Pacific Northwest NATIONAL LABORATORY

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Benefits of Energy Storage for Washington, D.C.

Analysis for the Department of Energy and Environment

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1.0 Introduction

PJM's annual forward capacity market conducted in July 2024 saw dramatic increases that resulted in record-high prices for the region. After clearing at $28.92/megawatt-day the previous year, prices increased nearly ten-fold to $269.92/megawatt-day in the 2024 auction.[1] After the Federal Energy Regulatory Commission (FERC) imposed floor and ceiling prices on future PJM capacity auctions, the 2025 auction price increased to the price cap of $329.17/megawatt-day. PJM attributes the price increases to a challenging mix of rapidly growing demand and retirements of generation resources, but states that efforts to accelerate the process of interconnecting new energy resources are proving effective in adding new capacity.[2] PJM has also engaged jurisdictions and utilities within its footprint to co-develop solutions to meet rapidly rising demand.

Energy storage technologies, which can be flexibly sited on the electric grid to meet local energy demands, can potentially be used to reduce reliance on high-cost generation resources during periods of high demand as well as the costs of delivering that generation over the transmission and distribution systems. The Washington, D.C. Department of Energy and Environment (DOEE) has requested technical assistance from the U.S. Department of Energy and the national laboratories to study the potential for deploying energy storage in Washington, D.C. (District) to improve electricity affordability for D.C. ratepayers through avoided costs for energy and infrastructure.

DOEE staff also requested assistance in identifying the potential size of an energy storage procurement target and mechanisms for achieving that target. While it is not the role of a national laboratory to make specific recommendations on how the District should proceed in pursuing its objectives, this memo will present objective analysis that will inform DOEE and its stakeholders as they work to identify a path forward.

Section 2 of the memo describes the different benefit streams that energy storage systems can provide and why energy storage systems that operate outside of wholesale energy markets are most aligned with DOEE's objective of reducing electricity costs. Section 3 quantifies the costs that can be avoided with non-market energy storage systems in the District, Section 4 presents case studies and design options for behind-the-meter storage programs that operate outside of energy markets, and Section 5 describes future considerations for DOEE.

2.0 Types of energy storage benefits

Energy storage deployed in Washington, D.C. can provide two main streams of economic benefits: avoided costs and market revenues. Understanding the difference between these types of benefits, what types of projects can provide them, and quantifying their values are necessary for designing procurement programs and compensation mechanisms. In some cases, avoided

[1] 2025/2026 Base Residual Auction Report (PJM).
[2] PJM News Release.

costs and market revenues are mutually exclusive, so achieving a particular outcome may require a particular type of storage deployment.

Avoided costs are achieved by strategically discharging storage during high-demand periods to reduce the costs of operating the regional electric grid that are allocated to DC ratepayers. These benefits are independent of energy market participation and are indirect in that no market compensation is provided for services, but those services result in all customers paying less for electricity.

Market revenues are the financial compensation that energy storage assets receive from PJM for the grid benefits that they provide. These benefits are dictated by energy market structures and are direct in that they flow only to the asset owner through monetary payments. While they will influence the economics and investment decisions around specific energy storage projects, they do not flow to all customers.

Table 1 summarizes these different benefits:

Table 1: Benefit streams for energy storage technologies

Avoided costs: Benefits created for all customers by reducing local demand during peak periods		**Market revenues:** Compensation provided directly to the asset owner for its grid services	
Benefit	**Description**	**Benefit**	**Description**
Capacity	• PJM allocates the cost of procuring capacity resources based on each region's share of demand during the five highest-demand hours of the year. • By using storage to meet local demand during those hours, the District can reduce its share of peak load and the capacity costs that are allocated to it.	**Capacity**	• To ensure that there is enough generation to meet projected demand, PJM operates a capacity market that pays resources for their availability. • Four-hour storage resources are heavily derated in PJM's capacity market, receiving pay for only 50% of their nameplate capacity.[3]
Energy	• By charging during low-cost hours and discharging during high-cost hours each day, storage assets can	**Energy**	• Energy storage operators pay for the energy they use to charge and are paid

[3] NYISO de-rates four-hour storage technologies to between 64 and 79% of their nameplate capacity, depending on the region. No other market region de-rates four hour storage right now, though proceedings to implement effective load-carrying capability (ELCC) models are underway in MISO and ISO-NE.

	reduce the amount of high-cost energy utilities need to purchase during daily peak hours. • Requires market-informed charge and discharge cycles for storage assets.		for the energy that they discharge. By engaging in arbitrage, storage operators can earn revenue by selling low-cost energy during high-cost periods.
Transmission and Distribution	• By using locally sited resources to meet capacity and energy needs, less transmission and distribution infrastructure will be needed. • These benefits are more difficult to quantify, since they require counterfactual assumptions about what would have been built in their absence.	**Ancillary Services**	• To maintain grid reliability, PJM operates several market products to pay resources to quickly change their output in response to grid needs. • Frequency regulation is the most valuable service, but the market is saturated and new projects would likely be limited to the lower-value reserve services.

In a wholesale market region like PJM, the type of benefits that a particular storage asset can provide depend on whether the asset participates in PJM's markets; those that do participate in PJM will generate market revenue and those that do not will generate avoided costs. This analysis will therefore differentiate between energy storage projects that participate in PJM markets (market-facing) and those that do not (non-market). While front-of-meter (FTM) and behind-the-meter (BTM) terminology is often used to differentiate different types of energy storage projects, given the pending ability of BTM projects to participate in energy markets and the potential for FTM projects to serve reliability functions outside of energy markets, that distinction will generally not be used in this analysis. The exception is in Section 4, which will present case studies of BTM energy storage programs in other jurisdictions that were designed to meet similar objectives to those identified by D.C. DOEE.

2.1 Benefits of Non-Market Systems

Storage systems that participate in in PJM's capacity and energy markets realize their economic benefits through market revenues that are captured by system owners and not shared with customers. If a battery receives market compensation for providing a service, it cannot avoid the cost of that service. For example, a market-facing storage system participating in PJM's capacity market cannot avoid capacity costs, since it would collect the very capacity costs that DOEE seeks to avoid. Similarly, a market-facing system cannot avoid energy costs on behalf of all customers since the arbitrage benefits of charging when energy is cheap and discharging when energy is expensive are captured solely by the asset owner through energy market transactions.

Market-facing systems sited in the District can avoid transmission and distribution system costs, as they can meet local demand during peak periods and thereby reduce the need for transmission and distribution infrastructure to deliver power from outside the District, and there is no market product that would otherwise compensate that service. Market-facing systems sited in the District would also have positive effects on the PJM capacity market by providing regional capacity that helps manage capacity market prices generally and local capacity in the PEPCO zone that would reduce the risk of congestion-driven price spikes like those seen in the Baltimore Gas & Electric and Dominion zones in PJM's 2024 and 2025 capacity auctions. However, market-facing systems have limited ability to support DOEE's immediate objective of reducing costs driven by regional energy market outcomes.

To meet DOEE's objective of avoiding capacity costs, an energy storage system cannot participate in PJM's capacity market. Only by discharging during high-demand periods while not collecting capacity revenue can a system avoid capacity costs on behalf of all DC ratepayers. But if a system is not earning market revenue, its economic viability depends on other funding sources. Large, utility-scale battery systems in particular would require other funding sources, such as regulated cost recovery for providing transmission or distribution reliability, to offset that market revenue. Incentive payments may also be used to offset foregone revenue, but collecting incentive payments from D.C. residents through taxes or utility rates would make it difficult for the utility-scale system to deliver net savings.

Because market-facing systems are dependent on market revenue for financial viability, non-market systems are the type of energy storage most likely to meet DOEE's objective.

Non-market energy storage, particularly BTM systems, also offer the potential for a shared investment model between utilities and customers, which reduces the utility's cost of procuring energy storage. Host customers purchase the system for their own purposes, such as backup power or time-of-use savings or self-consumption of distributed generation, and bear most of the system costs in exchange for those benefits. A utility can then pay customers to also use their storage systems to provide grid benefits. Utility customers who fund those payments receive the benefits of avoided capacity and energy costs at a discount, and host customers bear the remaining costs. This shared investment model allows for an energy storage system to operate independently of energy markets and still be economically viable. Figure 1 summarizes this model:

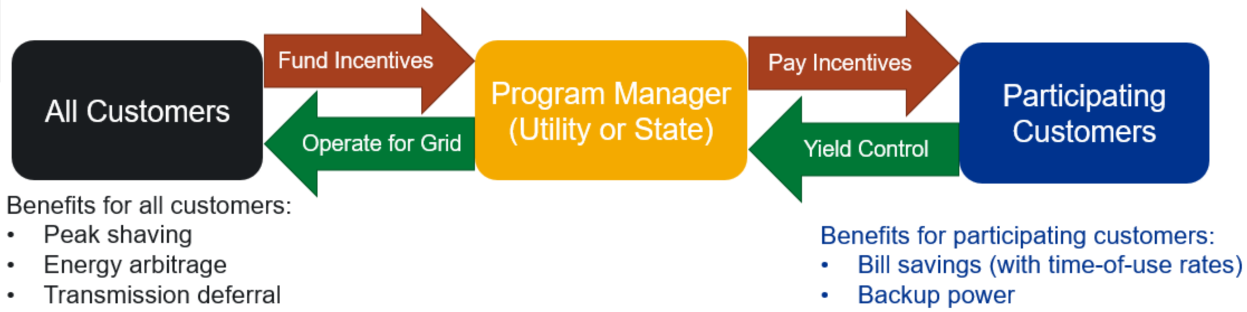

Figure 1: Shared investment model for BTM energy storage systems

Section 4 provides several case studies of how different states and utilities have implemented this model.

3.0 Avoided Costs

This section will quantify the avoided cost benefits of energy storage investments in the District: capacity, energy, and transmission and distribution as well as the input assumptions used in the analysis.

3.1 Input Assumptions

In this analysis, we consider two scenarios to determine avoided capacity payments, first for the for the entire PEPCO zone, and second for the Washington D.C. subzone. The 2023 summer peak load values (in MWs) are considered for both scenarios to determine various benefits of energy storage systems; these values were published in PJM's Regional Transmission Expansion Plan (RTEP) 2023. To simplify the sizing of the energy storage facilities, different peak shaving values are assumed as a percentage of total peak load. It is also assumed that all energy storage systems would have capacity to operate for 4 hours (the rationale for this assumption is described in detail in Section 4.1).

Table 2 includes the input assumptions used to determine the range of potential benefits and savings in terms of avoided capacity payments in the PJM capacity market:

Table 2: Input assumptions

PEPCO peak load (summer) of 2023 (MW)[4]	5091.80
DC share of PEPCO peak load, 2023 (MW) [5]	1,977
Energy storage system duration (hours)	4
PJM clearing price for 2024/25 ($/MW-day)[6]	28.92

[4] https://dataminer2.pjm.com/feed/hrl_load_metered
[5] https://www.pjm.com/-/media/DotCom/library/reports-notices/2023-rtep/2023-rtep-report.pdf
[6] https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx

PJM clearing price for 2025/26 ($/MW-day)[7]	269.92
PJM clearing price cap for 2026/27 and 2027/28 ($/MW-day)[8]	325
PJM clearing price floor for 2026/27 and 2027/28 ($/MW-day)	175
BGE clearing price for 2025/26 ($/MW-day)[9]	466.35
Additional storage share of peak (%)	1, 5, 10, 15
Avoided transmission capacity cost ($/kW-yr)[10]	30
Avoided distribution losses ($/MWh)	3

Both scenarios (PEPCO zone and D.C. subzone) consider cost sensitivity by studying a wide range of potential capacity cost savings considering different capacity prices. The next few sections describe the quantified benefits of energy storage systems, and all input assumptions in Table 2 would be described in these sections according to how they are used in various calculations.

3.2 Avoided Capacity Costs

As mentioned in Table 1, PJM allocates the costs of its capacity market to participating utilities based on each utility's demand during PJM's five highest-demand hours of the year. PJM's Data Miner tool records that PEPCO's peak load was 5,091.8 MW in 2023. Additionally, according to PJM's RTEP 2023 report, the utility's peak load inside of Washington, D.C. was 1,977 MW, which allows for more granular analysis for the District. The Federal Energy Regulatory Commission (FERC) also recently approved a proposal from PJM to set a price cap and floor for its next two capacity auctions. The proposal sets a roughly $325/MW-day price cap and $175/MW-day floor for its capacity auctions over the next two years. Therefore, to provide a range of potential savings depending on different capacity prices, we use these cap and floor as low and high scenarios of avoided capacity payments calculations, while keeping the 2025/26 capacity price as a medium case. In addition to that, the analysis also covers very low and very high scenarios, to quantify the avoided costs once (and if) the price collar is lifted. For simplicity, and to keep the numbers realistic, PJM's 2024/25 capacity price of $28.92/MW-day is considered for the very low scenario, and Baltimore Gas and Electric (BGE) zone's 2025/26 clearing price of $466.35/MW-day is considered for the very high scenario. Four levels of peak shaving cases are explored here, ranging from 1% to 15% of total peak demand for both PEPCO, and Washington, D.C.

Table 3 summarizes these results for the PEPCO zone:

[7] https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx
[8] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250421-3069&optimized=false
[9] https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx
[10] https://edocket.dcpsc.org/apis/api/Filing/download?attachId=194999&guidFileName=a1a60613-580e-46fe-8ca0-b6578d6f2c1d.pdf

Table 3: Avoided capacity cost benefits in the PEPCO zone

Peak Reduction	Capacity Requirement (in MW)	Potential avoided capacity payments with cost sensitivities ($/yr, thousands)				
		Very Low (2024 PJM price)	Low (PJM price floor)	Medium (2025 prices)	High (PJM price cap)	Very High (2025 BGE price)
1%	50.92	$537.28	$3,252.39	$5,016.48	$6,040.15	$8,667.15
5%	254.59	$2,687.40	$16,261.94	$25,082.42	$30,200.74	$43,335.75
10%	509.18	$5,374.80	$32,523.88	$50,164.83	$60,401.49	$86,671.49
15%	763.77	$8,062.20	$48,785.82	$75,247.25	$90,602.23	$130,007.24

Table 4 summarizes these results for the Washington, D.C. subzone:

Table 4: Avoided capacity cost benefits in the Washington, D.C. subzone

Peak Reduction	Capacity Requirement (in MW)	Potential avoided capacity payments with cost sensitivities ($/yr, thousands)				
		Very Low (2024 PJM price)	Low (PJM price floor)	Medium (2025 prices)	High (PJM price cap)	Very High (2025 BGE price)
1%	19.77	$208.69	$1,262.81	$1,947.76	$2,345.22	$3,365.20
5%	98.85	$1,043.44	$6,314.04	$9,738.78	$11,726.08	$16,826.02
10%	197.7	$2,086.88	$12,628.09	$19,477.56	$23,452.16	$33,652.05
15%	296.55	$3,130.32	$18,942.13	$29,216.34	$35,178.24	$50,478.07

As depicted in Table 3, the PEPCO zone could potentially avoid capacity payments from around $0.51 million to $130 million annually by installing energy storage systems, depending on how much peak is shaved and the underlying capacity market price. Correspondingly, up to $50.4 million annually could be saved just from the D.C. region.

3.3 Avoided energy costs

In addition to avoiding capacity costs, discharging energy storage during high-demand periods reduces the amount of high-cost energy that a utility must purchase for its customers. Assuming that the storage system was charged using lower-cost energy during a period of low demand, it can create economic benefits by using low-cost energy to offset demand during periods of high-cost energy. Because the PEPCO zone experiences significant daily price swings most days, energy storage projects in the District would have significant opportunity to engage in energy arbitrage. While a market-facing system participating in PJM's energy markets would capture those benefits solely for the system owner through energy market revenues, non-market systems reduce the amount of energy that needs to be purchased and delivered to an area during peak hours, which spreads the avoided cost benefits to all customers in that area.

To quantify the benefit of avoided energy purchases for energy storage assets in Washington, D.C., we studied hourly load data for the PEPCO node during 2024. For each day of the year, we identified the four hours with the lowest energy costs and the four hours with the highest energy costs. We assumed a round-trip efficiency for energy storage assets of 85 percent,[11] and increased the amount of charge energy each day by 17.6 percent (1 / 0.85) relative to the discharge energy to account for round-trip losses. In other words, for every megawatt-hour (MWh) of energy discharged during high-demand hours, 1.176 MWh needed to be charged during low-demand hours.

Dispatched in this manner, a 1 megawatt (MW), 4 MWh battery would generate $60,061 in avoided energy costs per year. That amount, however, assumes perfect foresight, or that the storage owner would always know in advance the best four hours to charge the battery and the best four hours to discharge the battery each day. In reality, unforeseen fluctuations in hourly prices mean that avoided energy costs would likely be lower in practice, depending on dispatch strategies. To illustrate this point, Figure 2 below shows the average hourly energy price for the PEPCO zone within PJM for each hour of the day during each month in 2024, and a dispatch strategy that directs BTM assets to charge during the four contiguous hours with the least total costs on average (green shading) and then discharge during the four contiguous hours with the highest total costs on average (red shading).

Hour	Jan	Feb	March	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
12:00 AM	36.97	19.12	19.05	24.00	28.17	18.72	24.73	21.87	19.89	23.37	21.83	31.30
1:00 AM	32.48	19.63	19.18	23.85	20.46	18.13	20.82	18.53	17.01	20.03	22.46	28.13
2:00 AM	31.03	19.32	16.61	17.69	16.70	15.74	17.16	15.67	15.59	17.61	18.42	28.16
3:00 AM	31.60	22.71	16.13	17.70	15.88	14.57	15.57	14.35	14.56	18.15	18.39	28.29
4:00 AM	32.08	24.70	17.79	18.96	17.90	13.95	15.84	14.82	14.70	21.46	18.89	27.50
5:00 AM	32.11	26.91	19.66	22.20	24.47	15.94	19.80	17.32	17.34	22.12	21.66	32.34
6:00 AM	52.13	48.13	27.75	33.98	24.97	17.29	21.40	21.56	27.06	36.21	30.39	39.73
7:00 AM	60.38	48.32	37.99	31.08	27.36	19.02	23.36	20.97	27.77	49.16	32.86	60.65
8:00 AM	46.28	29.99	27.00	25.27	32.96	19.84	24.84	19.65	22.03	33.32	28.39	37.18
9:00 AM	46.19	22.24	23.36	25.52	33.38	22.52	31.14	25.02	24.61	22.31	27.33	30.67
10:00 AM	52.22	22.79	23.17	24.30	30.01	25.23	28.30	26.57	24.68	23.96	26.73	32.36
11:00 AM	43.87	23.68	21.17	23.90	30.56	34.04	49.07	28.95	27.51	23.59	25.45	29.47
12:00 PM	44.33	24.58	20.04	23.32	32.95	31.54	48.06	34.90	28.15	24.87	25.92	28.42
1:00 PM	36.94	20.51	17.59	24.69	32.55	37.05	51.26	39.17	35.18	24.39	25.73	27.04
2:00 PM	33.28	16.08	17.19	23.58	36.80	40.47	65.90	51.11	35.72	25.22	25.64	27.15
3:00 PM	34.02	17.35	16.36	23.95	43.78	41.95	74.34	45.70	41.05	26.05	29.49	28.56
4:00 PM	36.15	20.03	15.74	23.72	47.07	45.78	86.84	63.30	47.42	29.48	35.07	34.01
5:00 PM	64.14	28.42	19.31	27.09	61.36	51.38	101.60	60.10	57.41	49.95	49.80	45.84
6:00 PM	48.53	34.58	35.89	30.52	60.38	54.32	78.33	69.65	52.19	64.73	35.53	36.42
7:00 PM	43.28	34.33	29.36	38.63	53.75	53.58	54.70	51.51	43.24	60.40	32.52	38.60
8:00 PM	41.73	28.93	32.20	48.36	45.80	40.19	47.00	39.04	37.45	32.79	31.23	37.66
9:00 PM	38.97	25.80	24.14	32.26	36.28	39.57	47.70	32.79	32.25	33.73	27.88	35.16
10:00 PM	32.38	25.79	21.43	27.96	29.08	28.05	34.63	27.29	27.89	31.22	25.00	31.88
11:00 PM	30.84	20.12	18.59	22.62	27.79	24.19	28.49	22.96	26.97	24.12	22.41	28.21

Figure 2: Average hourly energy prices by month for the PEPCO zone, 2024

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PNNL Energy Storage Cost and Performance Database, https://www.pnnl.gov/projects/esgc-cost-performance/lithium-ion-battery.

If a 1 MW/4 MWh energy storage system were dispatched based on the average low-cost and high-cost hours in Figure 1, it would only generate $38,690 in avoided cost benefits per year, a reduction of about 34 percent from the perfect foresight case. The primary driver of this decline is demand volatility in the winter months. Average peaks in winter usually occur in the morning hours, but winter days also usually see a second average peak in the afternoon that is only slightly smaller than the average morning peak. On mild days (which happen several times each winter month), the afternoon peak exceeds the morning peak.

Figure 2 illustrates the value of dynamic dispatch for energy storage assets. A dispatch strategy that is based on monthly or seasonal averages, such as a time-of-use rate, would achieve significantly lower avoided energy cost benefits than a real-time dispatch strategy. Dynamic rates are one option for achieving more efficient dispatch of energy storage assets, but dynamic rates are difficult to implement and may only benefit customers who have the financial means to implement technologies that respond to those rates. Because utilities have sophisticated forecasting tools and real-time grid visibility, they are better situated to optimally dispatch BTM energy storage assets and maximize avoided energy costs for all customers. Section 4 will discuss these considerations in greater detail.

3.4 Avoided Transmission and Distribution Costs

When energy storage is used to help meet local load during periods of high demand, less electricity needs to be delivered through the transmission and distribution (T&D) systems. If enough local peak demand can be served locally, less long-distance infrastructure will be necessary to supply reliable power. In addition to providing capacity and energy cost savings, investments in energy storage can allow for a more efficient capital deployment in a continuously modernizing grid.

An exact assessment of the T&D infrastructure upgrades that a storage system avoids would require detailed information about local infrastructure plans or transparent counterfactual assumptions, which were unavailable for this analysis.

Absent that data, the team's analysis relied on the avoided T&D costs from a report by Synapse Energy Economics, Inc. created specifically for the District of Columbia.[12] The study's avoided transmission cost of $30/MW-yr and the avoided distribution losses of $3/kW-yr are used as input assumptions for this analysis, as shown in the inputs in Table 2. The study team used a similar approach to the avoided capacity cost calculations by calculating savings of different peak reduction values from 1% to 15% of total load for the PEPCO zone, and Washington, D.C. subzone. The findings are presented in Tables 5 and 6, respectively:

[12] https://edocket.dcpsc.org/apis/api/Filing/download?attachId=194999&guidFileName=a1a60613-580e-46fe-8ca0-b6578d6f2c1d.pdf

Table 5: Avoided T&D cost benefits in the PEPCO zone

Peak Reduction	Capacity Requirement (in MW)	Energy requirement for 4-hour battery (MWh)	Potential avoided transmission costs ($/yr, thousands)	Potential avoided distribution losses ($/yr, thousands)
1%	61.66	246.64	$1,849.80	$0.74
5%	308.3	1233.2	$9,249.00	$3.70
10%	616.6	2466.4	$18,498.00	$7.40
15%	924.9	3699.6	$27,747.00	$11.10

Table 6: Avoided T&D cost benefits in Washington, D.C. subzone

Peak Reduction	Capacity Requirement (in MW)	Energy requirement for 4-hour battery (MWh)	Potential avoided transmission costs ($/yr, thousands)	Potential avoided distribution losses ($/yr, thousands)
1%	19.77	79.08	$593.10	$0.24
5%	98.85	395.4	$2,965.50	$1.19
10%	197.7	790.8	$5,931.00	$2.37
15%	296.55	1186.2	$8,896.50	$3.56

Based upon these input assumptions for avoided T&D benefits, energy storage has potential to save about $1.8 million annually in the PEPCO zone by installing enough capacity to shave 1% of peak load. The annual savings from avoided transmission deferrals extends up to almost $28 million if peak load is reduced by 15%. For the D.C. subzone, the annual savings range from $0.6 million to $8.9 million. Savings from avoided distribution losses are much smaller, ranging from $740 to $11,000 for the PEPCO zone and from $240 to $3,500 annually in the Washington, D.C. subzone.

However, the Synapse data only included avoided costs for distribution system line losses, not avoided capital costs. While identifying specific avoided costs for distribution infrastructure would require specific information about the type and timing of infrastructure investments that were unavailable for this analysis, Table 7 provides illustrative examples of energy storage projects in other jurisdictions that were able to account for avoided/deferred transmission and distribution system costs.

Table 7: Examples of Energy Storage Projects with T&D Deferral Benefits

Location	Project	Storage size (MW/MWh)	Electrical equipment avoided	Avoided / deferred cost
Brooklyn & Queens, NY (USA)[13]	Con Edison – Brooklyn-Queens Demand Management (BQDM)	DER mix incl. batteries	New area substation + feeders/transformers	≈ $1.0–$1.2 billion
Pomona, Rockland County, NY (USA)[14]	Orange & Rockland – Pomona NWA BESS	12 MW / 57 MWh	Pomona substation + 138 kV underground transmission loop	$55.7 million (vs. $7.4m spent for BESS)
Westmoreland, NH (USA)[15]	Eversource – Westmoreland Microgrid (NWA)	1.7 MW / 7.1 MWh	10-mile distribution circuit (redundant line)	$6 million (line) avoided (BESS cost ~$7m)
Punkin Center, AZ (USA)[16]	APS – Punkin Center BESS (Fluence)	2 MW / 8 MWh	≈ 20 miles radial 21 kV poles & wires	Less than half cost of line rebuild (no $)
Nantucket, MA (USA)[17]	National Grid – IslandReady BESS + CTG (NWA)	6 MW / 48 MWh (+15 MW CTG)	Third undersea cable to island	≈ 110 million (cable avoided)

13 https://www.utilitydive.com/news/bqdm-program-demonstrates-benefits-of-non-traditional-utility-investments/550110/
14 https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={609AC944-F838-4240-AC33-0600A8A7E2FC}
15 https://www.utilitydive.com/news/eversource-turns-to-non-wires-solution-in-outage-plagued-new-hampshire-town/555370/

16 https://blog.fluenceenergy.com/aps-to-use-energy-storage-in-place-of-traditional-infrastructure-on-the-distribution-grid#:~:text=For%20APS%2C%20this%20new%20system,battery%20storage%20in%20the%20future.

17 https://www.osti.gov/servlets/purl/1564262

Montgomery County (MD)[18]	Montgomery County Bus Depot Storage Project	1MW/ 3.0 MWh	The Project is planned to defer the need to upgrade a feeder in Silver Spring to accommodate incremental loads due to electric bus charging and provide support for bus charging during distribution system outages	$6,372,200
Leighton Buzzard, England (UK)[19]	UK Power Networks – Smarter Network Storage (SNS)	6 MW / 10 MWh	Third 33 kV circuit + 38 MVA transformer	£8.6 million

To inform future efforts to quantify specific avoided distribution system costs in Washington, D.C., Appendix 1 provides a high-level framework for performing a rough estimate analysis with equations and an example.

4.0 Design Considerations for BTM Storage Programs

Designing a BTM energy storage program involves two important, but competing, objectives: providing a sufficient incentive for participating customers to install energy storage systems and ensuring that the utility customers who fund those incentives receive a net benefit. If the incentive is too small, customers will not install enough energy storage systems to achieve the desired outcome and if the incentive is too big, customers will overpay for the BTM storage fleet and the desired outcome of reducing costs will not be met.

As described in the previous sections, an energy storage system must do two things to achieve DOEE's objective of reducing electricity costs: 1) operate outside of PJM's capacity and energy markets, and 2) discharge during the five highest-demand hours of the year. Failure to meet either of these conditions would significantly reduce the cost savings to D.C. ratepayers. This section will summarize various considerations relevant to the design of a BTM storage program that satisfies these requirements.

4.1 Scale

One of the challenges of implementing a BTM program is that it can be difficult to scale up to the level that will provide significant benefits. As described in Section 2, megawatts and megawatt-hours of storage will be required to meaningfully reduce electricity costs for D.C. ratepayers. However, the average size of seven leading BTM energy storage systems is only about 7.9 kilowatts and 13.2 kilowatt hours, meaning that 127 BTM systems would be needed to achieve a megawatt-scale fleet (1 MW/1.68 MWh).

[18] https://www.psc.state.md.us/wp-content/uploads/Energy-Storage-Pilot-Program-Interim-Report.pdf

[19] https://innovation.ukpowernetworks.co.uk/projects/smarter-network-storage-sns

Table 8 summarizes publicly available technical specifications and costs for commonly deployed BTM energy storage systems, which were used to generate the average BTM system of 7.9 kW and 13.2 kWh that was used in this analysis:

Table 8: Commercial BTM Products

Product	Rated Power (kW)	Rated Energy (kWh)	System cost (uninstalled)
Tesla Powerwall	11.5	13.5	$9,892
Enphase IQ 10	3.84	10.1	$8,500
FranklinWh aPower	10	15	$11,000
SolarEdge 400v	7.5	9.7	$9,000
Bluetti EP900	7.6	9.9	$10,298
Eguana Evolve	5	14	$12,500
SonnenCore+	10	20	$10,300
Average	**7.9**	**13.2**	**$10,213**

Since PJM's capacity market costs are allocated based on the top five hours of highest demand in the year, the storage devices must be discharging energy during those five hours to reduce local demand and avoid capacity costs. But those top five hours must be predicted beforehand, and if a prediction is missed and the BTM fleet is dispatched during the wrong hour, it will significantly reduce the avoided capacity costs. As an added challenge, in 2023 and 2024, three of the top five highest-demand hours each year occurred consecutively on the same day, meaning that the BTM storage fleet would need to maintain its output for at least three hours to ensure that it can get all five of the top hours.

Between the concentration of top hours on a single day and the significant reduction in avoided costs if even one of the top five hours are missed, the District would likely need to have a BTM storage fleet that can sustain the desired reduction in load for four hours. Assuming the average BTM storage system size of 7.9 kW and 13.2 kWh, 5,991 units would be required to sustain a peak demand reduction of 19.77 MW (1 percent) over four hours.

Finally, the desired dispatch window has strong implications for program design. Longer dispatch windows can be achieved with a time-of-use program, which provides incentives for customers to limit their electricity usage over several hours. Shorter dispatch windows require a more active control strategy that can dispatch the BTM fleet in real time based on grid conditions. While time-of-use rates have their place in motivating customers to reduce their demand during peak periods, energy storage assets require a more hands-on strategy to maximize their output during a much narrower window.

In summary, the question of how many BTM systems will be required to reduce load and avoid capacity costs depends on four factors:

- The amount of load reduction desired
- The duration (in hours) that the load reduction is to be maintained
- The average system size of the BTM fleet
- The dispatch signal that the systems will be following

4.2 Costs, Benefits, and Compensation for BTM Storage

To establish a compensation program for BTM energy storage systems that incents some customers to install energy storage while ensuring that remaining customers who fund the program receive a net benefit, a full accounting of the costs and benefits of BTM storage is required. Table 9 summarizes the benefits and costs from the preceding sections that would be expected for 1 kW and 4 kWh of BTM energy storage in Washington, D.C., assuming a 10-year useful life and a discount rate of 7 percent.

Table 9: Total 10-year benefits and costs for 1 kW/4 kWh of BTM energy storage in Washington, D.C. ($/kW)

	Avoided Cost Benefits				**Installed System Costs**		
	Capacity	**Energy**	**T&D**	**Total**	**System**	**Installation**	**Total**
Low	$448.67	$421.84	$0.21	$870.71	$3,095	$1,830	$4,925
Medium	$691.96	$421.84	$0.21	$1,114.01			
High	$833.77	$421.84	$0.21	$1,255.82			

Because the figures in Table 8 are based on 1 kW and 4 kWh of storage, they can be applied indiscriminately to any BTM system by dividing the system's total rated energy (kWh) by four and then applying the payment to the resulting power (kW). In other words, these benefits apply the same to 1 kW/4 kWh of storage regardless of the system size and specifications.

For example, the average BTM system used in this analysis would be rated at 3.3 kW of four-hour storage (13.2 kWh/4 h) and would receive a payment of $3,676.23 under the medium case ($1,114.01 * 3.3). With an expected installed cost of $16,250 ($4,925 per kW * 3.3 kW), the payment would cover about 23 percent of the system cost.[20]

[20] The average installed BTM energy storage system cost of $16,250 was obtained from Energy Sage (https://www.energysage.com/local-data/energy-storage-cost/dc/). Using our average system cost of $10,213 from Table 7, this means average installation costs in D.C. are about $6,000.

While the avoided cost benefits of an energy storage system would not change by the size or configuration of the system, the cost information would, as larger, utility-scale systems generally have improved economies of scale that result in lower costs on a per-kW basis. Table 10 presents the avoided cost benefits against the cost of utility-scale energy storage.

Table 10: Total 10-year benefits and costs for 1 kW/4 kWh of Utility-scale energy storage in Washington, D.C. ($/kW)[21]

	Avoided Cost Benefits				Costs		
	Capacity	**Energy**	**T&D**	**Total**	**System**	**Installation**	**Total**
Low	$448.67	$421.84	$0.21	$870.71			
Medium	$691.96	$421.84	$0.21	$1,114.01	$1,186	$433	$1,619
High	$833.77	$421.84	$0.21	$1,255.82			

Because the cost of a utility-scale system is much lower than an average BTM system on a per-unit ($/kW) basis, their relative value is much higher. If the full benefit of $1,114.01 per kW were offered to a utility-scale system with a cost of $1,619 per kW, it would cover about 69% of the system cost. While such an approach may reduce program expenses, it could potentially create tradeoffs with other program objectives, such as providing local resilience and delivering targeted benefits.

A BTM storage program that includes commercial and industrial (C&I) customers, who can host larger systems and are likely to place a higher value on backup power than the average residential customer, may help to reduce program expenses while still allowing for broad residential customer participation. Table 11 illustrates how the presence of larger C&I systems in a BTM program portfolio designed to provide 19.77 MW for 4 hours can reduce the overall number of participating systems needed, assuming an average size of 50 kW/200 kWh.[22]

[21] Cost data for a 10 MW, 4-hour lithium-iron battery system from https://www.pnnl.gov/projects/esgc-cost-performance/lithium-ion-battery.

[22] The most recently available, public data regarding average non-residential energy storage systems was from Lawrence Berkely National Laboratory's 2021 report, "Behind-the-Meter Solar+Storage: Market Data and Trends." That report identified a median non-residential storage system size of 100 kW/200 kWh; in keeping with the four-hour paradigm described in Section 3, that corresponds to an average size of 50 kW/200 kWh.

Table 11: Impact of C&I Systems on BTM Program Needs

Share of C&I Systems in Portfolio	Total Number of Systems Required
0%	5,991
10%	5,431
20%	4,872
30%	4,312
40%	3,753
50%	3,193

4.3 Case studies

Several U.S. utilities have developed peak shaving programs using BTM storage in recent years that are functionally similar to the objectives identified by DOEE. Several states have also implemented programs to encourage energy storage deployments. This section will briefly summarize three utility programs and several state programs to illustrate the different models that have been employed.

4.3.1 Green Mountain Power: Utility Control, Upfront Payment

Green Mountain Power in Vermont was a pioneer in BTM storage programs, launching a program in 2015 that allowed up to 2,000 customers to buy or lease a Tesla Powerwall at a steep discount, with the utility paying the difference. In exchange, participating customers agreed to yield control of their Powerwalls to Green Mountain Power during normal operations so that the utility could use them for peak shaving and energy arbitrage. Participating customers received financial benefits from the storage reducing their load during the most expensive hours of Green Mountain Power's time-of-use rates and resilience benefits from using the storage for backup power during grid outages.

The program has since evolved into a bring-your-own device program that allows participating customers to choose their storage system and receive a flat, upfront incentive from the utility of $850 per kW for three-hour systems and $950 per kW for four-hour systems. Customers adding storage to an existing solar system in a transmission-constrained area can receive an additional $100 per kW.

Green Mountain Power reports that the program saves customers about $3 million per year by reducing demand during peaks and thereby reducing capacity market and transmission system costs allocated to the utility by the Independent System Operator of New England (ISO-NE).[23] In 2023, the Vermont Public Utility Commission approved Green Mountain Power's request to remove the annual limit of 5 MW of new participating systems each year, and the program is now open to all interested customers without any cap.

4.3.2 Eversource: Demand Response, Annual Payments

Eversource, another utility operating in ISO-NE, took a different approach to using BTM storage to shave peak demand. Through Eversource's ConnectedSolutions Demand Response program in Massachusetts, customers can enroll their BTM storage systems and be paid for allowing the utility to use them to reduce demand during peak periods.

Eversource can call on participating batteries up to 60 times from June 1 to September 30 each year, and each call can last up to three hours. Customers are paid at the end of each season based on the average output of their system ($275 per kW) across all called events. Eversource says the average participating system averages 5 kW and is paid $1,375 per year.

From a grid perspective, there is little difference between a program structured around utility dispatch and one structured as demand response; in either case the utility is forecasting demand and trying to match storage dispatch with the highest-demand hours.

From a customer perspective, however, there are significant differences between the two program models. The Green Mountain Power program offers upfront incentives that help significantly reduce the cost of an energy storage incentive, reducing the upfront capital required and opening the program up to broader participation from moderate-income customers. The Eversource program requires customers to bear the upfront costs of purchasing and installing a BTM storage system, which can be a barrier to participation for low- and moderate-income customers, but generally provides more compensation over the life of the system. To help reduce the up-front costs required to participate, Eversource partners with the state of Massachusetts to offer no-interest loans to program participants.

4.3.3 California Self-Generation Incentive Program: Rate Design, Tiered Payment Structures

California's Self-Generation Incentive Program (SGIP) was originally created in the wake of the Enron scandal and the resulting rolling blackouts in 2001 to encourage the development of distributed generation to help shore up the state's electric grid. It was later amended to focus more narrowly on distributed solar, and then again to prioritize energy storage systems to help integrate distributed generation.

SGIP's storage compensation follows a complex structure that varies according to customer type, income, and physical location. Residential customers still receive payments on an upfront basis, but commercial customers only receive half of the payment upfront; the other half is paid out over time based on the storage system's response to dispatch signals. The program was designed

[23] Green Mountain Power: https://greenmountainpower.com/news/gmps-energy-storage-programs-deliver-3-million-in-savings/.

to go through steps; each step reducing the payments after certain levels of storage are installed. The program is currently in step five out of seven.

Table 12 summarizes the current total payments available for BTM energy storage through the SGIP program, by customer type:

Table 12: Current SGIP energy storage payments ($/kWh)

Residential	Residential Equity[24]	Residential Equity Resilience[25]	Large-scale[26]	Large-scale Resilience[27]
$150	$850	$1,000	$250 (without federal tax credit) $180 (with federal tax credit)	$400

4.3.4 Utility Case Study Takeaways

Table 13 compares the total compensation that our average BTM system (7.9 kW/13.2 kWh) would receive under these three programs over 10 years:

Table 13: Revenue Comparison

Green Mountain Power	Eversource	California SGIP (basic residential)
$3,731.90	$12,073.81	$1,980.00

These case studies illustrate the decision points involved in designing a BTM compensation program:

- **Compensation level**: should it be based only on the value of grid services (as in the Eversource and Green Mountain Power programs), or should other desired characteristics like resilience be compensated (as in the California program)?[28]
- **Compensation structure**: Should compensation be provided upfront as a means of defraying purchase and installation costs for participating customers, thereby allowing more participation, as in the Green Mountain Power and California residential programs? Or should it be based on actual performance, as in the Eversource program? Can loan

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[24] Households making 80% or less of Area Media Income

[25] Households making 80% or less of Area Media Income and subject to Public Safety Power Shutoffs

[26] All non-residential systems and residential systems of 30 kWh or more

[27] Large-scale systems that otherwise meet the residential equity resilience requirements

[28] Connecticut and Maine both operate programs that also provide tiered compensation based on resilience and/or low-income benefits.

programs (as used by Eversource) or hybrid incentives (as used for California non-residential customers) be used to pursue both objectives?

- **Dispatch signal**: Should the utility have direct control over participating devices, as in the Green Mountain Power program, or should customers be given more control over device operation through a dispatch strategy based on demand response signals (Eversource) or rate design (California SGIP)? As discussed in Section 4, real-time dispatch of BTM systems will most efficiently achieve the objective of shaving peaks, but there are multiple strategies for achieving that outcome.

As these programs illustrate, there is no single approach to designing a BTM storage compensation program. There is room for flexibility in determining the size of the payment, how it is structured, and how to secure the desired performance of the device.

4.3.5 State Programs

D.C. DOEE also requested information about the different energy storage procurement targets enacted by states and how they are structured, including any carveouts. Table 14 summarizes this information:

Table 14: State energy storage procurement targets

State	Target	Year(s) Enacted	Target Year	Carveouts
California	1,825 MW	2013, 2016	2020	• Transmission: 700 MW • Distribution: 425 MW • BTM: 700 MW
Connecticut	1,000 MW	2021	2030	BTM: 580 MW
Maine	400 MW	2021	2030	BTM: 15 MW (critical facility resilience pilot)
Maryland	3,000 MW	2023	2033	None, but the state recently launched a BTM incentive program
Massachusetts	5,000 MW	2024	2030	Duration-based carveouts
Michigan	2,500 MW	2023	2029	None
Nevada	1,000 MW	2020	2030	None
New Jersey	2,000 MW	2018	2030	None required by law, but the New Jersey Board of Public

				Utilities will initiate a BTM storage incentive program in 2026
New York	6,000 MW	2024	2030	None required by law, but the state has established BTM incentive programs
Oregon	10 MWh	2015	2020	None
Rhode Island	600 MW	2024	2033	None required by law, but the law does require a funding program for BTM storage
Virginia	3,100 MW	2020	2035	At least 35% must be non-utility owned

Utility ownership of energy storage projects is a topic of discussion in several proceedings, primarily in states that participate in regional markets. Programs in Michigan, Oregon, Nevada, and Virginia all directly assign procurement responsibilities to utilities, though Virginia's program does require 35 percent of the installed storage capacity to be owned by third parties. Maryland's legislation leaves details such as ownership to the state Public Service Commission, which has an active proceeding on program design.

Utility ownership was debated in the New York proceeding, which defined a narrow set of use cases in which utility ownership would be permissible, consisting of projects that provide direct support to the transmission or distribution system and demonstration projects.[29] It was also discussed in Maine, where the Legislature directed the Maine Public Utilities Commission to conduct a proceeding on utility ownership and report back. The Commission's report recommended that utility ownership of storage be narrowly limited to projects that improve distribution system reliability.[30] The question of utility ownership does not appear to have been resolved.

5.0 Looking ahead

Deploying a fleet of non-market storage systems can support DOEE's objective to reduce electricity prices for District residents in the short term. But impending changes driven by FERC Order 2222, which will facilitate participation of distributed energy resources (DERs) in electricity markets, will have major implications for BTM storage in PJM in future years.

Order 2222 requires wholesale market operators like PJM to allow for DERs to aggregate and sell their output into capacity, energy, and ancillary service markets. Aggregations can be as small as 100 kW, and there is no limit on their maximum size. PJM will begin implementation of Order 2222 in May 2026, when DER aggregators may submit bids on the capacity market for the

[29] New York Department of Public Service, Order Establishing Updated Energy Storage Goal and Deployment Policy.
[30] Maine Public Utilities Commission, Report on Utility Control or Ownership of Energy Storage.

2028/2029 delivery year. PJM has proposed to implement DER participation in energy and ancillary services markets on February 1, 2028; the request is pending with FERC.

If a BTM energy storage system is paired with a solar system that is participating in a net energy program, it may only participate in PJM's capacity market if the local utility and PJM concur that double counting would not occur. Absent that finding, such systems may only participate in PJM's ancillary services markets. PJM is investigating potential revisions to this policy.[31]

A key component of Order 2222 is that since states (or the District, in this case) have jurisdiction over the distribution system and DERs, they decide whether the DERs under their authority may participate in wholesale market aggregation. For regulators and policymakers in Washington, D.C., that decision can be summarized in a simple question: are the District's ratepayers better served by BTM storage systems operating outside of PJM's markets to avoid capacity costs, or operating within PJM's markets to help control capacity prices?

The answer to that question will largely depend on the number of BTM storage systems in the District at the time the decision needs to be made. At small scale, participating BTM systems would be price takers (accepting whatever capacity market prices are set by other generation assets) and would have no ability to affect capacity market prices. To become price makers that can actively affect the capacity prices that Washington, D.C. residents pay, a significant number of BTM systems would need to participate in the capacity market. Determining where BTM storage systems can deliver the most value will require analysis that accounts for the overall size of the BTM storage fleet in the District and PJM capacity market dynamics at the time of the decision.

While such an analysis cannot be done at this time, one factor in such an analysis would be the value that customers could receive by participating in the PJM capacity market. Table 15Table 15 shows the potential revenues that customers could receive, using the high/medium/low sensitivities described in Section 3 and different levels of revenue sharing with the aggregator. Aggregator contracts are proprietary information and we were unable to identify a standard revenue sharing agreement between aggregators and participants, so Table 15 uses a range of theoretical sharing levels. Understanding aggregator offerings and practices will be an important component of the analysis to determining where BTM storage can provide the highest value to DC ratepayers.

Table 15: Projected PJM revenue

Aggregator Revenue Share	Low Capacity Market Prices	Medium Capacity Market Prices	High Capacity Market Prices
10%	$581.55	$691.04	$754.85
20%	$516.94	$614.25	$670.98

[31] https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250507/20250507-item-03-1---der-regulation-only-at-nem-customer-sites----presentation.pdf

30%	$452.32	$537.47	$587.10
40%	$387.70	$460.69	$503.23
50%	$323.08	$383.91	$419.36

Equipped with information about the avoided cost benefits of energy systems operating outside of PJM markets, the potential impacts of those systems on capacity and energy prices if they moved into the market, and the potential market revenues they would receive, decisionmakers in Washington D.C. can determine the participation model for BTM storage systems that will maximize benefits to D.C. ratepayers.

A.1 Appendix 1: Calculating Avoided Distribution Costs

As mentioned in the body of this report, the distribution system costs that can be avoided with energy storage investments depend on a utility's specific needs as well as the size, location, and timing of the storage investments. This appendix provides a high-level example of how those avoided costs may be calculated when that information is known, followed by a simple case study to demonstrate its use.

A.1.1 Avoided Cost Formula

To calculate the amount of stored energy (in MWh) needed to meet an identified distribution need, the following formula may be used:

$$E = \frac{(P_{peak} - P_{capacity}) x\ t}{\eta}$$

Where:

E= required storage energy capacity (MWh)

P_{peak}= Projected peak load (MW)

$P_{capacity}$= existing infrastructure capacity (MW)

t= duration of peak overload (hours)

η= round-trip efficiency of the storage system (fraction)

As a simple example, if the local distribution system faced a peak overload of 10 MW that lasted for three hours, and a battery with 90 percent RTE were being evaluated as an alternative, the formula would be:

Storage energy capacity $E = \frac{10x\ 3}{0.90}$ = 33.3MWh

Once the required amount of storage needed to meet a distribution need is known, a pair of simple formulae may be used to compare the costs of the distribution infrastructure against the cost of the storage alternative:

Expected CAPEX (no storage) = $\sum_i^n (cost\ infrastructure * P_i)$

Expected CAPEX (with storage) = $\sum_i^n (Storage\ Cost_i * P_i)$

Savings = Expected CAPEX no storage – Expected CAPEX with storage

Net Savings = Savings – Cost of Storage

P_i=probability of each scenario (high vs low load)

Since the distribution infrastructure and energy storage alternative have different useful life, it will be necessary to account for the time value of money in the calculation, by comparing the cost of the storage against the savings of deferring the capital expense for the useful life of the storage asset. Alternatively, the storage costs may be increased to account for replacement or refurbishment necessary to achieve an equivalent useful life for the energy storage alternative. And since the storage alternative will have opportunity to earn additional revenue through other services, such as capacity and energy markets, a reasonable effort of those revenues should be included in the storage case. Alternate scenario analyses that include higher or lower load growth may also provide valuable insight.

The following step-by-step process describes how to use the formulae:

A.1.2 Case Study: Nantucket Island

Case: Nantucket Island "IslandReady" Hybrid (National Grid, MA)

Planned solution: A third undersea cable (~$200M).
Actual solution (2019): A 6 MW / 48 MWh Tesla BESS + 15 MW combustion turbine, with a total installation cost ~$ of $81M.
Benefits: Deferred cable until ~2033, providing interim reliability and deferred cost savings.

A. Storage sizing cross-check

Formula: E = (Projected Peak Load – Existing Capacity) × Duration ÷ Efficiency
Illustrative overload: MW deficit = 6, Duration = 7 hours, Efficiency = 0.90
E = (6 × 7) ÷ 0.90 = 46.7 MWh
Built system: 48 MWh, consistent with the requirement.

B. Economic value of deferral

Inputs:
- Traditional CAPEX (third cable): $200 million
- Hybrid solution CAPEX: $81 million
- Discount rate: 6%
- Deferral: 14 years (to 2033)

PV(no storage, cable now) = $200 million
PV(with solution, cable later) = $81 million + $200 million / (1.06^14) ≈ $169.5 million
NPV savings ≈$200 million - $196.5 million = $30.5 million

Even after paying $81 million for the hybrid option, the time value of moving the third line 14 years out produces $30.5 million in net benefits.

For a more comprehensive analysis of this project, see the PNNL report.[32]

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[32] Nantucket Island Energy Storage System Assessment, 2019 https://www.osti.gov/servlets/purl/1564262,

1-888-375-PNNL (7665)

www.pnnl.gov