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Judith Whitney, Clerk
Vermont Public Service Board
112 State Street, 4th floor
Montpelier, VT 05620-2701

Re: Act 53 Public Service Department Energy Storage Report Proposed Outline

Dear Ms. Whitney,

Dynamic Organics, LLC ("DO") and BayCorp Holdings, Ltd. ("BayCorp") are pleased to provide the following comments to the Vermont Public Service Department ("PSD", or "the Department") in reference to the PSD's preliminary proposed Act 53 energy storage report outline.

1. What is missing or should be otherwise modified in the proposed report outline?

Thermal Storage
The Department developed a substantial preliminary outline for this energy storage report. However, energy storage seems to be treated solely as electrochemical battery storage. There are numerous components of "energy storage" such as thermal storage (i.e. grid interactive water heaters and building mass intertials), and flexible demand resources that can respond to changing grid conditions – using renewable energy when abundant and storing for when it's scarce (or load shifting).

These types of storage are often more cost-effective than pure electrochemical storage, and should be considered as storage assets with specific grid values in the report. Although thermal storage systems such as ice storage cannot provide backup power like a conventional electrochemical battery, the ability to shift heating, ventilation, and air-conditioning ("HVAC") loads out of coincident peak periods provides the grid the same capacity reductions as a battery. This thermal storage can be used as a load reducer if applied during peak periods to decrease the capacity requirements of the distribution utility ("DU"). Air-conditioning ("AC") is provided to without any loss of comfort via a simple circulator pump running through the stored ice energy (in lieu of the normal compressor load requirements).

As the Department has outlined electric vehicles ("EV's") under the ownership options and delivery pathways for promoting storage section, we recommend that thermal storage be added to this same section. EV charging does not yet provide power back to the grid (though this is being piloted around the US, but will require large changes to EV warrantees if adopted at any scale), and therefore the EV inclusion in the storage report outline is based on the idea of load-shifting the charging of these vehicles to off-peak or over-generation hours.

This same load shifting can be accomplished by HVAC appliances, and can create even more value for the grid than EV's if properly incented. This is because the coincident peak demands of the grid normally occur on the warmest and coldest days of the year – when HVAC devices are running at full capacity. Load shifting of HVAC therefore reduces the coincident demands on the grid, rather than just offsetting these demands with electrochemical storage discharged to the grid during these times.

The definition of a battery in this context should be changed to capacitance, as batteries are acting as a surge device or capacitor for the grid. Flexible loads, such as HVAC thermal storage, can also act as a choke to slow the rates of change in load/demand. As Vermont transitions from fossil-fuel heating, the uncontrolled loads of heat pumps will increase peak demands unless better control and dispatch of these technologies is adopted. To sequence the dispatch and control of electrochemical batteries, thermal storage, and flexible demand response in the future smart grid, dynamic rates and secure telemetry will be required in an open environment that encourages the advancement of the renewable grid.

Smart Grid Architecture

Missing from the Department's outline is any discussion of the open smart grid architecture required across Vermont that enables both the storage deployment and the innovation needed to create a lower carbon grid. This architecture is relevant to all sections of the storage report outline, and examples of existing architectures such as the Open Automated Demand Response ("Open ADR") protocols should be reviewed and included in the report for discussion. Open specifications and flexible data models such as Open ADR 2.0b are used to facilitate common information exchange between electricity service providers, 3rd party aggregators, and customers – capable of even dynamic variable rate structures at increasing granular intervals.

Included in the Department's report should be a more fundamental background on other states and countries previous work developing solutions to how an interoperable, open, reliable, and secure smart grid architecture is managed and deployed. Extensive work has been undertaken by parties such as the Smart Grid Interoperability Panel ("SGIP"), Electric Power Research Institute ("EPRI"), Open ADR Alliance and others which can be adopted and built upon by Vermont to produce an open architecture smart grid that can be deployed across the state.
This architecture provides a secure and reliable platform to communicate forecast and real-time grid demands and pricing, providing the economic driver that will encourage behavioral change and deployment of enabling technologies.

2. What are the most compelling reasons for deploying energy storage in Vermont?

Energy storage is required to build a more renewable grid. Vermont is uniquely positioned to work collaboratively with stakeholders to develop storage deployment and smart grid solutions due to our alternative regulation plans and the Vermont legislature's history in properly valuing renewables. The value propositions these solutions provide need to be demonstrated to other states not as progressive as Vermont so that a cleaner grid can be adopted across the US.

Independent service operators ("ISO's") and DU's presented with increasing distributed renewable generation ("DRG") face steep ramping rates for conventional thermal generation as shown in Figure 1 below for ISO New England ("ISO-NE") and the Vermont Electric Company ("VELCO"). Note that Vermont has a high per-capita DRG installation compared with other New England states, and a corresponding 23% peak offset from maximum morning load to minimum afternoon load from solar vs. the 11% ISO-NE average.

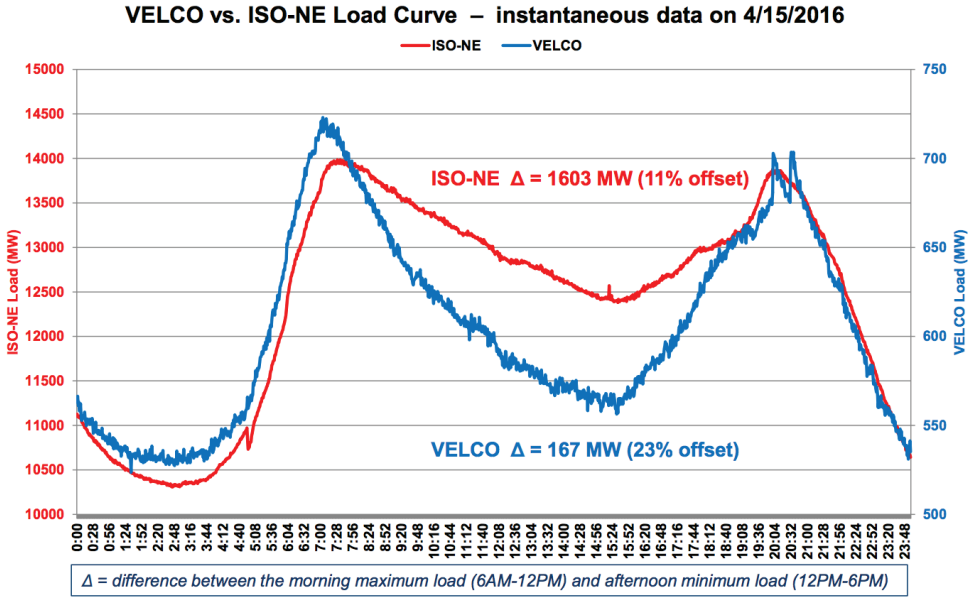

Figure 1. VELCO vs. ISO-NE "Duck Curve" Comparison from 4/15/2016 [1]

In addition to increasing DRG, electric vehicle charging loads and large increases in the use of high-efficiency electrical heating technologies such as heat pumps ("HP's") further challenge grid stability. Even in a cold climate such as Vermont, VELCO estimates that HP technology will account for three times more load than the EV market by 2035. Because outdoor air temperature ("OAT") is the primary driver of coincident electric grid peaking demands already, primarily due to air-conditioning ("AC"), the exponential growth of HP's will have significant impacts on the grid. This is evidenced below in Figure 2 with the VELCO forecast growth estimates of PV production and the oncoming demand of electrifying transportation and heating. Vermont's Act 56 and the Comprehensive Energy Plan lay out with specificity that DU's need to encourage this fossil-fuel transition while managing the coincident peaking of grid demands.

[1] Taken from the "State of Vermont's Transmission Grid" – 2016 REV Conference Presentation by Hantz Presume, VELCO

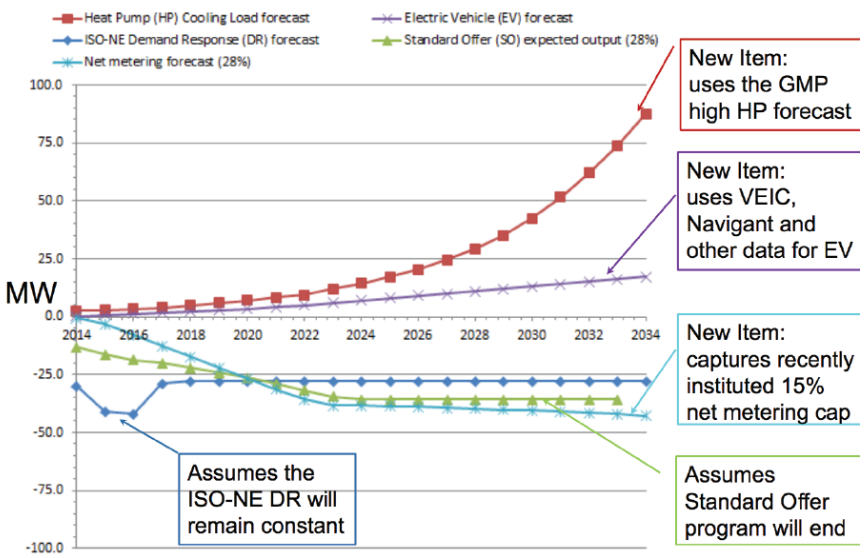

Figure 2. VELCO forecasts of Vermont PV, Demand Response, HP, and EV Growth [2]

Penetration of DRG and the growth of HP's and EV's will create problems for the current grid without significant changes to how we determine electricity rates. Storage is needed in Vermont to load shift DRG production, helping to maintain the value of renewable energy, specifically PV, and continue to incent its adoption. Present rate structures for renewables don't reflect the highly variable value of energy at different times, and we often value each kilowatt ("kW") the same as every other kW. When net-metering was conceived 40 years ago, any solar that could be produced and exported to the grid was occurring during normal daily peak load hours, and coincident with the warmest sunny days in mid-summer. As DRG penetration has increased rapidly in Vermont over the last 6 years, the FCM peak has been pushed back later and later into the evening following the significant ramping rates after PV generation drops off each day.

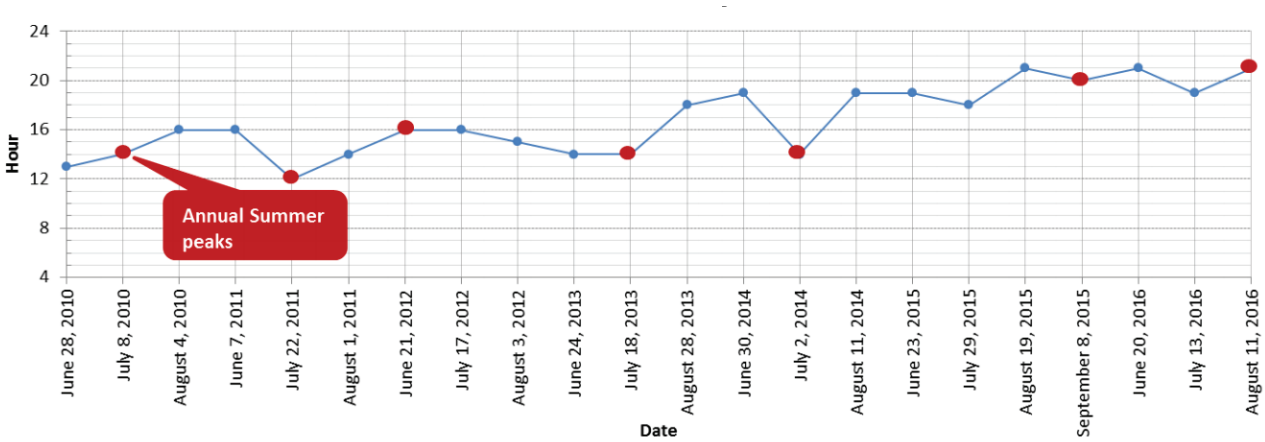

Figure 3. Vermont Summer Monthly Peak Times 2010-2016 [3]

[2,3] Taken from the "State of Vermont's Transmission Grid" – 2016 REV Conference Presentation by Hantz Presume, VELCO

As the FCM peak moves later into the evening, the value that solar provides in countering this peak load is decreased. The overall trend shown in Figure 3 illustrates how pushing down on the duck's back year by year with DRG, the coincident peak demands on the VELCO grid system is pushed later into the evening as the PV generation fades. Until we figure out storage and flexible capacity, each marginal kW of DRG will be less valuable.

3. What are the biggest barriers to deploying storage in Vermont?

To create a renewably powered grid and retire the current fossil fuel generation fleet, Vermont has to evolve its current regulatory markets, rate design policies, and redefine the roles of both the DU's and Efficiency Vermont ("EVT"), so that all stakeholders are aligned to facilitate the active balancing of DRG and continuous demand management of loads; or the smart grid. Simple efficiency measures, as effective as they have been in reducing total-energy consumption, may also burden utilities if not better managed. The heat pump program from GMP and EVT provides an example of this, where though there is a net-efficiency gain for the household, GMP is still subject to the coincident peaking of these uncontrolled loads.

Balancing intermittent DRG resources will require changing the current grid structure from a supply-side management framework where generation is dispatched to follow loads, to a demand-side management framework where load and storage are dispatched to follow and firm intermittent DRG production. DU's once performed this more active dispatch of generation, but due to deregulation and the decoupling of generation in the majority of the US, they often just manage billing and wires. This is not the case in Vermont, and our utilities are being forced out of necessity to take on this dispatch role once again. Green Mountain Power ("GMP"), for example, cites that they have gone from operating 10 power sources to operating 8,300 power sources in 10 years (this includes net-metered solar projects).

The smart grid will require magnitudes more DER deployed over the distribution grid, and because these resources are all below the ISO level, they can be better dispatched and managed below the substations by DU's. This balancing can be accomplished through price signals derived from existing forecasting tools already developed and continuously improved upon by VELCO's Deep Thunder machine-learning forecasting tool, and combined with the real-time voltages at substation feeders. Loads managed by the DU's, EVT, 3rd party aggregators, and customers across Vermont can use these locational economic signals to respond continuously, providing the aggregate demand-side management tool needed to balance a renewable grid.

With a reliable, secure, open architecture smart grid framework capable of sending these price signals and reliably accounting for flexible demand response and storage performance, Vermont can unlock smart grid innovation across the state. This is needed to evolve the current supply-side system where utility-scale DER is dispatched mainly by transmission authorities to one where dispatch signals are generated for the distribution grid - below the substation - allowing electrons to be renewably generated and used locally.

Distributional locational marginal pricing ("DLMP") signals may not be something that Vermont wants to tackle immediately, and can be difficult to cost-justify in comparison to current grid contracting and capacity obligations. However, this should be viewed as the penultimate goal for Vermont, and this report should outline steps that help to achieve this result. Pilots that can help to prove the value proposition of DLMP signals and demand-side response should be encouraged across Vermont to help define and adopt dynamic rate designs and policies.

Current renewable incentivizes in Vermont including utility rate structures for net-metering, feed-in tariffs under the Standard Offer Program, and even the Renewable Portfolio Standard ("RPS") legislation, do not incent peak load reduction, but total energy reduction. Because these current tariffs and incentives do not differentiate renewable power based on the time it was produced, and is therefore agnostic to the marginal generation unit at the time of production, Vermont runs the risk of catalyzing unequal grid-related and fuel-related benefits without a more granular approach to rate design.

This is further detailed in the report, "Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future," developed by Strategen Consulting on behalf of the Arizona Residential Utility Consumer Office, is recommended for Department review for background and inclusion in this storage report. [4]

Most Vermont households are charged for electricity under an average fixed residential rate. This volumetric $/kWh pricing blends the transmission and distribution ("T&D") with the generation portion of the utility costs. Fixed, averaged-cost electric rates incent efficiency, or total energy savings, but not peak grid demand and capacity reductions (a significant portion of average electric costs). This has enabled us to develop mechanisms like "net-zero" homes that generate 2-3X household load with photovoltaics ("PV"), pushing this power onto the grid during the day, and using thermally generated electricity during evening, night time, and cloudy periods.

This has a significant benefit for the customer, who uses the grid as a massive battery with no round-trip inefficiencies, but has left utilities incenting only the reduction in total energy consumption of buildings – without reducing overall capacity and peak demands of the grid. Although the home may have a "net-zero" kWh use, the KW demand and capacity requirements of the building may not change at all from the grids perspective. After the sun goes down, the same existing thermal generation capacity is required by the "net-zero" home in the evening as the non-DRG connected home, contributing to the ever-steeper ramping rates required as more DRG is put on the grid. This has created incentives that worked with smaller levels of DRG-penetration, but has less benefits for the grid as capacity peaks are pushed later into the non-solar evenings.

Additionally, DRG penetration and the increasing heat pump demands expected even in cold climate states like Vermont are changing the characteristics of supply and load. Rates need to evolve that distinctly address both energy and capacity on the wholesale and retail levels. This is

[4] https://www.strategen.com/new-blog/2016/12/1/evolving-the-rps-a-clean-peak-standard-for-a-smarter-renewable-future

already occurring in pilot format throughout the country, with some utilities adopting critical peak pricing ("CPP") and even piloting real-time rates. These kinds of dynamic rates will be required to incent and balance these increasing DRG resources behind the meter, providing an economic incentive for behavioral change and technology adoption that will create the smart, flexible, renewable grid we need. These same pilots need to be built upon with similar investigations across Vermont in order to define this value to the grid. DO and BayCorp recommend the Department review reports developed by the Rocky Mountain Institute regarding the economics of storage and flexible demands, specifically the following:

The Economics of Battery Energy Storage, 2015 [5]
The Economics of Demand Flexibility, 2016 [6]

Virtual Allocation of Demand through the GMP Curtailable Load Rider

Rate structures and tariffs that incent peak demand reduction and a smarter grid need to be developed, but Vermont already has existing tariffs (namely the CPP and Curtailable Load Rider ("CLR")[3] that can be amended to unlock storage value and create deployment opportunities resulting in savings for all system customers. Few customers currently participate in the CPP or CLR tariff rate and rider. DO and BayCorp reference them here as evidence of rate structures that are already available to GMP customers and which encourage peak demand reductions.

DO and BayCorp provide the following example of our current development work as an illustrative example and answer to both of the Department's questions 4 and 5:

Background
DO has been working with a large hospital in GMP service territory that is transitioning to the N63/65 C&I Time of Use ("TOU") rate and looking to use power more efficiently. Currently, the TOU rate is a simple on-peak (6am-10pm) and off-peak (10pm-6am) differential kWh rate structure with T&D broken out separately. The hospital has a summer peak of 650 KW and a winter peak of 350 KW (when the central biofuel boilers have replaced AC loads). There is currently a 3 MWh ice storage bank on the campus that charges overnight in the summer at the off-peak rate and then reduces on-peak AC kWh and demand during the day for the campus.

The hospital needs to have uninterruptible power supply – currently provided within 9 seconds of interruption by the onsite backup diesel-generators. Locating a grid-scale flow battery on the hospital campus can provide uninterruptable power supply ("UPS") within 200 milliseconds of interruption – and without any fossil fuel backup generation. This can be used as the primary backup system, and the 4 MWh of capacity of the flow battery (if fully charged) could provide power to the hospital for 6-7 hours in the summer and almost 14 hours in the winter (assuming an average 600 KW summer peak and 300 KW winter peak demand).

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[5] www.rmi.org/insights/reports/economics-battery-energy-storage/

[6] https://www.rmi.org/insights/reports/economics-demand-flexibility/

[3] http://www.greenmountainpower.com/wp-content/uploads/2016/09/Curtailable-Load-Rider-4.1.16-1.pdf

Creating a Virtual Curtailable Load

If sized solely to accommodate the hospital's load, the capacity of the battery would be less than 1 MW. The only revenues that would be received by the battery owner would be the compensation under the curtailable load program. If, however, the battery could be sized at 1 MW or larger, the battery could participate in the ISO-NE frequency regulation market. The revenues from frequency regulation would improve the economics of the battery installation and increase the likelihood of the economic viability of the energy storage project.

DO and BayCorp are discussing a concept development for a utility-scale storage asset located on the hospital campus that can achieve the economic benefit of participating in the frequency regulation market by installing a 1 MW battery and creating a 100 kW "virtual" curtailable load using a portion of the battery's capacity.

The flow battery would be available under contract with GMP to be dispatched at their discretion during peak periods for peak shaving. GMP determines these events, similar to a CPP, through forecast grid demands and other inputs. Using this same forecasting, GMP offers a Curtailable Load Rider ("CLR") tariff to C&I customers who can actively reduce load during the 4 to 6 hour curtailable periods, and offers a revenue-neutral TOU/CPP rate schedule for residential customers that has 10, 8-hour CPP periods (80 hours per year)[4]. When dispatched, GMP would realize the capacity, capacity-related (such as ancillary services), and other savings from the reduction in annual and monthly peak loads resulting in savings for all customers on the system. GMP would in turn reimburse the host facility for a portion of the demand reduction that the facility has been allocated and paid for. In this case, the allocation to the hospital would be 100 kW and they would receive curtailable load payment for that amount when the energy storage facility is discharged. Importantly, the energy storage facility can now participate in the frequency regulation market and use those revenues to support the construction and operation of the facility.

There is no reason why this "virtual" curtailable load arrangement need be limited to a single C&I customer. The allocation of the curtailable load rider payment is purely administrative much like the allocation of net metering credits that the Vermont utilities account for and credit to customer accounts. Multiple accounts could participate in owning all or a portion of the battery's capacity and the host utility derives benefit should any portion of the battery's capacity not be allocated.

In the case of the hospital presented below, allocating a portion of the storage output to the CLR can create the incentive needed for investment in other enabling technologies (active demand management and storage) that create a more flexible campus load profile. The CLR states that the C&I customer must be able to reduce loads 25% from average monthly peaks during the curtailable event. For the hospital, this means reducing summer loads by approximately 160 kW and winter loads by 90 kW. The outline below shows how the flow battery capacity would be allocated during the CLR.

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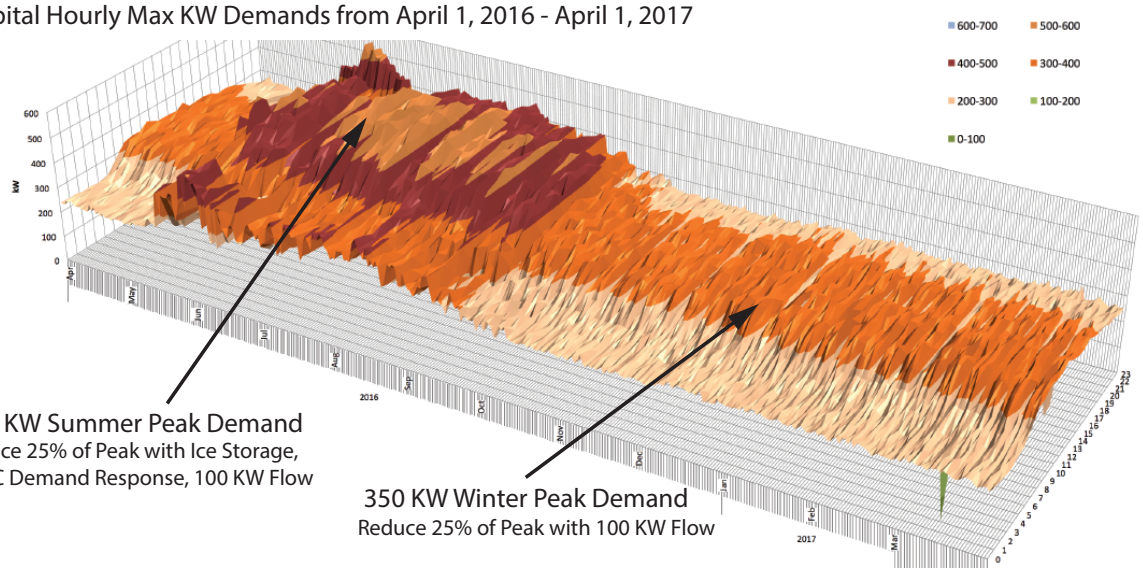
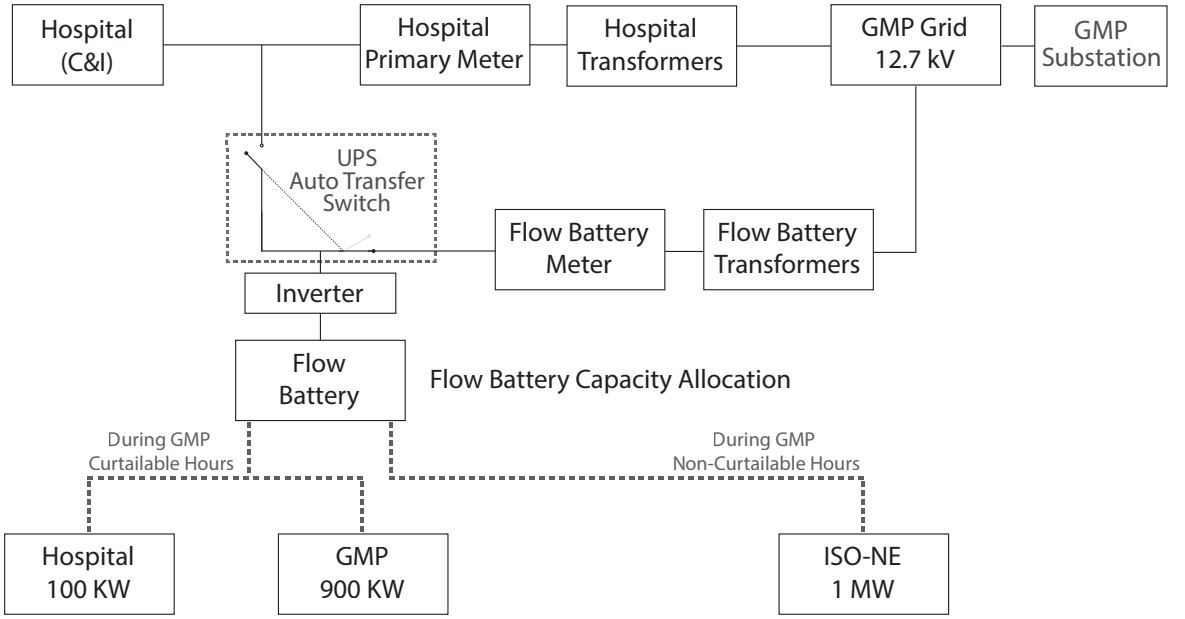
[4] http://www.greenmountainpower.com/wp-content/uploads/2016/09/Rate-9-Critical-Peak-Pricing-10.1.16-1.pdf

C&I Hospital in GMP Territory - Virtual Demand Allocation Example

Hospital Hourly Max KW Demands from April 1, 2016 - April 1, 2017



Example One-Liner of Flow Battery "Partition" at Hospital



Virtual Metering of Hospital Demand Reduction during Curtailable Load Hours

Flow Battery Participates in ISO-NE Frequency Regulation Market the Majority of Time

Collocating the flow battery "partitioned" around the primary meter of the hospital campus allows the value of the storage asset to be stacked between GMP and C&I customers. During non-curtailable hours the full 1MW flow battery capacity is used to participate in ISO-NE frequency regulation. 900 KW of battery capacity is available to be called upon 100 days per year (4 hrs/day) as defined by GMP during curtailable load periods. During this same time the hospital will use 100 KW for demand reduction to help 25% load rider reduction. The hospital benefits additionally by the uniterruptible power supply being available during grid outgages.

Figure 4. Example Virtual Demand Allocation of Battery Capacity with GMP's CLR Tariff

Stacking Function and Value, Incentivizing Peak Demand Reduction and a Smarter Grid
Beyond the benefits of the flow battery providing UPS power and allowing for 100 kW of demand reduction per month from the virtual demand allocation, participation in the CLR tariff provides the hospital with an economic incentive to demand manage and reduce peak loads across the campus. The existing 3 MWh ice storage asset is currently charged overnight during off-peak periods and then immediately begins discharging at 6 am at on-peak rates. The differential rate of on/off peak charging garners some savings for the hospital, but the binary TOU pricing schedule isn't aligned with the needs of the grid.

The ice storage is far more valuable to GMP if it can be charged overnight and then made available during the afternoon peak periods, especially during the steep ramp required of conventional thermal generation as daily solar production fades. As the hospital already owns this ice storage load shifting asset, the additional demand reduction benefits attained through participation in the CLR tariff comes at minimal costs to the campus. DO is currently modeling the capacity and performance characteristics of the flow battery, and working with EVT engineers on an efficiency optimization program algorithm for the standard TOU charging cycle of the battery. The DO controller developed for the project will discharge the ice using a different response program for CLR days when called upon by GMP.

Figure 4 illustrates how the ice storage asset could provide the additional kW demand reductions required for the hospital during the summer AC-season to reduce average monthly peaks by 25%. This supplants the 100 kW of demand that could be virtually allocated through the meter, and aligns the load shifting ice storage technology with the needs of the grid through the economic incentive of reduced demand charges provided by the CLR. Additionally, the CLR tariff encourages deeper adoption of enabling storage technology and flexible demand management, as every kW that the hospital can reduce during the CLR period is worth ~ $15 (approx. average $/kW-month demand charge of hospital during N63/65 transition from former CVPS Rate 04).

Conclusion
Storage is needed across the Vermont grid. Virtual allocation of storage using the CLR tariff is one example of how granular rate structures can help to incent the adoption of technologies that enable a smarter, flexible grid. The hospital example above illustrates how the coordinated dispatch of the flow battery, thermal storage, and building demand response combine to reduce the amount of overall storage capacity that would otherwise have been needed on the campus to offset these loads. This is the same 1+1=3 concept that DO and BayCorp suggest the Department consider in this storage report, namely, that a smarter grid with flexible loads aggregated with demand-side management tools can reduce the amount of storage needed to balance the future renewable grid. There doesn't need to be a 1:1 storage to DRG ratio if we can develop an open smart grid architecture that provides the secure communications and variable pricing signals needed to drive investment and innovation in the smart grid.

Energy Storage Report Outline Structure
In reference to the proposed outline, DO and BayCorp recommend that the Department consider the following revisions and additions to the Act 53 Energy Storage Report:

1. Introduction
2. State, regional, and national actions or initiatives affecting deployment of energy storage
    a. Storage description and definition
    b. Storage technologies
        Electrochemical
        Thermal Storage (Permanent Load Shifting, Flexible Demands)
        Hydro Reserve / Storage
    c. Storage applications
        HVAC
        EV
        Grid Support (Demand Flexibility)
    d. National storage landscape
    e. Regional storage landscape
    f. Vermont storage landscape
3. Federal and state jurisdictional issues regarding deployment of energy storage
    a. Wholesale/retail
    b. FERC orders
    c. ISO-NE storage activities
    d. VELCO or DU Defined Ancillary Service Signals
4. Benefits and Costs of Storage Systems in Vermont
    a. Uses Cases
    b. Benefits
    c. Costs
5. Ownership Options and Delivery Pathways for Promoting Storage
    a. Utility Ownership
    b. Third-Party Providers and Aggregators
    c. Electric Vehicles
    d. Open Smart Grid Architecture
    e. Virtual Demand Allocation ("Community Storage")
6. Potential Programs and Policies to Encourage Sound Storage Capabilities in Vermont
    a. Utility planning exercises
    b. Rate design
        Distribution Locational Marginal Pricing
        End Use Rates for New Technologies
    c. Energy assurance efforts
    d. Siting criteria/threshold for 248 review
    e. Interconnection standards
    f. EEU activities
    g. RPS multipliers
        Clean Peak Portfolio Standards
    h. Procurement targets
    i. Modification of existing (net metering, SO) or development of new incentive
        CLR Tariff, Virtual Demand Allocation
    j. Demonstration projects
    k. R&D
7. Recommendations

The Energy Storage report should focus on how the use of demand-management techniques and the development of an open smart grid architecture can reduce the amount of electrochemical storage needed to build the renewable grid. Adoption of Open ADR or other open standards already created can help Vermont evolve past a demand response framework and develop a flexible demand-side management system – with active, continuous balancing of DRG into buildings, vehicles, and storage to most cost-effectively deploy capacity across the grid.

Vermont should encourage and incent customers to change behavior and warrant the investment in enabling technologies that actively support the grid and encourage deeper penetrations of renewable energy. The Department should encourage the Public Utility Commission to develop a scalable, interoperable architecture that enables the partnerships with 3rd party aggregators and technology innovators that will be crucial to the ultimate development of the smart grid. Ultimately it will take a massive collaborative effort to build the renewable grid envisioned by Vermont.

Existing rate structures that incent peak demand reductions such as the CPP or CLR tariffs and rates should be adopted and encouraged immediately, with pilots that help prove the value proposition of even more flexible loads encouraged across the state. The Department should recommend similar interconnection options for virtual demand allocation of battery capacity. Just as community PV systems were enabled through virtual group net metering, batteries can be similarly developed as "community storage" projects with multiple offtakers. Under the CLR example provided above, it would be simple to have multiple virtual C&I customer offtakers using the utility-scale battery capacity.

The battery enables the hospital in our example to participate in the CLR tariff, as the ice storage alone would not be adequate to reduce peak demands, and unavailable for thermal storage in the winter. The 100 kW supplies the 25% winter demand reduction, and warrants the optimization of the ice storage control to attain the 160 kW reduction needed for summer peak reductions. The hospital is also investigating the flexible demand capabilities that already exist and might be able to be controlled by the campus building management system. The battery has therefore provided a carrot to the administration and facilities management team to investigate demand reduction and flexible capacities of the campus.

If this storage capacity can be virtually allocated to multiple campuses, the same economic drivers for curtailing peak loads can be made available to multiple C&I customers off the same battery. This allows the economies of scale of larger grid storage assets and unlocks available benefits to customers under existing rate structures. This can allow for no money down demand savings agreements, following on the power production agreements that unlocked PV growth. DO and BayCorp are excited to work with regulators and stakeholders to develop a smarter and cleaner grid for Vermont, and thank you for the consideration of these comments.

Sincerely,

Morgan Casella

Anthony M. Callendrello