

200820169

STATE CORPORATION COMMISSION
Division of Information Resources

July 29, 2020

2020 JUL 29 PM 3:30

MEMORANDUM

TO: Document Control Center
Clerk's Office

FROM: Ken Schrad



RE: PUR-2020-00120

I have attached a comment document dated July 29, 2020 from Jason Burwen, vice president for policy of the U.S. Energy Storage Association.

It was sent by email on the same date since the format could not be accommodated by the public comment text box feature available on the SCC website.

I ask that you submit these comments to the case file referenced below.

PUR-2020-00120

In the matter of establishing rules and regulations pursuant to § 56-585.5 E 5 of the Code of Virginia related to the deployment of energy storage

Attachment –

- July 29 comments of the U.S. Energy Storage Association

**COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION**

COMMONWEALTH OF VIRGINIA, *ex rel.*

STATE CORPORATION COMMISSION

Ex Parte: In the matter of establishing rules and regulations pursuant to § 56-585.5 E 5 of the Code of Virginia related to the deployment of energy storage

CASE NO. PUR-2020-00120

**COMMENTS OF THE U.S. ENERGY STORAGE ASSOCIATION ON
RULES RELATED TO THE DEPLOYMENT OF ENERGY STORAGE**

Pursuant to the Commonwealth of Virginia State Corporation Commission’s (“Commission”) Order Establishing Proceeding and seeking comment in Case No. PUR-2020-00120, the U.S. Energy Storage Association (“ESA”) respectfully submits these comments for the Commission’s consideration. In our comments below, ESA emphasizes key regulatory reforms and programs that will enable the Commission to meet the legislative intent on the 2020 Virginia Clean Economy Act (“VCEA”) while implementing energy storage targets that provide the greatest benefit and savings for residents and businesses in the Commonwealth.

I. ABOUT THE U.S. ENERGY STORAGE ASSOCIATION

ESA is the national trade association dedicated to energy storage, working toward a more resilient, efficient, sustainable, and affordable electricity grid—as is uniquely enabled by energy storage. With more than 190 members, ESA represents a diverse group of companies, including independent power producers, electric utilities, energy service companies, financiers, insurers,

law firms, installers, manufacturers, component suppliers, and integrators involved in deploying energy storage systems around the globe. Further, our members work with all types of energy storage technologies and chemistries, including lithium-ion, advanced lead-acid, flow batteries, zinc-air, liquid air, compressed air, and pumped hydro among others. A number of our members have operations in Virginia and/or are presently developing grid energy storage projects in the Commonwealth.

II. FRAMING COMMENTS

Virginia is the seventh state in the United States to establish an energy storage target through legislation, which currently stands as the largest target of any state in the nation. As the Commission navigates the goals and directives laid out in the VCEA with respect to energy storage, a key lesson learned from other states is that clear and reasoned regulations that include accountability are critical to the success of storage target efforts.¹ ESA appreciates the opportunity to submit these comments, many of which convey solutions gleaned from the experience of other states, to support the Commission in meeting the legislative intent of the VCEA while maintaining system reliability and affordability to households and businesses in the Commonwealth.

III. RESPONSES TO COMMISSION QUESTIONS

1. *What interim targets should be established for meeting the targets set forth in Code § 56-585.5 E 1 for APCo?*

ESA recommends that the Commission set initial interim targets for APCo of 100 MW cumulatively by Dec 31, 2022, and 200 MW cumulatively by Dec 31, 2025. Doing so will align interim target dates with APCo's current integrated resource planning ("IRP") cycle, and these

¹ A full list of states with energy storage targets is provided on ESA's website in the article "Energy Storage Goals, Targets, Mandates: What's the Difference?", 24 Apr 2020, available at <https://energystorage.org/energy-storage-goals-targets-and-mandates-whats-the-difference/>

values reflect reasonable expectations of the co-location of energy storage with renewable resources that APCo plans to procure over the next several years. Additionally, ESA recommends that the Commission review APCo's plans for future storage procurement in its IRP scheduled to be filed in 2025 and determine further interim targets at that time.

2. What interim targets should be established for meeting the targets set forth in Code § 56-585.5 E 2 for Dominion?

ESA recommends that the Commission set initial interim targets for Dominion of 400 MW cumulatively by Dec 31, 2023, and 900 MW cumulatively by Dec 31, 2026. Doing so will align with interim target dates with Dominion's IRP cycle, and these values cumulatively accord with planned storage procurements in the portfolio presented Dominion's most recent integrated resource plan, filed May 1, 2020, to comply with the VCEA.² The 2023 target represents an acceleration of procurement, which will enable Virginia ratepayers to benefit from federal tax incentives for solar-paired energy storage deployment that are presently phasing down, as well as to drive development of regulatory and business processes associated with storage procurement.

As new energy storage technologies are yet to be deployed at scale in Virginia, setting early targets is important to driving learning-by-doing for grid operators, storage providers, and state regulators. Learning-by-doing helps regularize business processes and familiarize officials with storage projects, reducing soft costs associated with energy storage project development in the Commonwealth. This in turn will help drive costs lower, sooner, and increase the likelihood of success in achieving overarching targets as specified in statute.

² See Figure 2.2.2. in "2020 Integrated Resource Plan of Virginia Electric and Power Company," Case No. PUR-2020-00035, *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's Integrated Resource Plan* filing pursuant to Va. Code § 56-597 et seq., 1 May 2020.

Additionally, ESA recommends that the Commission review Dominion's plans for future storage procurement in its IRP scheduled to be filed 2026 and determine further interim targets at that time. With the experience of meeting two interim storage procurement targets in succession, the Commission will be well-placed to consider what, if any, further interim targets are appropriate, as well as any lessons learned for shaping those further targets. Additionally, Dominion has received approval of its Preliminary Permit Application from the Federal Energy Regulatory Commission for an 800 MW pumped hydroelectric storage facility sited in Tazewell County. As this project is expected to be placed in operation toward the end of the 2020s, it is appropriate for the Commission to revisit targets based on the progress of that facility some years from the present date.

ESA respectfully recommends that the Commission require Dominion to conclude RFPs associated with these procurements at least two years prior to interim target deadlines (e.g., December 31, 2021 and December 31, 2024, respectively).³ Doing so will ensure that sufficient time is available for permitting and interconnection processes associated with new energy storage projects, particularly given the new processes which may be required for implementation of energy storage projects and the potential for unanticipated hurdles in permitting and interconnection. Additionally, early RFPs will provide Dominion and the Commission with storage project price information that can inform integrated resource planning cycles that follow, ultimately improving long-term resource planning decisions (see response to Question 3 below).

In the case that Dominion does not achieve or does not appear it will achieve an interim target by its deadline, ESA recommends that the Commission seek a report from the utility as to the reasons for not achieving the target. In addition, ESA recommends that the Commission

³ ESA notes that conclusion of RFPs up to 30 months prior to interim targets will help facilitate entry of newer, larger-scale storage technologies that have longer development timelines.

require a directed, storage-specific procurement by the utility to meet the expected or actual shortfall, unless the report indicates that non-achievement of an interim target is due to exceptional circumstances acceptable to the Commission or delays in procured projects coming online.

Finally, interim targets can be productive for spurring diverse storage projects early, assisting with operational experience that reduces barriers and lowers costs for subsequent procurements. For each of the first interim targets, ESA respectfully recommends that the Commission ensure consistency with the VCEA's requirement that at least 35% of storage capacity be procured from third parties. Doing so will ensure compliance with legislative intent and that the widest range of storage project offers is examined. In light of the VCEA's goal to deploy at least 10% of storage capacity behind the customer meter, ESA recommends that the Commission set the first interim targets with established proportions of capacity to be deployed at each of three types of interconnection: behind-the-meter, front-of-meter distribution-connected, and front-of-meter transmission-connected. ESA also recommends that the Commission pursue diversity of applications in its first interim targets, which can be achieved through the structure of complementary programs (see responses to Questions 5 – 8).

3. *What updates to existing utility planning should be adopted to facilitate the achievement of the Energy Storage Targets?*

Current integrated resource planning methods can be improved to ensure that energy storage is fairly considered at the outset in comparison to traditional resources to meet the system reliability needs. The National Association of Regulatory Utility Commissioners' 2018 *Resolution on Modeling Energy Storage and Other Flexible Resources* provide high-level

guidance.⁴ ESA also refers to a series of reforms discussed in our 2018 published report, *Advanced Energy Storage in Integrated Resource Planning (IRP)*.⁵

Advanced energy storage technologies have unique characteristics that can serve many of the needs of the grid, if considered appropriately in planning processes. Unlike generation resources, energy storage may both inject and withdraw electricity from the grid; it can respond nearly instantaneously to a control signal and can ramp nearly instantaneously up or down to a precise level of service; and it is “always on” and available for service, even when neither charging nor discharging. Such unique characteristics of storage require a different approach to resource modeling if a utility will realize the full value of storage to its system.

Several basic guidelines are intended to ensure inclusion of storage in IRP processes and enhance prudent planning for Virginia ratepayers:

- Use up-to-date storage cost estimates and forecasts to better identify near-and long-term opportunities for various storage technologies and durations;
- Employ sub-hourly intervals in modeling to quantify the value of both capacity and flexibility benefits provided by energy storage;
- Institute a “net cost” analysis of capacity investment options to more accurately compare energy storage with traditional capacity resources;
- Incorporate system flexibility needs into reliability metrics to better account for the characteristics of the future supply mix; and
- Analyze demand resources as distinct resource options separate from load forecasts to seek the widest range of cost-effective resources.

⁴ <https://pubs.naruc.org/pub/2BC7B6ED-C11C-31C9-21FC-EAF8B38A6EBF>

⁵ Energy Storage Association, *Advanced Energy Storage in Integrated Resource Planning (IRP)*, June 2018, available at: http://energystorage.org/system/files/attachments/esa_irp_primer_2018_final.pdf.

These recommendations have been incorporated into planning guidelines in other states such as Washington,⁶ New Mexico,⁷ Michigan,⁸ and Arizona.⁹ A number of utilities' IRPs have also included sub-hourly modeling,¹⁰ net cost approaches,¹¹ flexibility metrics,¹² and distinct demand resource modeling.¹³

A. Use accurate data on cost and performance

IRP rules should require that utilities use updated and accurate cost assumptions for energy storage to ensure that it is fairly evaluated next to traditional resources. It is critical that planners use up-to-date advanced storage cost estimates and forecasts for IRP model inputs. Not doing so risks basing investment decisions on outdated assumptions.

ESA recommends that utilities use estimates of advanced storage costs derived from actual RFP bids or contracts, where possible. Such cost figures reflect realistic expectations of project costs achievable by developers, and the use of a multiplicity of bid prices and configurations can reduce the uncertainty that utilities and regulators face regarding modeling

⁶ Washington Utilities and Transportation Commission, Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning, October 2017, available at: <https://www.utc.wa.gov/layouts/15/CasesPublicWebsite/CaseItem.aspx?item=document&id=236&year=2016&docNumber=161024&resultSource=&page=&query=&refiners=&isModal=&omItem=false&doItem=false>.

⁷ See New Mexico Public Regulation Commission, Final Order Amending Integrated Resource Planning Rules 17.7.3 NMAC to Include Energy Storage, Case No. 17-00022-UT, 9 August 2017, available at: <http://www.nmprc.state.nm.us/general-counsel/docs/17-00022UT%20Final%20Order%20Amending%20Integrated%20Resource%20Planning%20Rule17%207%203%20NMAC%20to%20Include%20Energy%20Storage%20Resources.pdf>

⁸ See Michigan Public Service Commission, Opinion and Order of the 21 December 2017 meeting of the Michigan Public Service Commission in Lansing, Michigan, available at: <https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001X2Co>.

⁹ See Arizona Corporation Commission, Decision No. 76632 in the Matter of Resource Planning and Procurement in 2015 and 2016, March 29, 2018, available at: <http://images.edocket.azcc.gov/docketpdf/0000186964.pdf>.

¹⁰ See *Hawaii Electric Companies' Power Supply Improvement Plan*, issued 23 Dec 2016, available at: https://cca.hawaii.gov/dca/files/2016/12/dkt_2014_0183_20161223_companies_PSIP_update_report_1_of_4.pdf

¹¹ See Chapter 8 in *Portland General Electric 2016 Integrated Resource Plan*, issued 15 Nov 2016, available at: <https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning>

¹² See *PNM 2017-2036 Integrated Resource Plan*, issued 3 July 2017, available at: <https://www.pnm.com/irp>.

¹³ See *APS 2017 Integrated Resource Plan*, issued April 2017, available at: <https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf>

assumptions. In the absence of RFP and contract information, ESA recommends utilities use storage cost estimates that are not more than one year old, due to the continuing rapid declines in cost and changes in performance of the energy storage projects.

Considering rapid and recent technical progress in storage, it is important to ensure that utilities use a declining cost curve when projecting the future cost of storage. Utility IRPs typically assume the cost of conventional supply technologies increase over time, based on inflation, since combustion turbines and other traditional generation technologies are no longer experiencing significant cost declines. Advanced storage is different because the rapidly increasing scale of manufacturing capacity and deployment has resulted in significant unit cost reductions. Numerous sources report the installed cost of advanced energy storage has declined significantly in recent years, generally faster than market expectations. While estimates of the rate of reduction vary, cost declines of 5-10 percent year-on-year are expected (see Figure 1 below).¹⁴ This trend is expected to continue within current IRP planning windows, typically 10 to 20 years.

¹⁴ See National Renewable Energy Laboratory, *Cost Projections for Utility-Scale Battery Storage: 2020 Update*, June 2020, available at: <https://www.nrel.gov/docs/fy20osti/75385.pdf>. See also “Battery Storage” page of *Annual Technology Baseline*, available at <https://atb.nrel.gov/electricity/2020/index.php?t=st> (accessed 27 July 2020)

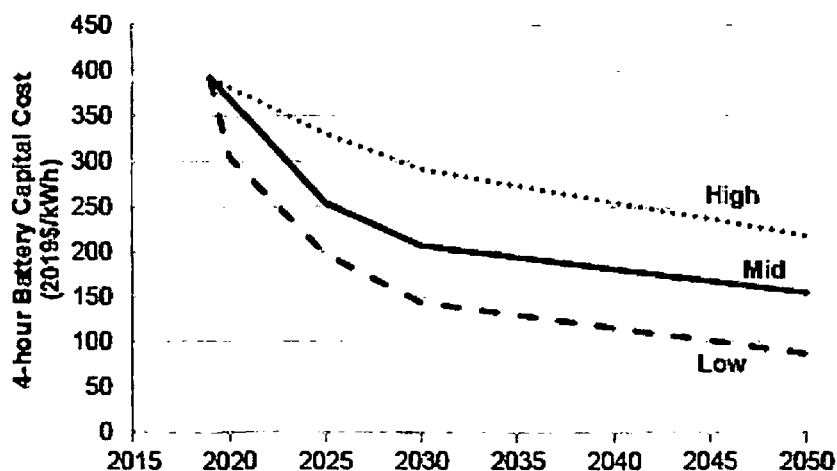


Figure 1 Battery cost projections for 4-hour lithium ion systems¹⁵

B. Employ granular resource modeling to capture storage benefits

Typical IRP models use three inputs—forecasted demand, the capital cost of available technologies, and those technologies’ operating profiles—to calculate long-term economic options for system capacity. These models tend to be simplistic because they only capture the uncomplicated operations of traditional generation units providing capacity. In contrast, current-day advanced energy storage provides high value grid flexibility services, like frequency regulation or ramping support, in addition to capacity. A large-scale energy storage resource dedicated to providing peak capacity when needed—typically a several-hour period in the afternoon and early evening—can also provide grid services for the many hours when its peak capacity is not needed. Storage resources can do this because they are “always on” and available for service, in contrast to traditional generation units that need to be started up and shut down to provide peak capacity and other services. As a result of these new attributes, planners do not often have updated tools on hand to estimate the full benefits of storage resources.

For this reason, ESA respectfully recommends that the Commission require utilities to

¹⁵ See National Renewable Energy Laboratory, *Cost Projections for Utility-Scale Battery Storage: 2020 Update*, June 2020, available at: <https://www.nrel.gov/docs/fy20osti/75385.pdf>

update the methods used in the IRPs to accurately model advanced storage. Models that use sub-hourly intervals can capture the flexibility of storage operations to provide both capacity and grid services. Several validated commercial models are available that can calculate economic resource options including intra-hourly dynamics, such as PLEXOS, SERVUM, and E3 REFLEX. These models are best when employed for multiple years in the planning window, although some utilities have used sub-hourly models for a sample year and then used that information as an input for more traditional planning models.

C. Compare resource options on a net-cost basis

ESA recommends that the Commission call on utilities to incorporate a net cost evaluation methodology within the IRP that better captures the value of flexibility from energy storage. The flexibility benefits and avoided system costs of advanced storage operations are significant and represent a substantial addition to the capacity value of storage. The simplest method to incorporate such storage benefits into the IRP is to use a net-cost-of-capacity approach, as pioneered by Portland General Electric in their 2016 IRP and the concept of which is illustrated in Figure 2:

$$\text{Net cost of capacity} = \text{Total installed cost} + \text{lifetime O\&M cost} - \text{Operational benefits (flexibility operations \& avoided costs)}$$

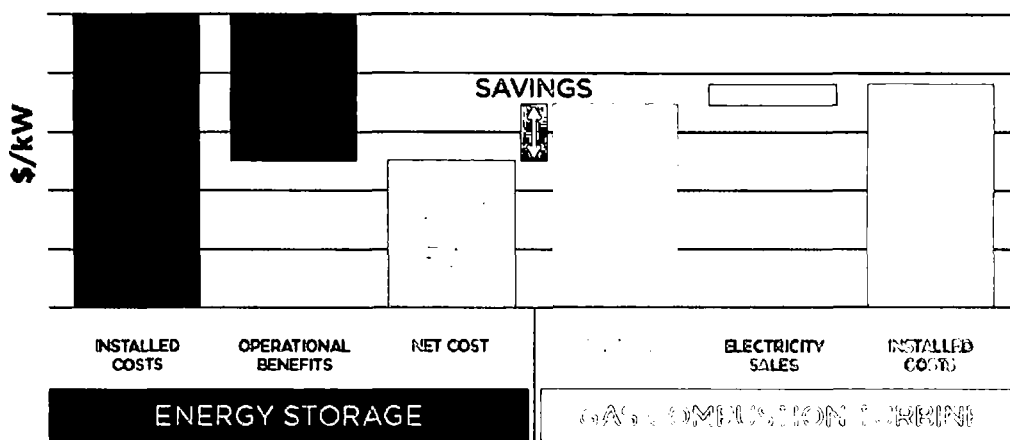


Figure 2 Example of Net Cost of Capacity Calculation

Some of the operational benefits of storage are flexibility services directly provided by the individual unit in question. Among these benefits are (1) regulation, (2) load following, and (3) contingency reserves. Other operational benefits of storage accrue to the entire system as avoided costs. Among these benefits are (1) reduced operating reserve requirements; (2) reduced start-up and shut-down costs of all generation facilities; (3) improved heat-rate efficiency of thermal plants; (4) reduced curtailment of renewable resources; (5) reduced risk of exposure to fuel price volatility; (6) reduced local emissions and ability to run without environmental restrictions on operations; and (7) improved grid frequency stability. As an example, a Massachusetts state-commissioned study of large-scale energy storage deployment found that the total value of these system benefits was greater than the value of the direct, compensated services of storage.¹⁶ Indeed, because these benefits increase the efficiency of the overall grid, they must be accounted for at a system level, rather than at the level of an individual storage resource. Taking account of such avoided system costs and flexibility benefits will ensure Virginia utilities take a more

¹⁶ See Section 4.8.3 in *State of Charge: Massachusetts Energy Storage Initiative Study*, July 2017, available at <https://www.mass.gov/files/2017-07/state-of-charge-report.pdf>

accurate view of the cost-effectiveness of energy storage solutions.

D. Incorporate system flexibility needs into reliability metrics

IRPs model the ability of different resources to meet resource adequacy in an electric service territory. Resource adequacy traditionally focuses on meeting the single greatest hour of demand in the planning horizon and defining an acceptable level of risk of not meeting that demand, called the Loss of Load Expectation (LOLE). The LOLE is typically based on a “1-in-10” standard — that is, available capacity will fail to meet system demand only once in 10 years. IRP modeling combines that LOLE standard with load forecasts and the attributes of existing resources to calculate the extra capacity (“planning reserve margin”) needed in the system—which informs new capital investments

The LOLE convention does not adequately capture the evolving needs for system flexibility. As a higher share of supply comes from variable renewable generation, utilities will be faced with periods of increasingly significant ramps in electric supply over short intervals. Yet, these fast and sudden changes in supply are not captured in the LOLE convention, which focuses only on evaluating risks to meet peak demands. Similarly, deliverability constraints on the distribution network may create local area resource adequacy needs, separate from the larger electric system. Addressing these local area and flexibility needs is not only important to accurately quantify the benefits of storage in IRPs but is also good practice to ensure prudent investment of ratepayer funds.¹⁷

¹⁷In California, system resource adequacy is complemented by local resource adequacy and flexible resource adequacy in utility integrated resource planning. See the California Public Utilities Commission’s webpage on “Resource Adequacy” available at <https://www.cpuc.ca.gov/RA/> (accessed 27 July 2020). Another method to incorporate flexibility into the resource adequacy of IRPs is to use a LOLE measure geared toward peak rates of change in supply, not simply peak periods themselves. This concept was pioneered by the New Mexico utility, PNM, in their 2017 IRP, which used two complementary measures: LOLE_{CAP}, the conventional reliability standard for events caused by insufficient resource capacity to meet peak demands, and LOLE_{FLEX}, a new reliability standard

As the VCEA requires much higher shares of renewable energy deployment over a timeframe within the IRP planning window, ESA respectfully recommends that the Commission direct utilities to develop a method to capture flexibility needs in resource planning.

E. Model demand resources as distinct resource options, separate from load forecasts

As the VCEA sets a goal that at least 10% of the energy storage target be met with customer-sited energy storage systems, ESA strongly recommends the Commission reform the IRP process to ensure effective consideration of demand resources. Doing so will be key to achieving the intent of the legislature.

All IRPs begin with a load forecast over the next 10-20 years. These load forecasts represent the anticipated needs that a supply portfolio must satisfy. While most utilities have engaged in demand-side management strategies for years, the results of those efforts most commonly have been factored into load forecasts, rather than treated as a capacity resource. Similarly, customer-sited generation is forecast and then factored into load forecasts. As a result, demand-side resources are not treated as options for a capital investment plan. This approach can produce sub-optimal investment results for utilities, precluding customer-sited energy storage investments for system capacity.

Customer-sited energy storage offers an innovative way to deploy demand resources as capacity. Customer-sited storage is highly controllable, can be dispatched quickly and precisely, and importantly, can be measured directly by utilities for system operations. Aggregations of customer-sited storage are already being used by utilities to meet capacity needs, such as in

for events caused by insufficient resources to respond quickly to meet the volatile nature of renewable resources. For more information, see pages 121-127 in PNM 2017-2036 Integrated Resources Plan, issued 13 July 2017, available at: <https://www.pnm.com/irp>.

Arizona and New York.

Instead of factoring demand resources into load forecasts, utilities can separately analyze controllable customer-sited resources such as energy storage as a potential supply option. For example, in its 2017 IRP, the utility Arizona Public Service (APS) examined a range of customer resources—energy efficiency, traditional demand response, rooftop solar, and energy storage—as separate supply options from its load forecast. APS ultimately selected demand response and microgrids, energy efficiency, and distributed generation as part of its portfolio.¹⁸

4. What updates to existing utility procurement rules should be adopted to facilitate the achievement of the Energy Storage Targets?

ESA recommends the use of storage-specific procurements at the outset of VCEA implementation. Virginia utilities have little experience in procuring energy storage beyond pumped hydroelectric storage and are now facing significant future changes that may result in new system needs. It will take time to update methods to quantify those new needs and evaluate a wider range of resources, including storage, to meet those new needs. For example, utilities' conventional resource adequacy need may be complemented by local area resource adequacy, due to deliverability constraints on a utility's network, as well as flexible resource adequacy, due to growing ramping demands of a system with higher shares of non-dispatchable renewable energy.¹⁹ Taking a focused approach to storage project procurement at the outset will help ensure utilities develop appropriate methods for the evaluation of storage bids and give due attention to the unique considerations in storage contracts.

¹⁸ See APS, 2017 Integrated Resource Plan, April 2017, available at <https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf>

¹⁹ System resource adequacy, local resource adequacy, and flexible resource adequacy are needs that can first be evaluated in utility integrated resource planning. See for example the California Public Utilities Commission's webpage on "Resource Adequacy" available at <https://www.cpuc.ca.gov/RA/> (accessed 27 July 2020)

Ultimately, ESA supports moving toward future requirements for all-source procurement, recognizing that updates to identification of system needs and procurement processes may be necessary before all-source procurement can produce optimal outcomes for ratepayers. That eventual framework should ideally solicit solutions to identified system needs and be open to all technologies. Three initial steps can assist in this effort. *First*, the Commission would direct utilities to ensure that solicitations are structured to enable appropriate and fair evaluation of various generation resources paired with energy storage, also termed “hybrid resources,” compared to other resources. *Second*, the Commission would direct utilities to ensure that aggregations of distributed storage, sometimes called “virtual power plant,” are able to bid alongside single larger systems. *Third*, in concert with a non-wires alternatives program (see response to Question 7), the Commission would direct utilities to begin identifying locations where distribution system network capacity may be needed and met with storage, in addition to system and local resource adequacy.

Additionally, ESA recommends that the Commission update rules to provide long-term contracts for energy storage systems procured by utilities from third parties. Traditional generation has significant variable costs, largely from fuel, that allow for spreading the effective cost of the resource over its lifetime and the ability to modify those costs over time depending on revenues. In contrast, most of the cost of energy storage systems comes from capital expenditure, rather than fuel or operations & maintenance. As a result, the cost of storage systems is incurred almost entirely upfront while revenues are forecast over many years; this raises the cost of financing for storage, compared to resources where costs are spread over a longer time. Long-term contracts increase certainty for storage resource providers by ensuring that upfront costs are

more likely to be covered over many years, reducing uncertainty and lowering financing costs, which ultimately lowers costs for ratepayers.

5. What competitive solicitation-related programs and mechanisms to deploy energy storage should be included in the required regulations?

As discussed in the response to Question 4, storage-specific solicitations should be used to meet the first interim targets while Virginia utilities update their processes to identify system needs and procure solutions to those needs in an all-source manner. In addition, storage-specific solicitations will be effective in achieving project diversity that is established in any interim targets.

To achieve the first interim targets, ESA recommends that storage-specific procurements conclude (i.e., with contracts proposed for Commission approval) not less than two years prior to the deadline of such targets. As discussed in the response to Question 2, leaving sufficient time to work out project permitting and interconnection is critical in earlier stages of storage procurement, when such processes and rules are not yet tested and updated for energy storage systems. As the VCEA requires that 35% of storage capacity come from third parties, allowing those parties a sufficient window will be critical to achieving compliance with that statutory requirement.

Additionally, ESA recommends that the Commission ensure that at least some fraction of capacity procured from third parties come in the form of a power purchase agreement or other service agreement. Doing so will attract a wider range of companies to compete, invest and hire in Virginia to develop and offer energy storage.

Finally, ESA recommends that the Commission update bid evaluation and benefit-cost analysis as appropriate to reflect the benefits storage can provide and that may not presently be

captured in evaluation of traditional supply resources. For example, these values may include environmental and public health benefits; distribution grid value; distributed energy resource (“DER”) and electric vehicle (“EV”) hosting capacity; modifications of load factor; and complementary wholesale market services. A joint utility and stakeholder working group of the Maryland Public Service Commission presented recommendations on such benefit-cost updates that may be useful for the Commission’s considerations on this matter.²⁰

6. *What behind-the-meter incentives to deploy energy storage should be included in the required regulations?*

ESA recommends that the Commission provide incentives to deploy behind-the-meter (“BTM”) energy storage to meet related policy goals for resilience. Incentives for resilience can drive near-term BTM storage deployment while longer-term regulations are developed. Certain customers may greatly benefit from the resilience provided by onsite energy storage, be that due to criticality of service during emergencies (e.g., schools that serve as shelter points), heightened vulnerability to certain disasters (e.g., hurricane-prone communities), higher customer sensitivity to disruptions (e.g., customers using life-supporting medical equipment), or the risk of failure from backup diesel generators. Prior work by NARUC has noted that the state regulatory benefit-cost framework for resilience investments is still under development.²¹ The Commission can begin to develop evidence on the benefit of resilience deployments and meet critical customer needs through an incentive for BTM storage deployment that provides resilience. ESA

²⁰ See “Submission of the PC 44 Energy Storage Working Group” in Case No. 9619, In the Matter of the Maryland Energy Storage Pilot Program, 31 Dec 2019, available at https://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?FilePath=//Coldfusion/Casenum/9600-9699/9619/2.pdf

²¹ National Association of Regulatory Utility Commissioners, *The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices*, April 2019, available at <https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198>

recommends that the Commission identify customer sites and customer characteristics where the Commission deems resilience investments are most merited, and subsequently direct incentives on an installed stored energy capability basis (i.e., \$/kWh) to be available for deployments of BTM storage with those customers. As an example, California's Self-Generation Incentive Program specifies specific incentives for customers and critical facilities identified to be prone to public safety power shutoffs.²²

Aside from programs on customer resilience, ESA notes that inclusion of customer-sited aggregated resources in planning and procurement (see response to Question 3) and effective programs for non-wires alternatives and peak demand reduction (see responses to Questions 7 and 8) will also promote deployment of BTM storage.

7. What non-wires alternatives programs to deploy energy storage should be included in the required regulations?

ESA recommends that the Commission implement a phased approach to non-wires alternatives programs run by Virginia utilities to build the foundation for effective solicitations. At the outset, ESA recommends that the Commission direct utilities to issue initial solicitations for specific distribution system sites where investments in distributed storage and other distributed energy resources ("DER") could provide a cost-effective alternative to conventional infrastructure investment. Doing so will drive the development of analytical methods and distribution system information needed to inform subsequent, more systematic approaches to non-wires alternatives procurements.

²² In preparation for the next wildfire season, the CPUC has authorized funding of more than \$1 billion through 2024 for SGIP. This funding includes prioritization of communities living in high fire-threat areas, communities that have experienced two or more utility Public Safety Power Shut-off (PSPS) events, as well as low income and medically vulnerable customers. The funds are also available for "critical facilities" that support community resilience in the event of a PSPS or wildfire. See "Self-Generation Incentive Program (SGIP)" on California Public Utilities' Commission program website at <https://www.cpuc.ca.gov/sgipinfo/> (accessed 27 July 2020)

Energy storage is being deployed across the country as a cost-effective solution to extend the life of distribution system infrastructure and investments, increase power quality on distribution circuits, and increase circuit and substation hosting capacity to meet the system demands posed by increasing proliferation of DERs, particularly non-dispatchable generation.

Utilities have begun to demonstrate the use of energy storage as a distribution asset, for example:

- Duke Energy is deploying 13 MW of energy storage across three projects on its distribution system in North Carolina, replacing distribution lines entirely in one instance and deferring higher-cost equipment and maintenance of distribution lines in another.
- Arizona Public Service purchased a 2 MW / 8 MWh battery-based energy storage system for less than half the cost of the traditional investment of a wires alternative in August 2017.
- New York's Con Edison is deferring a \$1.2 billion substation upgrade through its non-wires alternative program, the Brooklyn-Queens Demand Management Program, by contracting for 52 MW of demand reductions and 17 MW of distributed resource investments, including energy storage.
- PSEG Long Island has made similar solicitations to reduce peak demand as a means of avoiding network upgrades and has deployed two storage systems with a total capacity of 10 MW / 80 MWh in South Fork in 2018 for this purpose as well.

To achieve similar benefits in Virginia, ESA respectfully recommends that the Commission begin by including specific sub-targets for BTM storage and front-of-meter ("FTM") distribution-connected storage as a part of overall interim procurement targets (see response to Question 2). To inform the process of distributed storage solicitations, ESA recommends that the Commission direct utilities issue a pilot solicitation associated with one or several distribution sites where there is an anticipated need for new investment that may also be provided by non-wires alternatives. This pilot can be conducted under the current storage pilot program established by Senate Bill 966 (2018). Additionally, as discussed in the response to Question 5, updating the benefit-cost framework for energy storage as a part of evaluating its suitability and

cost-effectiveness as a non-wires alternative will improve the outcomes of solicitation.

Ultimately, the development of a non-wires alternatives program may warrant a separate proceeding to establish the associated rules and processes. In addition, ESA recommends that the Commission consider and clarify whether utility contracts for non-wires alternatives from 3rd-party or customer-owned storage should be recoverable and subject to earning a return by the utility procuring the service. Recovery by utilities on these contracts may mitigate the incentive to incur alternative, higher capital expenditure and returns, which may provide a more results-driven incentive of providing the best solution for consumers.

8. What peak demand reductions programs to deploy energy storage should be included in the required regulations?

A peak demand reduction program associated with BTM energy storage would be consistent with the 10% BTM storage goal minimum of the VCEA, and ESA supports the inclusion of such a program. The inclusion of a demand-side program such as this would also complement the already proposed supply-side programs, resulting in more comprehensive plans which select from a broader set of cost-effective options to help the Commonwealth to meet state goals cost-effectively. Key program features that ESA proposes for the Commission's consideration include:

- 1) Reasonable compensation per kW peak reduction: Reasonable \$/kW compensation will ensure greater participation in the program for customers.
- 2) Pay-for-performance rather than a kW commitment: This incents the utility to forecast the peak accurately and dispatch the signal to aggregators effectively. Pay-for-performance offers a way to match the compensation to the value the DER delivers.
- 3) Multi-year compensation level: Setting a compensation level at a stable rate for a minimum of five years will provide greater predictability of savings and revenue streams for both customers and utilities.

- 4) Participation in multiple programs: The ability to “value stack” by participating in multiple retail programs can create multiple value streams for the services storage provides, can improve the economics for consumers, and can optimize the operational value of the storage system. Currently, most systems are deployed for one of three single applications: demand charge reduction, backup power, or improving the capacity factor of solar self-generation. This results in storage systems being underutilized for much of the system’s lifetime.
- 5) Design features:
 - Standard offer for residential customers: A single, standard offer option for residential customers reduces program complexity, thereby increasing the likelihood of program participation. Commercial & Industrial (C&I) customers tend to have greater capability to compare offers and therefore may not find value in the benefit from standardization.
 - Varying dispatch options: Having a range of options for dispatch-hour windows each day, as well as frequency of dispatch (e.g., daily versus seasonal peaks) provides greater flexibility for program participants to choose the dispatch options that fit their needs and preferences, while addressing multiple local or system-wide grid needs. Doing so also allows incentive levels to match their contribution to avoided system costs. For example, offering a daily dispatch option for C&I customers with an incentive level that matches its value may enable high demand C&I customers to achieve potentially large cost savings.

Noteworthy examples of peak demand reduction programs involving energy storage systems are Massachusetts’ Connected Solutions Program and Green Mountain Power’s (GMP) programs in Vermont.

- The Connected Solutions demand response program incentivizes customers to install BTM energy storage and respond to a utility dispatch signal during peak hours. A key driver for Massachusetts’ effort to implement a peak demand reduction program was a report finding that 10% of hours on average in Massachusetts accounted for 40% of annual electricity spend (over \$3 billion in costs to ratepayers/year).²³
- In Vermont, GMP has two battery programs, (1) ESS Tariff program for third parties to provide BTM battery storage to customers in return for bill credits for providing peak event reduction, and (2) Bring Your Own Device (BYOD) program which allows GMP to lease BTM storage to customers for whole-home backup power.

²³ See *State of Charge: Massachusetts Energy Storage Initiative*, July 2017, available at <https://www.mass.gov/files/2017-07/state-of-charge-report.pdf>

Such a demand response program would provide opportunities to mitigate these costs for consumers while also helping the Commonwealth meet its requirements under the VCEA. Additional details of Massachusetts' Connected Solutions program and Green Mountain Power's programs are provided in Appendix A.

While the total program size should be informed by analysis of the load duration curve and costs of serving peak energy, ESA recommends beginning with a program size of not less than one percent of system peak load, which accords with expected peak load growth in recent utility IRPs.²⁴

9. Should the regulations mandate or limit the deployment of any particular type of energy storage resource or facility? If so, please explain.

The VCEA requires the Commission to limit the contribution of any single storage project to meeting the procurement target at 500 MW. The intent of this statutory limitation is to ensure that the storage targets are not achieved through a small number of very large projects, which would be contrary to the economic development aims of the VCEA. ESA therefore recommends that, in addition to encoding this requirement in regulations, the Commission emphasize procuring a diversity of project sizes, technologies and applications in solicitations to meet the storage targets. It is in the interest of the Commonwealth to maximize information for consumers and utilities on a range of offerings by ensuring that no single project, technology, or company dominates the market; doing so will better reveal cost-effective and appropriate solutions for customer and system benefit.

²⁴ See Section 4.1 in Dominion's Intergrated Resource Plan, Case No. Case No. PUR-2020-00035, 1 May 2020, available at <https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2020-va-integrated-resource-plan.pdf>

10. Should the required regulations apply to non-utility energy storage? For example, should the regulations include a mechanism by which the Commission can issue permits for non-utility-owned storage?

ESA defers to the Commission's authority to ensure the safety and reliability of electric service in the Commonwealth. Ultimately, regulations captured in the VCEA should not raise unnecessary obstacles to the deployment of energy storage in the Commonwealth, including storage not providing services to the utilities. As non-utility developers have begun work on storage projects already in the Commonwealth, ESA would appreciate clarification from the Commission as soon as possible—preferably sooner than a final Order in the instant docket—as to whether and to what extent it may extend permitting regulations to non-utility projects

11. Code § 56-585.5 E refers to "energy storage," "energy storage resources," "energy storage facilities," "energy storage project," and "energy storage capacity." The statute provides no definition of any of these terms.

a. Should the regulations include a definition for each term? If so, please provide necessary definition(s).

For the purpose of implementing the VCEA, ESA recommends the following definitions:

- “Energy storage” refers to any technology that is capable of absorbing energy, storing that energy for a period of time, and re-delivering that energy after storage, including through electrochemical, chemical, thermal, or mechanical means.
- “Energy storage resources” and “energy storage facilities” are synonymous and refer to a project that employs energy storage technology.
- “Energy storage capacity” refers to the installed rated power of an energy storage facility.

b. Does each included term require its own set of regulations? Why or why not?

ESA believes that the definitions provided in this filing are sufficient for the purposes of implementing Code § 56-585.5 E.

12. Code § 56-585.5 E requires Dominion and APCo to "petition the Commission for necessary approvals to construct or acquire new, utility-owned energy storage resources" (emphasis added). Code § 56-585.1 E 5 provides in part that: After July 1, 2020, at least 35 percent of the energy storage facilities placed into service shall be (i) purchased by the public utility from a party other than the public utility or (ii) owned by a party other than a public utility, with the capacity from such facilities sold to the public utility.

- a. Does the energy storage required by Code § 56-585.5 E count toward the targets set forth in Code § 56-585.5 E 1 and E 2, or is it incremental thereto?
- b. Should this requirement be incorporated in some way into the interim targets to be adopted for Dominion and APCo?

ESA recommends that non-utility owned energy storage should count toward the overall targets. As Dominion and APCo seek to meet their procurement requirements, both for interim and overall targets, the VCEA outlines that at least 35% of that installed capacity should come from 3rd parties. Counting such projects toward achievement of the targets would support the VCEA's intent to spur utilities to seek storage offers from 3rd parties.

- c. Should the regulation contain any limitation on the acquisition of energy storage facilities or purchases of capacity from utility-affiliated interests?

ESA respectfully recommends that the Commission focus on ensuring that energy storage services be provided through a framework that promotes competition and does not discriminate against any specific ownership models or vendors. Storage should be procured by utilities via mechanisms allowing offers from diverse business models to be evaluated competitively, and 3rd parties that are not utility-affiliated should have equitable access to relevant electric system data, with appropriate confidentiality safeguards in place for privacy, system security, and public safety. The method and criteria used to evaluate 3rd-party offers should be transparent to all stakeholders in advance so as not to advantage utility-affiliated interests, or indeed any party

over another. Similarly, all providers or prospective providers of energy storage should have fair access to grid interconnection. Interconnection processes for 3rd-party and customer-owned energy storage should be transparent, fair, and reasonable with respect to requirements, cost, timeline, and data access, and those processes should not advantage utility-affiliated interests, or any party over another.

With these core policies for competition in place, the Commission may not find it necessary to cap the procurements from utility-affiliated interests. However, absent this ability to promote these core policies for competition, ESA recommends that the Commission consider capping the capacity of energy storage procured from utility-affiliated interests that may count toward achievement of the interim and overall storage targets.

13. Code § 56-585.5 F permits recovery of costs of, inter alia, "energy storage facilities, that are constructed or acquired by a Phase I or Phase II Utility after July 1, 2020 "and costs of "energy storage facilities, purchased by the utility from persons other than the utility through agreements after July 1, 2020[.]" Is there a difference between energy storage facilities that are "acquired" by a utility and those that are "purchased" by a utility that should be addressed by the regulation? Why or why not?

ESA interprets that "acquired" refers to agreements where a 3rd party builds a storage project and ownership is transferred to the utility, whereas "purchased...through agreements" refers to service agreements with a utility where ownership of the storage is retained by the seller.

14. What additional provisions should be included in the required regulations?

Given the Commission's recent investigation in transportation electrification and electric vehicle (EV) charging infrastructure, ESA suggests that the use of stationary energy storage systems to help distribution systems manage EV charging loads may be an opportunity for

procurement consistent with a mechanism to deploy storage as a non-wires alternative. Additionally, ESA encourages the Commission to clarify to what extent discharges from EVs back to the electric system (“vehicle-to-grid”) would be counted for the purposes of procurement targets in the instant docket. There are variations of vehicle-to-grid service—i.e., managed charging of EVs (“V1G”), using EVs to serve native loads (“V2B”), and using EVs to discharge back to the electric grid (“V2G”)—as well as varying availability for grid service that any particular vehicle may be expected to provide. Should the Commission seek to incorporate vehicle-to-grid storage, ESA recommends that the Commission elicit further input from stakeholders on performance and availability criteria for such resources to count toward fulfillment of the storage procurement targets required of the VCEA.

Additionally, ESA respectfully asks that the Commission finalize updates to distribution interconnection regulations that can better facilitate the installation of energy storage on Virginia’s electric grids. There is no reference to “energy storage” at present in the *Chapter 314 Regulations Governing Interconnection of Small Electrical Generators*,²⁵ although proposed revisions by Commission staff in 2019 do contain such reference.²⁶ Given the use of energy storage for both charging and discharging, as well as its controllability and ability to co-locate with small generating facilities, ESA encourages interconnection updates that ensure success in meeting the VCEA’s intent, particularly with regard to BTM storage.

IV. CONCLUSION

ESA thanks the Commission for this opportunity to provide input regarding the

²⁵ See 20VAC5-314.

²⁶ See “Chapter 314 Final Draft Regulations”, Case No. PUR-2018-00107, 19 Sep 2019, available at <https://www.scc.virginia.gov/getattachment/ba06de8d-5737-47bd-84f3-70940c65a924/314RedRegs.pdf>

implementation of the VCEA. The energy storage procurement mandate of the VCEA not only puts Virginia in a position of national leadership on energy storage, but also lays a critical foundation for the transformation of the power system to 100% clean energy. The recommendations provided herein would fulfill VCEA statutory obligations and intent while positioning the Commonwealth to succeed in deploying reliable and competitive energy storage. ESA looks forward to working with the Commission, utilities, and other stakeholders to chart an optimal path forward on energy storage deployment that enhances the resilience, affordability, and sustainability of electric service.

RESPECTFULLY SUBMITTED on this 29th day of July, 2020.



Jason Burwen
Vice President, Policy
Energy Storage Association

APPENDIX A:
Examples of Peak Demand Reduction Programs

Massachusetts' Connected Solutions Program

Connected Solutions pays customers to curtail their energy when regional electricity demand is forecasted to peak. Customers own the batteries and are compensated on a pay-for-performance basis for the average kW they curtail during dispatch events.

General Program Features

- Uses BTM battery storage to reduce peak energy use
- Program is restricted to battery systems owned by customers
- Participation Options: (1) install battery with new solar; (2) add battery to existing solar; (3) install stand-alone battery
- Incentive rates are set for 5 years
- Program is standardized for residential customers
- Programs vary for C&I customers (each utility chooses their own program features)
- BTM storage is allowed to participate in other state programs
- Dispatch Options:
 - Dispatch for peak hours daily ("daily dispatch")
 - Dispatch for peak hours seasonally ("targeted dispatch")

Residential Program

The residential Connected Solutions program in Massachusetts is standardized across customers, with the incentive set for 5 years and seasonally-based (summer and winter) variations in the performance incentive level (\$225/kW and \$50/kW respectively) and the number of discharge events per season (30-60 and 5-15 respectively).

Standardized Program Features for Residential Customers

	Summer	Winter
Performance Incentive	\$225/kW	\$50/kW
Discharge Events per Season	30 to 60	5-15
Months Discharge Events Can Occur	June through September	December through March
Time Discharge Events Can Occur	2 p.m. to 7 p.m.	2 p.m. to 7 p.m.
5-year incentive lock	Yes	Yes

Commercial and Industrial Programs

For commercial and industrial customers, each utility may choose program features of their choice. Similarities between Massachusetts' utilities' program offerings include: (1) each offers C&I customers three options; (2) event durations are approximately 2-3 hours; and (3) the number of events is much higher in the summer than in the winter.

Eversource

Eversource offers a daily dispatch program in the summer only, and a targeted dispatch option in the summer and winter seasons. Incentive levels are \$200/kW for daily dispatch, \$100/kW for summer targeted dispatch, and \$50/kW for winter targeted dispatch. The number of events is typically higher in the summer (60 for daily dispatch; 8 for summer targeted dispatch; and 5 for winter targeted dispatch).

Program Features for C&I Customers of Eversource

	Daily Dispatch (summer only)	Summer Targeted Dispatch	Winter Targeted Dispatch
Incentive (per avg kW reduction per season)	\$200/kW	\$100/kW	\$50/kW
Season dates	June 1 – Sept 30	June 1 – Sept 30	Dec 1 – March 31
Number of events	60	8	5
Event duration	2-3 hours	3 hours	3 hours
Notification	Day before event	Day before event	Day before event
Event timing	2 – 7 pm*	2 – 7 pm*	2 – 7 pm

*on non-holiday weekends

National Grid

National Grid also offers its customers three options: daily dispatch in the summer; summer targeted dispatch; and winter targeted dispatch. The incentive levels are \$200/kW,

\$35/kW, and \$24/kW respectively. Similar to Eversource's dispatch events, National Grid's number of daily dispatch events is higher than its other dispatch options (30-60 events), while summer targeted dispatch (2-8 events) and winter targeted dispatch (~ 5 events) have fewer events.

National Grid's C&I Program Features

	Daily Dispatch (summer only)	Summer Targeted Dispatch	Winter Targeted Dispatch
Incentive	\$200/kW	\$35/kW	\$24/kW
Seasons dates	June, July, Aug, Sept	June, July, Aug, Sept	Dec, Jan, Feb, March
Number of events	30 – 60 (Reduce energy use for a few hours during ~50 periods of high demand during summer)	2-8 (Reduce energy use for a few hours during 2-8 periods of high demand)	~5 (Reduce energy use for a few hours during ~5 periods of high energy demand)
Event Duration	2-3 hours	3 hours	3 hours

National Grid's daily dispatch option has been a pilot program. However, all three utilities in the state have filed for approval of a permanent daily dispatch program that could be approved in the next one or two months.

Green Mountain Power Programs

GMP has two recently approved programs for behind-the meter (BTM) battery storage that offer incentive tariffs through September 30, 2022 to residential and small commercial customers that are not on a time-of-use tariff. The first program ("ESS Tariff") allows GMP to lease BTM battery storage to customers for ten years with an optional five-year extension. The second program is a Bring-Your-Own Device program ("BYOD Tariff") that allows up to 5 MW of battery storage capacity each year. Both Tariffs share the following features: will be offered for up to 5 MW of installed capacity per calendar year and tariffs will expire on 9/30/22.

GMP ESS Tariff

Customers electing the ESS Tariff will lease a battery storage system owned by GMP. The battery storage system can provide the customer with whole-home backup power during a grid outage. The duration of backup power will depend on the amount of energy stored in the battery system at the time of outage and the customer's energy consumption during the outage. The battery storage service also provides GMP with the ability to access and control the battery to reduce power costs.

GMP ESS Tariff Features

Ownership	Utility-owned and leased by customer for 10 years; optional 5-year extension without monthly fees
Eligibility	Residential and residential and small commercial customers not on TOU tariff
Program Duration	Tariff expires September 30, 2022
Size	Up to 5 MW/year
Cost	Leased to customers for \$55/month or an upfront one-time payment of \$5,500 per system
Participation Cap	Up to 500 customers/year

GMP BYOD Tariff

Customers electing the BYOD Program will purchase equipment from a third-party, which will be installed on their premises and subsequently enrolled into GMP's energy management platform. Customers will have the opportunity to earn up-front incentive payments by allowing GMP shared access to equipment to reduce costs at peak times and allowing GMP to control equipment to achieve other forms of wholesale power market value. This BYOD tariff follows an earlier BYOD pilot.

GMP's BYOD Tariff Features

Ownership	Customers purchase and install equipment

Eligibility	Residential and small commercial customers not on TOU tariff
Program Duration	Tariff will expire on September 30, 2022
Size	Up to 5 MW/year
Cost	<p><u>Access Disruption Fee</u>: \$12.70/equipment kW/month if equipment operation, communication, or access fails and is not restored within 30 days (until access is restored)</p> <p><u>Software Integration and Communication Fee</u>: \$3.97/month</p>
Participation Cap	Varies (Depends on how much each customer chooses to enroll. The system must be capable of providing 3 hours of dispatch at the enrolled kW. E.g. to enroll 5 kW, the system must have at least 15 kWh)
Incentive	<p><u>Back-up Only Incentive</u>: Customers who allow GMP to manage their system for 3 or 4 hours will get the incentives below.</p> <ul style="list-style-type: none"> • \$850/kW (up to 10 kW) duration of 3 hours at full chosen capacity rating; or • \$950/ kW (up to 10kW) duration of 4 hours at full chosen capacity rating. • An additional \$100/kW bonus (up to 10 kW) applies to installations in a GMP grid-constrained area <p><u>Self-Consumption Incentive</u>: Self-consumption customers are eligible for an upfront payment and a location-based adder, if applicable. <i>Note: These incentives do not include kW multipliers.</i></p> <ul style="list-style-type: none"> • \$850 (no kW multiplier) for equipment paired with self- consumption. • An additional \$100 shall apply to installations in a GMP-constrained area.