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September 15, 2020

VIA ELECTRONIC FILING

Clerk of the Commission
c/o Document Control Center
State Corporation Commission
1300 E. Main Street
Richmond, VA 23219

Re: *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*
Case No. PUR-2020-00035

Dear Sir or Madam:

Enclosed please find the Direct Testimony and Exhibits (Public Version) filed on behalf of Mr. Glen Besa in the above-captioned matter. An Extraordinarily Sensitive version of this testimony is being filed under seal pursuant to the Commission's Rules of Practice and Procedure.

Should you have any questions about this filing, please do not hesitate to contact me.

Sincerely,

/s/ William T. Reisinger

William T. Reisinger

cc: Service List

BEFORE THE COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

COMMONWEALTH OF VIRGINIA, ***ex rel.***	)	
	)	
STATE CORPORATION COMMISSION	)	
	)	**CASE NO. PUR-2020-00035**
In re: Virginia Electric and Power Company's	)	
Integrated Resource Plan filing	)	
pursuant to Va. Code § 56-597 et seq.	)	

PREFILED DIRECT TESTIMONY OF

Kerinia Cusick

On behalf of

Mr. Glen Besa

September 15, 2020

Testimony Summary

My testimony evaluates the proposed Tazewell County pumped-storage hydroelectric ("PSH") facility included in Dominion Energy Virginia's ("Dominion" or "the Company") 2020 Integrated Resource Plan and concludes that this facility is not needed. The Tazewell PSH resource was included in the resource portfolio despite there being more economic options and no demonstrated reliability need. Dominion's capacity expansion model did not select the resource in its optimal resource portfolio. Instead, the Company forced the selection of the Tazewell PSH resource into its resource portfolio.

There is no demonstrated reliability need for the project. The Company already has a long-duration energy storage asset in its fleet, Bath County, an existing PSH facility that is 10 times larger than the proposed Tazewell PSH project. The Bath PSH resource has nearly identical dispatch parameters to the Tazewell PSH resource and its capacity factor steadily declines over the Company's planning period. This means that Bath could likely provide its spare capacity to the system if there is a reliability need for Tazewell's proposed capacity. Additionally, if there is an economic need for a resource like Tazewell, a similar resource like Bath would have increasing capacity factors when Tazewell is proposed to come online in 2029. Instead, the data in the IRP shows exactly the opposite with declining capacity factors for Bath County.

The Tazewell County pumped hydro facility is not an optimal economic option. The generation facility is extremely expensive. The resource already has the highest capital costs of all assets included in the IRP, and these estimates are likely underestimating its true cost. There are a number of costs that were excluded from the estimate and they do not account for potential cost overruns that are likely for PSH resources. In addition, the Company itself does not seem to have a clear understanding of the resource's costs, providing differing cost estimates and differing capacities for the resource in its cited documents. My understanding is that the intent of the General Assembly is to provide economic development in Southwest Virginia. However, the economic cost to Virginia ratepayers associated with this facility, in terms of both rate impacts and the resulting economic losses, seem to far outweigh the benefits.

Battery storage and pumped-hydro are very different technologies that provide similar value to the grid. Both technologies can provide capacity and ancillary services. Batteries are already more cost effective than pumped storage for shorter duration discharges. In some scenarios, pumped storage may be more cost effective in the near-term than a battery where long-duration storage is needed. However, the cost trends for pumped storage are increasing while costs for batteries are declining rapidly.

Dominion's IRP also inflates the cost of battery storage while the cost of PSH is deflated. The cost assumptions for battery storage do not assume any future cost declines, and a number of cost factors such as interconnection costs, land, and property taxes have been bundled into the cost of batteries while excluded from PSH. By taking into account the cost declines and removing the cost factors from batteries that were excluded from pumped hydro, the capital cost of battery systems declines by nearly 50%.

Table of Contents

I. Introduction

Q. Please state your name, occupation, and business address.

A. My name is Kerinia Cusick. I am the Board President of Center for Renewables Integration. My business address is 107 S. West St. #731, Alexandria, VA 22314.

Q. Please summarize your professional and educational background and its relevance to this proceeding.

A. I am an engineer and an energy storage expert. I have worked in renewable energy since 2008 and energy storage since 2013. First, at Think Energy, a consulting firm that helped Fortune 100 companies procure clean energy. Then, in a variety of positions at SunEdison, a national solar, wind, and energy storage company, culminating as a Vice President of Energy Storage. Finally, as co-founder of Center for Renewables Integration ("CRI") a 501c(3), and as CEO at Distributed Energy Innovation ("DEI"), my own consulting firm. I have a Master of Science in Systems Management from the University of Southern California, and a Bachelor of Science in Mechanical Engineering from Drexel University. My experience and qualifications are described below as well as in my curriculum vitae attached as Exhibit KC-1.

At CRI, I work extensively on policy issues relating to the effective deployment of energy storage assets. On this topic, CRI has participated in ISO stakeholder processes, FERC technical conferences, Commission hearings, and performed extensive original qualitative research which is publicly available. CRI also does work for state energy offices. For example, CRI was one of the companies engaged by the New York State

Energy and Research Development Authority ("NYSERDA") to develop New York's Energy Storage Roadmap, which looked extensively at the issue of using energy storage as a Non-Wire Alternative Asset on the distribution systems and examined the impact of FERC's Order 841 on possible New York use cases.

At Distributed Energy Innovation, I provide go-to-market consulting services to companies entering the renewable energy sector, renewable companies looking to expand into energy storage, and energy storage companies navigating regulatory models to develop projects. I also work for investors performing due diligence on energy storage projects and support technology companies developing new products in energy storage. In the U.S. the primary nexus of my focus for clients has been California, Texas, and New York markets to date. I also do work internationally, providing analysis of energy storage opportunities in Canada and the European Union.

While at SunEdison, between 2013 and 2015, I led a team developing stand alone, as well as hybrid, solar plus storage systems in CAISO and PJM. SunEdison's assets in PJM participated in PJM's Frequency Regulation market and also provided peak reduction. In that role, I oversaw business development as well as storage financeability.

Also at SunEdison, in 2015, I was a leader on the team that was developing, under a joint development agreement, a series of behind-the-meter energy storage projects designed to defer transmission and distribution upgrades. These energy storage projects were contracted by Southern California Edison in 2014 to provide grid-support services as "virtual power plants" and recently announced 2 GWhr of hours in service.[1]

[1] See Jeff St. John, AMS Breaks 2 Gigawatt-Hours in Grid Services, GREENTECH MEDIA (Mar. 19, 2019), available at https://www.greentechmedia.com/articles/read/advanced-microgrid-solutions-breaks-2-gigawatt-hours-in-grid- services#gs.77t4ui.

From 2011 to 2013, I led a team of SunEdison electrical, power controls, and transmission and distribution system engineers, working to develop solutions to integrate solar into Puerto Rico's island grid to ensure grid stability in scenarios of very high percentage of solar and wind generation. Solutions examined included energy storage, including pumped storage, and using those assets to provide frequency, voltage, as well as ramp control to fulfill the utility's interconnection requirements.

Prior to entering the renewable energy sector, I was an aerospace engineer with a specialization in the design of aircraft digital flight control systems, as well systems engineering of complex solutions such as the United States Department of Defense's National Missile Defense system.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Mr. Glen Besa. Mr. Besa is a resident of Richmond, Virginia, and a customer of Virginia Electric and Power Company, doing business as Dominion Energy Virginia ("Dominion" or "Company").

Q. Have you ever testified before the Virginia State Corporation Commission?

A. Yes. I testified before the State Corporation Commission in Case No. PUR-2019-00124, Dominion's application for approval to participate in the pilot program for electric power storage batteries pursuant to § 56- 585.1:6 of the Code of Virginia, and for certification of proposed battery energy storage system pursuant to § 56-580 D of the Code of Virginia.

Q. Have you testified before other state public service commissions?

A. Yes. I have testified before the Public Service Commission of Wisconsin on the evaluation of the need for the Cardinal-Hickory Creek transmission line (PSC Ref #: 369775 and PSC Ref #: 369221) in 5-CE-146.

Q. What is the purpose of your testimony?

A. My testimony reviews the evidence provided by the Company regarding the cost effectiveness and need of short and long-duration storage in its 2020 Integrated Resource Plan ("IRP"). More specifically, my testimony evaluates the information and data presented by the Company regarding the proposed Tazewell County Pumped Storage facility and comparison to battery energy storage systems ("BESS"). My testimony will show the Company has not presented a need for long-duration storage, and the Tazewell County facility is uneconomic. I understand one of the objectives of Tazewell County may be economic development in Southwest Virginia, but my testimony will show the benefit ratepayers would receive, for the cost spent, is very low.

Q. How is your testimony organized?

A. My testimony is presented in the following sections:

1. Section 1 is an introduction to my testimony, including my company's expertise, my own credentials, and the purpose of my testimony.
2. Section 2 provides an overview of the similarities and differences between short and long duration storage, specifically pumped storage hydroelectric and battery energy storage systems.

3. Section 3 reviews how pumped-hydro and battery storage are modeled, highlights the fact that the model was forced to select PSH, and shows the cost of BESS are inflated, particularly as compared to PSH.
4. Section 4 highlights the fact that the Tazewell County pumped storage facility is uneconomic.
5. Section 5 shows there is no demonstrated reliability need for long-duration energy storage and identifies more cost effective options, if a reliability need is identified at some point in the future.
6. Section 6 discusses the economic analysis performed for the Tazewell County pumped storage facility, shows that it was performed for a larger facility, and highlights the lack of a cost-benefit analysis.
7. Section 7 provides recommendations for the Commission to consider to improve the analysis and inclusion of energy storage in the IRP.

II. Similarities and Differences Between Pumped-Hydro Storage and Battery Storage

Q. Can you describe how pumped hydro and battery storage technologies are different and how those differences impact cost and performance?

A. Pumped storage relies upon force of water falling from an upper reservoir to a lower reservoir to drive turbines connected to generators to produce electricity during peak hours. During off-peak, water is pumped from the lower reservoir to the upper one to repeat the process. Battery storage relies upon chemical processes to store and discharge electricity.

Pumped storage assets are, by definition, bespoke solutions, each one customized for the local environment, relying upon significant local construction to build dams, spillways and underground turbine rooms. As such, construction of such projects cannot occur in a modular and replicable fashion, which keeps costs down and decreases costs of construction over time. A risk factor with pumped storage is cost overruns during construction as well as increasing operations and maintenance costs. Once built the projects have a long life, operating for 50 years or more. Pumped storage is considered a mature technology in the US, with nearly 23 GW operational in the U.S. in 2018. Construction of pumped storage assets peaked in the 1970s. No new pumped storage has been built since 2012, although FERC has issued licenses for three proposed projects since 2014.[2]

Battery storage solutions are mass produced, typically containerized and shipped to a location nearly complete and ready to be dropped onto a concrete pad. Maintenance largely consists of periodic replacement, with the most frequent being the replacement of battery racks within containers, followed by inverter and HVAC maintenance. Compared to PSH, BESS is a newer technology, with slightly over 1 GW of BESS projects expected to be operational in the U.S. by the end of 2020, and 3.5 GW projected by the end of 2021.[3] Operational life for BESS is typically 10 – 15 years, potentially as long as 20 years with significant refurbishment of battery racks.

Exhibit 1 summarizes project installation by year for both PSH and BESS.

[2] See U.S. Energy Information Administration, October 31, 2019, www.eia.gov/todayinenergy/detail.php?id=41833

[3] See Wood Mackenzie / Energy Storage Association, Q3 2020 U.S. Energy Storage Monitor.

While the technologies are very different, the performance is similar. Both assets are used as capacity assets, providing electricity to the grid during peak hours and charging during off peak. Both assets can also be used to provide ancillary services, although BESS will provide a significantly faster response than PSH, with nearly zero lag.

The primary difference lies in discharge time. All PSH projects evaluated in recent planning studies have exceeded 8 hours in duration, with some as long as 16 hours of continuous discharge.[4] BESS projects can be built using a modular approach in duration sizes ranging from 15 minutes up to 10 hours. BESS projects are currently most cost effective between 2 to 4 hours of continuous discharge.

The second big difference is cost trends. Cost trends for BESS are declining rapidly, with the National Renewable Energy Laboratory (NREL) projecting battery costs to decline by nearly 50% by 2030.[5] Costs for pumped storage are increasing – both the capital cost as well as operations & maintenance costs. This is shown by the negative experience rates of pumped hydro of -1±8% vs. a positive experience rate of utility-scale lithium-ion batteries of 12±3%.[6] Another study found two-factor learning rates of 1.96% (learning-by-doing) and 2.63% (learning-by-researching) for large hydropower projects.[7] Battery storage learning rates were not included in this study. The study also found that

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[4] Electric Power Research Institute, Pumped Storage Hydro in Resource Planning in the U.S.: A Survey of Recent Results and Methods at 37. (July 2019).

[5] Cole, Wesley, and A. Will Frazier. 2019. *Cost Projections for Utility-Scale Battery Storage*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-73222, available at https://www.nrel.gov/docs/fy19osti/73222.pdf

[6] Schmidt, O. & Hawkes, A. & Gambhir, A. & Staffell, Iain, "The future cost of electrical energy storage based on experience rates." Nature Energy (2017).

[7] E.S. Rubin et al., "A review of learning rates for electricity supply technologies," Energy Policy 86 (2015) 198-218: pg. 204.

solar had learning rates of 18.4% (learning-by-doing) and 14.3% (learning-by-researching).[8]

In summary, while the two technologies are very different, their performance is similar. The core differences lie in discharge duration of both assets and cost trends.

Q. Can pumped storage be cost effective when compared to battery storage?

A. In some cases where long-duration storage is required, particularly in the near-term, PSH can be cost competitive with BESS. A 2019 EPRI-sponsored survey of planning studies that considered both pumped and battery storage is included in Exhibit 2. The table summarizes the assumed capital costs in eight recent IRPs where PSH was considered, six of which also considered BESS. The data shows how costs for BESS increase as longer duration solutions are considered. In the one state where both 8-hour PSH and 8-hour BESS were considered, the upfront capital cost of PSH is lower than BESS.

EPRI also conducted two surveys of PSH and BESS costs. The 2016 survey of PSH costs for 10-hour duration identified a wide range of costs for plants ranging from 300 – 1000 MW, $1,700 kW - $5,100 / kW, in 2017 dollars ($1,769 / kW - $5,306 / kW in 2019 dollars at EPRI's recommended 2% escalation rate).[9] EPRI's 2019 survey of

[8] See E.S. Rubin et al., "A review of learning rates for electricity supply technologies," Energy Policy (November 2015) 198-218: pg. 207.

[9] Electric Power Research Institute, Energy Storage Cost Summary for Utility Planning: Executive Summary (2016), available at https://www.epri.com/research/products/3002008877.

BESS costs estimated projects with an 8-hour duration between 30 – 50 MW in size have a cost range of $2,350 / kW to $3,800 / kW.[10]

EPRI's data is indicative but limited, making it difficult to compare project costs on an equal footing. The project sizes differ by an order of magnitude, and are for different duration times. But there is overlap in the broad range of costs listed for both technologies in 2019.

As mentioned, the more important issue to Virginia ratepayers is cost trends. The cost to build PSH projects is increasing, while the cost of BESS is declining rapidly.[11]

Q. In what scenarios may long-duration storage be required versus shorter-duration?

A. With relatively low levels of energy storage connected to the system, short duration storage is just as effective a capacity resource as long duration storage. As more and more energy storage is added to the system, and the load profile flattens, short duration energy storage will have less impact on system reliability, potentially creating a need for longer duration storage.

A recent study[12] examined the impact of energy storage on PJM's system and the ability of short duration storage to maintain loss of load expectation at a maximum of 0.1 (e.g. 1 day in 10 years), in lieu of long duration assets. The analysis concludes: "The results of our analysis demonstrate that with energy storage deployments up to 4,000

[10] Electric Power Research Institute, Energy Storage Technology and Cost Assessment: Executive Summary (2018), available at https://www.epri.com/research/products/3002013958

[11] Schmidt, O. & Hawkes, A. & Gambhir, A. & Staffell, Iain. (2017). The future cost of electrical energy storage based on experience rates. Nature Energy. 6. 17110. 10.1038/nenergy.2017.110.

[12] Astrape Consulting, Capacity Value of Energy Storage in PJM (July 2019), available at http://www.astrape.com/astrape-capacity-value-of-energy-storage-in-pjm/.

MW, 4 hours of duration allows those resources to provide full capacity value relative to a resource without duration limits. With energy storage deployments up to 8,000 MW, 6 hours of duration allows those resources to provide full capacity value. Within these limits, storage can replace traditional generation MW for MW with no reduction in system reliability."

Therefore, the long-duration energy storage provided by PSH may be appropriate when very high levels of short duration energy storage are interconnected in Virginia. Additional studies are recommended to determine at what point, if at all, long-duration storage becomes important in Virginia.

III. Modeling Pumped-Hydro Storage and Battery Storage in the IRP

Q. Can you summarize how the Company selected the amount of energy storage to model in the IRP?

A. In Plans B through D, the Company set constraints and required the PLEXOS model to select 2,700 MW of energy storage by 2035, consistent with the Virginia Clean Economy Act ("VCEA") legislation,[13] including 300 MW of pumped storage hydroelectricity coming online in 2030, consistent with legislation passed in 2017.[14] The model did not select amounts of storage based on cost effectiveness, nor was it structured to identify the minimum amount of storage required to maintain reliability. When it comes to storage, the Company didn't model what it needed or the most cost-effective solution for ratepayers. Instead, it directed its model to select the PSH resource.

Q. How does the forced selection of PSH compare to a capacity expansion model determining its selection within the Company's resource portfolio?

A. The Company forced selection of the 300 MW of PSH resource instead of allowing a capacity expansion model to select the most optimal resources. As such, PLEXOS, when modeling the production cost of the system, does not have a potentially lower cost resource (or a lower-cost portfolio or resources) to dispatch to meet system needs, thus increasing the overall cost for ratepayers.

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[13] 2020 Va. Acts ch. 1193 and ch. 1194.

[14] See IRP at page 74 and 85 (citing 2017 Senate Bill 1418).

Q. What would happen if the Company allowed its capacity expansion model to determine selection of the PSH resource rather than forcing it into its resource portfolio?

A. While I cannot draw a firm conclusion without having the Company model this scenario, a capacity expansion study that I reviewed, which modeled Virginia's electricity system through 2050 using a 100% carbon-free generation mix, found an optimal resource portfolio that did not include new PSH resources due to their high costs.[15] This indicates that models are not showing any reliability need for longer duration energy storage assets, with a high variable generation mix, which would force the model to select more expensive assets in order to continue to meet standard NERC reliability thresholds.

Q. If the Company did not force its inclusion into its optimal resource portfolio, are there other reasons that the capacity expansion model would likely not select the Tazewell PSH resource?

A. Yes, the fact that the capacity factor of the Bath County PSH resource decreases over the planning period indicates there isn't an economic need for another PSH resource. From a capacity factor of 10.7% in 2021, Bath County PSH decreases steadily to 7.5% in 2035.[16] According to the Company, the parameters of the Tazewell PSH resource differ

[15] The Greenlink Group. (2019, September). *Virginia's Energy Transition: Charting the Benefits & Tradeoffs of Virginia's Transition to a 100% Carbon-Free Grid.* Advanced Energy Economy.
[16] IRP at Appendix 5 D.

from the Bath PSH resource in only two instances: Tazewell is 2% more efficient than Bath[17] and Tazewell's variable O&M is $0.155/MWh less than Bath's variable O&M.[18]

These are small differences and do not seem large enough to drastically change the dispatch of Tazewell relative to Bath. As such, with only small differences in dispatch parameters, the resources would be dispatched in a similar manner by the Company's production cost model. This means that the Tazewell resource would also have low capacity factors through the planning period after it comes online in 2029.

Additionally, the reason that Bath has a variable O&M greater than zero is unclear. In PJM Manual 15 Cost Development Guidelines, "Pumped Storage Hydro Units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market may not include maintenance costs in their offers because such offers may not exceed an energy offer price of $0.00/MWh."[19] In addition, EIA considers the variable cost component of hydroelectric plants to be zero because "the annual cost of consumables, such as lubricants, filters, chemicals, etc., is estimated as a fixed amount."[20]

Q. Can you summarize cost and performance assumptions used in the IRP for battery and pumped storage?

[17] See Exhibit 5 (Company answers to Besa Set 2-14c).

[18] See Exhibit 5 (Company answers to Besa Set 2-14c).

[19] See *PJM Manual 15 Cost Development Guidelines* at 63 (September 2020), available at https://www.pjm.com/-/media/documents/manuals/m15.ashx.

[20] Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies* (February 2020) at 17-4, available at https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

A. The Company assumed a 2020 NPV capital cost of $7,541/kW for pumped storage and $2,224/kW for battery storage.[21] Therefore, using these numbers, Tazewell County PSH with an assumed capacity of 300 MW / 3,000 MWh (10-hour duration) has a total 2020 NPV capital cost of $2.3 billion. A BESS project with the same nameplate capacity of 300 MW, would have a 2020 NPV capital cost of $667,000,000. It is worth noting that the Company assumed a 4-hour duration for all BESS projects; therefore a 300 MW BESS project would have energy capacity of 1,200 MWh per discharge, versus Tazewell County's 3,000 MWh.

The variable costs reflect the assumed cost of electricity to charge the facility, typically done during off-peak hours.[22] This is either pumping water from the lower reservoir to the upper, or charging battery racks. The variable cost for Tazewell PSH is $47.66/MWh and for BESS is $36.51/MWh. The variable costs impacts how IRP models select assets. Unless forced to do otherwise, the model will select assets with the lowest variable costs first. That means IRP models would choose BESS first, only selecting PSH when more capacity is required. Based on information provided by the Company, variable costs for Tazewell are assumed to be the same as Bath County.

The ongoing operations and maintenance (O&M) costs are folded into the fixed costs. For new PSH, as reflected in Busbar assumptions, Appendix 5N of IRP, the total fixed cost is $757.12 /kW-yr, which can be broken into an economic carrying charge of $723.56/kW-yr and O&M cost of $33.56/kW-yr.[23] A further examination of the

[21] IRP at Appendix 5N.
[22] See Exhibit 5 (Company answers to Besa Set 2-14b and 14c).
[23] See Exhibit 5 (Company answer to Besa Set 2-13a and 13b).

Company's financial models for PSH, shows O&M costs are assumed to start in 2029 and are distinguished from major maintenance which is scheduled to occur twice during the 50-year life of the PSH project.[24] The Company assumes the O&M costs escalate at 2%.

The total fixed costs for BESS listed in Appendix 5N is $410.69 / kW-yr. A similar examination of Company's financial models for BESS shows all costs for refurbishment required to maintain the battery capacity is included in operations and maintenance.[25] Therefore the O&M costs for BESS do not reflect an assumption about escalation rate that can be discerned.

The costs for new PSH are based on Company's internal estimates for construction, equipment, and other costs. The costs for BESS are based on bids received from third parties as part of the Company's BESS pilot program. It is worth noting that the bids were for small projects (e.g. 2 - 10 MW in size) for delivery in 2020. Therefore, no economies of scale are assumed in the Company's cost estimate, and more importantly, no cost declines are expected for future BESS projects. Both assumptions are incorrect and discussed further in this testimony.

The model assumes a capacity factor of 15% for pumped storage based on historical performance of existing pumped storage assets,[26] and the Company found battery assets were dispatched by the model once a day for four hours, leading to an approximate 15% capacity factor for BESS.[27]

[24] ES Exhibit 6 (Staff Informal 1-1 (28) ES-Pump Storage Long-term).
[25] ES Exhibit 6 (Staff Informal Set 1-1 (09) ES Battery Storage Long-term).
[26] IRP at 94.
[27] See Exhibit 5 (Company answer to Besa Set 2-16).

The Company only considered 4-hour discharge duration for BESS (e.g. 1 MW / 4 MWh), and did not consider any other discharge durations (e.g. 2, 6, or 8 hours).[28] The Company is derating the capacity factor of BESS based on PJM's current requirement of a 10-hour run time for capacity assets.[29]

While not specified in the IRP, the Company's Preliminary Permit Application at FERC specifies the facility is being designed for 10 hours of continuous discharge for both alternatives included in the application.[30]

Decommissioning costs are not included for either PSH or BESS.

The Company assumes 100% availability for BESS, 70% availability for new pumped storage, and 90% availability for Bath County.[31]

Q. Is the Company consistent in the costs it included in estimates for PHS and BESS?

A. It is not. The Company folds both land, interconnection, and soft costs into the total capital cost for BESS and not for PSH.[32] A more equitable treatment of the two technologies would remove those costs for both technologies in order to provide an "apples to apples" comparison. Removing these costs reduces the 2020 NPV capital costs for BESS to $1901/kW from the Company's initial estimate of $2224/kW. Using these

[28] See Exhibit 5 (Company response to NRDC Set 2-8).
[29] IRP at 60.
[30] Before the Federal Energy Regulatory Commission, Application for Preliminary Permit. September 6, 2017. The FERC application specifies 2 alternatives. Alternative 1 is 446 MW, 10 hours of continuous duration, with an expected energy generation of 1,302 GWh/yr (page 6). Alternative 2 is 870 MW with 10 hours of continuous duration and expected energy generation of 2,450 GWh/yr (page 7).
[31] IRP at Appendix 5C.
[32] See ES Exhibit 6 (Corrected Attachment Staff Set 1-2 (BMH)).

revised numbers, the 2020 NPV capital cost of a 300 MW /1,200 MWh BESS facility is $570,300,000 not $667,200,000.

Additionally, in calculating the total revenue requirement (i.e., the project lifetime costs) for BESS, the Company included property taxes in O&M. Property taxes are not included for PSH.[33]

A more equitable cost comparison of the two technologies would remove all of these costs that have been folded into BESS assumptions and not included in PSH. The net effect is inflating the cost assumptions of BESS while deflating PSH.

Q. Is it appropriate to use the costs of the BESS pilot programs as the basis for all future BESS procurements planned in the IRP?

A. It is not. It has been well documented that costs of BESS have declined significantly in the past decade due to increased manufacturing capacity, increased competitive pressures and learning, as well as other factors. Costs for BESS are expected to continue to decline. Some of the reasons for this are well documented. Manufacturing capacity is expected to continue to grow world-wide, providing increased economies of scale. Additionally, in the past, grid-connected BESS have used the same technology as electric vehicles. As the demand for grid-connected energy storage grows, companies are now manufacturing lower-cost solutions designed specifically for grid-connected storage

[33] See ES Exhibit 6 (Staff Informal 1-1 (28) ES Pumped Storage Long Term and Staff Informal 1-1 (09) ES Battery Storage Long-term).

applications. Grid-connected solutions don't require the same energy density as cars, which provides some cost savings.[34]

The National Renewable Energy Laboratory surveyed future costs announced by a number of manufactures, and calculated a "mid-point" estimate, as shown in Exhibit 3.[35] This mid-point estimate is neither optimistic, assuming the most aggressive possible cost declines, nor pessimistic, assuming very conservative cost declines. Even the mid-point estimate concludes that costs will decline 35% between 2020 and 2025, and an additional 10% between 2025 and 2030. This further reduces the capital costs of BESS from the Company's current estimates.

Taking into account NREL's mid-point estimated cost declines, the capital costs of a BESS project installed in 2025 would decline to $1,243/kW (excluding land costs, soft cost and interconnection as discussed previously to maintain consistency with PSH estimates). Therefore, the capital cost of a 300 MW / 1,200 MWh project declines to $372,900,000 from the Company's initial estimate of $667,200,000. This is in contrast to 300 MW / 3,000 MWh of PSH with capital costs of $2.3 billion. Therefore, the Company could procure 300 MW of BESS for installation in 2025 at a capital cost of $372,900,000 which represents a saving of nearly $2 billion for Virginia ratepayers.

The impact of project size on project cost, for example increasing a BESS from 10 MW to 300 MW, while real, is difficult to quantify and has not been well documented by third party studies. Therefore, it is not addressed in this testimony.

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[34] See Bloomberg New Energy Finance, Battery Pack Prices Fall (December 2019), available at https://about.bnef.com/blog/battery-pack-prices-fall-as-market-ramps-up-with-market-average-at-156-kwh-in-2019/

[35] Cole, Wesley, and A. Will Frazier, "Cost Projections for Utility-Scale Battery Storage," available at https://www.nrel.gov/docs/fy19osti/7322.pdf

Q. Dominion is derating BESS based on PJM's current 10-hour requirement. Is this a valid assumption?

A. It is a conservative assumption that has the net effect of increasing the cost of storage for ratepayers. As a PJM member, the Company is aware that FERC did not approve the 10-hour minimum run-time requirement as part of PJM's Order 841 compliance filing and that PJM is in the process of seeking an alternative solution, one that increases the capacity value of short duration energy storage, at FERC's direction.

As part of approving PJM's Order 841 compliance filing, FERC initiated a paper hearing in Docket No. EL19-100-000 to investigate whether PJM's "minimum run-time" rules and procedures are unjust, unreasonable, unduly discriminatory or preferential as applied to Capacity Storage Resources.[36]

On February 27, 2020, PJM filed comments at FERC in Docket No. EL19-100-000 and asked FERC to hold comments in abeyance through January 29, 2021, while it worked with stakeholders to develop a new construct for minimum run-time based on Effective Load Carrying Capacity ("ELCC").[37] In its filing, PJM explains ELCC as follows: "Practically speaking, ELCC breaks down an individual generator's contribution to system reliability — meaning it can distinguish among generators with differing levels of reliability, size, and on-peak vs. off-peak delivery. Resources that are able to deliver during periods of high risk have a high ELCC, and resources less able to do so consistently have a lower ELCC. Under an ELCC construct, the capacity value will be

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[36] FERC Docket No. EL19-100-000, October 17 Order at 140-143.

[37] See Docket No. EL19-100-000, MOTION OF PJM INTERCONNECTION, L.L.C. TO HOLD PROCEEDINGS IN ABEYANCE AND FOR SHORTENED COMMENT PERIOD AND EXPEDITED ACTION.

adjusted in response to resource penetration levels. At the current level of market penetration, shorter duration Energy Storage Resources would be expected to receive higher capacity value than under the current framework." FERC did not grant PJM's request to extend time, instead requiring PJM to file by October 30, 2020.[38]

As an additional point of information, modeling of Virginia's electricity system conducted by The Greenlink Group for Advanced Energy Economy did not affix a 10-hour requirement to battery storage but instead used utility-specific reserve margin capacity values as determined by the model.[39] This study shows that by the late 2020s, battery storage becomes the least-cost capacity resource,[40] which means that durations of less than 10-hours still have capacity value.

[38] 171 FERC ¶ 61,015, Docket No. EL19-100-000, ORDER ON COMPLIANCE FILING, ESTABLISHING PAPER HEARING PROCEDURES, CONSOLIDATING AND HOLDING PROCEEDINGS IN ABEYANCE, April 10, 2020.

[39] See *Virginia's Energy Transition: Charting the Benefits & Tradeoffs of Virginia's Transition to a 100% Carbon-Free Grid*, Advanced Energy Economy, Appendix A at 5.

[40] See *Virginia's Energy Transition: Charting the Benefits & Tradeoffs of Virginia's Transition to a 100% Carbon-Free Grid*, Advanced Energy Economy, Appendix A at 5.

<u>IV. The Proposed New Pumped-Hydro Storage Facility In Tazewell County is Uneconomic</u>

Q. Can you summarize the cost impact of Tazewell PSH facility on ratepayers?

A. Tazewell is an expensive project for ratepayers. It represents the highest capital investment included in the IRP on a $/kW basis. At $7,541/kW it is 340% higher per kW than the next costliest unit listed in the IRP, which is BESS at $2,224/kW, and those costs for BESS are inflated, as discussed in this testimony.

The impact of this single project on ratepayers is measurable. Based on the information in the Virginia Addendum to the IRP, the cost impact of Tazewell PSH on the average $1,000 kWh residential bill in 2030 is **[BEGIN EXTRAORDINARILY SENSITIVE]** [redacted]**[END EXTRAORDINARILY SENSITIVE].**[41] The Tazewell project alone represents a **[BEGIN EXTRAORDINARILY SENSITIVE]** [redacted]**[END EXTRAORDINARILY SENSITIVE]** increase on the typical residential bill in 2030 of $132.73.[42]

Q. How does the proposed Tazewell PSH facility capital compare to typical prices for pumped storage?

A. Since only one new PSH project has come online since 2006 in the U.S.,[43] there is limited data to determine trends and average costs for PSH projects. However, based on the available data, the Tazewell PSH project significantly exceeds the upper limit of expected costs.

[41] 2020 IRP - Va. Addendum 1 (ES) FINAL (May 1, 2020).
[42] Ibid.
[43] See Oak Ridge National Laboratory, 2017 Hydropower Market Report. (April 2018).

EPRI's 2016 survey of PSH costs for 10-hour duration estimated a wide range of costs for plants sized from 300 – 1000 MW citing an overnight installation cost range of $1,804/kW - $5,412/kW in 2020 dollars.[44] In contrast, the 2020 overnight installed cost listed for Tazewell in the IRP is $7,541/kW.[45] Tazewell is $2,129/kW higher than EPRI's upper limit. For a 300 MW project, the 2020 overnight installed cost is $0.64B higher than EPRI's upper range ($2.3B for Tazewell County versus $1.6B for an EPRI upper limit project).

Q. Is the Company's escalation rate for operations and maintenance for Tazewell County realistic?

A. The Company uses a standard 2% escalation rate for Tazewell County PSH. A report from Oak Ridge National Laboratory,[46] which examines actual O&M costs from all hydro facilities required to report a FERC Form 1, is shown in Exhibit 4. It finds that costs for facilities under 500 MW are escalating faster than the Consumer Price Index. At 300 MW, the Tazewell County PSH would be considered a large project, defined as 100 - 500 MW in the report. Exhibit 4 shows that O&M costs for large facilities rose by nearly 40% from 2007 to 2017, compared to an inflation rate of 16% over the same time period. Therefore, it is probable that a standard escalation rate for O&M during Tazewell's

[44] Electric Power Research Institute, Energy Storage Cost Summary for Utility Planning: Executive Summary (2016), available at https://www.epri.com/research/products/3002008877. The EPRI cost range is provided in 2017 dollars. The data here is translated to 2020 dollars to provide an equitable comparison to IRP data using EPRI's recommended 2% escalation rate.

[45] IRP at Appendix 5N

[46] See ES Exhibit 6 (Staff Informal 1-1 (28) ES Pump Storage Long term).

projected 50-year life underrepresents actual costs that will be incurred by Virginia ratepayers.

Additionally, actual reported O&M data indicates that using the same O&M assumptions for Bath County and Tazewell County would be inappropriate. As Exhibit 5 shows, Bath County has the lowest O&M costs, in $/kW-yr, since it is the largest hydro facility in the U.S. A facility the size of Tazewell would be significantly more expensive to operate on a relative basis.

Q. Does a 2020 NPV of $2.3 billion represent the complete capital costs associated with the project?

A. It does not. A review of the data provided by the Company in response to Staff questions[47] shows a number of capital costs were not included in the $2.3 billion estimate. My understanding is that the proposed facility would be located in Appalachian Power Company's ("APCo") territory, and the interconnection costs will be incurred by APCo. But the costs will be recovered from Dominion's Virginia ratepayers. Additionally, the Company has stated that it already owns the land where it is considering locating the Tazewell facility. However, the land has value. By locating the project on this land, it eliminates any value it could otherwise generate, by being sold for example.

Additionally, an analysis of pumped storage projects shows PSH projects are likely to incur significant cost overruns during development with an average of 70.6%

[47] See ES Exhibit 6 (Company answers to Staff Set 1-2, spreadsheet titled Corrected Attachment Staff Set 1-2 (BMH)).

cost increase and a 63.7% time increase relative to budget and plans, respectively.[48] Therefore, the forecasted costs for the Tazewell facility and its estimated 2029 COD could be understated. It is also worth noting that, when announced in 2017, the proposed Tazewell County PSH was estimated at an overnight capital cost of $2 billion for a 1,000 MW facility,[49] but this estimate has now changed to $2.3 billion for a 300 MW facility.[50]

As the Commission well realizes, the $2.3 billion overnight capital cost represents a small fraction of the total revenue requirement for the project. Folding in operations and maintenance costs, major refurbishments, and financial costs, the total estimated revenue requirement for the project, over its 50-year life, is approximately **[BEGIN EXTRAORDINARILY SENSITIVE]** [redacted] **[END EXTRAORDINARILY SENSITIVE]**.[51] As I mentioned previously, this estimate excludes interconnection costs and property taxes which will further increase the cost.

[48] B.K. Sovacool et al., Risk, innovation, electricity infrastructure and construction cost overruns: Testing six hypotheses, Energy 74 (2014) 906-917
[49] See CHMURA Economics & Analysis, *The Economic and Fiscal Impacts of a Potential Pumped-Storage Hydroelectricity (PHS) Station in Southwest Virginia.*
[50] Dominion IRP and 74 and Appendix 5N.
[51] See ES Exhibit 6 (Staff Informal 1-1 (28) ES Pump Storage Long term).

V. No Demonstrated Reliability Need for Proposed Tazewell PSH Facility

Q. **Has the Company demonstrated a need for long duration storage to ensure reliability in their IRP?**

A. No, they have not. There is no evidence that a long-duration energy storage asset is required to meet reliability requirements, and no apparent transmission constraints in the Southwest Virginia region that would cause a project to be cited there. The IRP provides no evidence that the 300 MW Tazewell PSH facility is needed. In fact, the declining dispatch of the Company's existing long-duration energy storage facility, Bath County Pumped Storage Station, indicates there isn't a need for long-duration storage, particularly with all of the shorter duration BESS the Company plans to add to its generation mix.[52]

Q. **If the Company identifies a reliability need for long-duration storage at some point in the future, what options would it have other than building Tazewell PSH facility?**

A. The Company already owns 60% of the Bath County Pumped Storage Station, which has a total generating capacity of 3,003 MW (1,808 MW owned by Dominion) and 11-hour continuous discharge capability.[53] The project was commissioned in 1985, and with an expected 50-year life, the facility should be operational until at least 2035. This is confirmed by the Company, which shows no planned changes for Bath County generation in Appendix 5K. Therefore, the Company already has a long-duration energy

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[52] IRP at Appendix 5D

[53] See Hydro Review, Energy Cast Podcast: Insight Into the 3,000 MW Bath County Pumped Storage Station. https://www.hydroreview.com/2020/07/31/energy-cast-podcast-insight-into-the-3000-mw-bath-county-pumped-storage-station/#gref

storage asset, and there is the potential for the Company to procure a larger percentage of Bath County from the companies that own the other 40%, if needed.

Additionally, the Company can access long-duration storage from other assets in PJM, which already has the most pumped storage of any ISO, without the addition of Tazewell County PSH.

Finally, the Company can choose to add discharge capacity to existing BESS facilities, if needed.

Q. Can duration be added to BESS facilities after they have already been built?

A. Yes, it is feasible to add discharge duration to existing battery facilities. Most BESS solutions are designed to be fully containerized - with the batteries, HVAC and inverter included in a single container. Imagine an 18-wheeler container which includes battery racks, an inverter, and HVAC. Adding duration to an existing system can be accomplished by adding more containers.

While it is feasible, it may not always be the most cost effective solution. Interconnection costs, land availability and other factors might also preclude this option.

VI. Economic Development and Benefit to Cost Analysis of Tazewell County PSH

Q. Can you summarize how the project has changed since it was initially proposed and how that might impact the local economic development?

A. When the Tazewell County project was announced in 2017, it was accompanied by an economic development study.[54] It is important to note that the economic study assumes a project is more than three times greater than the current project size. The economic study assumes a 1,000 MW generation facility[55] for a $2 billion investment.[56] A new study is required to determine how the economic benefit has declined based on the project size decreasing.

The study concluded the project, during its development and construction phase, would generate $319.5 million in total economic impact in Southwest Virginia through increased employment and ongoing operations would add $36.9 million annually through increased employment locally. The study also concluded the development and construction phase would generate $576.3 million for the entire state of Virginia, or 2,980 job-years,[57] and $38.6 million annually during the ongoing operations phase. The economic impact for Virginia is total and includes Southwest Virginia, it is not additive.[58]

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[54] CHMURA Economics and Analytics, The Economic and Fiscal Impacts of a Potential Storage Hydroelectric Station in Southwest Virginia. June, 2017.

[55] Ibid, page 5.

[56] Ibid, page 3. How the investment is defined is not specified in the report. It is presumed to be an overnight capital cost, but it is not stated.

[57] Job-year is defined as 1 person for 1 year. For example, 2,980 job-years could be 2,980 people working for 1 year, or 1,490 people working for 2 years.

[58] $576.3 million for the state includes $319.5 million which is specific to Southwest Virginia.

Most localities in Southwest Virginia do not have a business, professional and occupational license tax. Therefore, there is very little tax benefit assumed for the local communities during the development and construction phase. However, once completed, the local communities would benefit from property tax payments, which were calculated at $12 million per year for Southwest Virginia. The state would benefit from higher corporate and individual income tax during the development phase, collecting $7.7 million. The ongoing benefit for the state is much lower, only an additional $257,000 annually. The total benefit for the state is additive in that different taxes are collected (e.g. property tax collected locally and income tax collected by the state).

The economic benefits identified in this report, and summarized here, were used to perform a benefit to cost analysis, even though the costs are for a smaller project and the benefits for a larger project.

Q. Has the company performed a benefit-to-cost analysis for the proposed Tazewell County PSH facility?

A. No. While the company references the economic benefits, those benefits have not been compared to the cost of the project. Any benefit / cost analysis at a minimum should include: the full revenue for the Tazewell County PSH facility (development cost plus 50 years of operations); total Virginia economic impact of increased employment (development phase plus 50 years of ongoing operations); increase to Virginia tax base (property taxes collected in Southwest Virginia during ongoing operations plus income and corporate taxes collected during development phases as well as ongoing operations); revenue generated by facility (capacity plus energy).

It is unrealistic to look at the benefit / cost ratio just for Southwest Virginia since that would assume that only Southwest Virginia ratepayers are paying for Tazewell County facility.

Q. Do BESS projects provide the opportunity for economic development in Virginia?

A. A 2019 study commissioned by the Virginia Department of Mines, Minerals and Energy (DMME) concluded that 1,123 MW of BESS deployed in Virginia would add 4,132 job-years and $387 million in labor income. While deploying BESS across Virginia does not have the benefit of targeting Southwest Virginia in a manner similar to Tazewell County PSH, the economic benefit of BESS upon the state is measurable.

VII. Recommendations

Q. Please summarize your recommendations for the Commission based on the review of the record regarding energy storage in Virginia.

A. Tazewell County PSH is too expensive an asset for the Commission to consider without any evidence to demonstrate there is a reliability need for long-duration storage, and there is none at this point. If the Commission is inclined to consider Tazewell County, at a minimum it should require the Company to perform modeling that doesn't force the model to include the project to determine whether Tazewell County runs the risk of immediately becoming a stranded asset upon completion due to high variable and fixed costs.

My understanding is that one objective of the proposed Tazewell County PSH facility is economic development in Southwest Virginia. However, the economic benefit modeling is out of date since it was performed for a 1,000 MW facility and the Company is currently considering a 300 MW facility. At a minimum, the Company should be required to repeat the economic benefit modeling to show how decreasing the project size negatively impacts the overall benefits. Additionally, legislation encouraging the Tazewell County facility was passed in 2017, prior to VCEA legislation. It seems highly probable more cost effective projects could be identified relating to battery storage, solar or wind that provide economic development opportunities in the region at much lower cost. The Commission should consider economic studies that look at alternative clean energy solutions to bring economic development to the region.

The cost of BESS is inflated in the IRP and the cost of PSH is deflated. The Company should be required to compare the costs of both technologies equally. For example, interconnection costs, land costs and property taxes are folded into the cost assumptions for BESS while they are excluded for PSH. A careful review should be performed to ensure costs are either included or excluded for both. The IRP is currently skewed to represent PSH more favorably than it should.

The declining dispatch of Bath County in the IRP should be a concern to the Commission. The Company should be encouraged to consider solutions that lower the variable costs of Bath County to ensure it remains economic. This might include creative solutions such as locating BESS at Bath County to lower the overall variable O&M.

Q. Does this conclude your testimony?

A. Yes.

Attachment KC-1

KERINIA CUSICK

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PROFESSIONAL EXPERIENCE

CENTER FOR RENEWABLES INTEGRATION (Jan, 2017 – Current)

Co-founder of a small company performing qualitative consulting on issues relating to high penetration variable generation. Working with state electricity regulators, Independent System Operators, FERC, and state energy offices on issues including energy storage, interconnection standards, and procurement of renewable energy. Relevant energy storage projects include:

- Development of New York's energy storage roadmap for in-front of the meter, large-scale energy storage assets. Identified regulatory levers and barriers to encourage large-scale development, assisted in the evaluation of potential incentives structures, and integrated relevant FERC Orders into state's strategy.
- National expert storage as a transmission asset. Extensively researched relevant FERC regulations, participated in year-long ISO workshops, provided expert witness testimony in transmission siting cases, conducted training sessions for state regulators, briefed FERC staff and participated in FERC hearings.
- Expert witness in Virginia Dominion's battery storage pilot.

DISTRIBUTED ENERGY INNOVATION (Jan, 2016 – Current)

Principal Consultant

Providing go-to-market consulting in renewable energy and energy storage sectors. Performing project development work on portfolios of front of meter and behind the meter energy storage assets in the U.S. Providing due diligence for investors evaluating projects and companies for potential investment. Relevant energy storage projects include:

- Investor due diligence on very large energy storage projects located in Texas; analysis of market opportunity for company developing new energy storage technology.
- Project development work on: aggregated behind-the-meter residential storage participating in ISO markets; front-of-meter energy storage portfolio sized at hundreds of MW in New York; behind-the-meter commercial/industrial projects located in California.
- Go-to-market consulting for company adapting technology to energy storage sector. Identifying target cost structures, prioritizing markets, and developing investor materials.

SUNEDISON, LLC **(Sept, 2009 – Dec, 2015)**

Vice President, Advanced Solutions / Energy Storage *(2013 – 2015)*

Market development leader launching SunEdison into the energy storage market.

- Co-authored SunEdison's energy storage go-to-market strategy, secured $10M from leadership to build a new line of business which created a $250M pipeline within 20 months through combination of greenfield development, joint development agreements and acquisition.
- Launched Demand Charge Management product offering leading to creation of $32M in new pipeline within 14 months via greenfield development.
- Launched residential storage. Developed cash-sales strategy for Australia and lease model for U.S. Led participation with EPRI/Southern California Edison on zero-net-energy home community with distributed assets controlled by SunEdison's storage NOC.
- Participated on M&A/JDA teams acquiring $53M pipeline and assets in PJM, and securing JDA to develop a $165M storage project for Southern California Edison.
- Led storage financeability. Attracted and educated new investors; worked to develop new financial products to hedge merchant revenue streams; teamed with legal and finance to develop new contracts and models; worked on warrantee and insurance products as well as long-term product replacement strategies to mitigate financing risk.
- Led detailed evaluation of solar-diesel hybrid market, ultimately recommended not pursuing market due to limited size and inherent financing challenges.

Managing Director, Government Affairs *(2012 - 2013)*

Led national team responsible for opening and defending markets across the US, concurrently engaging in legislation and regulatory interventions to create opportunities for solar in approximately 15 states and at the federal level. Responsible for:

- Team leadership: secured and managed annual budget over $2.5M, hired and fired, set strategic priorities, defined annual targets and ensured team met or exceeded annual targets, worked with internal customers to ensure satisfaction with results.
- Team results: Delivered NPV greater than $130M in new opportunities. Intervened in Qualifying Facility rate design cases, raised state-wide net-metering caps, mitigated onerous interconnection standards for variable generation, improved interconnection screens at FERC, influenced the design of new solar programs, passed tax parity legislation as well as community solar.

Director, Government Affairs, Eastern US & Caribbean *(2009 - 2012)*

Managed territory of states in Mid Atlantic, Mid-West and Caribbean and led all regulatory and legislative activities in the region.

- Opened and defended solar markets by either getting legislation passed to create incentives, reduce or eliminate taxes, allow net-metering or 3rd party ownership, and facilitate interconnection.

THINK ENERGY **(2008 – 2009)**

Vice President, Business Development

Led business development activities for a small renewable energy consulting firm.

- Negotiated strategic partnership with ESCO to develop state-wide renewable procurement plan

INFORMA, plc **(1999 – 2008)**

Business Development and Project Management consultant

Worked at three Informa wholly owned subsidiaries in District of Columbia metro area: ESI International, Robbins Gioia, and Huthwaite.

- ESI International: Principal Consultant and Business Development COO. Created and delivered new products within Project Management consulting firm. Directed operations for business development, billing over $45M annually in revenue. Consistently exceeded annual revenue commitment for 5 years running.
- Huthwaite: Senior Client Executive responsible delivering business development consulting services to executives at the firm's largest strategic account, which represented 22% of the firm's annual revenue.
- Robbins Gioia: Sales operations consultant advising Business Development VP on compensation plans, organization design, and go-to-market strategy at project management consulting firm.

ADDITIONAL PROFESSIONAL EXPERIENCE

Hughes Electronics Corporation and Grumman Aerospace

Engineer and program manager on aircraft, space-based defense and communication satellites.

EDUCATION & CERTIFICATION

- Master of Science, Systems Management, University of Southern California, LA, CA
- Bachelor of Science, Mechanical Engineering, Drexel University, Philadelphia, PA
- Master's Certificate, Project Management, George Washington University, D.C.
- Project Management Professional (PMP) ® certification, Project Management Institute

SELECTED PUBLICATIONS & PRESENTATIONS

- National Associated of Regulatory Utility Commissioners (NARUC) Webinar: The Electron Superhighway; Modernizing the U.S. Transmission Infrastructure. April, 2020
- VERGE 2019 Conference: Building the Energy Cloud. October, 2019
- DR & DER World Forum: FERC DER Aggregation Opportunities for DER. October, 2019.
- It's Time for States to Get Smart About Smart Inverters. October, 2019.
- Transmission Planning Protocol. August, 2019
- The Role of Distributed Energy Resources in New Jersey's Clean Energy Transition. July, 2019
- Mid Atlantic Conference of Regulatory Commissioners presentation. June, 2019
- Storage as Transmission Asset, 2018 Progress and Report Card. February, 2019.
- ACORE Renewable Energy Grid Forum presentation. November, 2018.
- DER World Forum presentation. October, 2018
- WIRES Summer Meeting presentation. August, 2018.
- NY Energy Summit presentation. August, 2018.

· Alternative Transmission Solutions: CAISO Planning Process. March, 2018.

· GTM Power & Renewables presentation. November, 2018.

· Common Storage Misperceptions, Public Utilities Fortnightly, June, 2017

· Primary author of Center for Renewable Integration comments in D.C.'s "Modernizing the Energy Delivery System for Increased Sustainability" initiative.

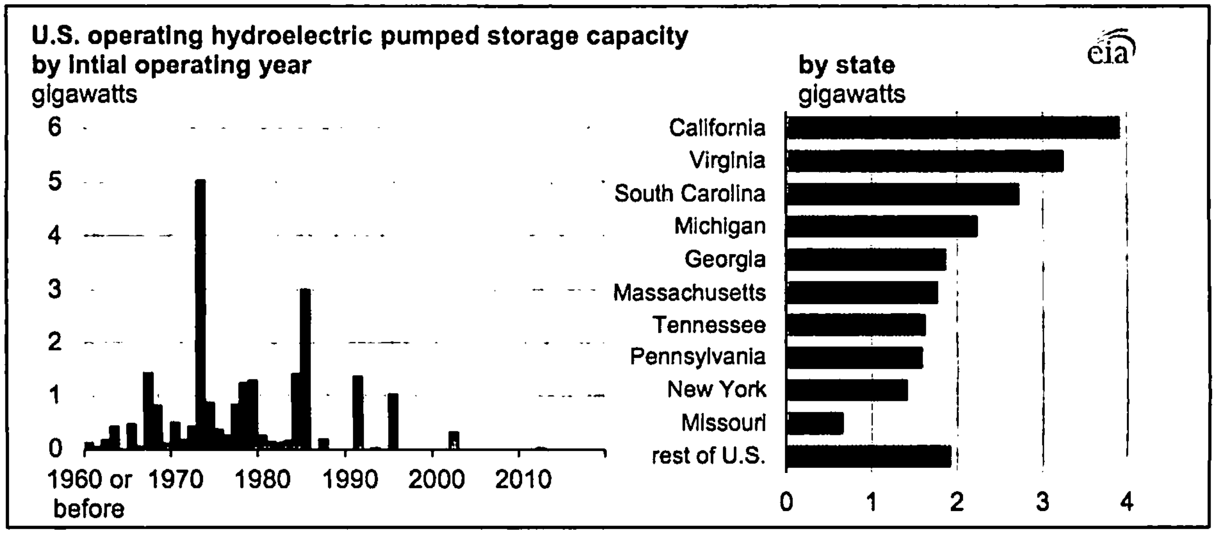
· Puerto Rico Minimum Technical Requirements: Recommendation by the Puerto Rico Energy Cluster Interconnection Committee, filed with Puerto Rico utility (PREPA), Governor's office and General Assembly, June 2013. Detailed analysis of opportunities, challenges and solutions associated with interconnecting variable generation with Puerto Rico's electricity grid.

· Solar and Storage Trends and Opportunities, Energy Thought Summit, March, 2014.

200920054

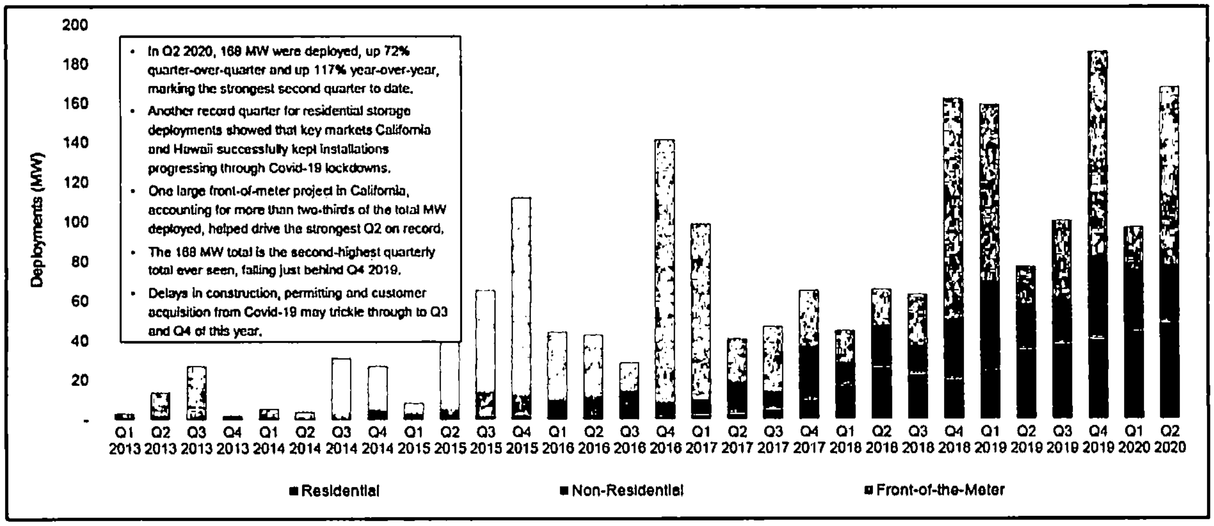
Exhibit 1:
Comparison of Energy Storage Technology Installed by Year - Pumped Storage and Battery Storage

1. Construction of Pumped Storage Peaked in the 1970s in the U.S.



Source: https://www.eia.gov/todayinenergy/detail.php?id=41833

2. Construction of Battery Storage is Slowly Ramping Up in the U.S.



Source: https://www.woodmac.com/research/products/power-and-renewables/us-energy-storage-monitor/

Exhibit 2:
Comparison of Energy Storage Costs Included in Recent Integrated Resource Plans in the U.S.

Summary of energy storage capital costs used in recent IRPs comparing pumped storage (PSH), compressed air storage (CAES), lithium-ion BESS, and flow battery BESS

Table 5-2: Assumed installed costs ($/kW) of different ESS in recent IRPs and other planning studies

State	Utility IRP or other planning study	PSH	CAES	Lithium-ion BESS	Flow battery
		Midwest			
Missouri	Ameren Missouri, 2017 IRP [39]	$1,647	$889		$3,458
		South			
Tennessee	Tennessee Valley Authority (TVA), 2015 IRP [49]	$2,365 (2013)	$1,072 (2013)		
		West			
Arizona	Arizona Public Service (APS), 2017 IRP [70]	$3,139	$3,246	$1,539	$1,589
Montana	NorthWestern Energy, Montana 2019 Electricity Supply Resource Procurement Plan [44]	$1,700–$3,000 for fixed speed; variable speed 20% higher (9 hour closed loop)	$1,500–$2,300 Adiabatic (8 hour)	$1,660 (4 hour)	$1,700 (Vanadium, 4 hour)
New Mexico	Public Service Company of New Mexico (PNM) 2017 IRP [73]			$1,892 (2 hour) $2,925 (4 hour)	
Oregon	Portland General Electric, 2019 IRP [77]	$2,252 (8 hour)		$916 (100 MW, 2 hour), $1,554 (100 MW, 4 hour), $1,902 (100 MW, 6 hour)	
Washington	Puget Sound Energy (PSE), 2019 IRP underway [93]	$2,612 (8 hour)		$1,550 (2 hour) $2,680 (4 hour)	$1,732 (4 hour) $2,378 (6 hour)
Multiple Western states	PacifiCorp, 2019 IRP underway [92]	$2,680 (8 hour) to $3,255 (10 hour) (5 projects)	$1,625	$1,473 (15 min) $2,615 (2 hour) $3,412 (4 hour) $5,455 (8 hour)	$3,996 (6 hour)

Source: Electric Power Research Institute, Pumped Storage Hydro in Resource Planning in the United States: A Survey of Recent Results and Methods. July, 2019.

Exhibit 3: Projected Battery Cost, Lithium Ion BESS, 2020 - 2050

Summary of National Renewable Energy Laboratory (NREL) survey of announced future costs for lithium-ion based battery storage solutions.

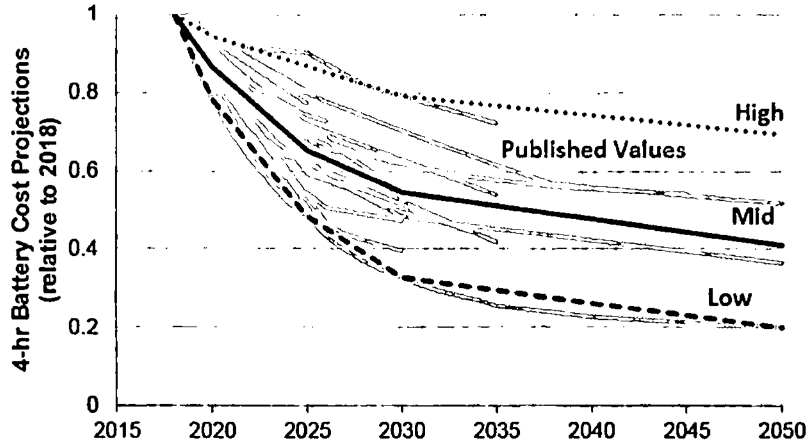


Figure ES-1. Battery cost projections for 4-hour lithium-ion systems, with values relative to 2018.
The high, mid, and low cost projections developed in this work are shown as the bolded lines.

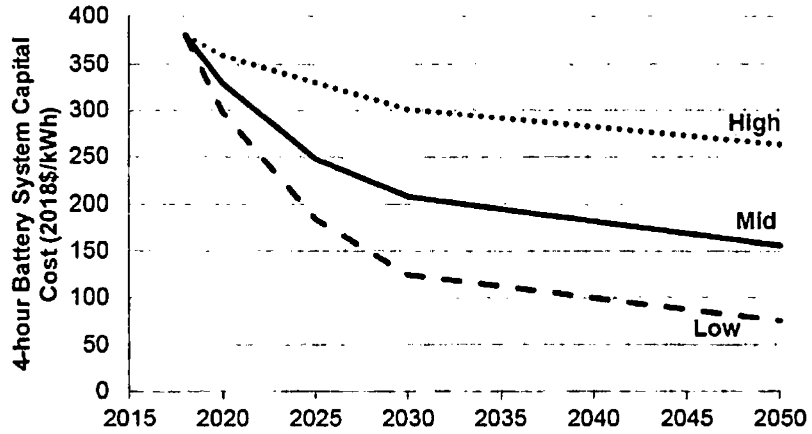


Figure ES-2. Battery cost projections for 4-hour lithium ion systems.

Source: Cole, Wesley, and A. Will Frazier. 2019. Cost Projections for Utility-Scale Battery Storage. Golden, CO: National Renewable Energy Laboratory. NRE/TP-6A20-73222. https://www.nrel.gov/docs/fy19osti/7322.pdf

Exhibit 4:
Projected Battery Cost, Lithium Ion BESS, 2020 - 2050

PJM pumped storage capacity exceeds availability in any other ISO, including ISOs with significant variable generation such as CAISO, SPP and MISO.

Table 2-2 – Energy storage capacity (MW) operational by ISO, as of March 2019

ISO/RTO	Batteries and Flywheels	Pumped storage hydro	
	Numbers given are MW	MW	Number of plants
ISO-NE	Batteries – 30.4	1,797	3
NYISO	Batteries – 1 Flywheels – 20	1,406	2
PJM	Batteries, grid connected – 280.1 Flywheels – 20 Batteries, Demand Response – 8	5,244	5
MISO	Batteries – 24	2,451	2
SPP	Batteries – 2.2	186	1
ERCOT	Batteries – 94.3		
CAISO	Batteries – 181.3	2,275	6

Source: Electric Power Research Institute, Pumped Storage Hydro in Resource Planning in the United States: A Survey of Recent Results and Methods. July, 2019.

<u>Exhibit 5</u>

Company Responses to Besa Set 2-13, 2-14, and 2-15

NRDC Set 2-8

Virginia Electric and Power Company
Case No. PUR-2020-00035
Mr. Glen Besa
Besa Set 2

The following response to Question No. 14(b) and (c) of the Second Set of Interrogatories and Requests for Production of Documents Propounded by Mr. Glen Besa received on August 31, 2020, was prepared by or under the supervision of:

Kevin Cross
Energy Market Consultant
Dominion Energy Services Inc.

Question No. 14(b) and (c)

Reference Appendix 5N. The assumed variable cost for a 300 MW pumped storage facility is $47.66/MWh.

b. Please provide a comparison of the variable cost of the proposed 300 MW pumped-hydro storage facility vs. the Bath pumped-hydro storage facility.

c. Please detail any other cost or other constraints related to these two resources that are used by PLEXOS to determine dispatch in the system modeling conducted by the Company.

Response:

b. The variable cost for Bath County would likely be the same as the proposed pumped storage facility—approximately $47.66/MWh—which represents the cost of off-peak power, which is typically used to fill a pumped storage facility.

c. Operational characteristics for the 300 MW pumped storage facility in the PLEXOS model are identical to Bath County aside from the following characteristics:

	Bath County	New Pump Storage
VOM	.155/MWh	None
Efficiency	80%	82%

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Virginia Electric and Power Company
Case No. PUR-2020-00035
Mr. Glen Besa
Besa Set 2

The following response to Question No. 16 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by Mr. Glen Besa received on August 31, 2020, was prepared by or under the supervision of:

Kevin Cross
Energy Market Consultant
Dominion Energy Services Inc.

As it pertains to legal matters, the following response to Question No. 16 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by Mr. Glen Besa received on August 31, 2020, was prepared by or under the supervision of:

Sarah R. Bennett
McGuireWoods LLP

Question No. 16

Reference Figure 5.5.2.3, Energy Storage LCOE. Provide all reference analysis or other documents used to determine the Company's battery storage capacity factor of 15%.

Response:

The Company objects to this request as overly broad and unduly burdensome to the extent it seeks "all reference analysis or other documents." Notwithstanding and subject to these objections, the Company provides the following response:

The 15% capacity factor for battery storage is based on the average utilization output produced by the PLEXOS model. See Appendix 5D for capacity factor outputs.

Virginia Electric and Power Company
Case No. PUR-2020-00035
Mr. Glen Besa
Besa Set 2

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Question No. 16

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Response:

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Virginia Electric and Power Company
Case No. PUR-2020-00035
Natural Resources Defense Counsel
NRDC Set 2

The following response to Question No. 8 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by Natural Resources Defense Counsel received on July 29, 2020, was prepared by or under the supervision of:

Bradley M. Hanks
Manager – Construction Services
Dominion Energy Services, Inc.

Question No. 8

Please reference IRP Section 4.7, page 74 ("This BESS is based on a 4-hour discharge configuration."). Did the Company consider or analyze 2, 6, or 8-hour discharge durations? If not, why were those durations excluded from the analysis?

Response:

Only a discharge durations of 4 hours was analyzed, as the discharge durations were provided to the Company through the BESS RFP, which only included lithium ion applications. Lithium ion applications of 6 or 8 hour discharge durations were not provided by the bidders.

Extraordinarily Sensitive Exhibit 6 (REDACTED)