VERMONT

State of Vermont
Department of Public Service
112 State Street
Montpelier, VT 05620-2601
http://publicservice.vermont.gov

[phone] 802-828-2811
[fax] 802-828-2342
[tdd] 800-734-8390

January 31, 2019

Vermont General Assembly
115 State Street
Montpelier, VT 05633-5301

Re: Demand Charges Report

Dear Senators and Representatives:

The Department of Public Service is pleased to present its report on Demand Charges. If you have any questions or concerns upon reading this report, please do not hesitate to contact me.

Very truly yours,

June E. Tierney
Commissioner

Demand Charges

Analysis and Recommendations

Pursuant to Act 194, Section 9

Prepared by:

Vermont Public Service Department

January 31, 2019

Contents

I. Introduction

Through Act 194,[1] the Vermont General Assembly asked the Department to investigate and make recommendations for possible changes to a rate design element associated with demand charges. Specifically, the Vermont legislature requested information on the following:

> …an analysis of the alternatives to these tariffs that will improve the ability of industrial enterprises to locate in rural towns of the State, including the use of energy efficiency, self-generation, and other measures to reduce the demand of such enterprises on the interconnecting electric utility;
>
> … the Commissioner's recommendations on changes to demand charge tariffs and other methods to reduce demand that would encourage locating industrial enterprises in rural towns of the State or that would reduce or remove disincentives posed by demand charge tariffs to such locations.

The request was precipitated by concerns of some commercial businesses with potentially adverse financial impacts from demand charges, and a desire to explore what alternatives exist. In this report, the Department addresses the question of whether demand charges are a sound rate design element, and whether sensible options exist to improve them for customers and systems. The question is particularly relevant today—a time in which technology is enabling more flexibility for the utility to measure loads in real time, and for customers to alter demand on that basis using a combination of smart end use devices and modern communications. For some customers, particularly customers with low load factors,[2] demand charges can seem overly burdensome and potentially unfair in those cases when their own peak load does not add to system costs. We review the questions of burden, fairness, efficiency, and potential alternatives in this report and assess mechanisms that could help both the utility and its customers make the transition to rate structures that lower system costs and customer bills.

The Department uses this report as an opportunity to address concerns associated with demand charges not only for customers located in rural towns and in rural systems but also – more expansively – for individual customers and utility systems across the state. A particular concern is associated with emerging enterprises like public EV charging stations, especially higher voltage DC fast charging stations, which may face particular difficulty with demand charges in their early stages of market development. These challenges can exist in either rural or more urban communities. For the remainder of this report, we feature the challenges and the opportunities that demand charges present generally, recognizing that customers of Vermont's more rural utilities can, in any given instance, experience these challenges more acutely than customers in more urban settings.

---

[1] https://legislature.vermont.gov/Documents/2018/Docs/ACTS/ACT194/ACT194%20As%20Enacted.pdf.

[2] Load factors are the ratios of average to peak loads. As described below, Vermont enjoys a relatively high load factor of 70%. The New England load factor is about 54%. Other things being equal, a higher load implies greater capacity utilization and system efficiency.

Goals for this report center on two objectives: developing forward-looking, or avoidable, cost-based rate structures[3] and establishing a means to effect smarter and more cost-effective behavior by consumers for system benefit. When customer load management results in a system benefit, it is appropriate for the customer to realize a share of that benefit and, ideally, for non-participants to also gain from the improvement to system efficiency. The design of the modifications will contribute to greater fairness in the application of demand charges when the prices align with drivers of system costs and underlying prices. The Department is not interested in simply driving costs from one customer to another without a sound system cost (or rather avoided cost) rationale for change.

A. What are Demand Charges?

Demand charges are part of the typical 3-part rate structure used by utilities to provide an effective

> *Demand charges exist to cover the utility's fixed costs of providing a certain level of energy to their customers at the utility's peak periods. At the utility system level, and at the regional level, utilities have to maintain enough capacity in power plants, substations and wires to deliver energy at the utility system peak. This capacity is expensive, and the utility needs to cover these costs. In addition to allowing the utility to recover these costs, demand charges, when well designed, can provide a price signal to encourage sound conservation and/or to shift peak during periods of high demand.*

price signal and recover their "cost of service."[4] The rate components include a monthly customer charge, an energy (per kWh) charge, and a charge for the customer's peak energy demand (the "demand charge"). These 3-part rate designs are generally applicable to non-residential customers who have electric demand that require a utility to ensure that it has adequate capacity to serve that load. Furthermore, the demand charge provides a capacity-related, or customer peak hour–related,[5] price signal that distinguishes it from energy or customer related costs.

Demand charges exist to cover the utility's fixed costs of providing a certain level of energy to its customers at the utility's peak periods. At the utility system level, and at the regional level, utilities have to maintain enough capacity in power plants, substations and wires to deliver energy at the utility

[3] The glossary included as an attachment to this report defines the terms "forward-looking" and "avoidable" cost. Briefly, they refer to costs that can be avoided for the benefit of the distribution utility system and are typically distinguished from the historic or embedded cost bases that are generally used as the basis for the development of traditional demand charges that exist today.

[4] Cost of service pertains to the total annual costs of an electric utility's operations and includes the costs of generation (typically 50-65% of costs), bulk transmission (about 10-15% of costs) and distribution (15-40% of costs).

[5] More typically, it is the peak demand associated with a 15-minute period.

system peak. This capacity is expensive, and the utility needs to cover these costs. In addition to allowing the utility to recover these costs, demand charges, when well designed, can provide a price signal to encourage sound conservation and/or to shift peak during periods of high demand.

At the subtransmission and distribution system level, the systems need to have adequate capacity to meet the collective demand of customers served by local facilities. These requirements may be customer- or circuit-specific and likely do not coincide with the system peak. Demand charges were first introduced over 125 years ago and are applied in some form through the U.S. and the globe. They have existed in Vermont for most of the last century.

In addition to sending a price signal to encourage better management and operation of the electric distribution system, demand charges may contribute toward important ends like fairly allocating capital cost in establishing rate recovery, and assuring a source of stable revenues to the utility. Most of the focus of this report is on economic efficiency. However, fairness and revenue adequacy represent important touchstones for any discussion of rate design. We also review price stability and simplicity as relevant touchstones to our conclusions and recommendations.

Lagging Rate Impacts – When Customer Load Management Doesn't Correspond to Utility Cost Reductions

This example is based on a simple utility with only two customers. As in all cases, the utility has the right to recover costs of previous investments in infrastructure to provide service. The total cost including its state contribution to forward-looking costs, energy costs, transmission and distribution is $100,000 in this example. Assume both customers have the same loads and characteristics and therefore each pay $50,000. Assume further that demand charges recover 1/3 of the costs, or roughly $16,666 each. If Customer A is able to reduce its peak monthly energy demand by half, through a shift in load, and this shift does not affect the statewide peak costs, then the utility costs will not change and the lost revenue from the demand charge from customer A must be replaced by a rate increase (either demand or energy) that generates new revenue of $8,333. Customer B, which did not participate, sees an increase in its rates generating a new bill of $54,545; the customer that shifted load realizes only a $4,545 share of savings rather than the anticipated $8,333. If however, Customer A reduces peak use during the time of an overall state and regional peak, the forward-looking costs may be reduced even more than $8,333 and the rates can decrease for both customers so that Customer A sees a reduction of greater than $8,333 and Customer B sees a decrease, as well.

There are reasonable grounds for concern that the traditional demand charge[6] regime existing in Vermont is not well aligned with utility system costs.[7] In the absence of more focused capacity or energy-based price signals, traditional demand charges provide a limited price signal for encouraging avoidance of both monthly and annual peak-related utility system costs. Traditional demand charges do, however, provide a signal that is probabilistic in nature. There are many hours in each month where loads are close to monthly peaks. An average of 4 or 5 hours each month are within 2% of the monthly peak.[8] Often, the hours that come closest are adjacent hours, but also can occur on different days. In order to effectively target the 12 hours of monthly peaks, at least a handful of hours, potentially over 2 or more days, must be targeted. Months without a weather extreme, typically shoulder months, will be associated with flatter loads that are less easy to target peak but also contribute less to system capacity demands. Effective price signals can either target one of a handful of hours, or can target a wider swath of hours through focus and segmentation of demand charges, by differentiating price signals and the application of ratchets by time of day or season.

From the utility perspective, there is typically limited alignment between the utility's system costs and customer peaks. Demand charges can assess higher-demand customers with higher charges, regardless of their contribution as a cost causer to the utility system. Utilities in Vermont experience most of their demand-related costs during the overall utility system peak hour demand each month and annually. As a general case, the large user with higher peak demands will contribute more to the system peak than the smaller user. Management of customer-specific peak loads corresponds to little change in the system costs unless the customer peaks coincide with that of the system. This sometimes means that a significant reduction in peak load from the perspective of individual customers can correspond to a significant loss in revenue to the system without a commensurate reduction in costs. For smaller rural or municipal utility systems a significant customer load reduction from a major industrial customer can correspond to the need for a near-term rate increase for all remaining customers. The sidebar above helps to highlight this challenge using simplified assumptions. The example attempts to simplify real-world experience but has implications for many of the utility systems in the state that depend on major employers like manufacturing customers for a substantial share of their overall cost of service. Even a larger system like GMP's is exposed as it depends on a single customer for more than 6% of its cost of service.

For some customers, adding flexibility in loads under traditional demand charges yields little corresponding financial benefit. Specifically, commercial and industrial customers that have relatively flat daytime loads, with little ability to move those loads except for relatively short periods, will find it hard to reduce their monthly demand charge. Avoiding high demand charges would require a major

---

[6] Here, and throughout the document, the reference to "traditional demand charges" refers to a single monthly charge based on a customer peak of either a 15-minute or hour-long duration, that is ratcheted, typically at a rate of 50 to 90% for the subsequent 11 months. The meaning of the term "ratchet" is defined in the glossary, but generally refers to a minimum charge for demand that will apply in the ensuring 11-month period as a share of peak demand in a single month.

[7] As will be discussed below, some significant modifications to the traditional demand charge have already taken hold as "riders" to the demand charge in Green Mountain Power territory. These riders have introduced more focused price signals that serve to better align system costs with customer costs, consistent with some of the recommendations in this report. However, the traditional demand charge structures are still largely in place.

[8] Based on a review of monthly loads in Vermont during the 12 months ending in December 2018, 52 hours were within 2% of the monthly peaks.

investment in energy efficiency or a substantial shift of labor schedules. The figure below characterizes a typical manufacturing load, for example, that of a lumber mill (see Figure 1). There is little ability to shift load away from core daytime operations without a material shift to evenings thereby causing labor disruptions. New technologies like battery storage can help, but the investment required to shift and spread the load enough to meaningfully reduce demand charges would be substantial relative to a more targeted shift.

That said, for price signals to be successful in motivating customer response for the collective benefit, there needs to be a corresponding system benefit. Those benefits can more readily be targeted at the system level – i.e., Regional Network Service (RNS) and Forward Capacity Market (FCM) – rather than at the sub-system level (distribution and subtransmission costs). At the sub-system level, ratchets may continue to provide value as a price signal and mechanism for fairly compensating the system (and other ratepayers) if there is no practical ability to avoid the costs of equipment necessary to support the local capacity required. That said, the majority of capacity-related costs seem to be at the system level and these costs can be readily avoided in response to an effective price signal.

Of course, customer loads vary. Peakier flexible loads that comprise a substantial share of the bill may provide substantial opportunity for customer savings.[9]

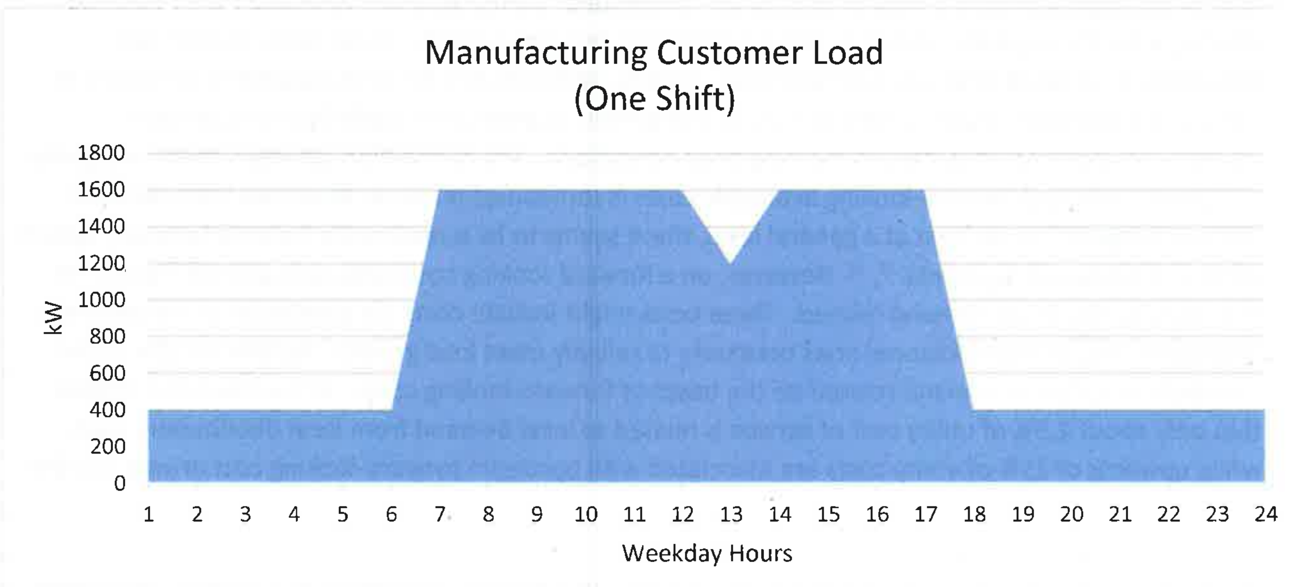

Figure 1: Typical manufacturing customers with limited ability to shift load for extended periods of time

When you combine limited customer flexibility with the disconnect between customer and utility peaks, the result is little hope for meaningful customer response to demand charges that translates into system benefits.

As a result, the current demand charge regime has emerged as an important price component for our electric companies to recover their cost of service. While seemingly important for rate stability, the

[9] An analysis of load profiles from the National Renewable Energy Lab suggests that approximately 5 million of the 18 million customers in the U.S. can cost-effectively reduce their energy bills under traditional demand charges using storage: https://www.cesa.org/webinars/nrel-demand-charges-storage-market/.

current use of demand charges is missing some opportunities for longer term savings and bill reductions available to the utility and its customers. The concern here is that customers with lower load factors, but with load profiles that impose little by way of costs on the system,[10] are bearing a larger share of the costs that are deemed to be demand related. New methods exist, at least conceptually, for both cost containment and cost recovery that are presented as better alternatives to the traditional demand charge.

II. Demand Charges in Vermont

Demand charges are applied widely in Vermont. All electric utilities in Vermont apply demand charges to their larger (higher usage) customers. (Appendix III provides a summary.) Several distribution utilities also apply a non-optional demand charge to their larger demand residential customers.[11] Some offer smaller residential customers an optional demand charge rate. Of the roughly 264,000 customers that GMP serves, approximately 8,800 customers incur demand charges. All of GMP's commercial and residential customers can elect to use demand charges. However, some utilities apply demand charges to only a very few customers, e.g., in the case of rural, largely residential systems, like WEC, to a mere dozen customers.[12]

In general, approximately a third of historic or "embedded" utility costs are associated with demand (that is, with the capacity needed to serve customers' demand overall). These costs include cost categories associated with land property and property rights needed for pole placement necessary to carry even minimum loads, as well as historic investment in generation capacity and substation investments deemed necessary to meeting peak obligations. The connection between these categories of historic costs and forward-looking avoidable costs is sometimes tenuous. Revenues from demand charges suggest that, at least at a general level, there seems to be a reasonable balance between system costs and customer payments.[13], [14] However, on a forward-looking cost basis, only a small fraction of the costs appear to be demand related. These costs might include costs for substation or transformer improvements, or reconductored lines necessary to reliably meet load growth. As little as 15% of the distribution system is demand related on the bases of forward-looking costs. In Vermont that implies that only about 2.5% of utility cost of service is related to local demand from local distribution, even while upwards of 25% of utility costs are associated with upstream forward-looking cost drivers like the

[10] We acknowledge here that there are also many customers that have low load factors that are well aligned with the system peak, as one might expect from air-conditioning loads during summer peaks. That said, even these customers may find ways to manage these loads through innovations in cooling that do not draw electricity during peak periods. Technologies are introducing flexibility that did not exist in the past, and customers have historically been shielded from the underlying cost to the system of these loads.

[11] Mandatory residential demand service applies to larger residential loads in three systems in Vermont: Barton, Ludlow, and Morrisville.

[12] WEC is largely a rural system comprised largely of a residential and small commercial customer base.

[13] GMP comments provided at the Public Service Department led workshop on rate design on August 15, 2018.

[14] It is worth noting, however, that the link between historic or embedded costs, as reflected in the accounts of the utility, and the forward-looking notion of costs, is increasingly strained. For example, the components of costs attributed to demand include accounts that are associated with land, property rights, and poles. But these relationships to actual forward-looking drivers of costs that are peak-demand related are thin even in an era of steady growth. Vermont and the region have not seen even modest growth for more than a dozen years, and it is not expected for the foreseeable future.

forward capacity market and regional network service bulk transmission costs. This implies a fairly wide disparity between forward-looking costs and embedded costs.

More concrete evidence is needed here for the Vermont systems. Vermont-based information on

...demand charges for utilities vary substantially by utility, ranging from just under $9 per kW to more than $20 per kW.

marginal costs would be helpful. But if these figures are correct, it suggests that traditional demand charges may provide a pricing signal, but only for a small share of the system costs. There is room to lower the demand charges and the associated application of ratchets relative to current levels to provide a better match between forward-looking costs that center on distribution-level service.

A summary of the demand charges is reflected in Figure 2 as they apply to generally large commercial and industrial customers. (The figure is a sampling of demand charges, as some utilities, like GMP offer a wide variety. The full range is available in Appendix III.) The graphic shows that the demand charges for utilities vary substantially by utility, ranging from just under $9 per kW to more than $20 per kW. (As Appendix III shows, the range can also vary significantly within a utility.) The graphic helps introduce the concept of demand charge ratchets, corresponding to the dark blue segment of the stacked bars. Ratchets represent the share of the initial costs that are billed in the subsequent 11 months. (For example, a 10 kW demand charge in the first month is carried forward as a 5 kW ratcheted demand charge in the subsequent 11 months.)

The yellow line Figure 2 represents a proxy for the costs that could be avoided by the utility based on upstream costs (i.e., excluding any that are associated with the distribution system). (The yellow line, however, fails to capture the full costs of additional load on each utility's FCM obligations. Rather, the FCM obligations, and the yellow line would be increased year by a reserve requirement ratio that have historically exceeded 20%, and in recent years run much higher.) They provide a forward-looking reference point for the demand charges that exist today. On the one hand, the yellow line suggests that even on a forward-looking basis these costs are reasonably bounded by the range of utilities in the state. Allowing for further adjustments associated with reserve ratios, they may even be low. On the other hand, these costs correspond to a period of 12 monthly peaks and a single annual peak, just 13 hours of the year. This suggests providing a more targeted signal may be more appropriate.

But even while the target is fairly precise, these hours are only known with certainty after the fact. And, even if the forecasts were completely accurate, the monthly targets will shift with effective targeting. Also, the forecasting itself will likely become more complex with the addition of a more dynamic system targeting these loads. The 12 monthly RNS peaks (i.e., Vermont's coincident peak) will simply shift to an adjacent hour or day. Targeting these 13 hours requires effective forecasting and targeting a larger number of hours, potentially centered on as many as 5 or 6 days across a single month. In the end, the shoulder months present a formidable barrier to effective peak targeting. The effective value of such targeting is also diminished. In the end it may only be practical for most systems to target 8 or 9 of the 13 hours referenced.

The costs are comparable when averaged across the month, but represent a mismatch relative to the time that these costs are experienced, largely associated with upstream costs like the FCM and RNS.

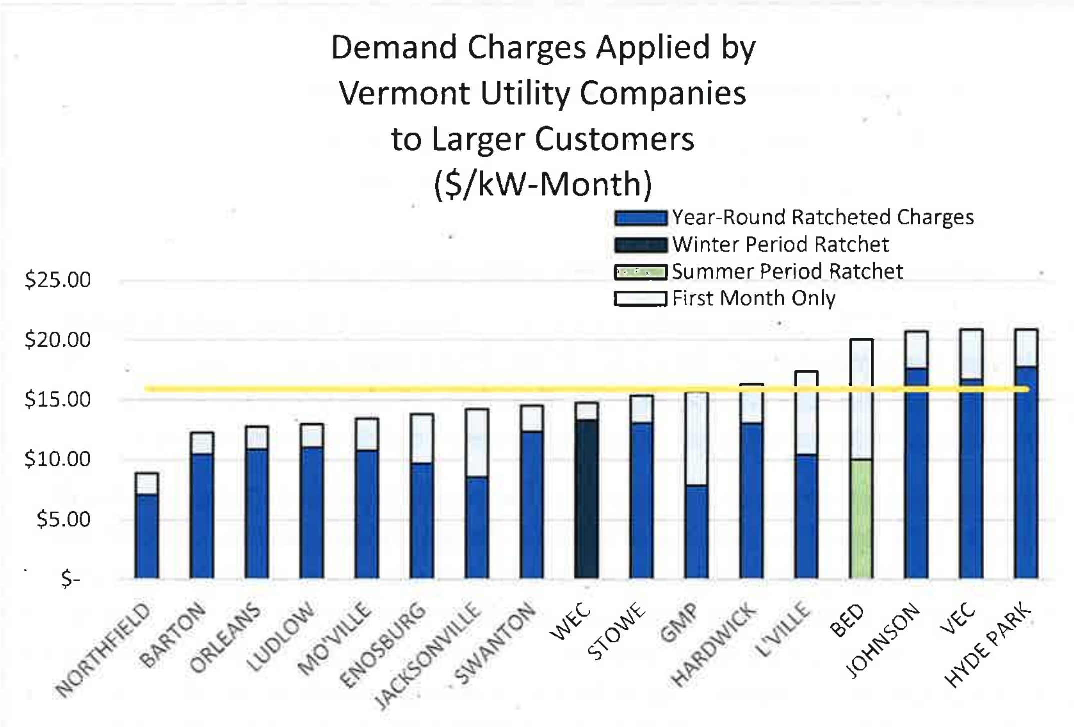

Figure 2: Existing demand charges by electric utility – large commercial and industrial rates[15], [16]

Demand charges typically apply to larger commercial and industrial customers rooted in the highest

Most of the more rural Vermont utilities apply it from 60% or 90% of the monthly peak 15 minutes. VEC applies a 80% ratchet. WEC applies a 90% ratchet.

demand over the month for a 15-minute period or hour-long period over the prior 11 months (covering a 12-month period).[17] Demand charges also typically apply to qualifying residential and small commercial customers. BED, and GMP generally, apply a 50% demand ratchet. In the case of BED, the ratchet is based on 50% of the summer peak load, taking a much more seasonal approach than other

[15] The chart above is intended to provide a simple comparison of rates relative to forward-looking costs. Some utilities, like BED, appear to allocate a greater share of their costs to demand rather than energy, thus having a higher demand charge and helping to keep the per kWh charge lower.

[16] The yellow line in the graphic does not include all of the costs associated with the annual FCM. For each 1 MW of load at the peak hour, the utility's capacity obligation will be more than 1 MW. The reserve ratio has historically been more than 20%, so 1 MW of load translates to a capacity obligation (and cost) of 1.2 MW. Reserve margins have been at much higher levels recently, so the effective costs associated with the yellow line fail to include the full impact of the capacity reserve margin.

[17] Bonbright, J.C., *Principles of Public Utility Rates*, 1988, at 399.

Vermont utilities. GMP and BED also further differentiate the demand charges between peak and off-peak periods. Both GMP and WEC also offer a seasonally differentiated ratcheted demand charge, but, in the case of WEC, based on a winter peak period. (This seems likely to be a legacy of the fact that we have historically been a winter peaking system—but now a mixed system with occasional summer annual peaks.) Most of the more rural Vermont utilities apply it to 60% or 90% of the monthly peak 15 minutes. VEC applies an 80% ratchet. WEC applies a 90% ratchet. (Appendix III provides an overview of the demand charge regime for Vermont's 17 electric companies.) The figure below shows the a subset of demand charges for Vermont's two largest electric distribution companies: GMP and VEC (see Figure 3). These two were selected to help demonstrate the range of demand charge–related pricing among even the largest systems in Vermont.

It should be noted, however, that GMP has already implemented a number of reforms that directionally resemble reforms later recommended in this report. Among those reforms are the establishment of dynamic rate features that ride on top of existing rates that can apply (optionally) to any commercial or industrial customer. GMP, for example, offers a load response, critical peak, and curtailable load rider to its Industrial/Large Commercial Customer Rate 63/65. Dynamic rates have also been applied to the residential class. GMP provides a critical peak pricing mechanism that combines with the time-of-use rate under its Rate 14. Customers have been slow to adopt these new rate elements, however. This may be due to the lack of customer acceptance, challenged marketing, or the absence of new agents like load aggregators and energy service companies (ESCOs)[18] that can help build a bridge between customer acceptance and utility value. The reasons for this deserve further investigation as we look to adjust charges looking forward.

Utility	Rate Class	$ per kW/Month	Demand Ratchet
Green Mountain Power	Rate 8 - General Service	$16.740	50% of the highest 15-minute peak occurring during the previous 11 months.
		$17.090	50% of the highest 15-minute peak occurring during the previous 11 months.
		$17.448	50% of the highest 15-minute peak occurring during the previous 11 months.
	Rate 12 - Primary Service	$9.856	Highest 15-minute peak during current month.
	Rate 63/65 - Commercial & Industrial Time-of-Use Service	$14.023	Highest 15-minute peak during current month.
		$17.962	Highest 15-minute peak during current month.
		$18.710	Highest 15-minute peak during current month.
		$18.710	Highest 15-minute peak during current month.
VEC	General Service Rate Demand Billing Provision	$20.88	80% highest kW previous 11 months
	General Commercial Time of Use Rate	$24.34	80% highest kW previous 11 months
		$17.56	80% highest kW previous 11 months
	Industrial Rate:		
	Distribution - Firm	$19.89	80% highest kW previous 11 months
	Distribution - Interruptible	$16.32	80% highest kW previous 11 months
	Subtransmission - Firm	$12.04	80% highest kW previous 11 months
	Subtransmission - Interruptible	$8.48	80% highest kW previous 11 months

Figure 3: Demand charges for Vermont's largest electric distribution companies

[18] "Load aggregators" refers to entities that work with customers to control flexible end use energy demands, like those with storage capability to provide services to the system, or in response to price signals that can be arbitraged and managed. Services include the delivery of energy and capacity upstream to wholesale markets or to meet the requirements of the local distribution system. "Energy service companies: include the likes of major engineering firms that often provide services, like energy efficiency, through performance contracts. ESCOs also can function as load aggregators to provide services through well-formed rates and rate design.

III. Looking Beyond Today's Demand Charge

A. Benefits of Traditional Demand Charges

Traditional demand charges clearly have value, even in current market conditions. But as we argue below, traditional demand charges can be improved as a price signal or incentive to control system costs. Traditional demand charges do reasonably well in serving the objectives for customer fairness and utility system revenue adequacy with respect to costs that are deemed to be demand related. By carrying a portion of the embedded costs, traditional demand charges also offer the potential to help keep down per kilowatt-hour rates bringing energy prices closer to marginal energy supply costs.

There are other ways to structure utility compensation for demand-related expenses. Similar ends can be achieved through the direct assignment of costs that are indeed customer specific, such as substation equipment or transformers that are dedicated customer requirements, or by assigning a higher per kilowatt-hour rate or customer charge to the entire customer class for costs that are not customer specific. Another fruitful pathway that may be relevant, at a minimum, to the transition, is to apply dynamic rate or incentive riders as an overlay to well-formed demand charges (those that fairly allocate system costs). In general, the Department embraces efforts to strengthen the "cost causer pays" principle, which is not accurately reflected through the misalignment of customer peak demand periods and distribution grid peak capacity periods. Reliance on dynamic tariff riders that overlay demand charges is an approach that GMP has adopted for both residential and commercial customers.

B. Emerging Technologies and Opportunity

Demand charges exist today with little modification over a century. That they remain so is partial testament to their value but also the power of inertia in the system that is perpetuated by customers, utilities, legacy billing and software platforms, and regulators alike. There is a compelling case for a course correction that includes some ongoing reliance on ratcheted demand charges, but also on more narrowly targeted price signals or incentives.

Pricing that motivates load changes is needed, in particular more effective capacity-related price signals or incentives passed to ultimate consumers. Sharper price signals or incentives can be passed to consumers through either a separate pricing element like a reformed demand charge, or through a commodity price that signals scarcity. Reasons for doing so include the following:

Flexible end user loads – Demand for electricity services is increasingly flexible. New loads like those associated with heating and EV battery charging can be more readily timed to match available price incentives. Demand charges were well suited to another era in which the emphasis was arguably well focused on cost causation and the fair allocation of costs rather than encouraging cost management. Technology now permits us to more precisely measure demand; align price signals and incentives with cost causation; and empower customers to respond through communications, automation, and utility controls. These developments also create potential opportunities for emerging business models that promise to expand the reach of managed load through energy service companies (ESCOs), solar installers, and load aggregators.

Technology now permits us to more precisely measure demand; align price signals and incentives with cost causation; and empower customers to respond through communications, automation, and utility controls.

Sharper system cost drivers – Relatively sharp forward-looking price signals exist today for resource adequacy (i.e., the forward capacity market) and the assignment of costs for pooled bulk transmission (i.e., the regional and local network service charges that are allocated based on a forward-looking measure of load—coincident statewide system peak). Together, these cost drivers correspond to roughly 12 or 13 hours of the year and can relatively easily be passed to end users. Together, these 13 hours correspond to roughly a quarter of the total costs that must be covered by Vermont utilities. (Again, even while utilities cannot realistically precisely target these 13 hours, they can pivot and provide sharper, more targeted signals.) If loads are flexible, customers can easily respond using the technologies and enablers discussed above. If they are not flexible, storage can play a role.

New technologies and storage – Storage has emerged as a cost-effective technology for some applications. Storage here refers to battery storage, but also the inherent storage capabilities of certain major end-use devices, including water heating, electric vehicles, air-conditioning and heat pumps. Storage is most efficiently used for relatively short-duration applications. Storage and load control can be increasingly relevant and can cost-effectively defer loads for the handful of hours each month discussed above. Customer-level storage is a cost-effective technology that has been employed by utilities in Vermont for decades through water heater load control. Vermont utilities are already finding new applications for advancements in storage technologies. Battery storage through EVs is another promising low-cost pathway to manage loads. The significant advances in storage capabilities only grow with the wider range of applications, including the GMP Powerwall program. Storage is less well suited to managing loads throughout extended periods, as would likely be required through management of existing demand charges for high load factor customers.

Customer fairness – Customers and loads can be differentiated by their load shapes, but also their capacity to shift loads. (And with the advent of cost-effective storage and related technologies, the pool of flexible loads can expand with appropriate price signals and incentives.) Customers that can manage loads to reduce system costs should be encouraged to do so and be compensated for their efforts. This is a matter of both economic efficiency and fairness. In the existing ratemaking environment, customers of most utilities in Vermont have little opportunity to manage loads for their benefit.[19]

Economic efficiency – Most customers have little ability to avoid ratcheted demand charges because peak demands may exist over many hours and across different seasons. Ratchets currently apply to any

[19] GMP offers a number of dynamic rate riders available to its customers in ways that can be coupled with the demand charges. These include a load-response, critical peak, and curtailment rider to their Rate 63/65 TOU and demand-response rate for larger commercial and industrial customers. Burlington Electric Department (BED) differentiates peak and off-peak application of demand charges. BED is also announcing additional end use–specific rates for EV charging that introduces additional dynamic elements.

single-month peak regardless of its coincidence with system costs. The charges are simply not sharply centered around the cost drivers, but rather they apply broadly to charges for an entire month, and also linger through the following 12 months. A sharper (more time-limited target) may be easier to hit for system benefit. Ratchets may, however, continue to be relevant to annualized costs that are not easily relocated, deferred, or resold.

Rationale for Re-evaluating Demand Charges	
Flexible end user loads	Align price signals with cost causation in an increasingly flexible demand-side marketplace
Sharper system cost drivers	Engage end users and storage to lower system costs related to resource adequacy (i.e., forward capacity market)
New technologies & storage	Defer loads during just a handful of hours each month that drive roughly 25% of system costs to utilities
Customer fairness	Reward customers with malleable loads and improve the relationship between customer-facing prices and utility system costs
Economic efficiency	Tighten timeframe around prices to improve customer ability to respond to utility signaling

Figure 4: Rationale for evaluating demand charges

C. Character of System Costs

Between half and two-thirds of the total utility cost of services is associated with upstream wholesale and bulk transmission costs.[20] Of these two categories of costs alone, approximately 50% of these costs are associated with monthly and annual cost drivers that are limited to one or two hours of the month. The figure below provides a graphic depiction of the cost drivers (see Figure 5). FCM charges and RNS charges reflect the majority of demand-related costs. As the figure suggests, these costs can be

[20] A recent review of GMP's embedded cost of service revealed that about 60% of non-capital-related costs are associated with upstream wholesale and bulk transmission costs.

narrowly targeted for greater system benefit. The majority of these costs tie simply to the coincident system peak of New England and Vermont (FCM, and RNS, respectively).

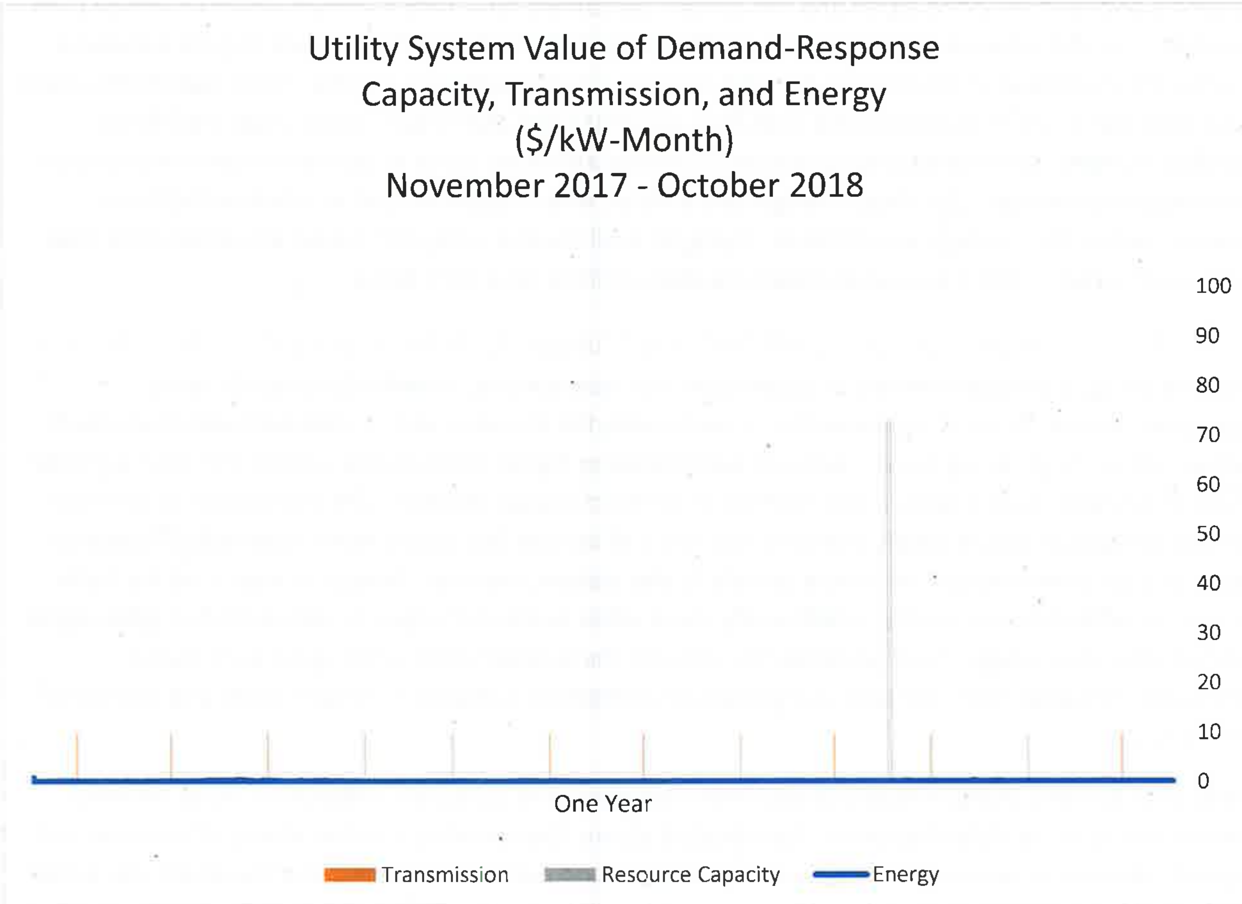

Figure 5: Cost drivers could be narrowly targeted to dramatically decrease overall utility expenses

Not all of these costs can be avoided, but even if only 20% of these costs could be avoided over time, it suggests that Vermont could reduce the cost of service by roughly $48 million or approximately 6% of retail costs[21] through pricing and incentive reforms.

Demand-related costs are also relevant to the distribution system. With the introduction of distributed generation, there will be increasing challenges and opportunities to employ incentives, including locational incentives to manage these costs. Distribution and administrative and general (A&G) costs combined represent approximately 30% of the overall cost of service.[22] Forward-looking components related to demand account for at least 25% of the cost of service.

D. Challenges with Traditional Demand Charges in Managing System Costs

There are two basic problems in trying to apply traditional demand charges to solve or avoid current system costs. First, traditional demand charges are keyed to each individual customer load rather than

[21] Assumes that 60% of overall costs are wholesale and bulk transmission cost related, approximately half of these costs are demand related, and approximately 20% of these costs can be avoided.
[22] Distribution costs are about 17% while A&G costs are about 13%. Sean Foley, Public Service Department.

to system conditions. System benefits associated with customer-owned load management is correlated, but only to the extent it is coincidental. Second, even if the price signal and the response provided a closer tie between the price signal and the system, customers have only a limited ability to reduce their own bill. The shift of loads between peak conditions and alternative periods would require a massive investment in storage or timeframes for work to have a material impact on bills. Most customers simply have fairly flat loads in relation to the peak load circumstances that trigger costs under traditional demand charges. Altering business practices or energy efficiency seem to be more fruitful avenues for reducing these charges. But these changes are difficult when customers are focused on their core business rather than energy use patterns. Dynamic load control using cost-based incentives may have limited influence unless it is easy and does not distract from their core focus.

E. Options to Traditional Demand Charges to Achieve Greater System Benefit

Demand charges provide a relatively stable source of revenue and, notwithstanding concerns highlighted above, do so in a manner that is reasonably fair to customers. Customers with lower load factors, other things being equal, correlate with imposing higher costs on the system and bear a greater share of demand-related costs under traditional demand charge regimes. The elimination of demand charges altogether would simply translate into costs of service that would need to be redistributed to usage and customer charges with little benefit to the system, and cost changes in ways that are likely less fair to individual customers. Additionally, even while demand charges provide a limited price signal for customers to manage loads (to serve the system), there is still some price signal such that a wholesale shift away from demand charges would precipitate increases to system loads and additional system costs.

Traditional demand charges have changed little over time, and continued reliance on those demand charges would cause little disruption. As indicated above, they provide a stable source of revenue, and arguably allocate costs more fairly between customers and customers classes. But the downside is that continued reliance on these charges without modification or enhancement will in effect leave money on the table that can be returned in the form of a lower system cost, lower customer charges (bills), and lower rates (for both participants and non-participants).

In offering the following options, the Department acknowledges that customers have made investment decisions of their own based on a particular existing rate design. Changes are not to be taken lightly. Nonetheless, there are pathways to facilitate change, while respecting a fundamental fairness to customers that have made investments or are otherwise attached to a particular rate. These include optional service offerings, optional rate riders and the closing off of rates through some form of "grandfathering."

There are a host of options available for modifying the regime around traditional demand charges that include the following :

1. Demand Charge Preferential Rate

The concept of a demand charge preferential rate (or waiver) is one that essentially removes the demand charge in some form for an alternative rate that could be for a set period of time or on a more enduring basis. This may be relevant to emerging businesses and business models that will face very high levels of demand (e.g., an EV fast charging level 3 station), but with relatively modest energy requirements in the early years. (The concept could be broadened further to form a green infrastructure development rate that applies to any new loads, provided they cover in aggregate their marginal costs with a contribution to the margin between marginal and fixed costs.) The biggest concern with merely waiving the demand charge rate element is that these loads are potentially still significant cost causers. The most significant contribution to costs are likely upstream RNS and FCM charges (and relevant margins). But considering the modest timeframes involved (monthly Vermont peaks during typically evening hours, and an annual peak that typically occurs in late July or August), there may be a sensible hybrid that allows a preferential rate from traditional demand charges, and also introduces new categories of costs that are just adequate to compensate the system.

As one example, estimated demand charges could be incorporated into the energy rate for the first three years of operation, provided the EV charging station owner allows for active and dynamic load control capabilities to the host utility.[23]

2. Eliminate or Reduce the Demand Charge Ratchet

As noted above, the ratchets typically range between 50% and 90% of the initial charge and apply for the next 11 months. High levels for ratchets would make sense for customers with loads that correlate with annual peaks, the burden for which is carried another 11 months. But such ratchets may make less sense if the customer, or perhaps their agent (or the utility ..., or its agent) has the ability to target such loads for a shift, say by using storage or load management in a targeted fashion.

In the current environment, the value of demand ratchets still persists, but is diminishing. Ratchets spur load management by some customers, provide some measure of fairness in allowing recovery of annualized capacity costs and, in the case of sub-system loads they may still represent a sensible price signal. But the vast majority of demand-related costs seems to be the upstream costs that have little or no cost implications if loads fail to materialize during the monthly and annual peaks. The bulk of the system costs that relate to demand are upstream costs like the RNS charges that disappear after each month, or the FCM charge that can be readily avoided providing a more targeted (albeit dynamic) price signal on an annual basis. The local demand-related charges that remain include cost elements that do get or can be folded into one or more of the other categories of exceptions listed above. To the extent that these exceptions do not apply, they can be addressed through a very small demand charge ratchet, much smaller than the charges that currently prevail.

3. Narrow the Window Timeframe for Demand Charges or Peak Period Demand Charges

Another option available to utilities is to simply narrow the timeframe over which the demand charge on the peak demand applies. Utilities in Vermont offer a variety of timeframes that are relevant to the demand charge. Most of Vermont's electric companies apply the same demand charge across all hours of the day and then across all seasons of the year. BED is one exception and differentiates by season and between peak and off-peak periods. Demand can be differentiated based on coincident or clean peak standards in the future—not simple TOU fixed peak periods as they exist presently. Sixteen hours on-peak is not reflective of a normal window of peak capacity occurrence, and limits technologies that can employ storage or load shift for 2-4 hours. A clean peak standard has been advanced in Massachusetts to help encourage the management of peak demand with clean resources. Certain components of demand that impact the utility are highly seasonal, and all material drivers of upstream

---

[23] BED first introduced this concept in a PUC filing dated Jan. 9, 2019 in Docket 18-2660.

demand-related costs occur between 5 PM and 10 PM. With the increasing levels of net metering, the timeframe that is more relevant is between 7 PM and 10 PM. Demand charges can be restructured to fruitfully target these shorter periods by narrowing the timeframe and coupling the charges with a credit. Alternatively, demand charges can be reduced or eliminated and replaced with a limited-duration critical peak price.

Narrowing the windows for demand charges can also be coupled with differential demand rates for peak and off-peak. Conceptually, peak periods would correspond to times of the day when demand is most likely to trigger upstream costs from monthly peaks. Off-peak periods might be associated with all other periods that are likely to trigger new costs in the local distribution system. Applicable off-peak periods would be associated with a lower demand charge and could similarly be narrowed to periods when the costs of the local distribution system are mostly likely to be adversely impacted by new loads.

4. Time-Varying and Time-of-Use Pricing

Time-varying and time-of-use pricing may bring forward sensible pricing solutions and may provide a welcome complement to capacity-related charges. When capacity-related charges or incentives are combined with sound time-varying price signals, they can present a compelling formula for load management to the benefit of the system that can be managed either directly by the customer, or potentially by third parties that serve as agents for the utility or the customer. Time-varying pricing taken to a relative extreme in terms of customer exposure to risk would involve signals that bill the customer for real-time energy, and expose customers to peak hourly costs for capacity in the form of a critical peak price, a form of dynamic pricing discussed below. Short of such extremes, TOU pricing can provide a useful foundation that can be structured as GMP has done by coupling a TOU rate with additional dynamic rate riders that customers or their agents can opt for.

5. Utility Load Management

Utilities have historically acted on behalf of customers to offer rate discounts on electricity service if load-management controls are implemented. Interruptible loads are offered to large industrial customers and ski areas in Vermont. Ripple controlled systems and clock-managed service[24] have been offered to residential and small commercial customers. More recently, GMP has offered load management service in relation to controlled charging of electric vehicles, load management of water heaters, pilot programs that offer discounts on battery storage in exchange for load management of the battery recharge, and load management as a rider for time-of-use rates for commercial and industrial customers on Rate 63/65. Load management options have been offered with varying degrees of success in customer participation, begging the question of whether the utility could achieve more success by offering rates and services that might allow other aggregators, ESCOs, and other third parties acting on behalf of the utility or customers to provide comparable system value. Some view this as the core path to delivering a decarbonized future at least costs.[25] Admittedly, these rate offerings already exist, but can be tailored, over time to provide a better match with the character of the system costs to include additional dynamic components differentiated by time and location. Current rate differentials seem to

---

[24] "Ripple control" systems are associated with a flexible load, like a water heater that can be turned on and off remotely with frequency signals. Ripple control is used worldwide. It works by sending a high frequency signal onto the 60 Hz main power signal. Attached devices shut off the load until the signal is disabled. Clock-based water heater systems rely on a more distributed time clock that similarly shuts down the load and turns it back on.
[25] Personal communications, Morgan Casella, Dynamic Organics, 1/28/19.

obscure the full risk and opportunity for customers and their agents by softening the price signals available to end users. In any event, load management services can be and are offered by utilities in Vermont. There may be additional opportunity for finding ways to leverage customers' loads and introducing new actors through well-formed rates and incentives.

6. Introduce Dynamic Capacity-Related Charges

Capacity-related charges may range from critical peak prices that may apply to a single hour of a grouping of hours around a time of day and month when the system is forecasted to bear the full brunt of either FCM or RNS charges. Examples of such charges include critical peak prices (CPP), variable peak pricing (VPP) and peak-time rebates. Most customers are loathe to participate in such rate plans directly due to the risks and associated anxiety of extreme price exposure. Third parties can play a role in helping here by managing loads on customers' behalf and offering some measure of protection from the down-side risks. In the early 2000s, a new industry was formed with the entry of large demand-response providers like Comverge and EnerNOC that helped to provide load management services on behalf of large customers, and provided services upstream to ISO-NE. Even while some (or many) of these entities no longer provide that service, there is a new class of providers that provide similar services.[26] Innovations in communications and automation are now increasing the opportunities to provide similar service to a broader base of customers to include smaller commercial and potentially even residential customers. GMP has already made such offers to residential customers (Rate 14) and commercial and industrial customers as a rider to Rate 63/65 (a time-of-use rate with demand charges).

F. Analysis of the Options

Rate design potentially represents one of the lowest-cost pathways to achieving the statutory objectives of least-cost delivery of service required under Vermont Statutes (30 VSA §§202a and 218c). Viewed in isolation of other rate options listed, there is little value in simply redistributing the revenues collected through changes in demand charges that are not linked to reductions in system costs. But simply continuing a heavy reliance on demand charges without further modification no longer seems like a sensible option. The industry has changed in fundamental ways that have provided a compelling basis for more focused targeting of the few hours of the year that offer the greatest potential to achieve savings for ratepayers. Even while utilities have recognized load management as an opportunity for decades, the declining costs and flexibility and convergence of enabling technologies are moving the demand side forward. Residential scale storage is growing at an exponential scale and exceeded even utility scale storage in the second quarter of 2018.[27] Distributed generation is creating new pressures that will likely precipitate the need to better manage voltage levels on the distribution system without precipitating the need for additional investment in distribution facilities or moratoriums on new electric loads – EVs and cold climate heat pumps (CCHPs) – or solar PV. Improvements in technology include communications, automation, personalized smart devices and battery storage and are all creating new pressures and opportunities.

---

[26] CPower continues to provide similar services in Vermont. There is a new class of independent power providers that include ESCOs, solar installers, and software providers that appear poised to provide demand-side management services that complement their current core services.

[27] https://www.woodmac.com/our-expertise/capabilities/power-and-renewables/extracting-value-from-energy-storage-participation-in-energy-markets-can-boost-customer-adoption/.

1. Embedded versus Forward-Looking Cost Emphasis

The existing framework reflects a relatively limited price signal to end users that provides a form of rough justice by providing only a limited match between demand-related costs and demand-related prices. In broad terms, the costs and the revenues need to be better aligned. In the current environment it is the largest customers that are in the best position to respond to dynamic price signals and manage loads. Even in the current environment, large customers participate through load aggregators and rely, to a limited degree, on dynamic rates. Declining costs of storage and related technologies are extending the feasibility and cost-effectiveness to smaller-load customers.

Coincident peaks in Vermont are experienced for only 1 out roughly 730 hours per month, or just over 0.1% of the time. ... Vermont utilities could realize substantial benefit through a significant shift in loads from about 7-9 PM in most months, and around 4-6 PM on the July or August peaks.

Coincident peaks in Vermont are experienced for only 1 out roughly 730 hours per month, or just over 0.1% of the time. However, in recognizing the inherent uncertainties in chasing this 1 hour, efforts to target these loads may require the utility to target 5 or even 15 hours in a given month. This 1 to 2% of the time contrasts sharply with existing demand charges that typically apply to customers for all 8,760 hours of each year. The disconnect is pronounced. Vermont utilities could realize substantial benefit through a significant shift in loads from about 7-9 PM in most months, and around 4-6 PM on the July or August peaks. Yet the price signals that users see center on their individual peak. A shift in the timing of a customer peak provides little or no benefit to the customer if the magnitude of the system peak is not reduced. And only when the customer peak coincides with the system peak does load shifting have a system benefit.

Customer responsiveness is improving with the underlying advances in technology. However, their responsiveness is improved if the inconvenience can be narrowed to an hour or a few. Customers increasingly enjoy the advantage of modern communications, high levels of broadband (93% at lower speeds)[28], automation, end use metering, and for 91% of Vermonters, AMI meters that have the ability to check and report customer loads every 15 minutes. Furthermore, new business models that are available from third-party aggregators can help to reduce complexity and bring new technologies, including storage systems, to bear to change individual customer demand patterns.

The Department concludes that traditional demand charges will continue to have a role moving forward. They appear to provide value in recovery of embedded costs that are most relevant at the sub-system level. However, more emphasis is need on dynamic load control incentives that can serve to actually drive timely reductions in utility costs that will allow for overall customer cost reductions.

[28] https://publicservice.vermont.gov/content/broadband-availability

2. Narrowing Targets for Demand or Capacity-Related Charges

The costs that Vermont utilities face are more narrowly centered on the upstream drivers of costs that are associated, largely, with just 13 hours of the year.

From the local utility perspective, the costs that the local system bears are those that are passed to it from ISO-NE, VELCO, and upstream utilities. The individual costs are passed forward to utilities and result in monthly coincident peak (CP) demand charges. The utilities' monthly CP charges are part of the basis for demand charges levied on individual customers. Of course a customer's CP demand charge presents challenges, such as understandability, predictability, and bill stability, but these can be managed by making these features available and by leveraging customer agents (i.e., third-party aggregators) or the utility functioning in such a role.

The system drivers will change over time as markets are redesigned and the focus shifts toward local drivers in the distribution system. Customer flexibility and responsiveness will be needed looking forward, and a more robust ratemaking structure will support the grid of the future.

Over time, the Department concludes that demand charges should apply more narrowly around the time (and where relevant, location) that represents critical system loads, rather than remain focused on customer loads.

3. Stopgap Solutions and Demand Charge Preferential Rate

Traditional demand charges can present a formidable barrier to the development of public EV charging stations that promise to help transform the transportation sector. These stations promise to help meet the state's environmental objectives and create new loads and margins for our utilities and their customers. Short-term relief from demand charges can be delivered in sensible ways that avoid adverse impacts to other customers. Examples of such an approach might include demand charge preferential rate, discussed above, perhaps coupled with some measure on limits to help reduce the use of DC fast charging during the 13 hours of the year when these stations potentially adversely impact the entire system. Effective use of planning and incentives to help locate stations where the existing distribution system is best able to receive these loads, also seems sensible.

Traditional demand charges represent a formidable barrier to the development of other new customers, as well. The concept of a demand charge preferential rate may be appropriate for certain new loads without material risk of cost shifts. Indeed, the introduction of a preferential rate extending over a longer period may make sense if it can be accompanied with other rate elements or pathways that help to ensure that other customers benefit or are fairly compensated using one of many potential pathways.

The Department concludes that Vermont utilities should offer a pathway for immediate relief from demand charges to new loads like EV public charging stations.

4. Demand Ratchets

Demand charge ratchets are less relevant today as a meaningful price signal (to align the price with system costs) or as a mechanism for fairly assigning costs to cost causers. A disproportionate share of the forward-looking capacity-related costs today are of a short duration (e.g., RNS costs) and/or are associated with just a single hour (both FCM and RNS charges). Local distribution costs may be fairly assigned through a ratchet, but there are many other pathways apart from the application of a small residual ratchet for ensuring that other customers are fairly treated. Emerging technology may help us to isolate and value costs, or rather avoid costs, even at the distribution system level.

There is little inherent economic efficiency benefit associated with ratcheting monthly demand charges, at least for the main drivers of demand-related costs. Admittedly ratchets allow one to annualize a cost that is coincident with annual regional peak. But most customer peaks occur at different times. Ratchets mean that the full cost to the customer is carried for 12 months even if the customer contributes little to the annual peak. The primary benefit is one of fairness in compensating the collective system for embedded demand-related costs that have been introduced to the distribution network to more fairly apportion local demand on the distribution system. But even as a path to customer fairness, the benefits can fall at an individual customer level, where low load factor customers that impose few costs on the system may be penalized. Ratchets for these cost drivers are no longer meaningfully connected to forward-looking drivers of system costs. To the extent that metering infrastructure allows, demand charge ratchets should be removed or reduced to only address issues of residual concerns for customer fairness. Ratchets can also apply to customers that contribute to the coincident regional peak, as an alternative to bearing the full cost of the system costs in a single month. Better alternative price or incentive frameworks exist for promoting management of peaks of the regional coincident peak, rather than relying on broadly framed demand charges with ratchets.

The Department concludes that for the longer term, Vermont utilities should not include a reliance on demand ratchets for recovery of regional capacity and bulk transmission–related costs that are only system costs for the single months and do not affect future-month costs.

5. Time-of-Use and Time-Varying Rates

Time-varying rates may be sensible from the standpoint of sending appropriate price signals, but add complexity that risks customer resistance. Time-varying and time-of-use pricing are no substitute for a capacity-based price signal, but can be coupled in ways that provide an effective price signal.

The Department concludes that the coupling of sound time-varying or time-of-use charges with a capacity price component, either as part of a price stack or a distinct price element, provides a promising pathway for utilities and the Department to explore more deeply over time.

6. Load Management

Utility load management may be a sensible pathway. In effect, utility load management provides a customer return for non-participating customers, by ensuring that the rates continue to provide a margin greater than the benefits. Well-formed utility load management programs compensate participating customers—while reducing the risk of extreme price signals under a dynamic retail price alternative when the customer fails to adequately respond,—by either providing ample customer notice, or by controlling the loads directly.

The Department supports continued and expanding reliance on utility-driven load management solutions. That said, further emphasis on forward-looking, cost-based pricing solutions may enable a new class of providers that include load aggregators, ESCOs, and even solar providers, to effectively serve as both agents of customers and utilities to extend the opportunities of load management for additional customer and utility system savings.

7. Dynamic Pricing

Dynamic charges and incentives like critical peak prices and peak-time rebates offer promising pathways to lower cost, but introduce complexity and risk to ultimate users that seems to be met with resistance among all but the largest and more sophisticated customers with energy managers. The most immediate solution is to simply offer these features at accompanying elements of a base rate, as GMP has done with its CPP rate rider on Rate 63/65. Another pathway to achieving success is to allow other third parties to gain access and rely on and manage the complexity and risk of these rates or rate riders as agents of either the customer or the utility.

The Department concludes that some form of capacity-related price signal or incentive for load management should extend to all customers. These signals can come in the form of a peak-time rebate, a critical peak price, or even a real-time price signal. Given advances in automation and communications, and the potential for new business models and opportunities for utility controls, there is little to distinguish one class of utility customers from another. Therefore, there is little reason to limit the reach of capacity savings that can be passed on to customers large and small. All customers should have access to either a tariffed program that provides a charge for critical peak avoidance that can be managed by either the customer, a third party, or the utility through controls. These mechanisms can be readily implemented through pricing reforms initially introduced as tariff riders or as incentives that can apply to almost any ratepayer without risk or disruption.

The Department concludes that dynamic capacity-related price signals or incentives should, at a minimum, optionally extend to all customers and rate classes.

IV. Conclusions and Recommendations

The main reason for revising demand charges as they exist today is to provide an improved price signal for customers relative to the system costs that they should help avoid or reduce.

Rural customers, especially those located in smaller utility systems, may feel the effects of demand charges that do not reflect system cost variables even more than those located in urban settings.

The limited price signal that is associated with traditional demand charges represents both a threat and a lost opportunity. New technologies and business models hold increasing promise that system costs can be significantly reduced through better load management, to the benefit of the system and all consumers. In the short term this concern is relevant to both customers with comparatively poor load factors and are likely to persist and to customers that are in the early stages of important new markets, like high voltage DC fast charging public EV stations as they struggle in early stages of the market. In the longer term, failure to take advantage of new approaches will lead to adversely impacted system efficiency, with associated adverse implications for rates and bills.

That said, fundamental change to rate design is not to be taken lightly. Utilities depend on stable revenues from existing rates. Customers have made investments based on assumptions about their own electricity costs. Traditional demand charges provide a reliable mechanism for cost recovery of portions of the system that are deemed demand related. Technology considerations are also a factor. Approximately 12 utilities in Vermont lack the advance metering infrastructure necessary to take advantage of all of the benefits of advanced forms of pricing. Even with those examples of incomplete technology adoption, the opportunities to lower costs through a thoughtful redesign seems to be compelling. Existing demand charge structures provide only limited opportunities for customers and

The main reason for revising demand charges as they exist today is to provide an improved price signal for customers relative to the system costs that they should help avoid or reduce.

new agents to come forward for the mutual benefit of both participating and non-participating customers.

A. Recommendations

The Department recommends changes in demand charge structure going forward. More specifically, the Department recommends the incorporation of dynamic pricing elements as price signals available to customers. This can be readily implemented through tariff changes that ride on top of existing rates. The Department believes that almost all of these recommendations can be implemented through PUC-led initiatives, without legislation. Indeed the PUC is already poised to address the issue of appropriate rate design for EVs, and rates that apply for public charging stations in the context of its current

With adequate time, current demand charge regime should change in more fundamental ways that will lead toward a more targeted price signal to better match customer price signals with system costs that can be avoided.

investigation required by lawmakers. With adequate time, the current demand charge regime should change in more fundamental ways that will lead toward a more targeted price signal to better match customer price signals with system costs that can be avoided. In the context of the Commission's current investigation, the Department will foster further development of proposals to provide immediate relief for public EV charging stations especially as related to high voltage fast charging stations. Demand charges in the current form may present a formidable barrier to accelerating the market for this new class of customer. With respect to the specifics, the Department recommends the following, provided that the enabling technologies are in place. Utilities without the enabling technologies should begin the transition to invest and install these enabling systems where cost-effective to do so.

Recommendation 1: Forward-Looking Emphasis – Traditional demand charges as they exist for most utilities in Vermont should be modified. These demand charges are largely built up from the assignment of historic or embedded costs. Increasing emphasis should be placed on forward-looking more dynamic components of system costs, such as coincident system monthly peak periods and annual peaks.

(The determination of demand charge levels using historic approaches may still be appropriate for embedded sub-system components of costs. But this too may change as the visibility and control of the system improve with advancements in grid technology.)

Recommendation 2: Extend to All – Forward-looking and dynamic capacity-related price signals or incentives should be available for all customers and rate classes.

Recommendation 3: Reduce Reliance on Ratchets – In the longer term, Vermont utilities should transition away from reliance on broadly framed demand ratchets for components of costs that do not persist for the distribution utility.

Recommendation 4: Focus on System Rather than Customer Loads – Over time, demand charges should be segmented to better reflect the character of system costs. Drivers of system costs should apply more narrowly around the time (and location) that represents the critical system loads (or relevant sub-system loads), rather than remain focused on customer loads.

Recommendation 5: Facilitate a Smooth Transition – The emphasis on more targeted demand charges in the future can focus initially on new loads and new customers, and allow existing customers to transition toward these price signals over time at their own pace, by taking advantage of new rate riders and other rate features that strike an appropriate balance between change and fairness to pre-existing ratepayers.

Recommendation 6: Provide Stopgap Relief -- Vermont utilities should offer a pathway for immediate relief from demand charges to new loads like EV public charging stations, including but not limited to the preferential rate concept, provided that the rate covers marginal costs and reasonably protects the system from the burdens of new coincident system peak loads.

In offering this set of recommendations, the Department has attempted to avoid being overly prescriptive. Sensible pathways will inevitably vary between different utilities with differences in technical abilities, and tolerance for innovation. The Department believes that these are directionally sound and can be applied in appropriate ways across different systems.

Rural customers, especially those located in smaller utility systems, currently feel the effects of demand charges that may not reflect system cost variables even more than those located in urban settings.

For rural customers, service by cooperative utilities, municipal systems, or by GMP, these pathways should offer some relief, both over time and in the immediate future, provided utilities take further steps to implement. First, the addition of ***dynamic components of prices or incentives*** means that customers have greater opportunity to manage their demand-related charges without substantial disruption to operations or activities. Second, these opportunities can now extend (optionally) ***to all customers*** willing to modify loads over relatively short periods for potentially significant savings. Third, as utilities ***place less reliance on persistent ratchets***, the savings can be felt immediately and persist without carrying the burden of prior-month loads. Fourth, by ***narrowing the timeframes or location for incentives***, the window of opportunity for cost management is fairly focused, offering opportunities for innovations in storage and managed loads to help garner savings. Fifth, these pathways can begin relatively easily by building a path to new rates that can be accessed by both new and existing customers when they are ready and willing to participate, by offering ***new rates and rate riders that can be self-selected at the customer's option***. Sixth, rate relief can apply ***immediately to a new class of***

loads that promise to spur entry of public charging for electric vehicles, or extend to any new industrial load that opts for the innovative rate. Combined, these modifications can be implemented in ways that lower the costs of electricity for both participating and non-participating customers **because these pathways create real and almost immediate benefits to the utility system that correspond to benefits of participating ratepayers.**

In summary, the Department recommends that our electric utilities place greater emphasis on more focused and dynamic elements of costs that can more readily be avoided by customers, aggregators, and through utility controls. In effect, the Department recommends a shift from the current demand charge regime that centers on stable revenues to a stable source of earnings or margins that more closely pairs revenues with costs. The Department recommends providing a stronger emphasis on dynamic price signals that help avoid forward-looking system costs for the benefit of both participating and non-participating customers. The Department also recommends implementation through mechanisms that are effectively employed to facilitate the transition, and to do so without violating traditional sensibilities for price stability and simplicity. These elements rely on optional tariff riders for dynamic elements; closing out older rate elements; effective use of utility load management; and effective use of new business partners that can employ technology to provide both system value (for non-participating customers) and ratepayer dividends to participating customers with flexible loads and load profiles.

Acknowledgements

This report was prepared by the staff of the Vermont Public Service Department. The Department extends its gratitude to Ms. Bonnie Reese, Phd.-candidate from the University of Vermont, for her technical and editorial assistance throughout the project; Mr. Kenneth Jones, Phd., with the Vermont Agency of Commerce and Community Development, who provided editorial and technical assistance in the late stages of the draft; and to Mr. Rick Weston, Policy Director at the Regulatory Assistance Project that provided guidance and editorial assistance in early stages of project development. The Department also extends its gratitude to the individuals, and organizations that participated in the rate design workshop proceedings that collaborated and provided commentary on draft version of the report. The Department, however, takes full responsibility for the contents and recommendations contained in the report.

Appendix I

No. 194. An act relating to rural economic development.
(S.276)

* * * Electric Utility Demand Charges; Rural Towns * * *
Sec. 9. DEMAND CHARGES; REPORT
(a) On or before January 31, 2019, the Commissioner of Public Service (Commissioner), in consultation with the Secretary of Commerce and Community Development, shall submit a written report on electric utility demand charges in Vermont and their effect on the ability of industrial enterprises to locate in rural towns of the State.
(b) The Commissioner shall submit the report to the House Committees on Agriculture and Forestry, on Commerce and Community Development, and on Energy and Technology and the Senate Committees on Agriculture, on Economic Development, Housing and General Affairs, and on Finance.
(c) The report under this section shall include:
(1) a narrative summary of the terms, conditions, and rates for each demand charge tariff of each Vermont electric utility;
(2) a table that shows the rates and applicability of each such tariff, with such other information as the Commissioner may consider relevant, organized by electric utility;
(3) an analysis of the alternatives to these tariffs that will improve the ability of industrial enterprises to locate in rural towns of the State, including the use of energy efficiency, self-generation, and other measures to reduce the demand of such enterprises on the interconnecting electric utility;
(4) the Commissioner's recommendations on changes to demand charge tariffs and other methods to reduce demand that would encourage locating industrial enterprises in rural towns of the State or that would reduce or remove disincentives posed by demand charge tariffs to such locations.
(d) In this section, "rural town" shall have the same meaning as in 24 V.S.A. § 4303.

Appendix II -- Glossary of Key Terms

<u>Avoided costs</u>

Costs that are forward-looking in character and can be avoided by the system in response to well-formed price signals that trigger customer investment or behavioral response.

<u>Ratchets (on Demand Charges)</u>

Ratchets on demand charges pertains the residual share of monthly charges that serve as a minimum demand charge for the customers beyond the peak load in a given month.

For any given customer with a load of, say, 1 MW and a $10/kW-month charge, the resulting monthly demand charge would be $10,000. If an 80% ratchet applied, the charge for the subsequent 11 months would never drop below $8,000 (80% of the initial month) even is loads dropped to something well below the 80%. If, however, load exceeded the 1 MW in subsequent periods would serve to reset the minimum demand charge for the subsequent 11 months at 80% of the subsequent reference load.

<u>Embedded costs</u>

Embedded costs refers to the current and historic costs of service that must be recaptured in rates through the cost-of-service or "revenue requirement" determination of the regulator (in Vermont the Public Utility Commission). Cost-of-service regulatory settings, embedded costs may include the costs of expenses for recover of past capital investment (i.e., depreciation), ongoing operating accounts that are directly assigned or allocated to a given cost-element category (i.e., customer charge, peak demand, or energy). Embedded costs may be distinguished from forward-looking or marginal costs that are more readily associated with opportunities to target, avoid, and/or shift.

<u>Upstream costs</u>

Upstream costs as used in this report refers to costs that are typically above the retail and distribution system costs of the electric utility business. As used throughout this report they refer to costs that fundamentally arise upstream at the level of the Independent System Operator in New England in relation their operation of the Forward Capacity Market(FCM), and payment system for the pooled bulk transmission (i.e., Regional Network Service) that is associated with the bulk transmission (at or above 115 kV) system.

<u>Forward-looking costs</u>

Forward-looking costs reflect that costs that have yet to be incurred by the utility and, at least in principle, are potentially avoidable by the utility and/or their customers. Energy costs associated with wholesale market purchases, for example, may be avoided through utility conservation. Capacity charges, and the fees for pooled bulk transmission facilities that are imposed on utilities and passed to customers in rates may be avoided by reducing annual summertime coincident regional system and monthly Vermont system peaks.

Dynamic rates

Dynamic rates refer to rate designs that are fundamentally changeable in relation to time and/or price levels (and potentially location). Boundary on the rates included in the tariff ensure that appropriate ratepayer protections apply. By comparison, traditional rates are static in character, meaning that the price is known for each hour of the year and for each season. Examples of dynamic rates might include rates that only apply after the utility has given customer notices of a prospective peak period event and has notified the customer of the higher rate or has requested curtailment. Categories of dynamic rates include real-time or hourly rates, critical-peak pricing, peak-time rebates, interruptible rates.

Appendix III – Demand Charges in Vermont

Vermont Demand Charges

Utility	Rate Class	$ per kW/Month	Demand Ratchet	Note
Barton	Residential Demand Service	$7.91	85% highest kW previous 11 months.	
	Large Commercial Service	$12.28	70% highest kW previous 11 months.	
Burlington Electric Department	Large General Service (LG)	$20.03	50% of the highest summer month's demand (June through September) occurring within the preceding 11 months.	
	Large General Service Time-of-Use (LT)	$25.47	50% of the highest summer month's demand (June through September) occurring within the preceding 11 months.	Summer On-Peak
		$25.47	50% of the highest summer month's demand (June through September) occurring within the preceding 11 months.	Winter On-Peak
		$3.53	50% of the highest summer month's demand (June through September) occurring within the preceding 11 months.	Off-Peak
	Primary Service (PS)	$25.17	50% of the highest summer month's demand (June through September) occurring within the preceding 11 months.	On-Peak
		$3.45	50% of the highest summer month's demand (June through September) occurring within the preceding 11 months.	Off-Peak
Enosburg Falls	Large Commercial Rate 03	$10.91	50% of the maximum 15 minute metered demand occurring in the prior 11 months.	
	Industrial Demand Rate 04	$13.82	70% of the maximum 15 minute metered demand occurring in the prior 11 months.	
Green Mountain Power	Rate 8 - General Service	$16.740	50% of the highest 15-minute peak occurring during the previous 11 months.	April 1, 2018 - March 31, 2019 (Over 5 kW)
		$17.090	50% of the highest 15-minute peak occurring during the previous 11 months.	April 1, 2019 - March 31, 2020 (Over 5 kW)
		$17.448	50% of the highest 15-minute peak occurring during the previous 11 months.	April 1, 2020 and thereafter (Over 5 kW)
	Rate 12 - Primary Service	$9.856	Highest 15-minute peak during current month; not less than 80% in next 11 months.	Over 100 kW December through March
	Rate 63/65 - Commercial & Industrial Time-of-Use Service*	$14.023	50% of the highest 15-minute peak occurring during the previous 11 months' peak hour periods; greatest 15-minute peak occurring during off-peak hours.	April 1, 2018 - March 31, 2019 (First 5 kW); Peak hours shall be a period of 16 consective hours selected by GMP between 6 AM and 11 PM on weekdays (Monday through Friday). All other hours are considered off-peak.; Over 100 kW December through March - not less than 60% in next 11 months for legacy CVPS customers until March 31, 2020.

		\$17.962	50% of the highest 15-minute peak occurring during the previous 11 months' peak hour periods; greatest 15-minute peak occurring during off-peak hours.	April 1, 2018 - March 31, 2019 (Over 5 kW); Peak hours shall be a period of 16 consective hours selected by GMP between 6 AM and 11 PM on weekdays (Monday through Friday). All other hours are considered off-peak.; Over 100 kW December through March - not less than 60% in next 11 months for legacy CVPS
		\$18.710	50% of the highest 15-minute peak occurring during the previous 11 months' peak hour periods; greatest 15-minute peak occurring during off-peak hours.	April 1, 2019 - March 31, 2020 (First 5 kW); Peak hours shall be a period of 16 consective hours selected by GMP between 6 AM and 11 PM on weekdays (Monday through Friday). All other hours are considered off-peak.; Over 100 kW December through March - not less than 60% in next 11 months for legacy CVPS customers until March 31, 2020.
		\$18.710	50% of the highest 15-minute peak occurring during the previous 11 months' peak hour periods; greatest 15-minute peak occurring during off-peak hours.	April 1, 2019 - March 31, 2020 (Over 5 kW); Peak hours shall be a period of 16 consective hours selected by GMP between 6 AM and 11 PM on weekdays (Monday through Friday). All other hours are considered off-peak.; Over 100 kW December through March - not less than 60% in next 11 months for legacy CVPS customers until March 31, 2020.

* Subject to Curtailable Load Rider, Critical Peak Rider and Load Response Rider. Please see greenmountainpower.com for additional details.

Hardwick Electric Department	Industrial And Large Commercial Rate 03	\$16.31	80% highest kW previous 11 months.	
Hyde Park	Large General Service Rate	\$20.89	85% highest kW previous 11 months.	
Jacksonville Electric Department	Industrial	\$13.46	60% highest kW previous 11 months.	
Johnson Water & Light	Standard Large Commercial Rate	\$20.72	85% highest kW previous 11 months.	
	Johnson College Rate	\$23.26	85% highest kW previous 11 months.	
Ludlow	Residential Demand Rate 08	\$14.12	85% highest kW previous 11 months	
	Commercial and Industrial Rate 07	\$11.16	85% highest kW previous 11 months exceeding 15 kW	First 5 kW
		\$12.99	85% highest kW previous 11 months exceeding 15 kW	Over 5 kW
	Multiple Tenancy Rate 12	\$11.16	85% highest kW previous 11 months exceeding 15 kW	First 5 kW
		\$12.99	85% highest kW previous 11 months exceeding 15 kW	Over 5 kW
Lyndonville	Residential Rate "LP"	\$9.56	60% highest kW previous 11 months.	
	General Service Large (LG)	\$17.38	60% highest kW previous 11 months.	

Morrisville	Large Commercial Demand Rate S2a	$9.46	80% highest kW previous 11 months	
	Industrial S3	$13.46	80% highest kW previous 11 months	
	Industrial T.O.D. S9	$15.90	80% highest kW previous 11 months	
	Residential Demand S11	$5.80	80% highest kW previous 11 months	
Northfield	Large Power Consumption Rate:	$8.86	80% highest kW previous 11 months	
	Large Power Consumption Rate:	$6.61	80% highest kW previous 11 months	
	Large Power Consumption Rate: ED	$2.20	80% highest kW previous 11 months	
Orleans	Industrial Service	$12.79	85% highest kW previous 11 months	
Stowe	Large Commercial Rate 25	$16.58	85% highest kW previous 11 months	
Swanton	Residential Demand Service "A-	$9.17	85% highest kW previous 11 months	
	Industrial And Large Commercial Service	$14.54	85% highest kW previous 11 months	
VEC	General Service Rate Demand Billing Provision	$20.88	80% highest kW previous 11 months	
	General Commercial Time of Use Rate	$24.34	80% highest kW previous 11 months	demand vs. $23.52 per meter for non-demand)
		$17.56	80% highest kW previous 11 months	demand vs. $23.52 per meter for non-demand)
	Industrial Rate:			
	Distribution - Firm	$19.89	80% highest kW previous 11 months	
	Distribution - Interruptible	$16.32	80% highest kW previous 11 months	
	Subtransmission - Firm	$12.04	80% highest kW previous 11 months	
	Subtransmission - Interruptible	$8.48	80% highest kW previous 11 months	
Washington Electric Coop	Large Power Rev. Class 8	$15.60	90% previous applicable winter months	

Appendix IV – Response to Legislative Requirements

Act 194 Subsection 9(c) requires the following responses. The Department has endeavored to provide these responses through the body of report. Summarized here are the responses and references in the document:

(1) a narrative summary of the terms, conditions, and rates for each demand charge tariff of each Vermont electric utility;

A narrative explanation of the terms, conditions, and rates are explained in Sections I.A. and Section II. of the report. A further narrative explanation of the demand charge tariff for each Vermont electric distribution utility is contained in Appendix III.

(2) a table that shows the rates and applicability of each such tariff, with such other information as the Commissioner may consider relevant, organized by electric utility;

Appendix III provides the rates and applicability of each demand charge tariff accompanied with other information that the Commissioner considers relevant, organized by electric distribution utility.

(3) an analysis of the alternatives to these tariffs that will improve the ability of industrial enterprises to locate in rural towns of the State, including the use of energy efficiency, self-generation, and other measures to reduce the demand of such enterprises on the interconnecting electric utility;

Subsection III.E. and F. of the report provides an analysis of the alternatives to these tariffs that might improve the ability of industrial enterprises to locate in rural towns in the State, but the concepts and analysis provided extend further to include relevant alternatives that might serve the interests of any customer or utility system in Vermont. The sidebar in Section I.A. of the report highlights the basic challenge that rural utility systems face in response to efforts to manage loads through energy efficiency, self-generation, and other measures to reduce the demand of such enterprises on the interconnecting electric utility without a more fundamental shift in the design of traditional demand charges. In brief, demand charges as they exist, run the risk of creating unexpected financial disruption, cost shifts onto non-participating ratepayers, and undercutting the anticipated savings to customers that actively pursue energy efficiency and load management to reduce their own demand. Potential alternatives are presented in Subsection III.E. and F.

(4) the Commissioner's recommendations on changes to demand charge tariffs and other methods to reduce demand that would encourage locating industrial enterprises in rural towns of the State or that would reduce or remove disincentives posed by demand charge tariffs to such locations.

Section IV.A. of the report provides recommendations for changes to demand charge tariffs and other methods to reduce demand that could help to encourage, or at least, mitigate against rates that discourage industrial enterprises in rural towns of the State. The recommendations that the Commissioner offers in this report concern matters that extent to both rural and urban communities and systems. The thrust of these recommendations is to encourage a gradual shift from a primary focus on fairness and adequate recovery of historic costs, to one that gradually shifts toward a much more forward-looking and sharper prices signal that can be better employed to help reduce both system and customer costs. The Department believes that these ends can be accomplished in a manner that is sensitive to the distribution utility financial health, and that is also sensitive to investments and commitments of some customers to manage their loads based on historic rate designs that include traditional demand charges.