbers of ccHPs will be installed in the City to displace current heating systems unless creative ratemaking is employed. However, the installation of ccHP in newly constructed buildings may accelerate modestly in the near term as the initial, upfront cost of ccHPs and air conditioning benefits can be attractive to developers/builders as an alternative to traditional heating systems, plus air conditioning. Consequently, the impact of ccHPs on BED's energy and capacity needs will be minimal in the near term.

Battery-electric Transit buses

Technology description

In terms of their size, length and seating capacity, battery-electric buses are similar in nearly all respects to their diesel-powered counterparts. But, unlike diesel-powered buses, they are much cleaner and quieter to operate. Moreover, fuel and maintenance costs are reported to be substantially less.

On the other hand, battery electric buses are a new technology. Consequently, their initial cost is nearly twice that of diesel buses.

Many cities and transit operators are motivated to procure battery-electric buses to reduce emissions and other particulates. Indeed, transitioning from diesel to battery-electric buses is oftentimes a part of a city's overall sustainability efforts. City residents and commuters 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.[5] In 2015, approximately 17% of all transit buses were hybrid-electric or all-electric (hybrid vehicles made of the majority of this group). Cities that are currently operating all-electric buses include Dallas, Texas (seven all-electric vehicles scheduled for service in early 2017), Indianapolis, Indiana (21 battery electric buses currently in operation), Seattle, Washington (currently testing three zero-emission Proterra battery electric buses), and Worcester, Massachusetts (fleet of six Proterra plug-in, all-electric buses)[6].

While battery-electric buses engender numerous environmental benefits, they can also be challenging for transit authorities to procure and operate. Procurement challenges are primarily related to stringent federal and state processes that transit authorities need to comply with in order to successfully obtain grant awards for bus purchases and to retain ongoing operating funds. Awards of federal transit funds come with numerous conditions that persist for many years after procurement. Such conditions include but are not limited to:

- "Useful life" standards require transit agencies to retain heavy duty vehicles typically for 12 years or 500,000 miles, whichever comes first. If a transit agency wishes to replace or dispose of a vehicle in advance of meeting the useful life threshold, the federal interest in the asset must be repaid. Additionally, there are very specific requirements related to the disposal of assets purchased with federal funds.

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[5] Opportunity Assessment report prepared for the Chittenden County Transportation Authority and Vermont Gas Systems, Inc., Yborra & Assoc., Larsen Design Group, 2015 at pg. 7.
[6] "2016 Public Transportation Fact Book, Appendix A Historical Tables,"page 134, American Public Transit Association, April 2016

- "Spare ratio" standards limit the size of a transit agency's federally-funded fleet. The general rule is that transit agencies are limited to a spare ratio of 20%, meaning they can have a total number of vehicles that is 20% higher than their peak service requirement. Transit agencies need a sufficient number of spare vehicles to allow for reliable operations when vehicles are out of service for maintenance or due to an accident. However, the spare ratio cap does not offer sufficient flexibility for diverse fleets that tie certain vehicles to certain types of operation. Therefore, vehicles whose capabilities limit which types of routes they can operate on in many circumstances can place additional challenges on transit agencies with respect to staying within the spare ratio limits.

These requirements, while clearly intended to ensure taxpayer funds are used efficiently and appropriately, are typically viewed as a disincentive for transit agencies to try new transportation technologies. The potential burden associated with a poorly performing vehicle or fleet of vehicles is an understandable concern for transit agencies facing funding constraints and daily operating demands. Nonetheless, Green Mountain Transit (GMT), the regional transit provider, has expressed an interest in exploring new technologies such as all-electric and compressed natural gas buses.

The primary operating challenge of battery-electric buses is its limited range. While electric vehicle technology has advanced in recent years, the range of electric buses is still limited compared to other fuel technologies – about 146 miles on a single charge. The ability for transit agencies to efficiently schedule drivers and buses with minimal layover and out-of-service time is an important cost-control mechanism. While driver schedules must include some recovery time between operating individual trips on a route to account for delays on the previous trip (due to traffic or accidents), there is an inverse relationship between recovery time and metrics that measure the cost-efficiency of the transit system. With short range batteries, the need to charge batteries in between the operation of individual trips will, in most instances, require additional time to be added between trips, which will either increase operating costs or reduce the number of trips available to customers. Additionally, the short-range batteries would require charging infrastructure out in the field versus at a maintenance facility. On the other hand, longer-range batteries may eliminate the need for charging in between individual trips, but would require that those vehicles begin and end their shifts at locations with charging infrastructure. The need to return a bus to a specific location at certain times throughout the day has the potential to restrict the creation of the most efficient driver schedules and increase operating complexity and costs. For these reasons, transit agencies must consider how electric vehicles could be integrated into their operations so as to maximize their operational benefits and minimize any potential operational inefficiency.

A potential strategy to address the aforementioned procurement challenges that is currently under review is to engage a so-called Energy Service Company to lease the bus to GMT, and use the operational savings to pay for the incremental cost of the bus. Alternatively, BED could purchase the vehicle(s) and lease them back to GMT. These proposals could be independent of, or combined with more traditional incentives to make all electric buses more economical to GMT.

Key assumptions

BED made several assumptions about the operating characteristics of battery – electric buses in its models to determine their cost effectiveness. While several of the assumptions have a measurable impact on bus operations, the variables with a disproportionate effect on cost effectiveness include: incremental capital costs, price of diesel fuel, battery range and miles per gallon equivalent or MPGe. In the case of electric buses, MPGe is measured in terms of kWh consumed per mile.

For the purposes of this analysis, BED assumed that the full cost of an all – electric bus is $779,000 for a "long" range bus that would not require an additional investment in so-called Fast Charging infrastructure.[7] As noted, longer range buses can travel up to 146 miles on a single charge, about twice the average daily miles of most of GMT's buses. The estimated full cost of ownership is $325,000 more than the cost of a typical diesel bus.

Regarding diesel fuel, the model incorporates three price scenarios: low prices of $1.35/gallon, mid prices of $1.70/gallon and high prices $2.40/gallon (in 2016$). Each per gallon price point was then increased at an annual rate of 5.0 percent. The model then used a 12 year average cost of fuel, adjusted for inflation, to calculate the lifetime fuel expense of diesel powered buses under each price scenario.[8] Under these assumptions, total fuel costs are expected to range from $151,000 to $268,000; or about $9,000 to $17,000 annually. Thus, a $1.00 increase in the price of diesel per gallon could increase total fuel costs by more than $60,000 over the lifetime of a bus. This latter calculation assumes each bus has a 12 year life, can achieve exactly 4.26 miles per gallon of diesel fuel and travels 29,900 miles annually. In short, each diesel bus consumes 7,025 gallons of diesel annually; or approximately 19.25 gallons daily. Naturally, the lower the cost of diesel, the less appealing a battery electric bus is from a customer and societal perspective.

Assumptions regarding battery range also significantly impact model outcomes. As noted above, if battery-electric buses experience higher levels of down time due to recharging, costs

[7] See BYD cost schedule – although Proterra also has a long range option that does not require fast charging capabilities.

[8] BED has been informed that GMT included the high price scenario for budgeting purposes.

per revenue mile will increase which would negatively affect cash flows and GMT's ability to attract new funding for additional buses. Thus, it is important to fully understand and anticipate the mileage range of batteries onboard.

Industry literature calculates battery range in two ways. One method is referred to as the nominal range; the second, actual range. Both are used as indicators of how far a battery-electric bus can be expected to travel. The nominal range is derived using a deterministic approach. It is also a relatively straightforward calculation. The actual range, however, cannot be pre-determined as the range of the bus depends on a host of variables.

Under the nominal range approach, the total energy capacity of a battery pack on board the bus is divided by the efficiency of the battery. Fully equipped, battery packs contain between 250 and 300 kWh of stored energy. Battery efficiency is measured in terms of kWhs consumed per mile driven.

The actual range can only be measured after several trips have been completed along the same route or routes that a bus would typically travel. Actual battery range is impacted by the following variables: average speed, topography, outside temperatures, number of stops, passenger loads, vehicle weight, battery age, driving cycle, drive time, and use of regenerative braking.

For the purposes of this analysis, BED relied on the nominal range approach. The model assumes a battery pack contains 257 kWh and achieves an efficiency of 1.76 kWh consumed per mile. Accordingly, the total range of a battery electric bus is 146 miles per charge[9].

Modeling results

Customer economics

As the table below suggests, converting from diesel to battery-electric buses is marginally cost effective under the high-priced diesel fuel cost scenario if BED provides a $60,000 incentive towards the purchase of an electric bus. As the cost of diesel fuel increases, the economics of electric bus ownership improves considerably. At $2.40 per gallon, which is the amount that GMT has used in its most recent annual budget, GMT would save $60,595 over 12 years by converting to a battery– electric bus. Thus an electric bus could be viewed as a "hedge" for GMT against diesel prices climbing from today's low values.

[9] See Proterra ppt presentation to UVM, October 2015. See also BTD and Proterra sales brochures and web sites.

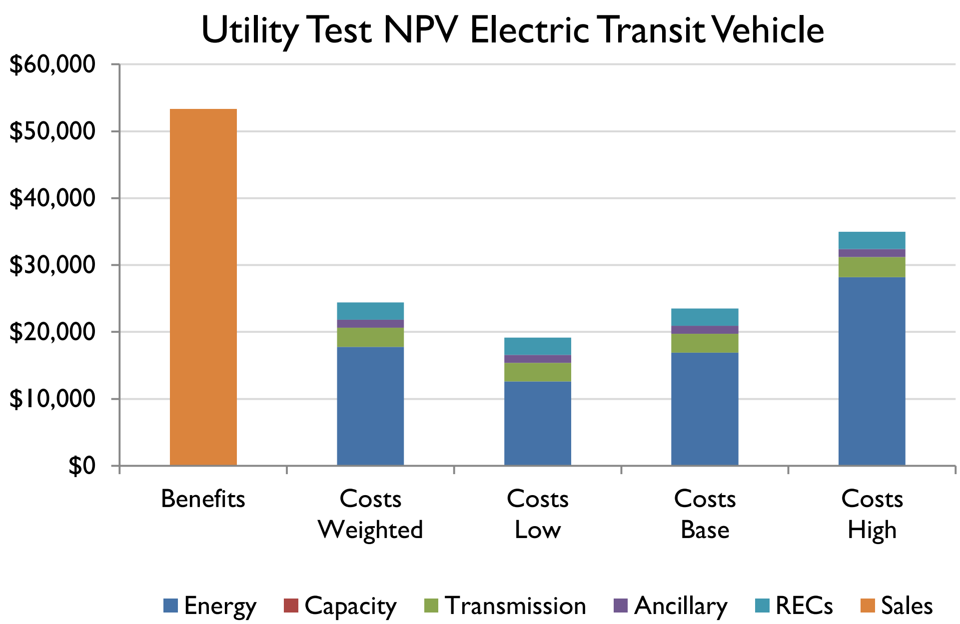
Total Cost of Ownership (Lifetime)	40 Ft Catalyst (Elec)	Diesel Low	Diesel Mid	Diesel High	CNG
Capital Costs	$ 779,000	$ 454,000	$ 454,000	$ 454,000	$ 470,000
Fuel Expense	$ 59,249	$ 119,162	$ 150,056	$ 211,844	$ 110,775
Maintenance	$ 320,767	$ 389,000	$ 389,000	$ 389,000	$ 432,000
Total Cost of Ownership	**$ 1,159,016**	**$ 962,162**	**$ 993,056**	**$ 1,054,844**	**$ 1,012,775**
TCO/ miles	$ 3.23	$ 2.68	$ 2.77	$ 2.94	$ 2.82
Lifetime Savings (**costs**)	$ -	**($196,854)**	**($165,960)**	**($104,172)**	**($146,242)**
Additional Infrastructure	$ -				$ -
Adj for Tier 3 incentive	$ (60,000)				$ -
Other Grants, including Fed	-	-	-	-	-
Total Cost of Ownership	**$ 1,099,016**	**$ 962,162**	**$ 993,056**	**$ 1,054,844**	**$ 1,012,775**
Adj savings (costs)		($136,854)	($105,960)	($44,172)	($86,242)
Adj TCO/mile	3.06	2.68	2.77	2.94	2.82

From strictly an operational point of view (i.e. fuel and O&M expenses, but not capital costs), a battery-electric bus would generate between $9,000 and $17,000 in annual savings due to lower fuel and maintenance costs, as shown in the next table.

2016 Annual Cost of ownership	40 Ft Catalyst (Elec)	Diesel Low	Diesel Mid	Diesel High	CNG
Capital cost	$74,405	$46,982	$46,982	$46,982	$48,637
Fuel Expense	$5,530	$9,484	$11,943	$16,861	$13,567
Maintenance Exp	$26,731	$32,417	$32,417	$32,417	$36,000
Total annual Expense	$106,666	$88,882	$91,341	$96,259	$98,204
Annual cost per mile	$3.56	$2.97	$3.05	$3.22	$3.28
Total annual savings(cost)		**($17,784)**	**($15,325)**	**($10,407)**	**($8,462)**
Fuel, O&M cost only	$32,261	$41,901	$44,360	$49,277	$49,567
Annual Fuel,O&M savings(costs)		**$9,640**	**$12,098**	**$17,016**	**$17,306**

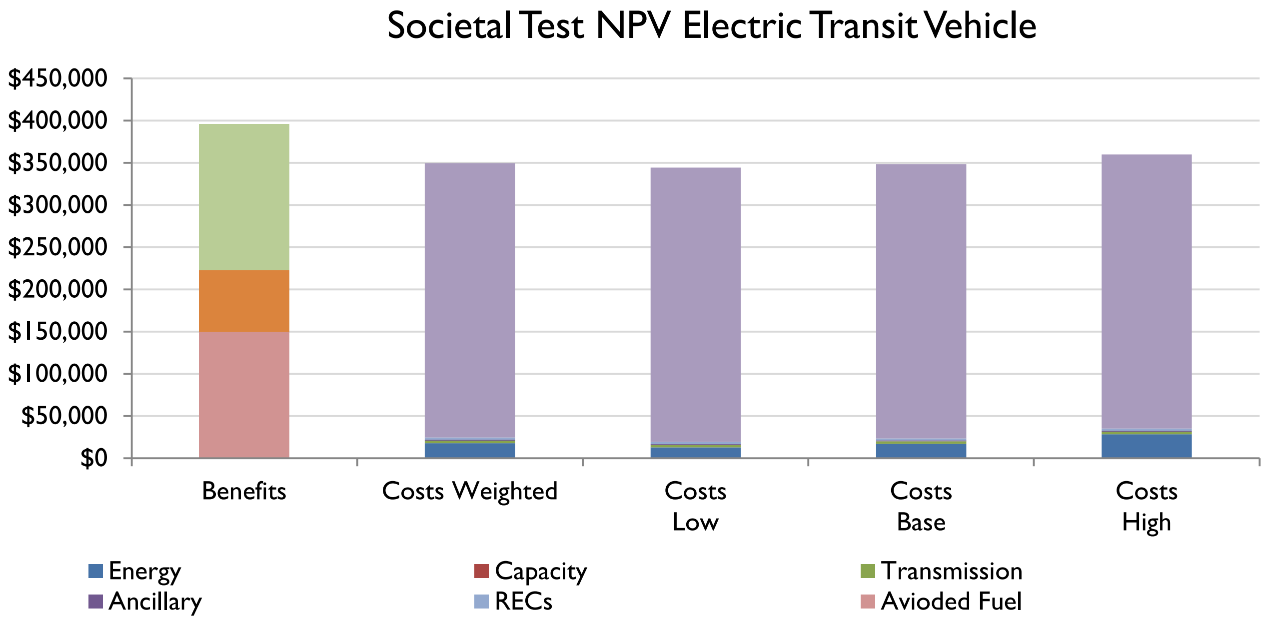
Utility economics

Under the utility cost test, promoting battery-electric buses in the City would result in positive net benefits to all ratepayers in the amount of $29,836 per bus over 12 years with electric sales under the Large General Time-of-Use rate. Benefits flow from increased electric sales of approximately $53,000 ($2016) per bus. Under this scenario, BED assumes charging would occur at night when the cost of wholesale energy, transmission and other ancillary costs are considerably lower. Because battery-electric buses are expected to be charging in the nighttime hours, BED anticipates there will be ample capacity from existing resources. Therefore, the model excludes additional capacity costs associated with battery-electric buses. Increased electric sales will also result in added REC costs of about $2,000 to $3,000 as BED would need to purchase more REC's to maintain its renewability status.



Societal Cost test

To evaluate the societal cost test, BED modelled the following benefit variables: net avoided fuel costs, avoided emissions and lower maintenance costs. Incremental cost variables included the incremental cost of battery electric bus relative to traditional diesel powered buses and increased wholesales costs associated with energy, transmission and ancillary services. As the graph below demonstrates, implementing a battery – electric program in the City would result in positive net benefits of approximately $47,000 over the life of the bus when societal costs are included.



Total benefits of $395,000 consist of avoided diesel costs ($150,000), lower expected maintenance costs relative to traditional diesel buses, resulting in savings of $173,000 and avoided GHG emissions costs ($72,000). Avoided emissions were based on historical annual miles that a diesel bus would have driven; the BTU content of the avoided diesel fuel and the weight of such emissions per BTU. A cost of $95 was assigned to each ton of avoided emissions. Per industry literature, the BED model assumed that the maintenance costs of a battery-electric bus would be $173,000 lower than a diesel buses over the 12 year life of the buses. At current diesel prices, lower maintenance costs are one of the largest benefits of electric bus ownership and the biggest contributor to the overall positive customer economics referenced above.

Total benefits are offset by the large upfront capital costs of an electric bus. All electric buses cost about $325,000 more than a diesel bus. Also, BED would incur additional wholesale energy, transmission and other ancillary costs to meet the electric bus charging demands.

Tier III implications

In accordance with current Tier III cost effective screening test protocols, BED can provide up to $60,000 for incentives per electric bus. Each bus would provide for approximately 1,200 MWh of Tier III "savings". If BED provided incentives of $180,000 for three electric transit buses in 2017, the total amount of displaced diesel fuel would help BED achieve approximately 50 percent of its first year Tier III goal. Three buses would potentially add 159 MWhs of additional load. Since the buses would likely be charged at night, BED anticipates that changes in its capacity and transmission requirements would be *de minimus*.

Recommended course of action

Electric bus technology has the potential to provide for significant societal benefits, and lower operational costs for Green Mountain Transit. Accordingly, BED will further assess all available options to improve the customer economics and total cost of electric bus ownership.

Deployment pace estimate

Current estimates assume that BED can provide incentives for 2-3 Electric buses over the next five years.

Electric Vehicles

Technology description

Because Burlington is the largest city in Vermont, a regional employment hub and tourist destination, BED is uniquely positioned to promote the use of all – electric vehicles (EVs) as a means to reduce greenhouse gas emissions to 5 percent of 1990 levels in 2050. [10] In this section, BED explores how the deployment of EVs in Burlington would contribute to the State's transformational efforts in the transportation sector.

At 13 square miles, the City is relatively compact. City residents could easily depend on EVs for most of their local transportation needs such as running errands, shopping and dropping children off at school. Indeed, most Vermonter's drive approximately 30 miles per day[11], which is well within the range of an EV. Moreover, Vermonters residing in neighboring towns could also rely on EVs to commute into Burlington for work.

But adoption of EVs will take time, effort and additional incentives to effectively address a number of barriers to EV ownership.

Electric vehicles are a relatively new technology that is rapidly improving. Currently, two basic EV types are commercially available: all electric vehicles and plug-in hybrid electric vehicles. All electric vehicles are powered solely by a rechargeable lithium-ion battery pack capable of storing up to 25 to 30 kWh of energy.[12] The range of a fully charged, all – electric vehicle is between 60 and 80 miles, depending on temperature. Plug-in hybrid electric vehicles (or PHEVs) include both a battery pack and an internal combustion engine. A PHEV's battery range is fairly limited compared to the all-electric vehicle but its total range with gas is comparable to traditional vehicles.

There are currently 12 to 14 different brands of EVs and PHEVs. As the table below indicates, the suggested retail price, total mile range, battery size and monthly lease amount vary considerably.

[10] 2015 Clean Energy Plan, Department of Public Service.

[11] Various studies indicate that most Vermonters drive an average 12,000 miles annually, suggesting that daily mileage approximates 30 miles.(12000/365)

[12] Tesla cars are capable of storing between 70 and 90 KWh of energy. However, because the current price of a Tesla exceeds $70,000, it was excluded from BEDs analysis.

Make / Model	Vehicle Type	Electric Range (miles)†	Total Range (miles)	Battery Size (kWh)	Fuel Tank Capacity (gallons)	DC Fast Charging	Seats	Cargo (ft^3)	MSRP for base model	Federal Tax Credit Amount	Standard 36 Month Lease; Monthly Cost	Lease Down Payment
Plug-in Hybrid Vehicles (Gasoline + Electric)												
Audi A3 e-tron	Plug-in Hybrid	16	380	8.8	10.6	No	5	9.9	$ 37,900	$ 4,168	TBD	TBD
BMW i3 REx	Plug-in Hybrid	72	150	22	1.9	SAE Combo option	4	9.2	$ 45,200	$ 7,500	$ 549	$ 3,460
BMW X5 xDrive40e	Plug-in Hybrid	14	540	9	21.9	No	5	34.2	$ 62,100	$ 4,668	$ 619	$ 3,500
Cadillac ELR	Plug-in Hybrid	40	340	17	9.3	No	4	10.5	$ 65,000	$ 7,500	$ 499	$ -
Chevrolet Volt	Plug-in Hybrid	53	420	18.4	8.9	No	5	10.6	$ 33,170	$ 7,500	$ 296	$ 296
Ford C-MAX Energi	Plug-in Hybrid	19	550	7.6	14	No	5	19.2	$ 32,645	$ 4,007	$ 169	$ 3,463
Ford Fusion Energi	Plug-in Hybrid	19	550	7.6	14	No	5	8.2	$ 33,900	$ 4,007	$ 265	$ 2,184
Hyundai Sonata PHEV	Plug-in Hybrid	27	600	9.8	14.5	No	5	9.9	$ 34,600	$ 4,919	$ 289	$ 3,199
Mercedes S550e	Plug-in Hybrid	12	450	8.7	16.3	No	5	13.9	$ 95,650	$ 4,043	TBD	TBD
Toyota Prius Plug-in	Plug-in Hybrid	11	540	4.4	10.6	No	5	21.6	$ 30,815	$ 2,500	$ 239	$ 2,499
Volvo XC90 T8 PHEV	Plug-in Hybrid	14	350	9.2	13.2	No	7	15.4	$ 68,100	$ 4,585	TBD	TBD
All Electric Vehicles												
BMW i3	All Electric	81	81	22	--	SAE Combo option	4	9.2	$ 41,350	$ 7,500	$ 499	$ 2,950
Ford Focus Electric	All Electric	76	76	23	--	No	5	14.5	$ 29,175	$ 7,500	$ 220	$ 865
Mercedes-Benz B-Class Electric Drive	All Electric	87; 104	87; 104	28; 31	--	No	5	17.7	$ 41,450	$ 7,500	$ 319	$ 4,113
Mitsubishi iMiEV	All Electric	62	62	16	--	CHAdeMO standard	4	13.2	$ 22,995	$ 7,500	$ 189	$ 3,388
Nissan Leaf	All Electric	84; 107	84; 107	24; 30	--	CHAdeMO option	5	24	29,860; 35,050	$ 7,500	TBD	TBD
Smart Electric Drive††	All Electric	68	68	17.6	--	No	2	12	$ 20,740	$ 7,500	$ 139	$ 1,433
Tesla Model S††	All Electric	240; 270	240; 270	70; 85	--	Tesla Supercharger	5 (+2)	31.6	73,700; 83,700	$ 7,500	$799; $954	$6,494; $6,649
Tesla Model X††	All Electric	220; 257	220; 257	70; 90	--	Tesla Supercharger	7	TBD	80,000; 93,000	$ 7,500	TBD	TBD
Volkswagen e-Golf	All Electric	83	83	24	--	SAE Combo standard	5	22.8	$ 33,450	$ 7,500	$ 229	$ 2,349

†Electric range is from official manufacturer ratings. Range is often 30-50% less in cold winter conditions.

as of 1/25/2016

††No Vermont dealerships, but vehicles are available to Vermonters in nearby states or online.

http://driveelectricvt.com/buying-guide/compare-vehicles

Since EV technology has improved over the past 2- 4 years, the number of registrations in Vermont has increased significantly; most of these new registrations are PHEVs located in Chittenden County.[13]

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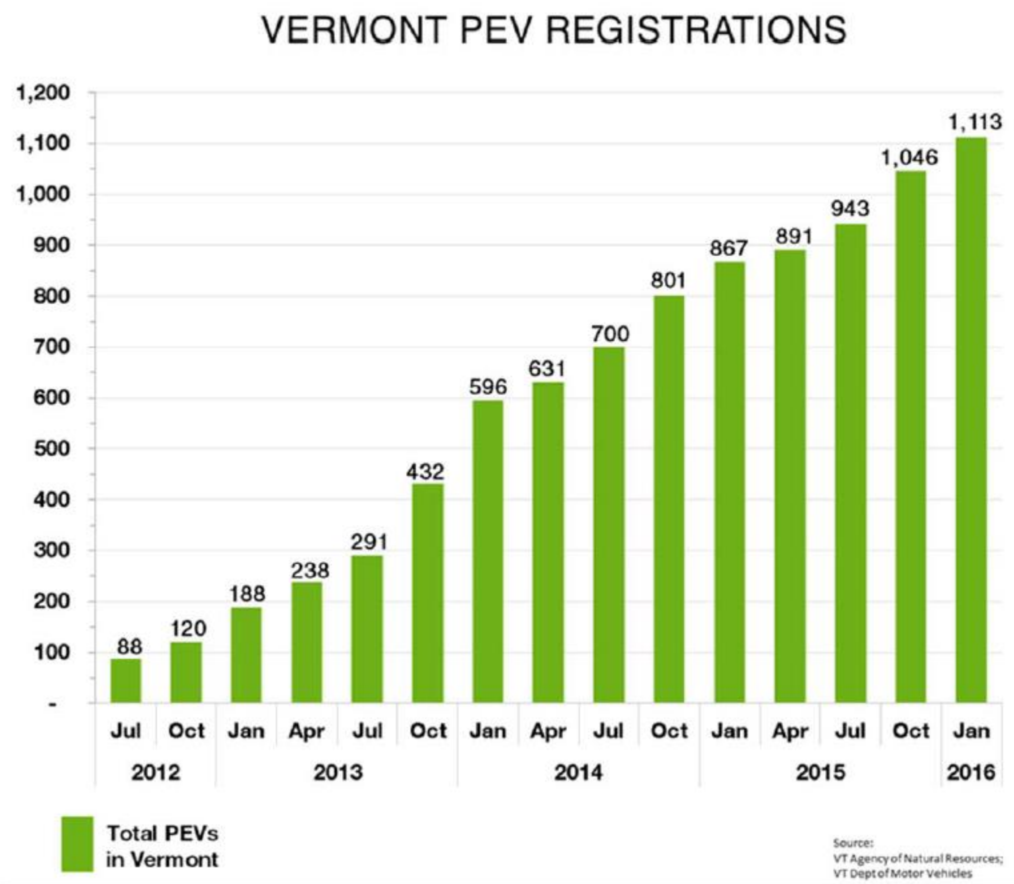
[13] Wagner, F et al., Drive Electric Vermont Case Study, prepared for the US Department of Energy, Energetics, March 2016.



Improved performance has mostly been in mileage range, efficiency, and operational features such as smartphone apps to locate public charging stations, monitor energy usage and tabulate electric fuel costs. The cost of all-electric vehicles, however, still remains high relative to traditional internal combustion engines (ICE). Because adoption of PHEV's has been accelerating in recent years, and given BED's compact geography, BED has focused its attention on all-electric vehicles to determine whether an EV program could cost effectively help to reduce fossil fuel consumption in the region and lower greenhouse gas emissions.

Key assumptions

Comparing the cost effectiveness of EVs to ICE vehicles required BED to make several significant assumptions about the characteristics of EV's and the driving patterns of City residents. Assumptions that have the most significant impact on customer economics are included in the table below. The assumption having the greatest impact on the utility and societal cost tests is whether EV owners actually charge vehicles during off-peak hours.

Major assumptions	
EV annual growth rate	30%, through 2026
Ann mileage driven	12,000
Federal Tax Credit	7,500
Tier 3 incentive	2,500
Ann. gas price inflation rate	1.05
Ann. electric price inflation rate	1.02
EV efficiency (kWh/mile)	3.15
Avg. ICE efficiency (MPG)	33
EV Measure Life	8
ICE Measure Life	8
EV Total Cost of ownership per mile driven	2.05
ICE Total cost of ownershop per mile driven	2.65

Modeling results

Customer economics

The economics of owning an all – electric vehicle from the customer's perspective are moderately positive. But, customer economics can vary widely and are highly dependent on key assumptions relative to manufacturing suggested retail prices (MSRP), gas prices, vehicle MPG, maintenance and repair costs, federal and state tax credits, other incentives, and interest rates. For the purposes of this analysis, BED compared the total cost of ownership of a new all – electric vehicle to a conventional passenger vehicle with an internal combustion engine. As the table below indicates, the total cost of owning (after incentives) an all – electric Nissan Leaf is approximately $24,600, a savings of $8,166.[14]

[14] Net Cost of ownership excludes taxes, delivery costs, registration and other fees.

	BMW i3	Nissan Leaf	ICE
MSRP	$ 42,500	$ 30,000	$ 25,000
FTC	($7,500)	($7,500)	$0
Tier 3 Incent	($2,500)	($2,500)	$0
Other Rebates	$0	$0	$0
Net Cost	$ 32,500	$ 20,000	$ 25,000
Car Payment/5Yr	$32,041	$19,718	$24,647
Ann Fuel&Maint(NPV)	$4,909	$4,909	$8,146
Total Cost of Ownership	$36,950	$24,627	$32,793
TCO per mile	$3.08	$2.05	$2.73
Lifetime Savings	$4,157	($8,166)	

Leaving aside the MSRP, the costs of a traditional gasoline vehicle associated with the price of gasoline, MPG and maintenance cost have the most significant impact on customer economics. For the purposes of this analysis, BED assumed a price of $2.04 per gallon for fuel and 33 miles per gallon for most traditional passenger vehicles.[15] If the current price of unleaded gasoline were to double, the total benefit of owning an all- electric Nissan Leaf would increase to approximately $12,000 (with the BED incentives.) Assuming that the current price of gasoline remained static but the MPG of a conventional passenger vehicle improved from 33 MPG to 45 MPG, the total benefit of owning a Nissan Leaf would decrease to $5,500 (with BED incentives).

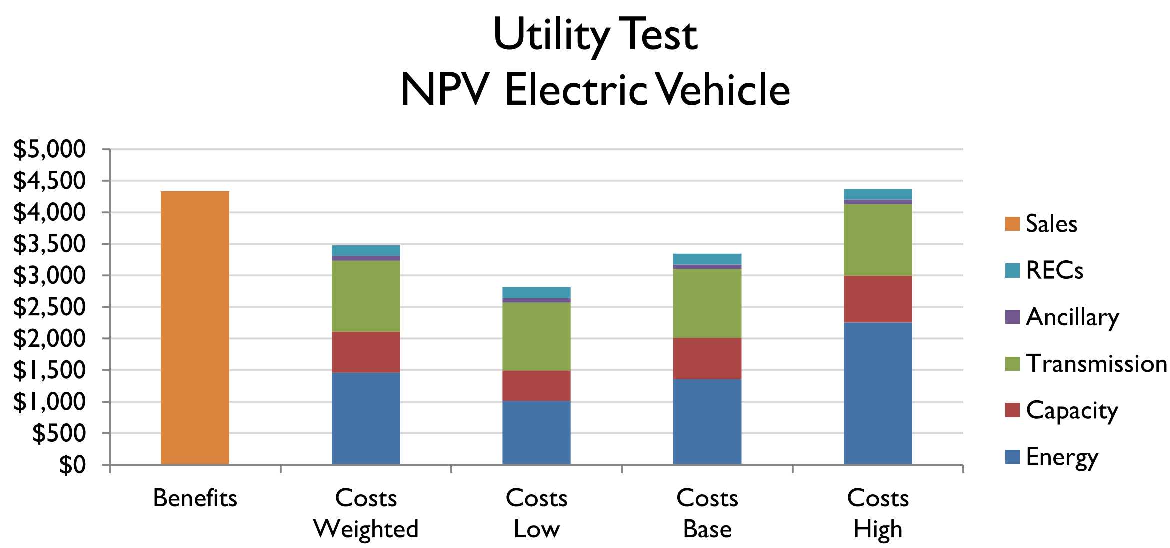
Utility economics

The net base case utility lifetime benefit per EV amounts to approximately $939 ($2016), assuming additional electricity sales of $4,246 and base case costs of $3,307 or less. For purposes of modeling, EV's are considered load builders. Thus, EVs will increase electric sales, which are shown as a utility benefit since the average cost to serve an EV is expected to be less than average wholesale costs. Such wholesale costs include additional services related to energy, transmission and capacity.[16] At this time, BED has not modeled any potential benefits associated with using EV batteries for peak load shifting. If such benefits were to be included, the utility benefit would be even greater. Also, additional new research from actual EV charging use in Austin, Texas indicates that charging times for EVs typically occurs later in the evening than current models indicate. Moreover, charging times and duration of charges appears to be more

[15] Fuel prices = ($2.00*0.9 unleaded)+($2.40*0.1diesel); MPG = (32*0.9)+(42*0.1 diesel engines)

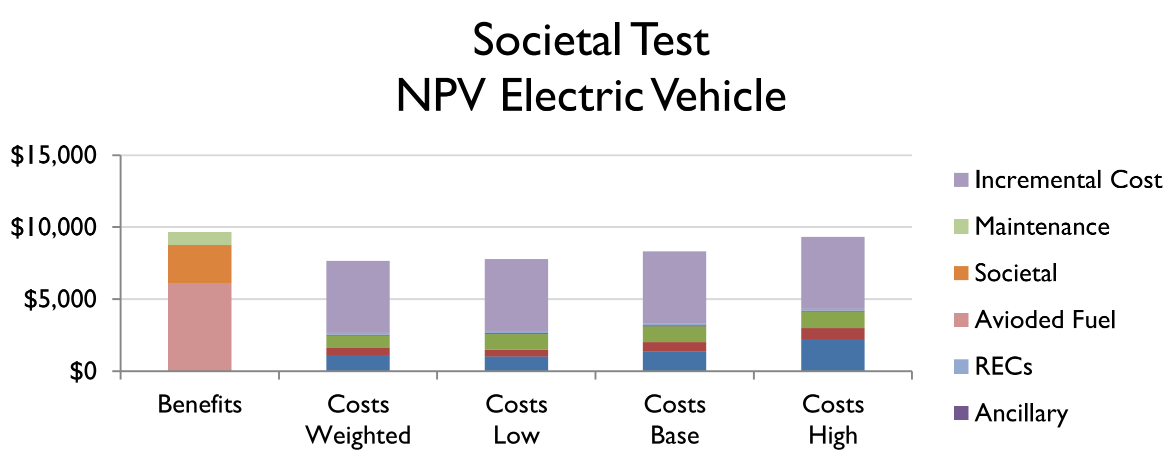
[16] This is the opposite situation compared to PVs (or load reducers) where the utility benefit includes avoided wholesale costs but the additional utility cost reflects the compensation payment to the PV host customer.

diverse than originally contemplated in BED's model. This suggests that the net utility benefits shown below are conservative.



Societal Cost test

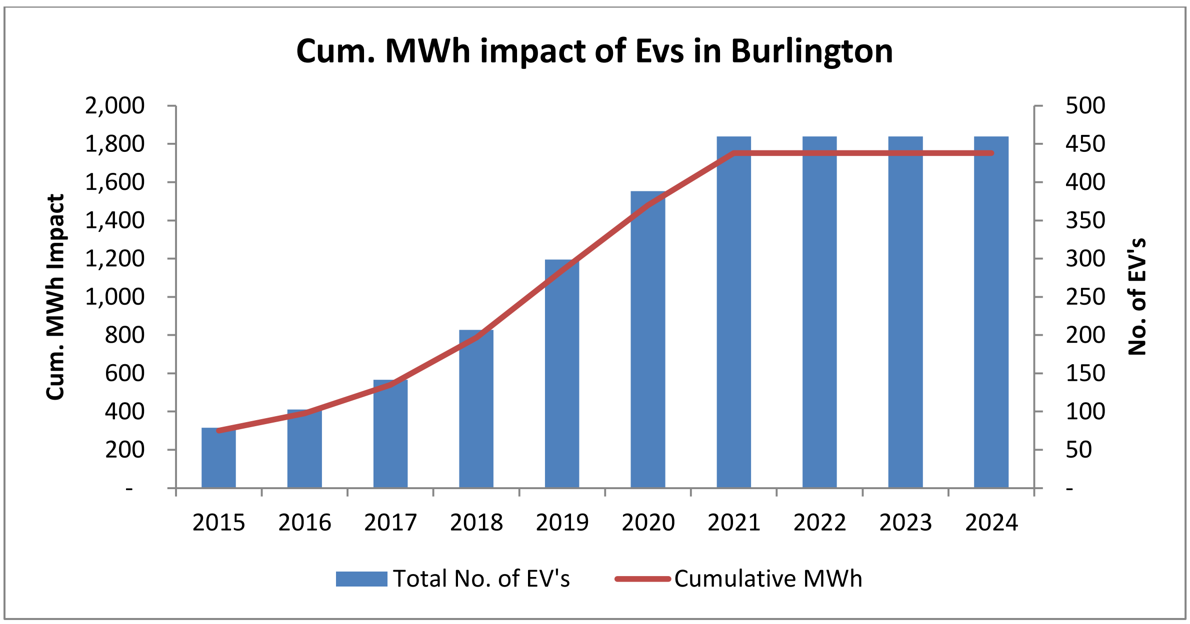
The net societal lifetime benefit of an EV is $1,336 (inclusive of the federal tax credit, but before BED incentives). Positive societal benefits are primarily a function of avoided fuel costs ($6,129), maintenance costs ($875) and avoided GHG emissions ($2,639). Positive societal benefits are partially offset by the higher incremental cost of an EV ($5,000), relative to the cost of traditional vehicles, and additional wholesale energy related costs ($3,307, noted above). As the MSRP of EV's declines further, BED anticipates that EVs will, in time, produce even more positive net societal benefits.



Tier III implications

EV's have the potential to be a significant contributor toward BED's efforts to achieve its Tier III goals. Statewide electric vehicle registrations are anticipated to increase 30 percent annually from 2016 through 2025, when annual sales are expected to reach 4,500 electric vehicles.[17] Thereafter, the rate of growth in EVs is expected to level off as the market matures.

Assuming that the growth rate of EV's in Burlington mirrors that of the State's, the number of EVs registered in Burlington is anticipated to increase from 79 to 460 in 2025. And while this rate of growth may appear extraordinary, BED does not anticipate that EVs will adversely affect resource adequacy. For every 10 new EVs charging at a BED station, energy loads are expected to increase 3.8 MW over the year. Should such forecasted EV sales materialize, energy loads are estimated to increase between 90 to 300 MWhs per year and add about 1600 MWhs to BED's total yearly load, shown below.



Recommended course of action

Given that EV technologies are expected to dramatically improve over the next several years and that consumer preferences about modes of transportation are changing, promoting electric vehicles and encouraging their adoption appears to be a cost effective, strategic electrification opportunity. Accordingly, BED recommends that it begin to design and implement an EV adoption program. To further EV adoption, BED also recommends that it

[17] 2015 CEP at 161.

begin to explore alternative rate designs to incentivize EV owners to charge vehicles during off-peak hours.

In multi-family buildings and condominiums, BED will also seek approval to allow for sub-metering. Sub-metering will help to address a significant barrier to EV owners who live in these types of buildings as EV charging equipment is unlikely to be connected to the customer's meter. Therefore, the only way for such EV owners to access charging equipment would be through a level 2 charger connected to a general purpose building house meter that is paid for by all residents, even non EV owners, or through a public charging station. Lastly, BED recommends implementing an "at -work" EV charging program such that employers could provide charging facilities to their employees as a means to reduce the company's carbon footprint.

Deployment pace estimate

As a consequence of the above-captioned factors and assuming that the MSRP of all –electric vehicles declines over time, BED estimates that, on average, between 30 and 40 new EV's will be registered in Burlington per year from 2017 through 2025. The total cost to implement an EV program will likely range between $80,000 and $100,000 annually, and add no more than 152 MWh per year, on average.

Passive House

Technology description

Passive House (or PassivHaus) is not a technology but rather a standard for new building construction and major renovations. Established in Germany during the 1980's, interest in the Passive House (PH) standard among U.S. based architects, developers, contractors and building owners has been steadily increasing since the mid-2000's. The intent of the PH standard is to dramatically improve building quality and occupancy comfort while also reducing total energy use intensity (i.e. BTU consumption per conditioned sq. foot). For BED, promoting Passive House construction is viewed as a means to address four imperatives of its 2016 strategic plan: carbon reduction, energy independence, economic development and greater building resiliency.

Building to the PH standard is voluntary. Nevertheless, earning a PH certificate is rigorous. It requires a paradigm shift in building design and construction techniques. The first step toward certification is to develop a building design that minimizes heating and cooling loads through so-called "passive" measures. Examples of such measures include but are not limited to orientating the building to take advantage of solar heat gain in the winter and shading during the summer, insulating the building well above current codes, using heat recovery technics to make optimal use of waste heat, eliminating thermal bridges, and ejecting incidental internal heat sources to the outside environment during the summer. Because the building is airtight, a continuous supply of filtered fresh air is supplied to living/working spaces and stale air is exhausted from services spaces; providing balanced and controlled ventilation with high-efficiency heat exchangers.

Any type of building can obtain a Passive House certification: single family homes, multi-family buildings, apartments, mixed-used buildings, office buildings, and even schools. Despite widespread and misleading descriptions, PH buildings still require heating systems in cold climate zones, like Vermont. Also, they are not necessarily net zero-energy buildings. However, because certified PH buildings consume 80-90 percent less energy per square foot than current code-compliant buildings, they allow contractors to "right-size" mechanical equipment to match the actual heating and cooling loads of buildings. Right sizing equipment reduces the upfront capital costs of boilers and air conditioners, as well as the annual operating costs of space conditioning buildings. And, in some cases, PH buildings can rely solely on alternative heating and cooling systems such as electric resistance baseboard, woodstoves or cold climate heat pumps. Passive Houses also employ day lighting strategies and task lighting techniques; both of which dramatically reduce the need for artificial lighting.

Building to the PH standard would have the effect of raising expectations about the quality and comfort of living and working spaces. In addition to using less energy, certified passive house buildings are known to be:

- Healthier than typical buildings as passive house standards rely on high-quality ventilation systems that pump fresh outside air that is free of mold and indoor air contaminants into the living space.
- More comfortable due to increased levels of insulation, elimination of thermal bridges and fewer air exchanges. As a result, the interior environment remains at a steady temperature level and there are no drafts.
- Affordable to own and maintain as higher initial construction costs for high performance building components are substantially offset by a reduction in system sizing and energy consumption.
- Resilient during inclement weather conditions as Passive house buildings are able to maintain habitable interior temperatures in freezing weather without power for longer periods of time than standard buildings; allowing people to shelter-in-place.

Constructing new PH buildings and/or upgrading existing buildings to the PH standard would also lead to greater levels of investment in the local economy. For example, if 5 percent of Burlington's 7,000+ residential buildings were upgraded, about 359 buildings, to the passive house standard over the next five years, energy expenditures in Burlington would be lowered by $425,000 in year 5 of the program. And, since Passive homes are resilient and have 50+ year lives, such reductions in energy expenditures would continue well into the future, possibly amounting to $9.4 million in savings ($2016) that could be recirculated back into the local economy. The cumulative cost of this investment to BED ratepayers would be approximate $7.0 million in the fifth year ($5.6M in incentive payments, $1.4M in general marketing, overhead, etc.), which would yield a benefit to cost ratio of 1.34 times. [18] [19]

Building Type	Building Counts
2 Family	1042
3 Family	364
4 Family	236
Apartments 5+Units	362
Single Family	5169
Total	**7173**

[18] For the purposes of this analysis, BED's estimates of net benefits assume that a PH program, if any, would terminate at the end of year five when building to the PH standard would become standard practice and incentives would no longer be necessary.
[19] Burlington Building inventory as of 2015, see https://data.burlingtonvt.gov/browse

Key assumptions

To estimate the benefits and costs associated with Passive House construction standards, BED modelled new construction, single family homes only.[20] BED's cost effectiveness model included the following basic assumptions:

Assumption		Code Compliant SF Home		Passive House
Total Building Energy Consumption (MMBTU/year)		90		18
Incremental cost to build	$	-		$16,200
Measure Life		50		50
NG cost per MMBTU	$	18.32	$	-
Electric cost per MMBTU	$	16.47	$	16.47
NG inflation rate		3.00%		
Electric inflation rate		2.00%		
Discount Rate		3.50%		

Building a new single family home to the PH standard is assumed to cost roughly 10 percent more ($16,200) than a code compliant house. Additional costs stem primarily from increased planning and design work, PH certification, more expensive materials (i.e. windows and doors, insulation) and higher contractor costs since PH homes are currently taking longer to build.[21] However, PH designs are known to be far more utilitarian than typical homes. Improved open floor concepts and better insulation around windows allow for greater use of the living space. Thus, PH homes are typically smaller than their counterparts but homeowners do not feel as if they're compromising on the size of their home.

Importantly, PH buildings consume far less primary energy per year than code compliant homes – 18 MMBTUs vs 90 MMBTU's (i.e. space conditioning, domestic hot water, lighting and

[20] Passive house Multi-family and large commercial new construction buildings and major renovations were omitted from this analysis as these projects typically require in-depth energy modeling to determine the costs and benefits of building to the standard.

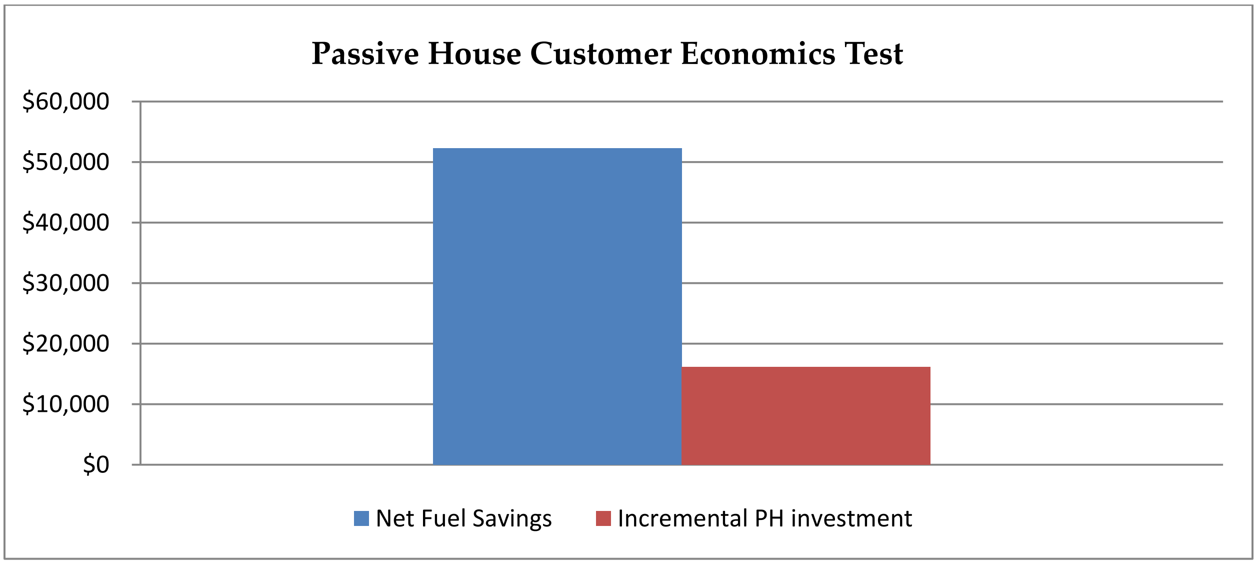
[21] Based on conversations with PH experts and consultants, some Chittenden county building professionals are developing greater confidence and expertise in PH standards and, consequently, have begun to build PH standard homes at cost parity with code compliant homes.

plug loads).[22] Such energy savings (approximately 80 percent) reduce a household's energy bill by $1200 annually.

Modeling results

Customer economics

With annual fuel savings of approximately $1200, a building owner could expect to earn an internal rate of return of 10.1 percent on their incremental investment ($16,200) in a certified PH home; or approximately $35,000 ($2016) over a 50 year life.[23] An owner could also expect a simple payback on their incremental investment of 13.7 years. As shown in the graph below, accumulated fuel savings amount to $52,500 ($2016).



Despite the robust customer economics associated with passive house ownership, there have not been many built in Vermont and none in Burlington that BED is aware of. The primary barriers to Passive House adoption is the lack of training in the design build industry and homeowner awareness.

As noted above, BED's model only considered the estimated fuel savings to determine the customer economics of Passive House ownership. These savings were, in part, derived from applying a higher annual rate of inflation to the cost of natural gas (3.0%) than electric costs (2.0%). Over time, the difference in the rates of inflation results is more than $2,500 in annual fuel savings; the model also assumes that PH homes rely more on electric heat (either electric resistance or ccHPs) as a primary heat source so that natural gas consumption in all but eliminated.

[22] See Dockets 8550 and 8311 before the VT Public Service Board.

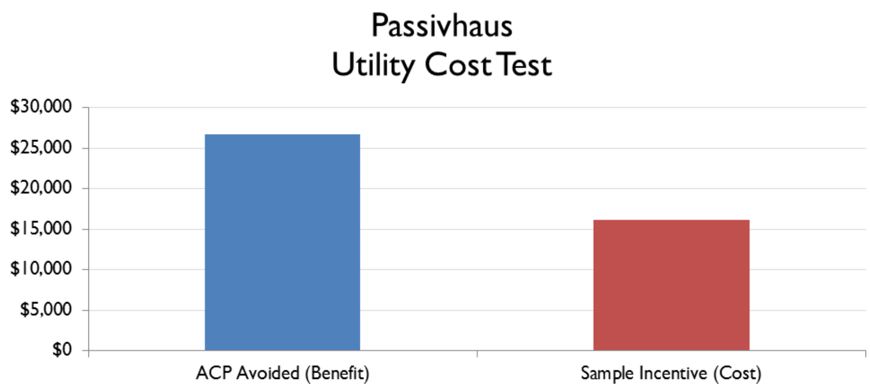
[23] This internal rate of return does not consider maintenance related savings or home value appreciation.

It is important to note that the customer economics model does not take into account non-energy benefits such as lower house maintenance costs, increased comfort or improved health. While there is a growing body of literature documenting these non-energy benefits, BED is uncertain about how to assign a monetary value to these benefits for the purposes of this analysis. BED does however assume that the value of non-energy benefits is not zero and a method for monetizing such benefits may be accepted at some point in the near future. At that time, BED will re-visit its analyses of PH.

Utility economics

Promoting and supporting a PH program that result in the actual passive house buildings being constructed in the City would result in substantial net positive benefits for BED. The primary benefit flows from the avoidance of an alternative compliance payment that would be incurred in the absence of a program. As noted elsewhere in this IRP, all distribution utilities are expected to displace a pre-determined amount of fossil fuel consumption in their service territory by encouraging the deployment of cost effective strategic electrification initiatives. Failure to make such investments could result in penalties or alternative compliance payments (ACP). For this analysis, the ACP was set at $534 annually for one PH home. Multiplying the ACP by the measure life of a home (i.e. 50 years) results in a potential ACP of $26,700. By supporting a PH program, BED would avoid having to make such a payment in the first year of a PH program. As a consequence, BED treats this avoided payment as a benefit similar to an energy cost that would be avoided due to energy efficiency (although Passive house programs will still need to "compete" for these funds against other means of meeting BED's Tier III needs).

On the other hand, costs associated with the promotion of a PH program are primarily related to incentive payments and other program costs (i.e. marketing, contractor training, administration and other overhead). As shown in the graph below, BED assumes that because the ACP would be higher than the incremental cost of building a PH ($16,200) that incentives would equal 100 percent of the additional cost of building a home to the PH standard.

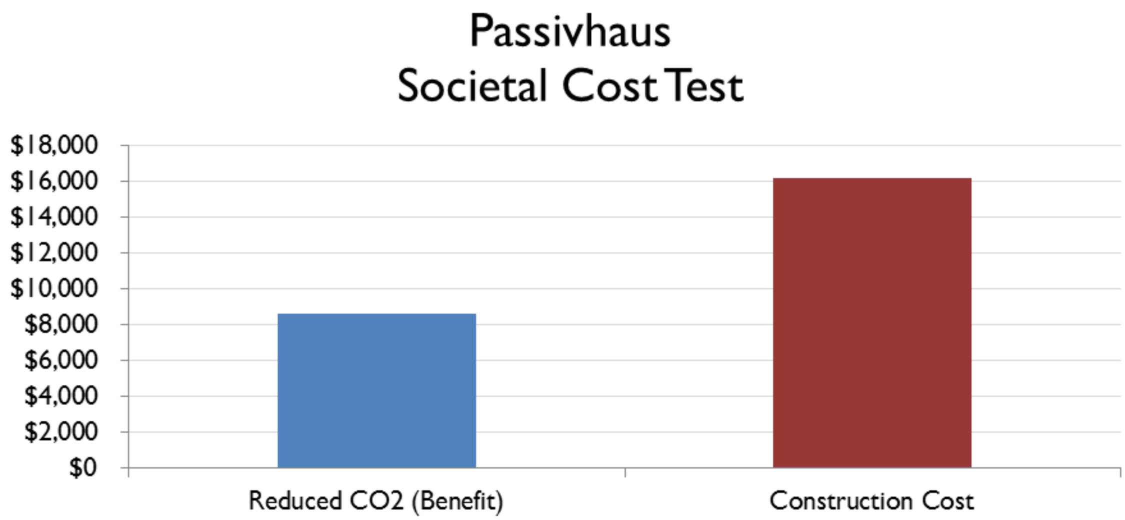


Furthermore, BED does not anticipate that electric sales would be materially affected in either direction by promoting a PH program, even though PH Homes would rely on electrically-sourced heating and cooling. This is mainly due to the fact that there will be relatively few Passive Homes or businesses built in the service territory and those that are built would rely on advanced technologies such as ccHP that do not use a lot of electric energy. Some reduction in lighting use should also be available to help offset and incremental space conditioning loads. Moreover, the energy use intensity of PH buildings is so much lower than code complaint buildings that the overall impact of increased electrification will, in all likelihood, be *de minimus*.

Societal Cost test

From a societal perspective, building to the PH standard is not currently cost effective under current assumptions. As highlighted in the graph below, the benefits of a PH program accrue to society in the form of avoided costs related to carbon and other GHG emissions that would have occurred absent a PH program. Thus, the total societal benefit reflects an 80 percent decline in energy consumption relative to code compliant homes. Because most homes and businesses in Burlington use natural gas for space heating, which is a much cleaner fuel than #2 heating oil, annual emissions-related cost savings amount to only $400 per home. For purposes of this analysis, carbon costs were set at $95/ton. Societal benefits, however, are more than offset since the incremental cost of building to the PH standard exceeds the monetized benefits of lower emissions.

It is important to note again that BED's model did not attempt to incorporate non-energy benefits in its analysis. Also, the societal cost test does not consider the "knock-on" effects, or indirect benefits, of lower energy expenditures. As noted above, funds that would have been exported out of the region in the form of natural gas expenditure are instead reinvested in the community.



Tier III implications

BED does not anticipate that a Passive House single family new construction program will contribute significantly to BED's Tier 3 goal over the next 3 – 5 years. This is largely due to the fact that relatively few single family homes are built in the city annually. Also, there are relatively few building trade professionals in Vermont that are trained to construct buildings to the PH standard. Accordingly, BED is not planning to claim Tier 3 savings for at least 3 years. Further, even if a few buildings were to be built to the standard, the impact on BED's resources would be *de minimus*, as noted above, since certified homes consumer very little electricity.

Recommended course of action

BED anticipates that statewide market transformation efforts (i.e. increased training and building professional educational outreach) will help to drive the cost of PH buildings down in a matter of 5 – 10 years so that PH homes will become the standard design for all newly constructed homes. Accordingly, BED intends to continue sponsoring PH training programs for the next several years as a means to increase the level of expertise in this field.

Deployment pace estimate

BED will continue to sponsor one to two training sessions in the City per year through 2019. Based on the results of these training sessions and other market information, BED will consider launching a full PH program and incentivize the construction of single family residences. In the meantime, BED would also evaluate projects on a customer basis which are brought to our attention by local contractors.

Behind-the-meter Photovoltaics

Technology description

Photovoltaics (PV) cells convert sunlight into direct current (DC) electricity through electro-chemical and physical processes using semiconducting materials. DC electricity is then converted into alternating current (or AC) electric power for use in homes and businesses. To generate electricity, PV cells are inserted into modules which are then combined into arrays. Modules can typically generate up to 315 watts each, but when combined into arrays, PV systems can produce enough energy for a typical single family home or even provide utility–scale generation (e.g. 2+ MWs).

Advantages of PV generated electricity include:

- Reduced carbon and other GHG emissions;
- Low operating costs – once installed, PV systems require very little maintenance and no additional energy to operate. Although, panels need to be cleaned periodically;
- Reliability and resiliency – distributed solar generation located close to energy load has the potential to be a component of a future micro-grid at that location;
- Modularity – PV systems can be expanded in size after the initial installation, assuming adequate space and insolation;
- Energy independence – locally generated electricity decreases Vermont's dependence of imported electric energy;
- Lower transmission and capacity costs – when installed near energy loads, PV systems can reduce the costs of capacity and transmission; and,
- Price and rate stability – unlike fossil fuel energy, the price of solar energy is not subject to abrupt changes; and,
- Lower risk profile and diversity.

Disadvantages of PV generated electricity include:

- Intermittency - PV systems are unable to generate electricity when there is significant cloud coverage or at night;
- Siting – PV systems need a significant amount of space per MWh generated; and, if built on a structure, require an engineering assessment of the structural integrity of the host building.
- Installation cost relative to traditional generation per MWh.

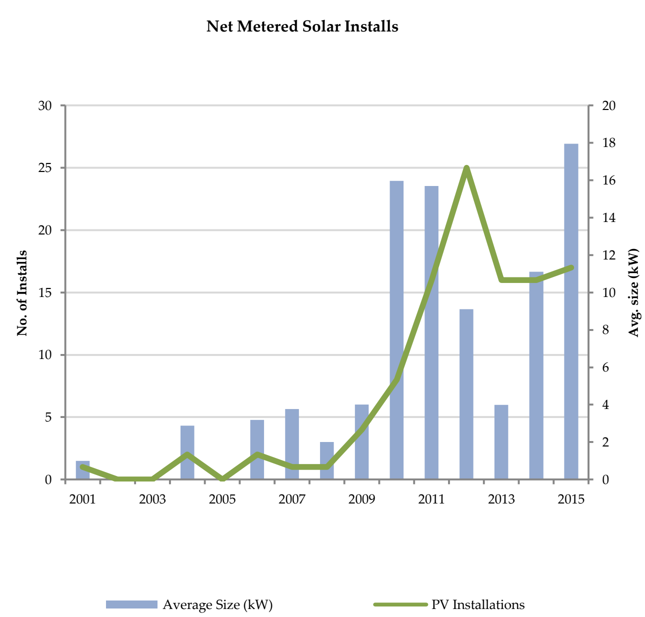
As of June 30, 2016, 100 "behind-the-customer meter" PV systems were installed and operating in the City, including a 107 kW system located at BED's 585 Pine St. headquarters building. Along with these behind the meter systems, there are currently 8 group net metering systems that account for 406 kW. These groups distribute the energy generated to their participating members, which is used to offset electricity consumption. The total capacity of these systems amounts to approximately 1,259 kW.

Solar NM Systems	Count	kW Capacity
Net Metering	100	853
Group Net Metering	8	406
Total	**108**	**1259**

In addition to the above-noted systems, 9 "behind-the- utility meter" PV systems are operational: one is a SPEED resource while eight systems generate electricity under long-term purchase power agreements with BED. The total capacity of these systems amounts to 937 kW. "Behind-the-utility" metered systems are not ISO-NE recognized and therefore serve as load reducers in the same way as the above-noted net metered systems do. As load reducers, behind-the-utility systems help BED avoid regional costs associated with energy, capacity and transmission as well as creating RECs. For the purposes of this analysis, behind-the-utility meter and behind-the-customer meter systems have been assessed together since they generate similar benefits and costs.

Net metered PV systems

Installed properly, net metered systems result in positive net economic benefits to the customer, BED and society at-large under current Vermont Public Service Board rules. (i.e. solar rider tariff). For the customer, the benefits primarily flow from lower electric bills. For BED, net benefits are a result of lower energy, transmission and capacity costs. Societal benefits are derived from a variety of sources but primarily stem from lower carbon and other GHG emissions from regional power plants.



Although net metering legislation took effect in 1998, the pace of solar installations in Burlington has only recently started to accelerate. In addition, the average size of the systems installed has increased substantially and are now generating approximately 1500 MWhs annually. As noted above, the cumulative installed capacity of PV systems installed in Burlington has reached approximately 2,200 kW, about 3.3 percent of total peak demand.

The increase in PV size and the faster pace of installations are primarily a result of two main factors affecting the industry in Vermont and nationally: the cost of installation has been decreasing and system efficiency or capacity factors have been improving.

Across the State, the installed cost of residential scale PV systems – between 2 kW and 15 kW – has decreased approximately 64 percent; from approximately $10 per watt in 2006 to $3.55 per watt in 2015.[24] Cost decreases can be attributed mostly to international competition for market share which lead to dramatic decreases in panel prices, increases in the number of local PV installers, and improved capacity factors. International competition for market share has had a dramatic impact on costs, as the PV panel arrays cost roughly one-third of the total installed cost. The number of PV installers has also increased 22 percent since 2013 to about 1,889 today.[25] The increase has created additional demand and helped to reduce installation costs as more installers compete for new business. And, as PV manufacturers have increased production, they have also increased the efficiency of PV cells, as measured by their capacity factor. PV Capacity factors have improved from approximately 10 percent to 14.5 percent over the last several years.

Key assumptions

To evaluate the potential impacts of photovoltaics on resource adequacy, BED made a number of assumptions with respect to the benefits and costs of PV. Assumptions concerning benefits included the following:

Assumptions	Input	From the perspective of:
Regulatory Policies	Proposed net metering rules take effect Jan. 1, 2017. Includes siting adjustors for eligible systems and 3 cent RECs	Customer
Low cost, innovative financing	On-bill financing, PACE or competitive purchase power agreements readily available	Customer
PV efficiency/capacity factor	14.5 %	Customer

[24] 2015 CEP at 284-288; Vermont Solar Cost Study, prepared for CESA and DPS Clean Energy Fund by L. W. Sheddon, LLC., February, 2016.
[25] Vermont Clean Energy Industry Report, August, 2015 at 11, prepared by BW Research Partnership for the Vermont Public Service Department.

Federal Income tax credit	30%, until 2021	Customer
Transmission and capacity	Assumed reliable performance at coincident peak	Utility
Circuit Congestion	Distributed resources help to avoid local distribution upgrades or do not create the need to upgrade circuits in near term	Utility

Assumptions relative to costs included:

Assumptions	Input	Perspective
Permitting and interconnection	Included with installed costs but assume processes will be streamlined.	Customer
Transferred REC's	$0.03/kWh	Utility, BED retires all REC's and applies toward Tier II goals.
Regulatory Policies	Proposed net metering rules take effect Jan. 1, 2017 (see above)	Utility
Carbon	$95/ton	Society and utility; assumes ISO NE generation mix, not BEDs generation and power portfolio

Modeling results

Customer economics

Customer economics depend on net metering policies that require utilities to "purchase" the output of systems at administratively set prices (currently, 19-20 cents per kWh). The economics are also highly dependent on current state and federal tax credits remaining in effect, as well as favorable financing and leasing terms. However, the Public Service Board has recently introduced changes to Vermont's net metering rule that could affect the compensation paid by utilities to PV host customers.

Under the proposed revisions, utilities with inclining block rates would pay for net metered generation at a blended residential rate, plus an applicable siting adjustor for eligible PV systems (denoted below as desirable siting locations). In addition, PV customers (or their vendor) may elect to transfer the associated RECs to the host utility or retain them for resale. If RECs are transferred to the utility, the compensation rate paid for electric generation would include an additional $0.03/kWh. If the customer (or vendor) retains the RECs, then the compensation rate from the host utility is reduced by $0.03/kWh. At this time, however, it is unclear whether solar vendors will pass along the value of RECs to the customer in the form of lower lease rates or retain them for resale and keep the profits. The table below summarizes the current and proposed compensation for solar net metered systems.

Proposed and Current Net Metering Credits

BED Blended Residential Rate (FY2015) $0.1367

PV Type	Size	Siting	Credit - No RECs	Credit w RECs to Utility	Current	Comment
Category I	Up to 15	Any	$0.1167	$0.1767	$0.2000	
Category II	15+ to 150	Desirable	$0.1167	$0.1767	$0.1900	
Category III	150+ to 500	Desirable	$0.0967	$0.1567	$0.1900	Mostly GNM
Category IV	15+ to 150	Any	$0.0767	$0.1467	$0.1900	

For the purposes of this analysis, BED estimated the customer economics of PV under three scenarios: a.) based on current BED terms and conditions for small-scale residential systems, b.) the proposed net metering rules when RECs are retained by the PV customer or vendor; and, c.) the proposed net metering rules when REC's are transferred to BED.

Under current terms, net metered PV customers taking service under the solar rider receive a $0.20/kWh credit for every kWh produced. If the customer leased their PV array at $0.145 from a solar vendor[26], their discounted net savings over a 20 year period would amount to approximately $4,966. Under scenario b., the customer's net savings would be negative $2,919, assuming the customer's vendor does not pass along the value of the REC's in the form of lower system lease rates. Under this scenario, BED's credit per kWh would be set at $0.117/kWh ($0.1367 blended residential rate, plus $0.01 for Category I systems, minus a negative $0.03 REC adjustment since solar contractors typical retain the RECs for sale. Finally, when REC's are transferred to BED, the customer's net savings would amount to $2,454 over the twenty year period.

[26] Leased payment terms are based on a current PPA from a solar vendor operating in Burlington.

Residential	Current BED NM terms	Proposed NM rules (No RECs)	Proposed NM rules (w/ RECs)
Assumed wattage(kW-DC)	6.0		
Assumed wattage (kW-AC)	5.4		
Capacity factor	0.14		
Ann. Production (kWh)	6,623	6,623	6,623
Lease rate/kWh	$0.145	$0.145	$0.145
Net Metered Rate/kWH(yrs 0-10)	$0.200	$0.117	$0.177
Net Metered Rate/kWH(yrs 11-20)	$0.200	$0.107	$0.167
Annual Bill reduction	$ 364	$ (187)	$ 210
Meas Life	20		
Degradation factor	0.5%		
Customer lifetime benefit (NPV)	$4,966	($2,919)	$2,454
Disc Rate	3.5%		

The above-noted customer benefits reflect the net present value of the annual bill savings derived from the difference between the net metered credit that BED pays for the host customer's generation, and the kWh lease rate that the customer pays to their solar vendor. This scenario assumes that all credits are used within a 12 month period, kWh production degrades by .5% annually, and any positive siting adjustor is eliminated after 10 years of operation.

At this time, it is unclear whether reductions in installation costs would be fully reflected in the contract price that customers pay their solar vendor ($0.145/kWh) for net metering systems installed in Vermont. With current net metering rates administratively set at 19 - 20 cents per kWh, PV installers have arguably been motivated to keep systems prices high, even though their costs have decreased substantially in recent years. Under the proposed rules, however, installers could face increasing pressure to change their pricing in order to stay competitive, especially if they retain the RECs. For now, BED has assumed that they will not.

Group Net Metering

Current and proposed rules allow for multiple customers located within the same utility service territory to participate in PV programs. However, because group net metering systems tend to be larger in size, and thus need a larger footprint than traditional net metered PV systems, BED believes that the construction of new, large scale group net metered systems in the city will decrease substantially, especially since the new proposed rules have disincentivized an entire category of PV systems – all systems between 150 kW and 500 kW.

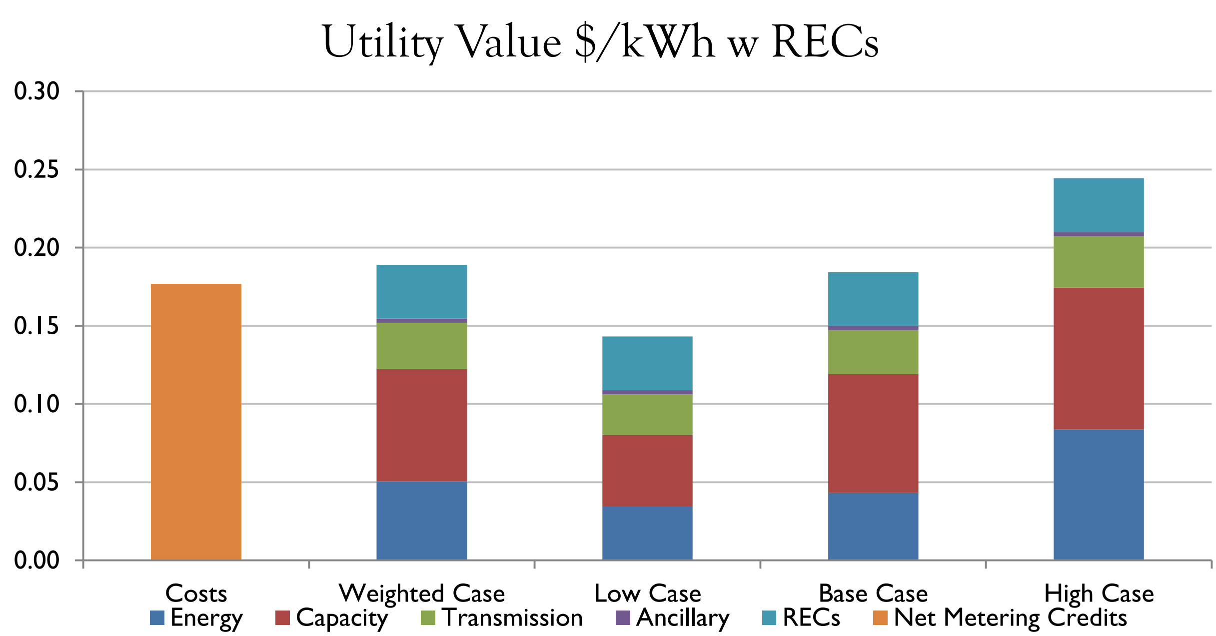
A reduction in the viability of group net metering, however, is not viewed as problematic by BED as:

1. Group net metering must be located in the same utility and BED has few "green fields" remaining for development.
2. Group net metered systems represent a non-traditional PV deployment and would therefore present additional challenges with regard to value stream. In particular, ISO-NE transmission savings may not continue to be allowed for such arrays as they are correctly interpreted by ISO-NE as being purchased power arrangements since they do not reduce the load at a retail meter.

For newly built systems that are able to qualify for siting adjustors, the customer economics are similar in most respects as shown above.

Utility economics

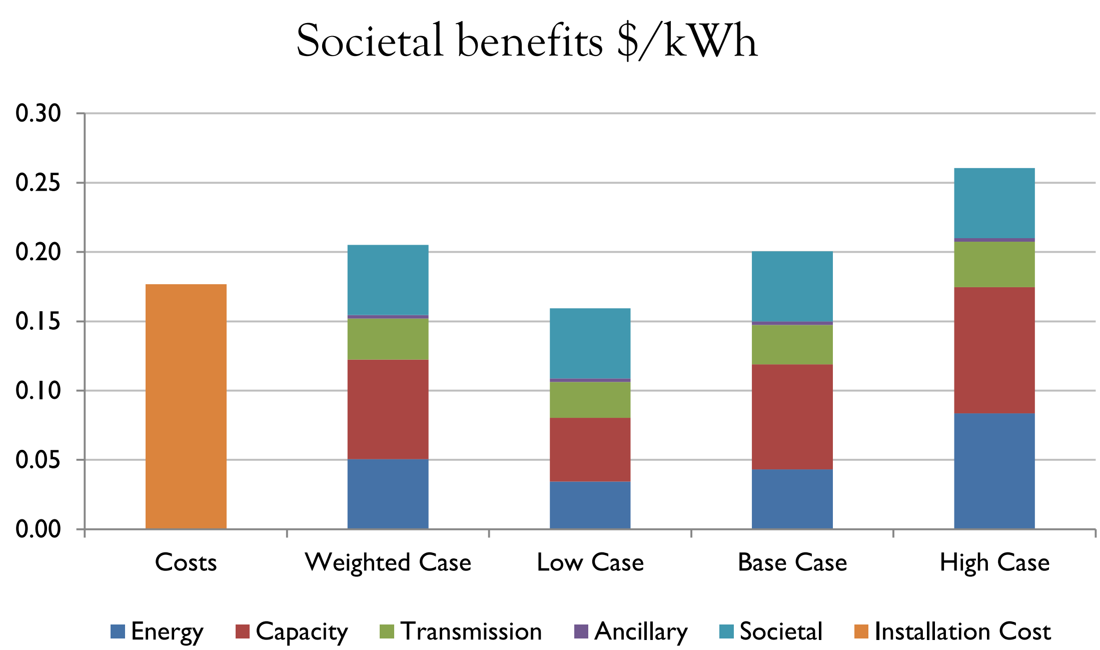
Under the base case scenario, the forecasted total net utility benefit amounts to $0.007 per kWh generated. The net benefit assumes roughly $0.184/kWh in avoided costs (reduced expenses) will be offset by $0.177/kWh in net metering compensation paid to the host customer and BED retires the RECs associated with the generation.



Of the net utility benefits generated from PV systems, avoided capacity, energy and transmission cost savings amount to approximately $0.147 per kWh. These benefits reflect BED's current understanding of the operating characteristics of PV systems. Such characteristics assume that PV systems will operate uniformly across the service area and that PV generation will occur during coincident peak periods when energy, capacity and transmission costs tend to be highest. Generally, solar systems remain to be a slightly net positive resource for BED. If the compensation rate paid to host customers is reduced, then such systems will be all the more cost effective in the future.

Societal Cost test

The societal cost test includes additional benefits related to the reduction in carbon emissions.[27] To capture these benefits, BED assigned a benefit of $95/per ton of carbon for every solar MWh generated. The total value of the carbon offset benefit reflects the ISO-NE generation mix, and equals approximately $.05/kWh. As shown in the graph below, the carbon offset is added to the utility cost test results. The societal test indicates that promoting local PV development on preferred sites is a cost effective pursuant to 30 V.S.A §218c.



Tier III implications

30 V.S.A. §8005(a)(4) states that if the Board has appointed a utility as an energy efficiency provider under subsection 209d, that distribution utility may satisfy its distributed renewable generation requirement (Tier II) by accepting net metering systems so long as the REC's associated with such systems are retired. The Board has appointed BED as an energy efficiency utility. Accordingly, BED intends to pursue this option.

[27] Under the societal cost test, REC values are eliminated as they represent a transfer payment.

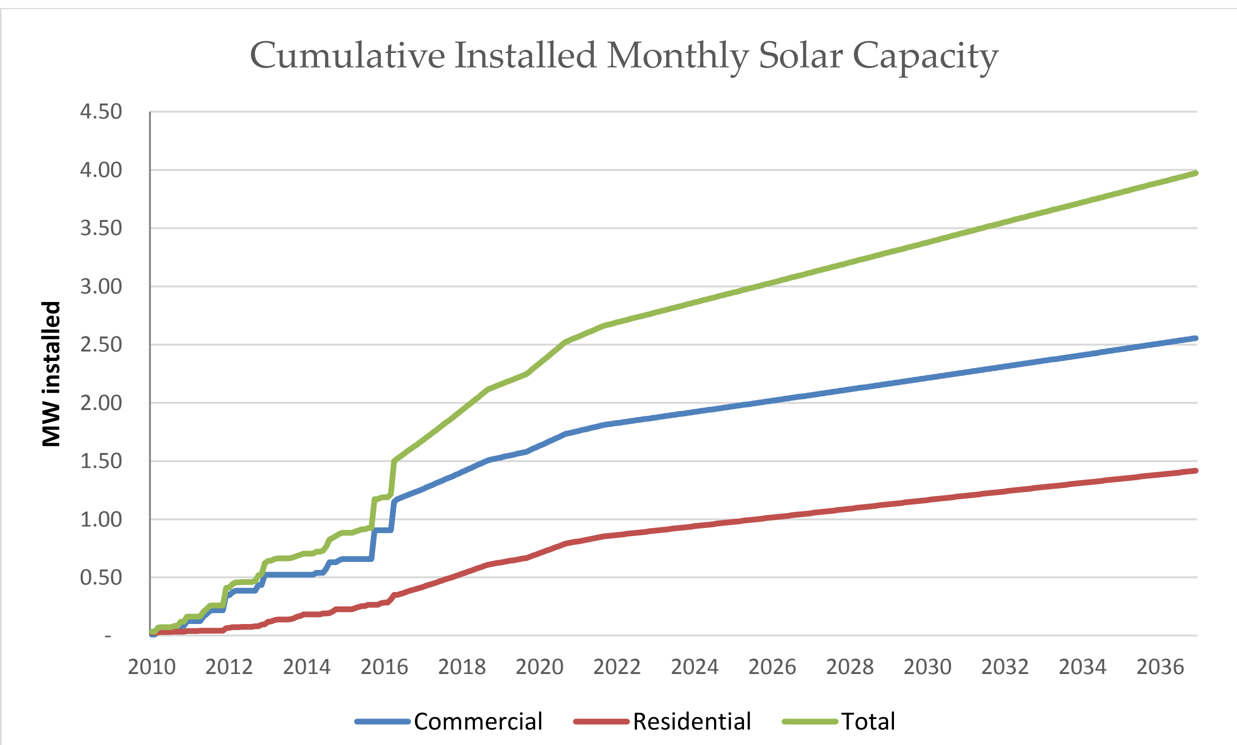
As noted, BED currently has approximately 3.3 MWs of installed net metered PV capacity operating within its system. It is anticipated that total net metered capacity will increase to approximately 4.0 MWs by 2036, and that all of the production from these new systems will count toward BED's Tier II requirements. At this point, BED does not anticipate additional owned PV systems will be built and only a few, if any, new in-city purchase power arrangements will be consummated.

Recommended course of action

Assuming the current proposed net metering rules (June 30, 2016) are enacted, as proposed, BED recommends extending the policy of accepting new eligible net metering and group net metering applications for interconnection and banking the excess generation from such systems for the purpose of satisfying BED's Tier III obligation.

Deployment pace estimate

Based on current trends (i.e. cost declines, tax credits and other incentives), BED anticipates that the number of net metered customers (residential and commercial) will increase from over 100 today to more than 400 in 2036. Assuming the average residential system size is 4 kW and the average commercial system is 36 kW, BED also anticipates that total annual incremental kW installed will roughly track the following trajectory:



Storage – Behind the customer meter

Technology description

Behind-the-customer-meter energy storage encompasses several types of technologies; examples include small scale generators ("gen-sets), thermal storage and batteries. At the most basic level, storage technologies either use stored fuel (i.e. diesel) to generate electricity from an engine or they consume low-cost, grid-supplied electricity during off-peak times to create and store chemical energy until needed. At the time of need, the stored energy is converted back into electricity and exported to the customer's internal electric distribution network.

Generation sets are 5-7 kW diesel or gas fired engines that can be plugged into a cross-wired circuit panel to provide back-up power until grid supplied power is restored.

Thermal – ice storage uses off-peak electric power to create ice to store during night-time hours. During the day, the ice is used to pre-cool conditioned air for circulation in large office buildings when cooling demand is highest. For additional information, see link.

Batteries – Lithium ion batteries are rechargeable mediums that rely on electro-chemical reactions to move ions between negatively charged electrodes and positively charged electrodes to discharge electricity when needed.

Unless a customer has a specific requirement, installing most types of energy storage technologies behind the customer meter is uneconomic at this time. Specific requirements typically include but are not limited to: emergency power back-up and redundancy, improved power quality and demand response. Some of the types of organizations that typically operate under these requirements are hospitals, emergency shelters, public safety buildings, telecommunication facilities, airports, and large corporations and/or office buildings located in areas where power capacity is highly constrained and expensive during peak demand periods. For these types of organizations, power outages of any duration are considered to be too risky to public safety or extremely expensive in terms of lost production. Consequently, the additional cost of storage is viewed as justifiable even though the benefit derived from back-up energy storage is difficult to calculate.

BED is aware of 113 energy storage facilities located behind the customer's meter. Nearly all of them are small to mid-scale facilities ranging from 25 kW to 1400 kW in size. These storage units are used primarily for emergency back-up power. Most of the units are diesel or natural gas fired combustion engines. BED suspects that residential and small commercial customers have also installed smaller 5-7 kW gen-sets for emergency use as well. However, BED is unable to determine how many of these exist in its service area. Regardless of the size and number of facilities, emergency generators have not had a material impact on BED's resource adequacy and, consequently, have not been evaluated in previous IRPs.

A recently introduced technology, however, warrants a closer inspection of energy storage technologies. Although battery storage technologies have been in existence for some time now, Tesla's launch of the Powerwall product has captured the attention of many industry experts, customers and utility managers. [28]

The Powerwall product is designed for residential and small business applications. For most single family homes, the Powerwall costs approximately $8,000 to install. Although the cost of a Powerwall is currently beyond the reach of most customers, prices are anticipated to decline as national demand increases. For this reason, BED has included behind-the-customer meter battery storage in this integrated resource plan.

The Powerwall is a 7 kWh, rechargeable lithium-ion battery capable of storing up to 6.5 kWh of electric energy, or about 6 - 9 hours of use depending on the internal loads connected to the device. The device weighs approximately 200 lbs and can be mounted on the wall in the basement of home or business.

Expected uses of the Powerwall include:

- Back-up power – when grid-supplied power is discontinued due to a storm-related event, for example, stored electricity is automatically made available for home appliances.
- Load shifting – to reduce electric bills, customers may opt to store electricity in the Powerwall at night when costs are low and use it later in the day when the retail cost of grid-supplied energy is highest.
- Peak reduction – the Powerwall can be called into action to provide stored electricity to internal loads at times when system-wide demands are at or near their peaks.

In addition to its use by the customer, the Powerwall or other similar small-scale battery pack can be utilized by a distribution utility to reduce transmission costs and system capacity charges, assuming that a significant amount of storage capability has been installed and they

[28] For the purposes of this analysis, BED evaluated the Powerwall product as a proxy for all types of small scale battery technologies. As such BED is not endorsing the Powerwall product.

can be controlled from remote locations at times when the regional grid is at or near peak demand.

Key assumptions

For the purposes of this analysis, BED assumed that the price of small-scale batteries would remain high in the near term but that installed costs would begin to decline between 5 and 10 percent annually over a 10 year period before levelling off. The analysis also assumes that dynamic pricing would be implemented in the near future, allowing for arbitrage opportunities (e.g.; to recharge batteries during inexpensive energy periods and discharge during peak demand periods). The price differential between expensive and inexpensive energy was set at 11 cents per kWh, which is currently reflected in BED's residential time-of-use tariff rate schedule. From the utility perspective, BED considered the following value streams associated with battery storage: wholesale avoided energy and capacity costs, transmission charges and lost revenues. At this time, benefits associated with regulation and other ancillary services were not included. The analysis also assumes that PV array penetration in the City will remain fairly low due to the nature of Burlington's buildings, low-cost utility energy and limited insolation. As a consequence, pairing battery storage with PVs as a means to improve customer economics is unlikely and has not been analyzed in this IRP.

Modeling results

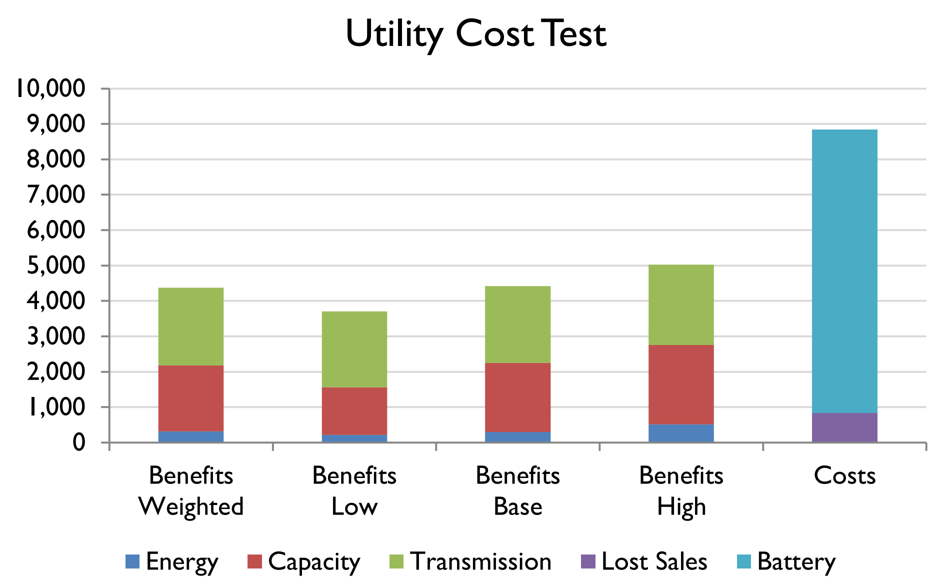
Customer economics

Today, the economics of battery storage behind the customer meter is extremely poor. Assuming that customers take service under the current time-of-use tariff, where the differential between peak rates and off peak rates is $0.11/kWh, they would save approximately $300 annually by installing a Powerwall if they consumed at least 500 kWh per month. Such customers would achieve a simple payback of 26 years on their $8,000 investment (before incentives). The payback however exceeds the 10 year lifetime warranty.

Assuming dynamic rates were in place that allowed for a demand reduction payment, as well as energy arbitrage opportunities, a customer's payback on their investment is shortened considerably. However, for residential customers the paybacks are still longer than the expected life of the battery. For commercial customers that have a more pronounced customer energy demand curve; meaning, energy consumption spikes considerably above average normal consumption then battery storage could provide marginal additional customer benefits in the form of rate arbitrage savings.

Utility economics

From the utility perspective, BTM storage would result in net losses of approximately $4400 per battery installed over 10 years, even if BED has direct and uninterrupted control of the device – which is, at best, a hypothetical proposition at this time. Net losses result primarily from the cost of the installing the battery and DC/AC inverter, approximately $8000, and the loss of retail sales of about $840. With respect to retail electric losses, BED would be in a position where sales at higher time-of-use retail rates would be demonstrably less than the electric sales at lower retail rates. As a consequence, electric revenues would decline even after accounting for a 92 percent conversion factor for the battery.



Societal Cost test

Because BTM storage does not displace fossil fuel consumption, there are no additional societal benefits to consider for this analysis. Therefore the only change under the societal cost test compared to the utility cost test, above, would be the elimination of lost sales amounting to about $840 over the lifetime of the battery. Lost sales are eliminated under the societal test because such lost sales are considered to be a transfer payment between customer classes. Consequently, society at large is held harmless.

Tier III implications

Battery storage does not displace energy usage, per se, but postpones the consumption of energy to a different time period than when it was generated. Thus, society does not benefit from avoided fossil fuel consumption except if it can be demonstrated that nighttime charging relies on non-fossil fuel resources and that the displaced daytime generation is fossil fueled. Accordingly, battery storage is not expected to be a cost-effective tier III measure, especially for BED since its power is predominately sourced from renewable generation facilities.

Accordingly, BED does not anticipate that energy storage facilities will have a role in BED's efforts to comply with the State's Tier 3 obligations.

Recommended course of action

Although energy storage may not affect BED's Tier 3 initiatives, BED does intend to initiate a limited pilot program of Tesla batteries to evaluate their performance and controllability. The pilot would include no more than 10 battery systems over the next two – five years. BED also recommends monitoring the cost of energy storage technologies. If the price of batteries declines sufficiently, then BED can re-evaluate their cost effectiveness using its mini-model tools and decision trees analytic framework.

In addition, the initiating a residential pilot program, BED is also in the process of developing specifications for two micro-grid applications. Each will include large scale battery storage capabilities ranging from 100 kW to potentially 1 MW in size. The two sites currently under consideration are 585 and 645 Pine Street (BED and Burlington Public Works Department) and the Airport. For more information, see the generation chapter.

Deployment pace estimate

Beyond the pilot participants, this IRP does not recommend deploying batteries over the near term.