Brandon Shores Retirement Analysis

Project Update

February 2024

TELOS ENERGY

GridLAB

Agenda

1. Overview of Brandon Shores Retirement Analysis
2. Proposed Alternative Technical Feasibility
3. Proposed Alternative Cost Feasibility
4. Summary
5. Technical Appendix

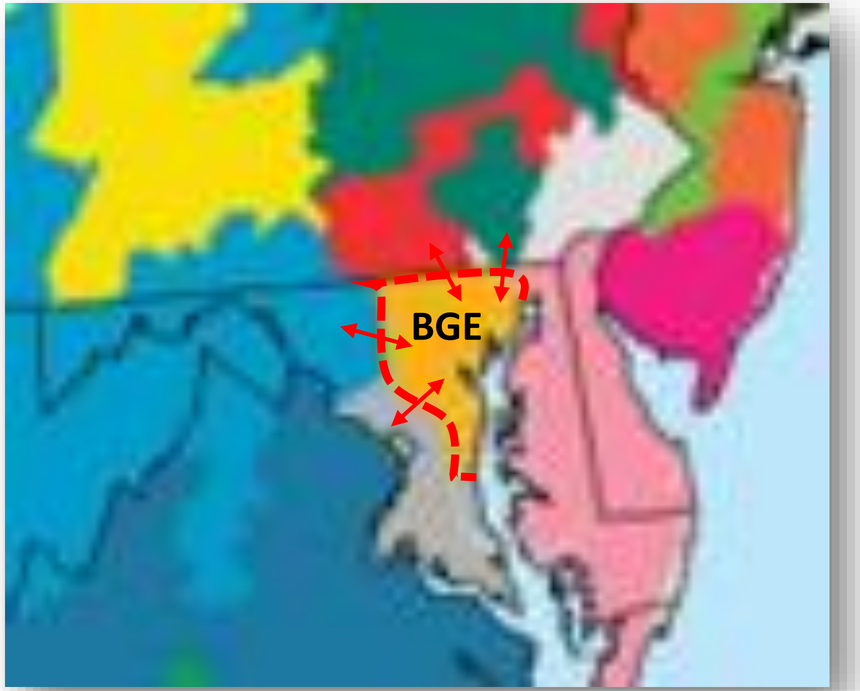
Overview of Brandon Shores Retirement Analysis

Overview of Analyses

PJM's results found issues with:

- **Load Deliverability (LD)** – A thermal analysis to check the ability to transfer power into a load pocket under stressed conditions (coincident high demand)
- **Generator Deliverability (GD)** – A thermal analysis to check the ability to transfer power out of a generation pocket under stressed conditions (coincident high generation dispatch)
- **N-1-1 Contingencies** – An analysis to evaluate thermal and voltage violations under a planned maintenance outage plus an unplanned contingency (outage of a transmission line or generator)

BGE and Transmission Transfer Paths



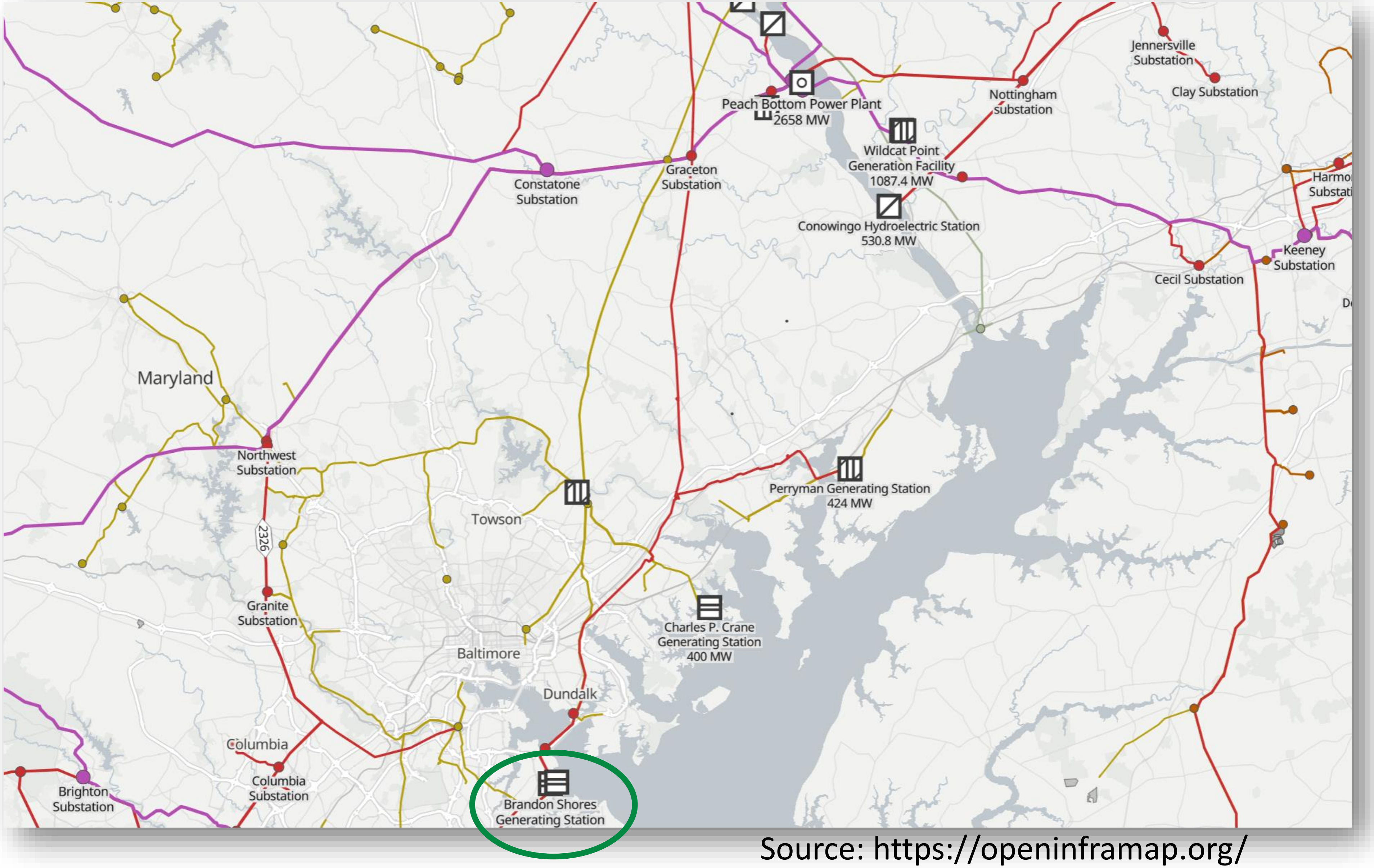
PJM'S Recommended Reinforcements

* Operating measures are not available

- To address these issues, PJM proposed a $780 million package of new transmission including
  - Two new high-voltage (500kV and 230 kV) transmission lines
  - Three new high voltage substations, and two substation expansions
  - Several voltage support devices ("STATCOMs" and "Capacitors")

- PJM is forecasting these upgrades will not be completed until **December 31, 2028**

- Until all upgrades are completed, PJM proposes to retain Brandon Shores from **3.5 years** past its requested retirement date (June 1, 2025), under a **reliability-must-run agreement (RMR).**



Source: https://openinframap.org/

RMR Risks

- A Brandon Shores RMR could cost **$258 million per year.**
- Which could total **$900 million in RMR costs** by the end of 2028.
- Meanwhile, region remains reliant on 33 – 40-year-old resources

This table was prepared by the Independent Market Monitor for PJM. The IMM confirmed the data with PJM.

Table 1 Part V reliability service summary[1 2 3 4]

Unit Names	Owner	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term	Initial Filing Total Cost	Initial Filing Cost per MW-day	Actual Total Cost	Actual Cost per MW-day
Indian River 4	NRG Power Marketing LLC	410.0	Cost of Service Recovery Rate	ER22-1539	01-Jun-22	31-Dec-26	$357,065,662	$520.25	$111,081,790	$556.33
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	01-May-19	$35,953,561	$328.34	$51,779,892	$472.88
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18	$9,739,434	$142.12	$8,427,011	$122.97
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18	$10,045,705	$142.12	$9,529,149	$134.81
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18	$28,710,481	$723.84	$10,058,665	$253.60
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15	$35,236,541	$176.25	$25,177,042	$125.94
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14	$20,842,416	$257.01	$18,484,399	$227.93
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14	$20,182,025	$248.87	$17,683,994	$218.06
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14	$20,192,938	$249.00	$17,391,797	$214.46
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14	$33,993,468	$240.47	$20,532,969	$145.25
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12	$15,435,472	$739.88	$7,576,435	$363.17
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12	$9,510,580	$715.19	$4,829,423	$363.17
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12	$20,213,406	$463.70	$17,776,658	$407.80
Eddystone 2	Exelon Generation Company, LLC	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12	$165,993,135	$1,467.74	$85,364,570	$754.81
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07	$60,933,986	$601.76	$23,507,795	$232.15
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11	$28,934,341	$32.90	$62,364,359	$70.92
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08	$47,633,115	$81.89	$79,580,435	$136.82

Transmission Line Schedule Risks

Can these new transmission lines be permitted, designed, and built in less than 4 years?

Example 500 kV structure

Existing 230 kV corridor

Risks in PJM's Transmission Upgrade Package Schedule

"PJM does not have the authority or ability to assess the local impacts of these routes" – 2022 RTEP Window 3 FAQ

"There are currently long lead times of **two to three years** for all circuit breakers above 115 kV." – PJM RTEP Window 3 Constructability & Financial Analysis Report

STATCOMs being quoted with a **three-year** lead time based on transformer availability

500/230kV Transformers can take **three to four years** to deliver

Proposed Alternative

Technical Feasibility

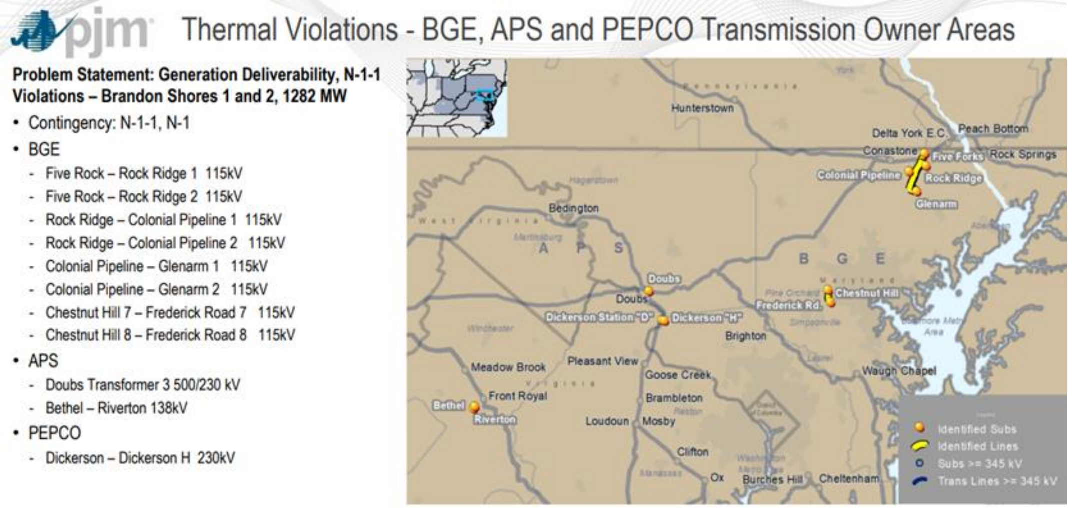
Our Approach

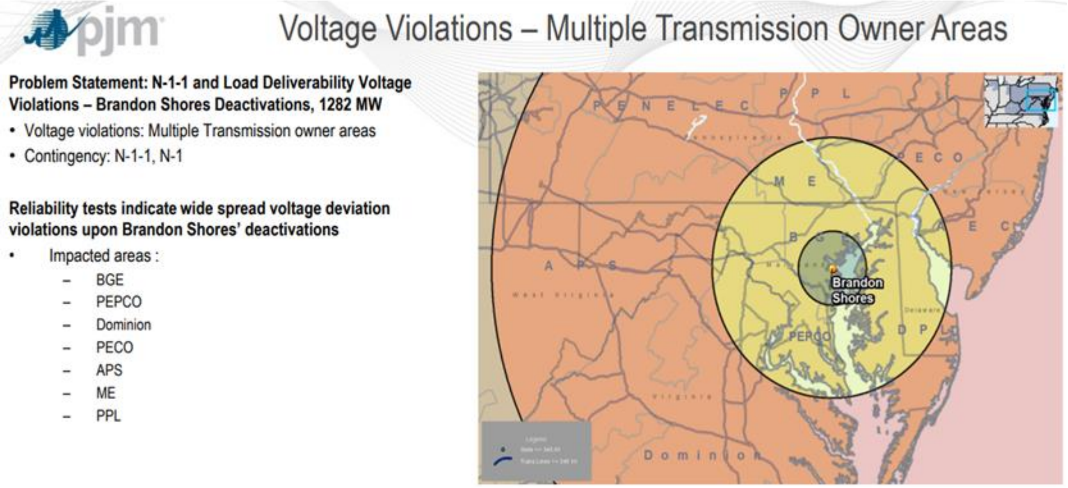
- **Objective:** Identify a set of mitigations to enable the fastest retirement of Brandon Shores (shortest duration of RMR, lowest RMR cost)

- Evaluate a set of models ("cases") representing summer and winter peak demand to understand the grid impact of the Brandon Shores retirement
- Consider the impact of potential alternative mitigations or combinations, including
  - Transmission reinforcements (including, but not limited to PJM's planned upgrades)
  - Synchronous condenser (MVAr only – helps with voltage violations only)
  - Battery energy storage (MVAr and MW – helps with voltage and thermal violations)
  - Long-duration capacity resources
- Evaluate costs of alternative mitigations that could reduce the duration of the Brandon Shores RMR

Key Findings

- Telos, in consultation with PJM, was able to create similar models to PJM and has confirmed that retiring Brandon Shores without mitigations **does cause reliability risks**
- The worst scenario in terms of **transmission line overloads** was summer peak conditions combined with a maintenance outage and unplanned outage (N-1-1)
- The worst scenario in terms of **voltage collapse** was an extended winter peak condition (Winter Storm Elliot) combined with generation outages





Scenario (Brandon Shores Retired)	Type of Analysis	Problem Identified	Alternative Solution
Summer Peak Load	Load Deliverability (An analysis to check the ability to transfer power into a load pocket under stressed conditions)	• **~430 MW of capacity shortfall**	**~600 MW x 4hr battery** at Brandon Shores
Summer Peak Load	Generation Deliverability (An analysis to check the ability to transfer power out of a generation pocket under stressed conditions)	• The power flowing through several 115-230 kV **lines exceed rating** (<10%)	**Reconductor** affected lines
Summer Peak Load	N-1-1 Analysis (a planned maintenance outage plus an additional unplanned outage)	• The power flowing through several 115kV **lines exceed rating** (<10%) • Moderate **voltage violations**	**Reconductor** affected lines Utilize the proposed 600 MW battery at Brandon Shores for simultaneous voltage support
Extended Winter Peak Load (Winter Storm Elliot)	N-1-1 Analysis (a planned maintenance outage plus an additional unplanned outage)	• Large voltage violations/**voltage collapse** when battery is depleted	Add voltage support approved by PJM **(Capacitors and STATCOMS)** & utilize Wagner 3&4 RMR and the 600 MW battery as a STATCOM
Extended Winter Peak Load (Winter Storm Elliot)	Generation Deliverability (An analysis to check the ability to transfer power out of a generation pocket under stressed conditions)	• Thermal violations when battery is depleted	Extended (100+ hour generation) **Wagner 3&4 RMR**

PJM Current Solution

- RMR for entire Brandon Shores plant until $780 million package is complete

- Install voltage support (STATCOMs & Capacitors)

- Construct new 500kV line
- Construct 500 kV and 230 kV system upgrades

Proposed Alternative

- RMR for entire Brandon Shores plant until battery, reconductor, and voltage support projects are complete
- New 600 MW x 4 hr battery at Brandon Shores (20-year life)
- Reconductor lines forecasted to overload

- Install voltage support (STATCOMs & Capacitors)

- Construct new 500kV line as load forecast requires
- Construct 500kV and 230 kV line and system upgrades as load and generation forecast requires

Which option is the lowest **cost** to customers?

Which option is the **quickest** to retire Brandon Shores?

Proposed Alternative

Cost Feasibility

Proposed Portfolio

Transmission

Prioritized Transmission Upgrades	Approved by PJM?	Estimated Cost ($MM)
BGE - Five Forks – Rock Ridge 1 115kV (GD + N-1-1)	No	$8.6
BGE - Five Forks – Rock Ridge 2 115kV (GD + N-1-1)	No	$8.6
BGE - Chestnut Hill 7 – Frederick Road 7 115kV (GD + N-1-1)	No	$4.0
BGE - Chestnut Hill 8 – Frederick Road 8 115kV (GD + N-1-1)	No	$4.0
APS - Bethel – Riverton 138kV (GD + N-1-1)	No	$5.6
APS - Line drops to Doubs Transformer 3 (GD + N-1-1)	Yes	$0.8
PECO - New Conastone Capacitor (N-1-1 Voltage)	Yes	$15.0
PEPCO - Brighton Statcom + Capacitor (N-1-1 Voltage)	Yes	$63.0
PEPCO - Burchess Hill Cap (N-1-1 Voltage)	Yes	$15.0
BGE - Build Solley Road Substation + Statcom (N-1-1 Voltage)	Yes	$109.0
BGE - Build Granite Substation + Statcom (N-1-1 Voltage)	Yes	$91.0

$31MM "New" / Incremental Upgrades

$294MM Short Lead-Time Upgrades already approved by PJM

Battery

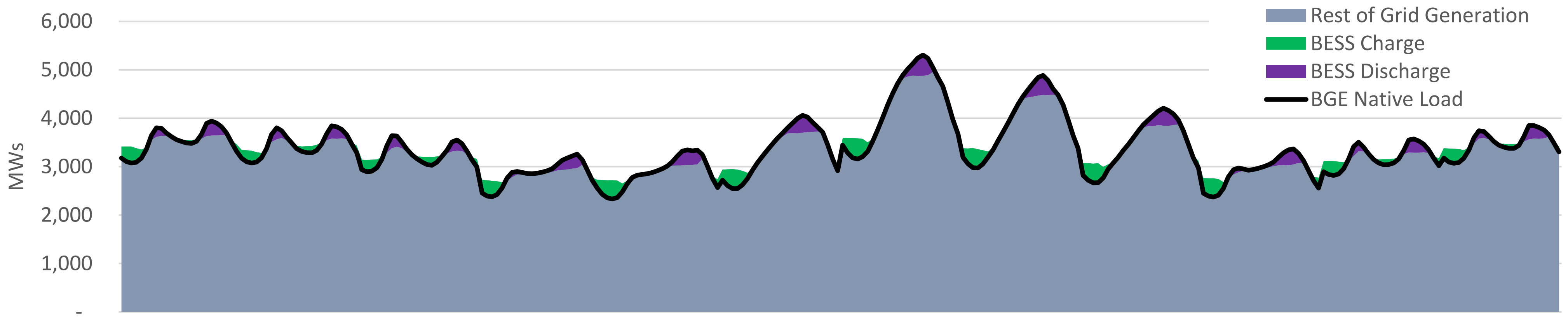
- Battery connected at the Brandon Shores POI (230kV)
- Power Rating: 600 MW / 300 MVAr (670 MVA inverters at 0.90 PF)
- Energy Rating: Assumed 4h

$753 million (before ITC, revenues etc.)
Revenues detailed in the next slides

Battery Operations: Optimized for BGE Peak Shaving

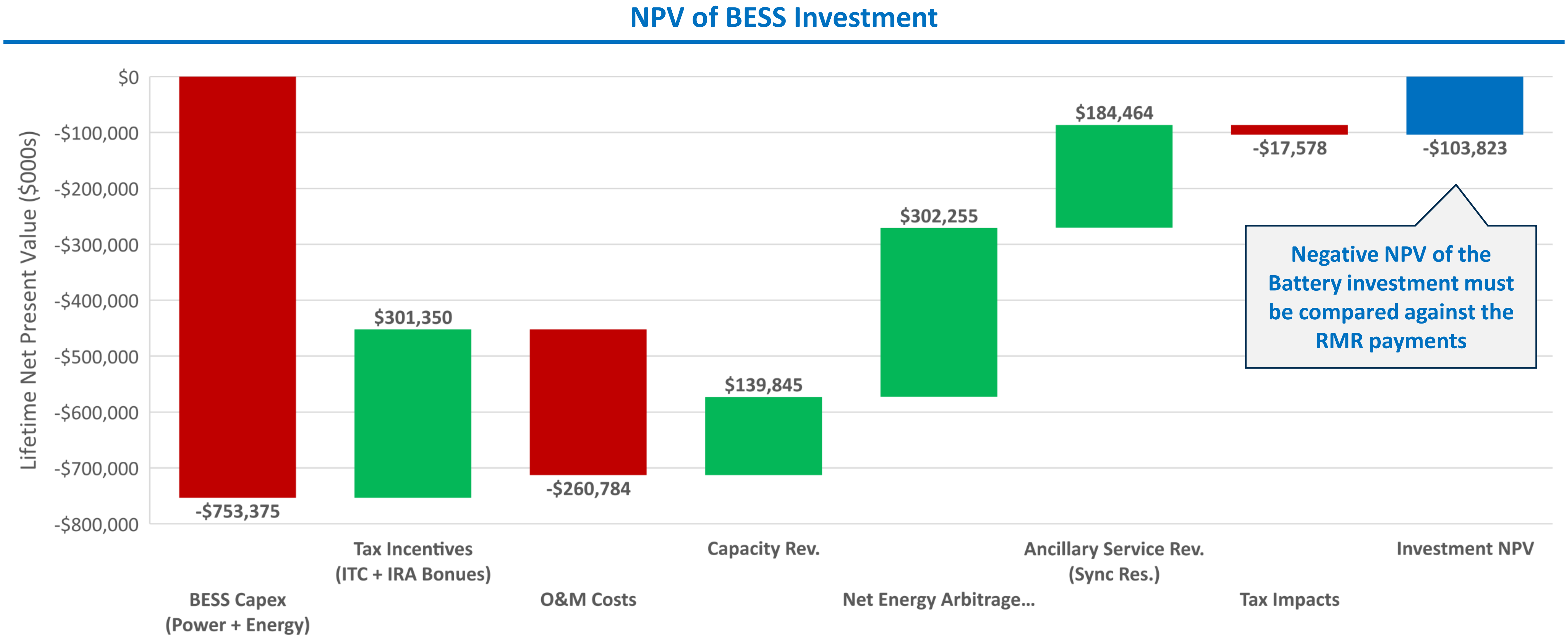
- Battery operations were optimized daily to shave BGE's peak loads – this analysis was performed using BGE's 2023 hourly loads
- This process generated charge, discharge and state of charge (SoC) parameters for the Battery which were used to estimate **revenues** relating to energy arbitrage and reserve provisions

2023 Average Day Per Month Battery Operating Profile



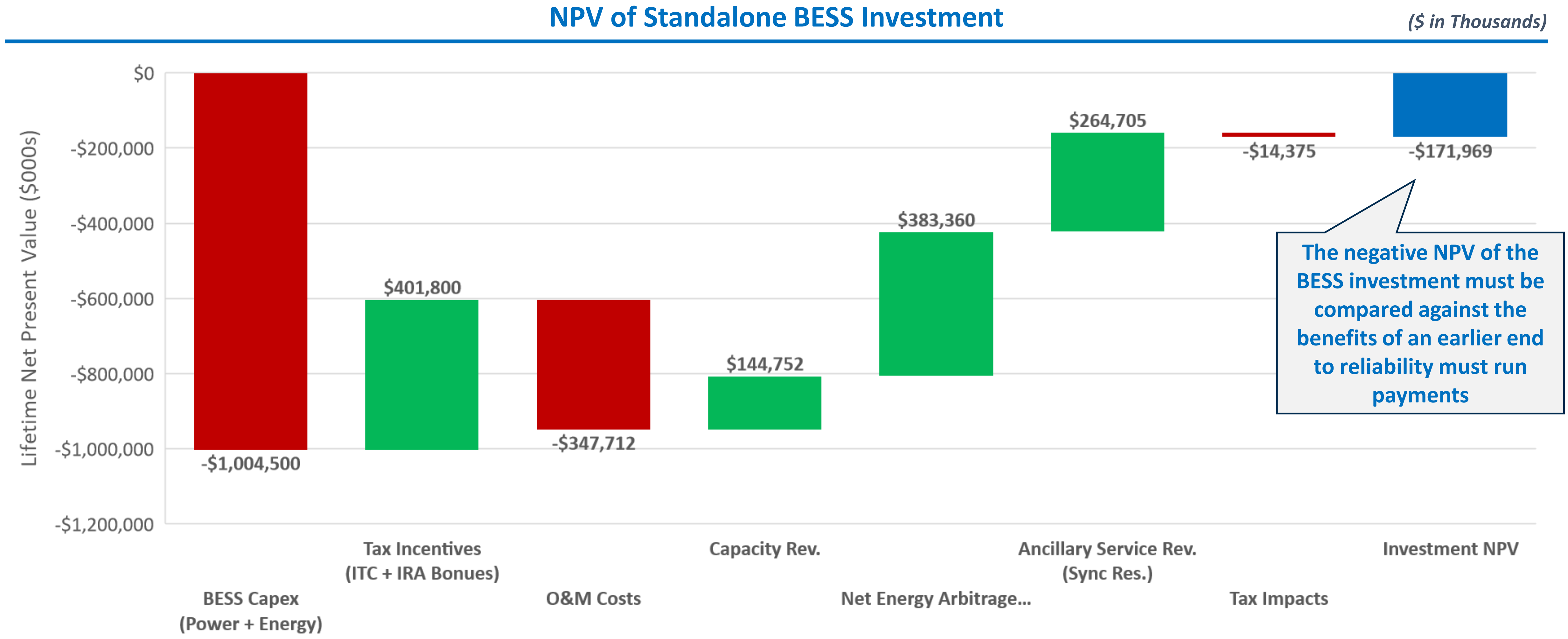
600 MW x 4-hour Battery Investment Net Present Value (NPV) Waterfall

ELCC Capacity Credit 78% = 468 MW



800 MW x 4-hour Battery Investment Net Present Value (NPV) Waterfall

ELCC Capacity Credit 59% = 472 MW



PJM Current Solution

Item	Estimated Cost
Brandon Shores RMR cost per year	$250 million

Proposed Alternative

Item	Estimated Cost
Targeted Reconductoring	$31 million
Battery (Capex – Tax Credits)	$452 - $603 million
20-Year Net Revenues (O&M cost - Revenue)	(-) $348 – $431 million
Total	$135 - $203 million

If the battery alternative can be installed on or before the start date of the RMR, it could solve the problem for **1/6 – 1/4 of the cost**

If the battery alternative can **offset 6 - 12 months of RMR** it could be a cost-effective alternative

The **current RMR is forecasted to be 3.5 years long,** so the sooner the alternative solution can be constructed, the more savings

Summary

Summary

- PJM Reliability Risks were confirmed

- Team studied an alternative solution including:
  - Targeted transmission line reconductoring
  - Installation of a 600 or 800 MW/4 hr. battery (Depending on ELCC Updates)
  - Construction of voltage support projects in RTEP Window 3 projects

- The proposed alternative is technically and highly cost effective

Thank you!

Storage Developers are interested in interconnecting in the area

Storage projects with active interconnection applications, but awaiting study

Project/OASIS ID	Name	State	Status	Transmission Owner	MFO	MW Energy	MW Capacity
Search	brandon shores			Search			
AG2-207	Brandon Shores 230 kV	MD	Active	BGE	275	275	110
AG2-319	Brandon Shores 230 kV	MD	Active	BGE	150	150	150
AG2-225	Wagner 115 kV	MD	Active	BGE	135	115	46
AH2-162	Northeast-CP Crane 115kV	MD	Active	BGE	200	200	200
AI1-130	Northeast-CP Crane 115kV	MD	Active	BGE	75	75	75
AI1-189	Northeast - Windy Edge 115 kV	MD	Active	BGE	110	110	110
AJ1-037	Northeast - CP Crane 115 kV	MD	Active	BGE	500	300	300

Glossary

- **MW –** Megawatt, a unit of electric power. ~1,350 horsepower
- **MWh** – Megawatt-hour, a unit of electric energy. 1 MW delivered for one hour
- **Capacitor –** A device typically installed inside a substation that provides voltage support
- **STATCOM -** A static synchronous compensator (STATCOM) reactive compensation device used on transmission networks. It uses power electronics to support voltage
- **Synchronous Condenser** - A synchronous condenser (also called a synchronous capacitor or synchronous compensator) is a large rotating generator whose shaft is not attached to any driving equipment. This device supports voltage on the transmission system
- **BESS** – Battery Energy Storage System

Technical Appendix Slides

Detailed Analysis/Results

Technical Appendix Slides

- Overview/Introduction
- Seasonal Considerations
- Load Deliverability Estimates
- Generation Deliverability Results
- N-1-1 Contingency Results
- Battery Financial Analysis

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Overview / Introduction

Analyses and Approach

Our Scenario Matrix

Incremental Retirements (Stress)

Case Description	No Retirements (Base Case)	BS1 Retired	BS 1 + 2 Retired (PJM's Case)
Retirements MW	0	638.9	1281.6
BS1		638.9	638.9
BS2			642.7

The Wagner plant (3 & 4, 770 MW total) is considered to remain in-service, though the Wagner Deactivation announcement is noted

Model Case Seasons Evaluated:

- RTEP Summer (Peak) 2025 (provided by PJM's Special Studies team)
- MMWG Shoulder 2027 (from PJM FERC 715), analyzed as a proxy case
- MMWG Winter (Peak) 2024 (from PJM FERC 715), analyzed as a proxy case

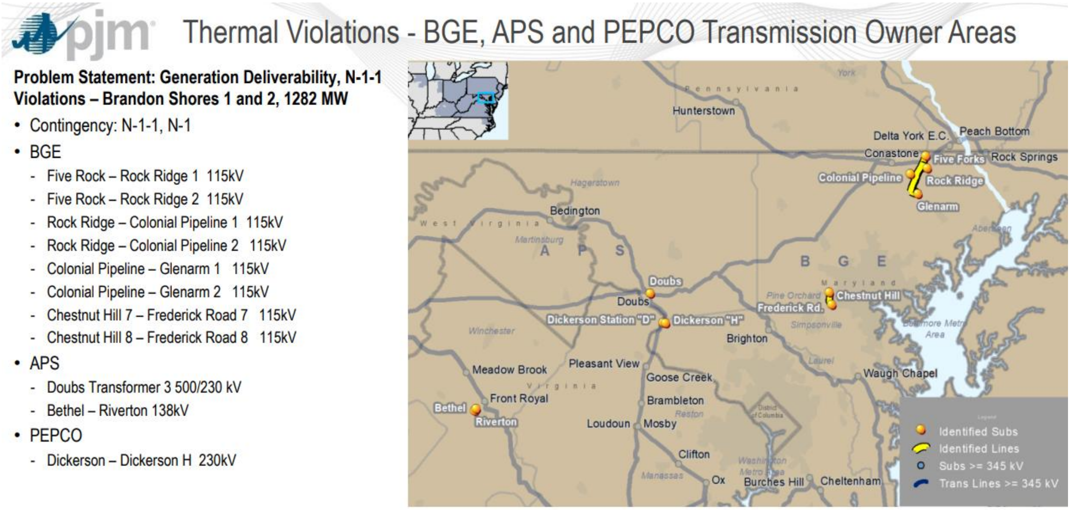
Benchmarking Against PJM's Results

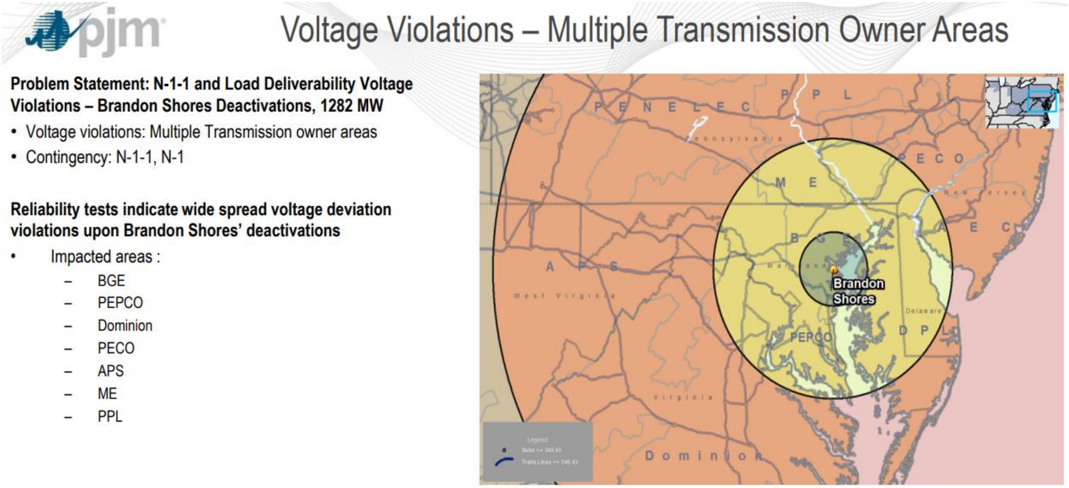
- [PJM's publicly published](#)(Update July 11, 2023) contingencies driving transmission reinforcements, with [upgrade details](#) (Aug 2023)
- All thermal violations have been identified in our analysis
- Similar voltage violations & voltage support needs have been identified in our analysis

Thermal Overloads

- BGE - Five Rock – Rock Ridge 1 115kV (GD + N-1-1)
- BGE - Five Rock – Rock Ridge 2 115kV (GD + N-1-1)
- BGE - Rock Ridge – Colonial Pipeline 1 115kV (GD)
- BGE - Rock Ridge – Colonial Pipeline 2 115kV (GD)
- BGE - Colonial Pipeline 1 – Glenarm 1 115kV (GD)
- BGE - Colonial Pipeline 1 – Glenarm 2 115kV (GD)
- BGE - Chestnut Hill 7 – Frederick Road 7 115kV (N-1-1)
- BGE - Chestnut Hill 8 – Frederick Road 8 115kV (N-1-1)
- APS - Doubs Transformer 3 500/230 kV (GD)
- APS - Bethel – Riverton 138kV (GD)
- PEPCO - Dickerson – Dickerson H 230kV (GD)

Voltage Violations: From N-1-1 Analysis for all





PJM'S Recommended Reinforcements

* Operating measures are not available

<u>500 kV Reinforcements</u>

1. PECO - B3780.1: Peach Bottom North Upgrades – substation work
2. PECO - B3780.2: Peach Bottom to Graceton – New 500kV Transmission line
3. PECO - B3780.3: West Cooper Substation expansion
4. BGE - B3780.4 : Peach Bottom to Graceton (BGE) – New 500kV Transmission line
5. PECO - B3780.8: Graceton 500kV expansion
6. PECO - B3780.10: Install New Conastone Capacitor
7. PEPCO - B3780.11 : Brighton Statcom and Capacitor
8. PEPCO - B3780.12 : Burchess Hill Cap

Projected ISD: 12/31/2028
Required ISD: 6/1/2025
Estimated Cost: $333 Million

<u>230kV and 115 kV Reinforcements</u>

1. BGE - B3780.5: Build Solley Road Substation + Statcom
2. BGE - B3780.6: Build Granite Substation + Statcom
3. BGE - B3780.7 : Build Batavia Road Substation
4. BGE - B3780.9: Graceton to Batavia Road 230 kV Double Circuit Pole Line
5. BGE – B3780.13: Batavia Road to Riverside 230kV reconductor
6. APS - B3781: Replace line drops to Doubs Transformer 3

Projected ISD: 12/31/2028
Required ISD: 6/1/2025
Estimated Cost: $ 452 Million

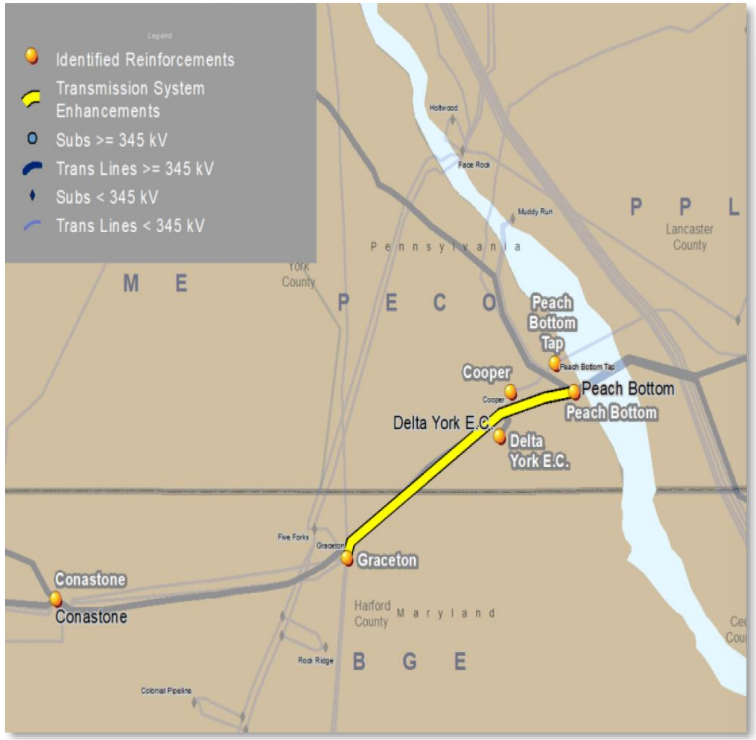
Projected ISD: 12/31/2025
Required ISD: 6/1/2025
Estimated Cost: $ 0.8 Million

Peach Bottom to Graceton (BGE) – New 500kV Transmission line (PECO - B3780.2/BGE - B3780.4)

Example 500 kV structure

PJM RTEP Window 3 Constructability & Financial Analysis Report:

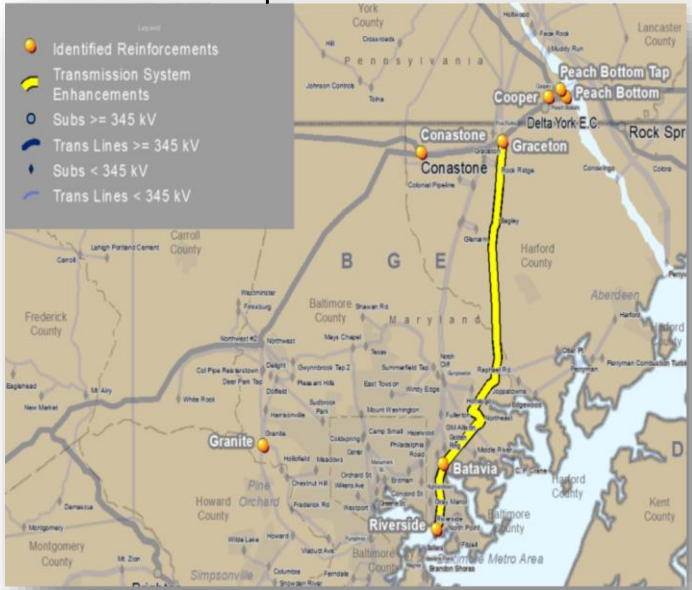
- The line will travel through new ROW parallel to existing 500kV and 230 kV lines
- Wetlands, waterbodies and high-risk flood zones appear to be crossed by the proposed line routes. The routes intersect seven waters that are subject to USACE Section 404 permitting.
- The proposed project components are within the range of both federally and state-listed species



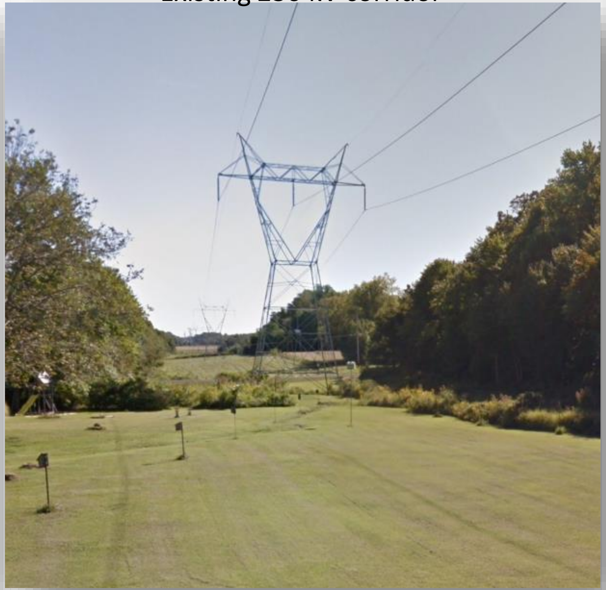
BGE - B3780.9: Graceton to Batavia Road 230 kV Double Circuit Pole Line

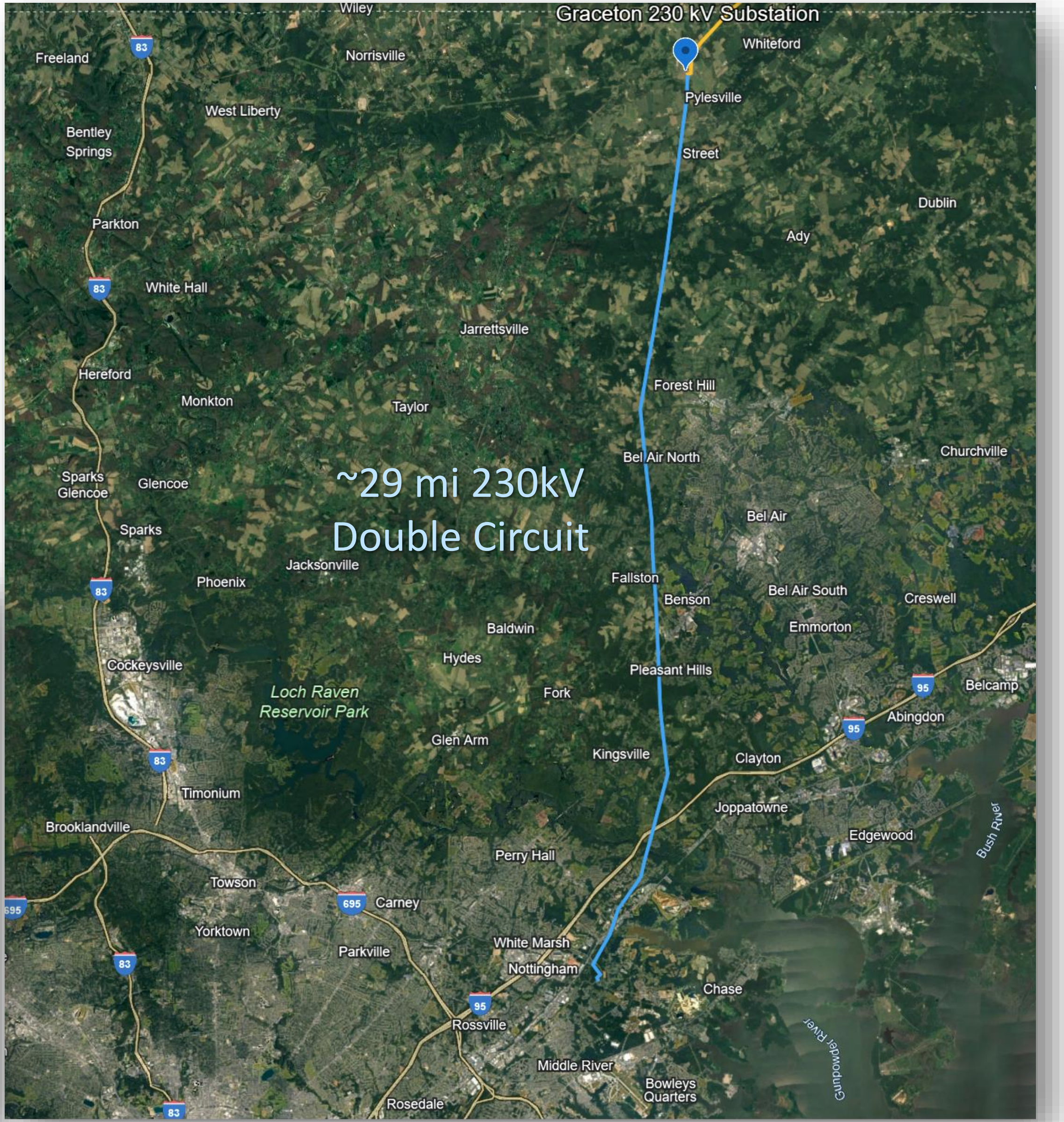
PJM RETP Window 3 Constructability & Financial Analysis Report:

- This line will be constructed on the edge of the current ROW
- Wetlands, waterbodies and high-risk flood zones appear to be crossed by the project components of the proposal.
- It is anticipated that the proposal could require permits, consultations, clearances and authorizations from three counties in Maryland (Howard, Baltimore and Harford). State PSC approval, CPCN and DOT utility permits and driveway/local road permits may be required.
- The proposed project components are within the range of both federally and state-listed species.



Existing 230 kV corridor





Seasonal Considerations

Summer and Winter Focus

GD, Seasonal Considerations

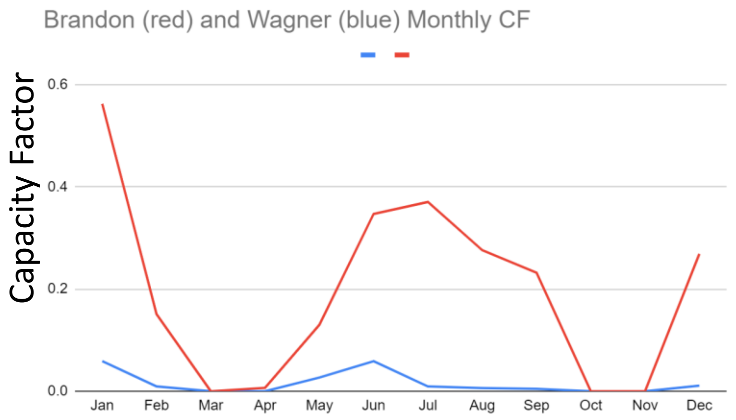
Is Summer Peak the Limiting Case for GD?

Prior discussion with PJM Special Studies team raised that winter cases may be a constraint for BESS mitigations because:

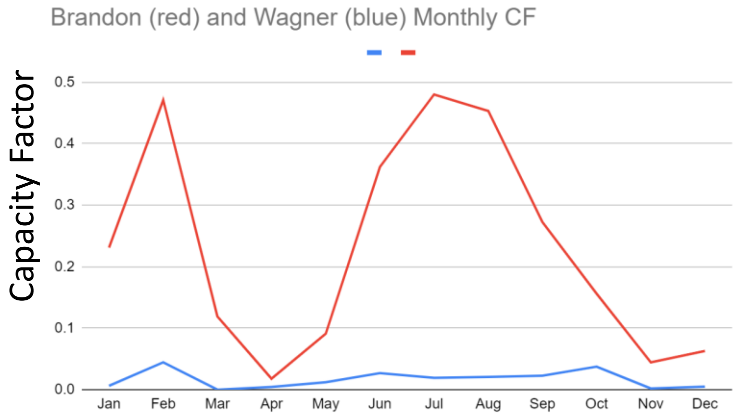
- Brandon Shores runs most in winter
- Winter in BGE has morning and evening peaks
- Ability to charge mid-day could be constrained

EIA Historical Data Observations:

- Most operation is in summer and winter
- Monthly capacity factor for Brandon Shores rarely exceeds 50%
- Monthly capacity factor for Wagner is < 10%



2022 (EIA Data)



2021 (EIA Data)

Intraday Load and Models

PJM's Gen Deliverability Analysis

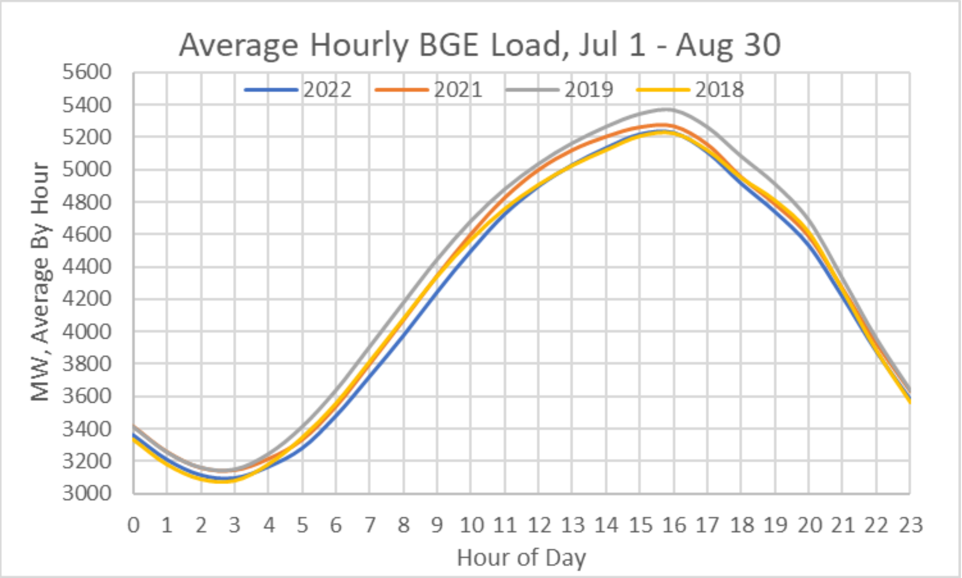
- PJM GD generally evaluates summer peak, winter peak, and light load
- For Brandon Shores, the PJM Special Studied team has only evaluated summer peak so far

To estimate the wintertime constraints, we looked at a proxy case considering BESS charging…

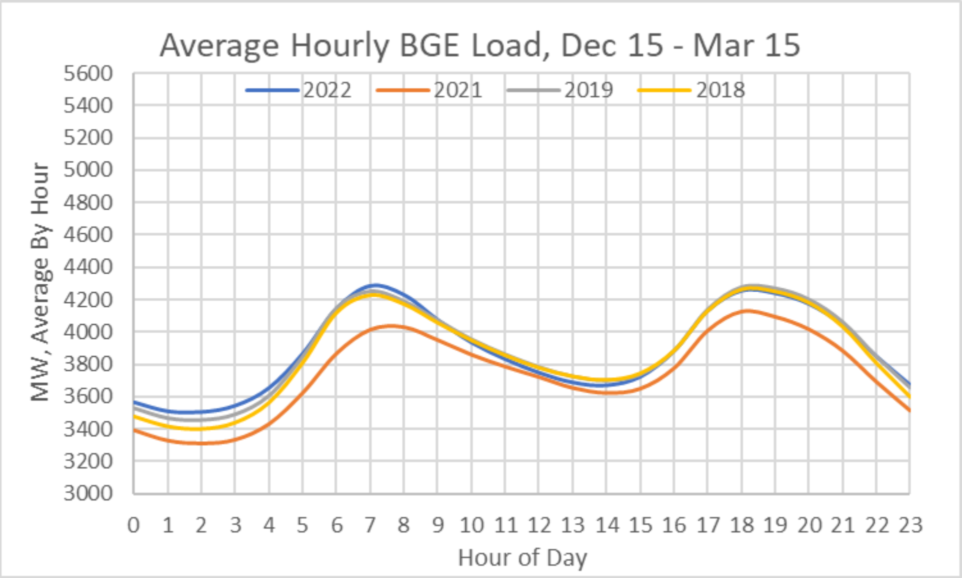
PJM Model Files, BGE Load:

- RTEP 2025 SUM (peak): 6,295 MW ← PJM's GD Case (and ours)
- MMWG 2024 WIN (peak): 5,763 MW ← Our "Proxy Winter Peak Case"
- MMWG 2027 SSH: 4,740 MW ← Our "Proxy Winter Charging Case"
- MMWG 2027 SLL: 3,163 MW
- MMWG 2027 SML: 2,071 MW

Summer

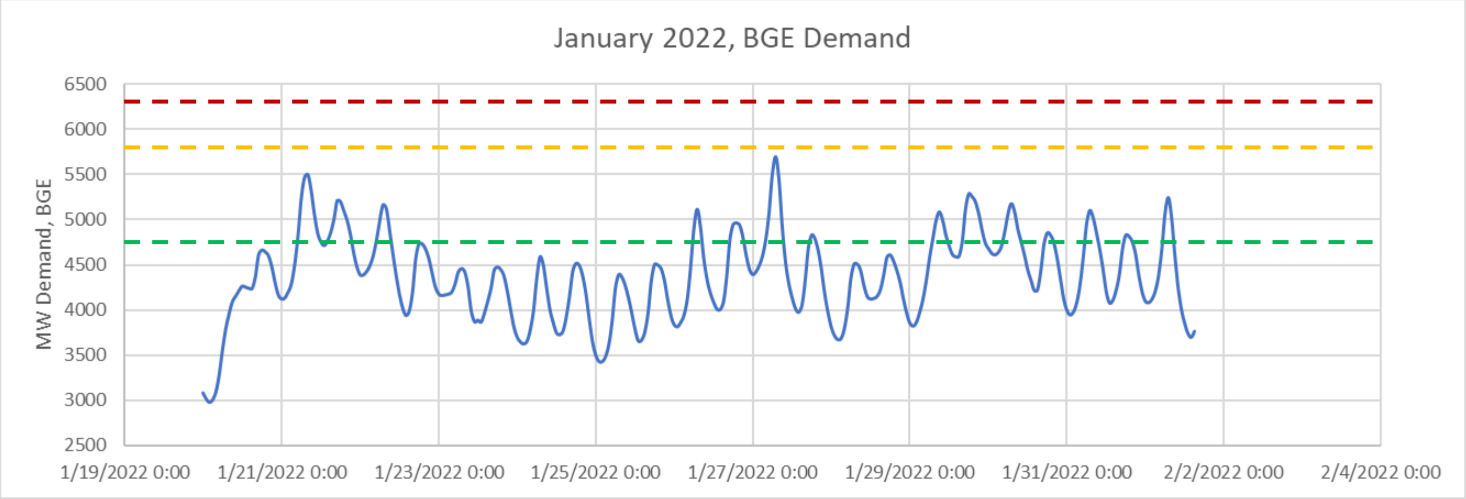


Winter



High Demand Winter Days in BGE

- BGE Historical high-demand periods from 2022
- Elliot showed flatter and higher load levels

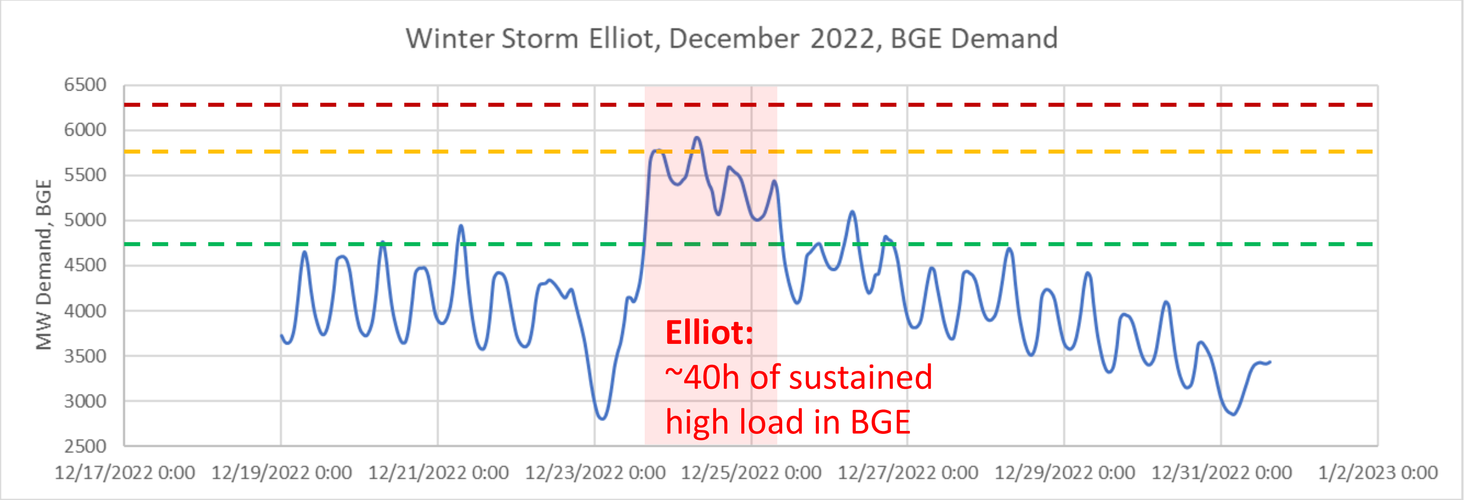


Cases (added) for Analysis:

RTEP 2025 SUM Peak Load: 6,295 MW
→ Assume BESS discharging

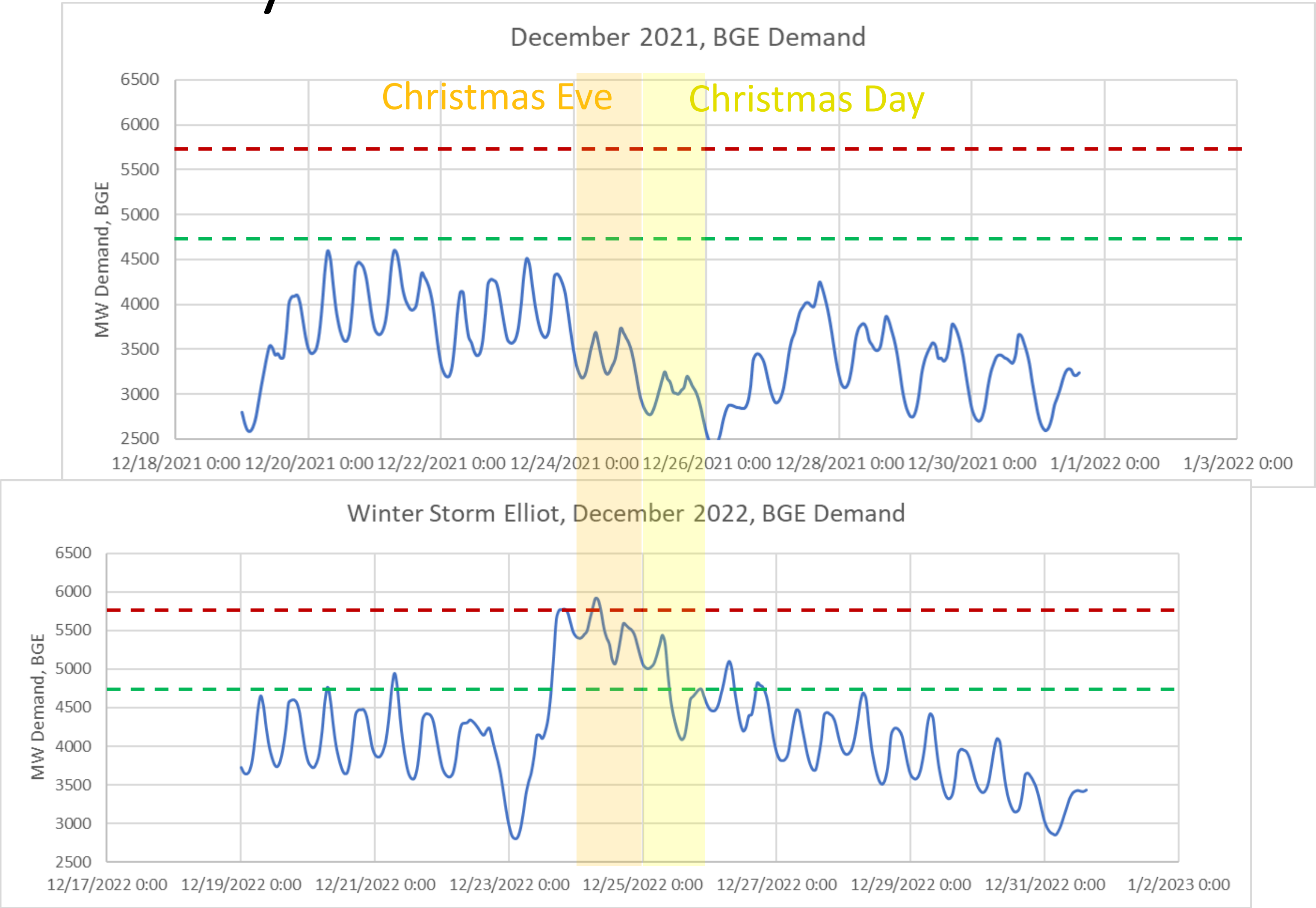
MMWG 2024 WIN Peak Load, 5,763 MW
→ Proxy winter peak case, assume **BESS depleted**

MMWG 2027 SSH Load, 4,740 MW
→ Proxy winter case, assume **BESS charging**



High Demand Winter Days in BGE

- Dec 2022 (Elliot) v. Dec 2021



Load Deliverability

Estimated Constraints

Load Deliverability

From the PJM 2024/2025 spreadsheet (Brandon Shores in-service):

- CETO (Capacity Emergency Transfer Objective): 4,660 MW
- CETL (Capacity Emergency Transfer Limit): 5,397 MW
- Reliability Requirement (= CETO + UCAP): 7,514 MW
- PJM LD Criteria: CETO < CETL (Limit greater than objective)

Brandon Shores: 1,270 MW (ICAP) and ~1,168 MW (UCAP)

Post-Retirement of Brandon Shores:

- CETO: 4,660 MW + 1,168 MW = 5,828 MW
- CETL and Reliability Requirement are roughly unchanged*
- Now, CETO is NOT < CETL; therefore, there is a load deliverability violation

→ Roughly, > 430 MW of UCAP must be added to BGE to clear the LD violation

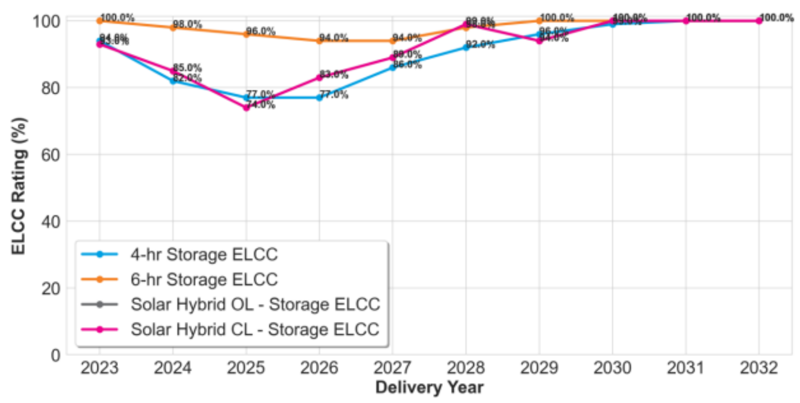
*Only PJM can study and determine the CETL, and it hasn't been re-studied as the Brandon Shores RMR and W3 are not complete (as explained by PJM on the Nov 8, 2023 call)

The PJM BRA parameters for 2024/2025 are here

1	**2024-2025 RPM Base Residual Auction Planning Parameters**		
2			
3		**RTO**	**Notes:**
4	Installed Reserve Margin (IRM)	14.7%	2021 IRM Study
5	Pool-Wide Average EFORd	5.02%	2021 IRM Study
6	Forecast Pool Requirement (FPR)	1.0894	2021 IRM Study
7	Preliminary Forecast Peak Load	150,640.3	2022 Load Repo
8			L
9		**RTO**	**BGE**
10	CETO	NA	4,660.0
11	CETL	NA	5,397.0
12	Reliability Requirement	164,107.6	7,514.0
13	Total Peak Load of FRR Entities	29,421.6	0
14	Preliminary FRR Obligation	32,051.9	0
15	Reliability Requirement adjusted for FRR	**132,055.7**	**7,514.0**
16	Gross CONE, $/MW-Day (UCAP Price)	$348.94	$357.45
17	**Net CONE, $/MW-Day (UCAP Price)**	**$293.19**	**$234.07**
18	EE Addback (UCAP)	7,668.7	378.6

PJM ELCC Report December 2022 for BESS

Figure 4: 2023 – 2032 ELCC Class Ratings for 4-hr Storage, 6-hr Storage, Solar Hybrid Open Loop (OL) - Storage Component, Solar Hybrid Closed Loop (CL) - Storage Component



Generation Deliverability

Results

GD Results: Summer Peak

Analysis

- Uses the same software package as PJM (PowerGEM's TARA)
- The PJM GD tool was run for our partial and full Brandon Shores retirement scenarios
- This considered the RTEP summer peak case, provided directly by PJM

What is Generation Deliverability Analysis?

Generation deliverability analysis works by adjusting dispatch of capacity resources to stress the system under each planning contingency

Key Takeaways

- Few GD violations for only BS1 retired (639 MW)
- Retirement of BS 1 & 2 results correspond closely with PJM's published results

Monitored Facility	PJM ID'd Overload	1: BS1 Ret.	2: BS 1&2 Ret.
221051 CHESTN8A 115 221049 FRED.RD8 115 1	TRUE		
221054 CHESTN7A 115 221050 FRED.RD7 115 1	TRUE		
221092 FIVE.FOR 115 221095 ROCKRGE2 115 1	TRUE	0	1
221092 FIVE.FOR 115 221096 ROCKRGE1 115 1	TRUE	1	1
221095 ROCKRGE2 115 221098 C.PIPE12 115 1	TRUE	0	1
221096 ROCKRGE1 115 221097 C.PIPE11 115 1	TRUE		1
221097 C.PIPE11 115 221100 GLENARM1 115 1	TRUE		1
221098 C.PIPE12 115 221090 GLENARM2 115 1	TRUE	0	1
235105 01DOUBS 500 235459 01DOUBS 230 1	TRUE	0	0
235105 01DOUBS 500 235459 01DOUBS 230 3	TRUE	1	1
235523 01BETHEL+ 138 235507 01RIVERT 138 1	TRUE	1	1

GD Results, Winter Proxy Cases

Shoulder, BS 1 & 2 Retired

BESS Assumed Charging

- No new violations found (beyond those already identified in the summer case)

Winter Peak, BS 1 & 2 Retired

BESS Assumed Depleted

- Some violations found with Wagner originally dispatched at 300MW
- Increasing Wagner to full output during winter peak mitigated the GD violations originally found in the winter peak case

Notes

These MMWG cases are from PJM's FERC 715 cases; they have not conditioned by PJM (they way the PJM RTEP cases have been). Therefore, they are considered proxy cases since the RTEP winter cases were not available for this analysis.

GD Results Analysis Summary

Summer Peak

- As expected, more retirements increases violations
- **<u>Summer peak</u> seems to be the most limiting condition**

Winter Proxy

- The proxy winter charging case does not show significant GD violations
- Battery impact is relatively minor, except during high load conditions

Winter Peak

- High load, no battery in-service
- Initial run with BS1&2 retired showed new overloads
- Re-ran with Wagner dispatched at P_{max} (+500 MW) – redispatching Wagner reduced generation deliverability violations
  - These results are based off the MMWG 2024 case – an RTEP case would better represent what PJM would see

Summer Peak Violations

	# Overload Level 1 (Moderate)	# Overload Level 2 (Severe)
Case 1: Without Brandon Shores 1	12	0
Case 2: Without Brandon Shores 1&2	22	0
Case 3: Without Brandon Shores 1&2 + Wagner Oil	31	2
Case 4: Without Brandon Shores 1&2 + Wagner	35	8

Winter Proxy Violations, BS 1&2 Retired

	# Overload Level 1 (Moderate)	# Overload Level 2 (Severe)
Case 1: No Battery	9	4
Case 2: 600 MW Battery	9	4
Case 3: 1200 MW Battery	10	4

Winter Peak Violations, BS 1&2 Retired

	# Overload Level 1 (Moderate)	# Overload Level 2 (Severe)
Without Brandon Shores 1&2	10	11
Without Brandon Shores 1&2, Wagner Dispatched at P_{max}	21	1

N-1-1 Contingency Analysis

Results

N-1-1 Thermal Violations, Summer Peak

- N-1-1 Analysis was performed on PJM's Summer Peak (RTEP) dataset
- Same device adjustment options (all taps and shunts regulating pre-contingency and locked post-contingency)

PJM's publicly published (Update July 11, 2023) contingencies driving transmission reinforcements, with upgrade details (Aug 2023)

PJM Identified Thermal Violations (Violations Identified in Telos Analysis)

- BGE - Five Rock – Rock Ridge 1 115kV (GD + N-1-1)
- BGE - Five Rock – Rock Ridge 2 115kV (GD + N-1-1)
- BGE - Rock Ridge – Colonial Pipeline 1 115kV (GD)
- BGE - Rock Ridge – Colonial Pipeline 2 115kV (GD)
- BGE - Colonial Pipeline 1 – Glenarm 1 115kV (GD)
- BGE - Colonial Pipeline 1 – Glenarm 2 115kV (GD)
- BGE - Chestnut Hill 7 – Frederick Road 7 115kV (N-1-1)
- BGE - Chestnut Hill 8 – Frederick Road 8 115kV (N-1-1)
- APS - Doubs Transformer 3 500/230 kV (GD)
- APS - Bethel – Riverton 138kV (GD)
- PEPCO - Dickerson – Dickerson H 230kV (GD)

Results correspond reasonably well with PJM's published results and from discussions with the Special Studies team

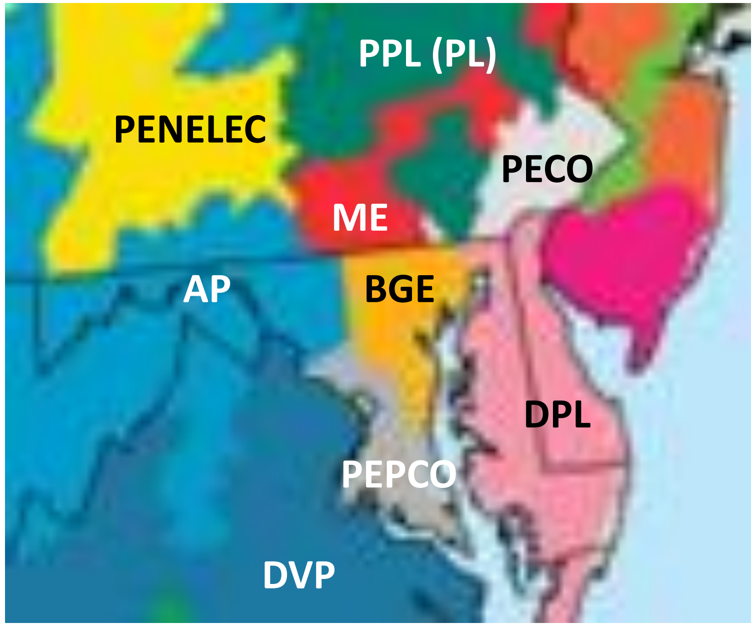
N-1-1 Voltage Violations, Summer

Key Findings:

- By maintaining MVAr capability at BS, voltage violations are no worse than the base case (with BS in-service)
- Maintaining MVAr capability at BS could be accomplished through:
  - BESS
  - Synchronous condenser conversion
  - STATCOMs
  - One of the above, possibly augmented with shunt capacitors

Voltage Violations with BS1 & BS2 Retired

Count of Vmag \	AP	PL	PECO	BGE	PEPCO	
Row Labels	201	229	230	232	233	Grand Total
34.5				93		93
69		7			2	9
115		4		187	1	192
138	2					2
230		1	3	36		40
Grand Total	2	12	3	316	3	336



N-1-1 Voltage Violations, Winter Proxy Cases

Shoulder, BS 1 & 2 Retired

BESS Assumed Charging

- No new violations found (beyond those already identified in the summer case)

Winter Peak, BS 1 & 2 Retired, Wagner

BESS Assumed Depleted but Functioning as a 300MVAr STATCOM

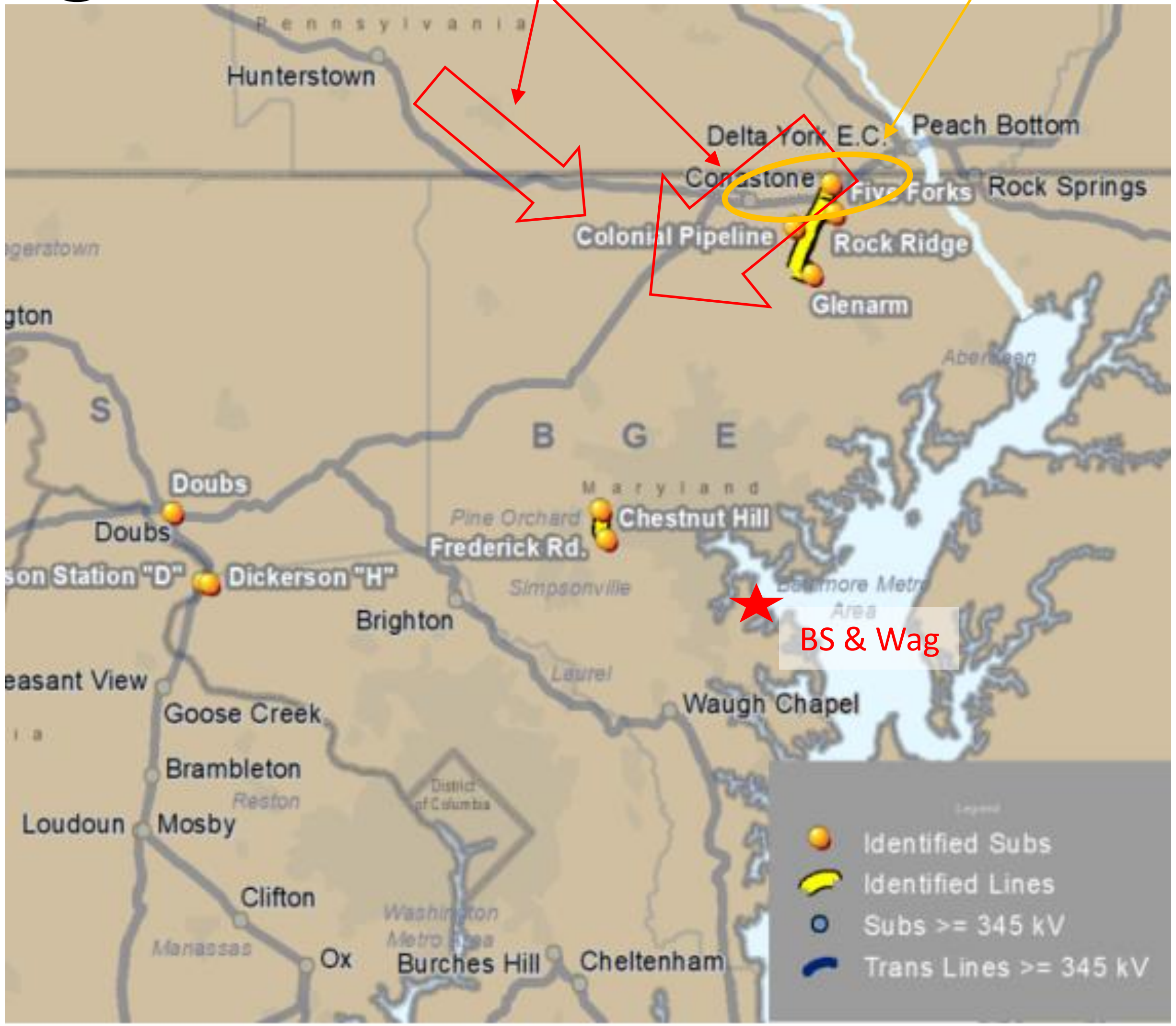
- Several voltage support deficiency observed
- Indicates that significant levels of additional voltage support resources are warranted
- PJM has approved voltage support in the $780MM:
  - 350MVAr Cap at Conastone 500kV
  - STATCOM at Brighton 500kV (165 MVAr assumed)
  - Cap at Brighton 500kV (350MVAr assumed)
  - Cap at Burches Hill
  - 350MVAr STATCOM + Cap at Solley Road
  - 350MVAr STATCOM + Cap at Granite

Voltage Support Challenges

- During certain dispatch conditions, there’s a lack of VARs in BG&E under N-1-1 contingencies
- The reactive power (Q) losses in BGE are much higher than we’ve seen in the other cases
- In particular, the 500kV Conastone region – where active power loading of 500kV and 230kV is very high → resulting in high Q losses
- This results in a Q insufficiency (and voltage collapse) for many N-1-1 contingencies

Very high power flows; very high Q losses

Location of new 500kV line



N-1-1 Voltage Violation Mitigations, Winter Peak

Possible Mitigations Include:

- Add a 500kV line near Conastone
  - This reduces line loading and Q losses substantially
- Add voltage support
  - At locations near Q losses (Conastone, Brighton, etc.)
  - At the Brandon Shores POI (BESS with 300MVAr capability)
- Increasing BGE generation dispatch to reduce import flows and therefore reduce Q losses

Approved by PJM; Technically sound. **Potentially long-lead time**

Approved by PJM; Technically sound. 3-year lead time

Proposed here; 2-3 year lead time

Proposed to keep Wagner units available for local BGE support (for energy and voltage)

Battery Financials – 600 MW x 4 hours

Financial Analysis

1 Detailed BESS Inputs and Assumptions

Input	Units	Assumption	Notes
Storage Specifications:			
COD Date	Date	6/30/2027	Project-specific Assumption
CapEx Deployment Date	Date	6/30/2026	Assumed to be 1-year prior to COD
Economic Life	Years	20	Project-specific Assumption
Storage Capacity	MW	600	Project-specific Assumption
Storage Energy	MWh	2400	Calculated
ELCC Capacity Credit	%	76%	Preliminary 2025/26 BRA Class Rating for 4-hour BESS
CapEx Assumptions:			
Energy	$/kWh	263	NREL 2023 ATB, (2021$) for a 2027 Install
Power	$/kW	290	NREL 2023 ATB, (2021$) for a 2027 Install
Total CapEx	$/kWh	336	Calculated
% Capex Subsidized	%	40%	IRA Subsidies: ITC 30% + Assumed 10% for 'Siting in Energy Community'
OpEx Assumptions:			
Fixed O&M Cost	$/kW-y	33.6	NREL 2023 ATB, (2021$) for a 2027 Install
Financing Assumptions:			
Date Used for Discounting	Date	12/31/2024	Project-specific Assumption
Discount Rate (Nominal)	%	6.8%	PJM Constructability & Financial Analysis Report 2022 RTEP Window 3
Long-term Inflation Rate	%	2.1%	PJM Constructability & Financial Analysis Report 2022 RTEP Window 3
Discount Rate (Real)	%	4.6%	Calculated
Other Financing Assumptions:			
Tax Rate	%	29.3%	21% Federal + 8.25% for Maryland
MACRS Depreciation	Yrs	5	NREL 2023 ATB
Grid Revenues:			
Arbitrage Revenue	$/kW-y	43.77	Peak Shaving Optimization Profile Coupled with Brandon Shores Bus LMPs (2022 & 2023 Avg.)
Capacity Revenue	$/kW-y	26.65	2024-2025 BRA Capcity Price for BGE Zone
Reserve Revenue	$/kW-y	26.71	Peak Shaving Optimization Profile Coupled with MAD SR MCP (Capped) (2023 & 2023 Avg.)

1 Standalone BESS Investment: NPV Analysis

Key Assumptions:

- All figures are in real $2023 dollars with no real dollar escalation; revenue and O&M costs are held constant over the projection period
- Storage O&M costs include the levelized cost of storage augmentation
- Project qualifies for 30% ITC + 10% IRA bonus for ‘Siting in Energy Community; this is applied to both energy and power-related capex
- Analysis is performed on an unlevered basis; NPV is calculated using a 4.6% real WACC/discount rate – all NPVs are calculated as of 12/31/2024

($ in Thousands)

Period Length		Quarterly	Quarterly	Quarterly	Quarterly	Quarterly	Quarterly	Quarterly	Annual	Annual	Annual	Annual	Annual	Annual
Period End		6/30/26	9/30/26	12/31/26	3/31/27	6/30/27	9/30/27	12/31/27	12/31/28	12/31/29	12/31/30	12/31/44	12/31/45	12/31/46
Investment P&L														
Capacity	-	-	-	-	-	-	3,038	3,038	12,150	12,150	12,150	12,150	12,150	12,150
Net Energy Arbitrage	-	-	-	-	-	-	6,565	6,565	26,261	26,261	26,261	26,261	26,261	26,261
Ancillary Service (Sync Res.)	-	-	-	-	-	-	4,007	4,007	16,027	16,027	16,027	16,027	16,027	16,027
Total Revenue	-	-	-	-	-	-	**13,609**	**13,609**	**54,438**	**54,438**	**54,438**	**54,438**	**54,438**	**54,438**
Storage O&M	-	-	-	-	-	-	(5,664)	(5,664)	(22,658)	(22,658)	(22,658)	(22,658)	(22,658)	(22,658)
Total Operating Cost	-	-	-	-	-	-	**(5,664)**	**(5,664)**	**(22,658)**	**(22,658)**	**(22,658)**	**(22,658)**	**(22,658)**	**(22,658)**
EBITDA	-	-	-	-	-	-	**7,945**	**7,945**	**31,780**	**31,780**	**31,780**	**31,780**	**31,780**	**31,780**
MACRS D&A	-	-	-	-	-	-	(48,357)	(48,357)	(154,743)	(92,846)	(55,708)	-	-	-
EBIT	-	-	-	-	-	-	**(40,412)**	**(40,412)**	**(122,963)**	**(61,066)**	**(23,928)**	**31,780**	**31,780**	**31,780**
Cash Taxes Paid	-	-	-	-	-	-	-	-	-	-	-	**(9,296)**	**(9,296)**	**(9,296)**
Cash Net Income	-	-	-	-	-	-	**(40,412)**	**(40,412)**	**(122,963)**	**(61,066)**	**(23,928)**	**22,484**	**22,484**	**22,484**
Free Cash Flows														
Energy Cost	-	(631,823)	-	-	-	-	-	-	-	-	-	-	-	-
Energy Cost Tax-Credits	-	252,729	-	-	-	-	-	-	-	-	-	-	-	-
Power Cost	-	(174,131)	-	-	-	-	-	-	-	-	-	-	-	-
Power Cost Tax-Credits	-	69,652	-	-	-	-	-	-	-	-	-	-	-	-
Capital Investment (Post Tax-Credits)	-	**(483,572)**	-	-	-	-	-	-	-	-	-	-	-	-
EBITDA	-	-	-	-	-	-	7,945	7,945	31,780	31,780	31,780	31,780	31,780	31,780
Taxes Paid	-	-	-	-	-	-	-	-	-	-	-	(9,296)	(9,296)	(9,296)
Capital Investment (Post Tax-Credits)	-	(483,572)	-	-	-	-	-	-	-	-	-	-	-	-
After-Tax Free Cash Flows	-	**(483,572)**	-	-	-	-	**7,945**	**7,945**	**31,780**	**31,780**	**31,780**	**22,484**	**22,484**	**22,484**
Investment Returns Summary														
Project NPV	**(103,823)**													

Incremental BESS Transmission: NPV Analysis

Key Assumptions:

- $31mm of incremental transmission is deployed to support BESS grid interconnection
- Transmission COD matches BESS COD of 6/30/27, Capex is deployed 1-year prior to COD
- O&M costs equal 1% of Capex per year
- Revenue requirements are solved for, such that the project NPV equals zero → the NPV of this revenue requirement is assumed to be the make-whole cost of the investment
- Analysis is performed on an unlevered basis; NPV is calculated using a 4.6% real WACC/discount rate – all NPVs are calculated as of 12/31/2024

($ in Thousands)

Period Length		Quarterly	Quarterly	Quarterly	Quarterly	Quarterly	Quarterly	Quarterly	Annual	Annual	Annual	Annual	Annual	Annual
End Date		6/30/26	9/30/26	12/31/26	3/31/27	6/30/27	9/30/27	12/31/27	12/31/28	12/31/29	12/31/30	12/31/65	12/31/66	12/31/67
Investment P&L														
Levelized Revenue Requirement	-	-	-	-	-	-	**585**	**585**	**2,342**	**2,342**	**2,342**	**2,342**	**2,342**	**1,171**
Transmission O&M	-	-	-	-	-	-	(78)	(78)	(310)	(310)	(310)	(310)	(310)	(155)
Total Operating Cost	-	-	-	-	-	-	**(78)**	**(78)**	**(310)**	**(310)**	**(310)**	**(310)**	**(310)**	**(155)**
EBITDA	-	-	-	-	-	-	**508**	**508**	**2,032**	**2,032**	**2,032**	**2,032**	**2,032**	**1,016**
MACRS D&A	-	-	-	-	-	-	(3,100)	(3,100)	(9,920)	(5,952)	(3,571)	-	-	-
EBIT	-	-	-	-	-	-	**(2,592)**	**(2,592)**	**(7,888)**	**(3,920)**	**(1,540)**	**2,032**	**2,032**	**1,016**
Cash Taxes Paid	-	-	-	-	-	-	-	-	-	-	-	**(594)**	**(594)**	**(297)**
Cash Net Income	-	-	-	-	-	-	**(2,592)**	**(2,592)**	**(7,888)**	**(3,920)**	**(1,540)**	**1,437**	**1,437**	**719**
Free Cash Flows														
Transmission CapEx	-	(31,000)	-	-	-	-	-	-	-	-	-	-	-	-
Capital Investment (Post Tax-Credits)	-	**(31,000)**	-	-	-	-	-	-	-	-	-	-	-	-
EBITDA	-	-	-	-	-	-	508	508	2,032	2,032	2,032	2,032	2,032	1,016
Taxes Paid	-	-	-	-	-	-	-	-	-	-	-	(594)	(594)	(297)
Capital Investment (Post Tax-Credits)	-	(31,000)	-	-	-	-	-	-	-	-	-	-	-	-
After-Tax Levered Free Cash Flow	-	**(31,000)**	-	-	-	-	**508**	**508**	**2,032**	**2,032**	**2,032**	**1,437**	**1,437**	**719**
Revenue Requirement Details														
Project NPV	**$0**													
Levelized Revenue Required for $0 NPV	**$2,342**													
NPV of Rev. Requirement	**(37,878)**													

3 Reliability Must Run: NPV Analysis

Key Assumptions:

- RMR cost of $200mm/year associated with keeping Brandon Shores online
- Without BESS, RMR is paid from 6/30/25 through 12/31/28
- With BESS, RMR is paid from 6/30/25 through BESS COD of 6/30/27 (1.5 year reduction in RMR payments)
- Difference in RMR NPVs with and without the BESS represents incremental savings attributable to BESS investment
- Analysis is performed on an unlevered basis; NPV is calculated using a 4.6% real WACC/discount rate – all NPVs are calculated as of 12/31/2024

($ in Thousands)

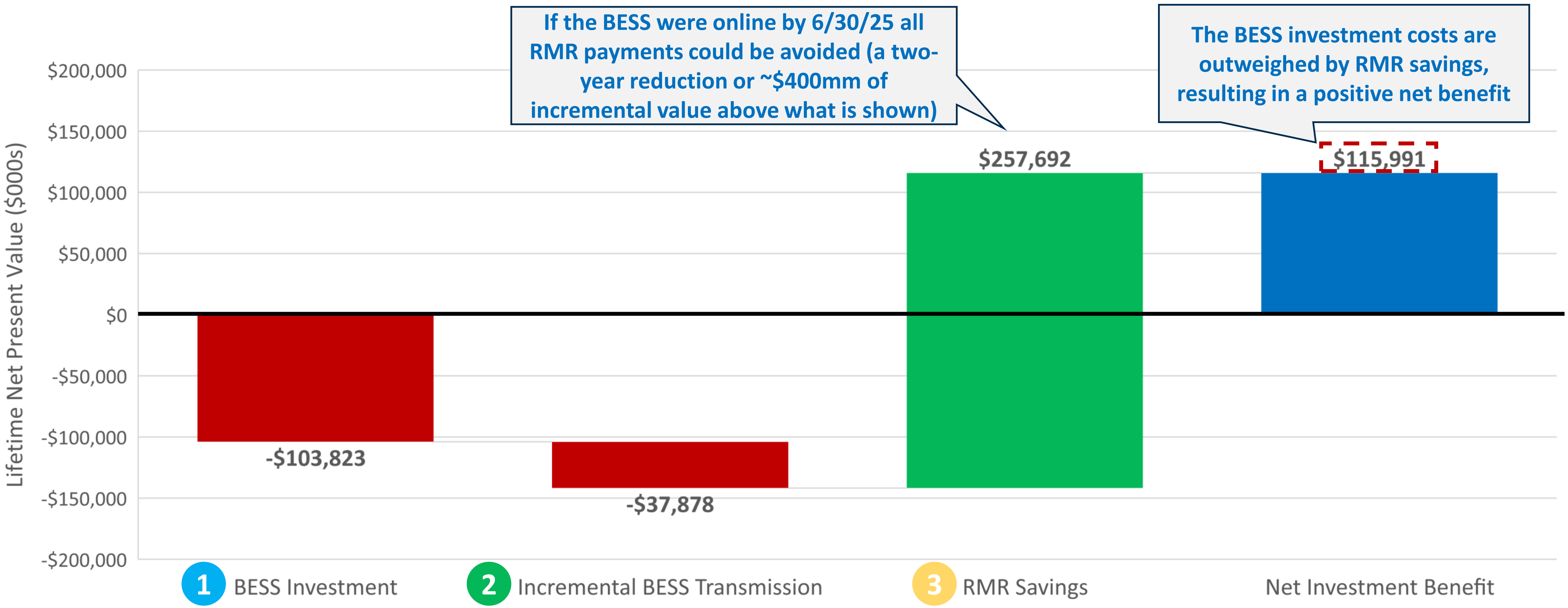
Investment Period	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Period Length	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**
End Date	12/31/24	3/31/25	6/30/25	9/30/25	12/31/25	3/31/26	6/30/26	9/30/26	12/31/26	3/31/27	6/30/27	9/30/27	12/31/27	3/31/28	6/30/28	9/30/28	12/31/28
RMR Costs Without BESS Addition																	
RMR Costs	-	-	-	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)
NPV	**(629,590)**																
RMR Costs With BESS Addition																	
RMR Costs	-	-	-	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	-	-	-	-	-	-
NPV	**(371,898)**																
Incremental RMR Savings Due to BESS																	
NPV Without BESS	(629,590)																
NPV With BESS	(371,898)																
Incremental RMR Savings	**257,692**																
Net Incremental Impact of BESS Incestment with BESS Transmission & RMR Reduction																	
1 NPV of BESS Investment	(103,823)																
2 NPV of BESS Transmission	(37,878)																
3 NPV of RMR Reduction	257,692																
Overall Investment Savings	**115,991**																

Full Project Investment Impacts: NPV Waterfall

"Conservative Estimate"

NPV of BESS Investment, Incremental Transmission and RMR Savings

($ in Thousands)



Impacts of Large-Scale Transmission COD & Ancillary Service Revenues on Investment NPV

NPV of BESS Investment, Incremental Transmission and RMR Savings *($ in Millions)*

Additional BESS Value as a Result of Transmission Delays →

Ancillary Service Revenues ($/KW-yr)	Large Scale Transmission COD (RMR End Date Absent BESS)						
	12/31/2028	6/30/2029	12/30/2029	6/30/2030	12/30/2030	6/30/2031	12/30/2031
$0.00	(51)	31	111	190	267	342	415
$25.00	107	189	269	348	424	499	573
$26.71	116	198	278	357	434	509	582
$50.00	239	321	401	480	556	631	705
$75.00	366	448	529	607	684	759	832
$100.00	492	574	654	733	810	885	958
$125.00	617	699	779	858	934	1,009	1,083
$150.00	741	823	903	981	1,058	1,133	1,206
$166.21	821	903	983	1,061	1,138	1,213	1,286
$175.00	864	946	1,026	1,105	1,181	1,256	1,330

$26.71: $/KW-yr revenues assuming avg. of 2022/23 Synchronous Reserve pricing

$166.21: $/KW-yr revenues assuming avg. of 2022/23 Regulation Reserve pricing

Base Case Assumption: 116 (12/31/2028, $26.71)

Impacts of Large-Scale Transmission COD & Annual RMR Costs on Investment NPV

NPV of BESS Investment, Incremental Transmission and RMR Savings

($ in Millions)

Additional BESS Value as a Result of Transmission Delays

Annual RMR Cost ($MM)	Large Scale Transmission COD (RMR End Date Absent BESS)						
	12/31/2028	6/30/2029	12/30/2029	6/30/2030	12/30/2030	6/30/2031	12/30/2031
$50	(77)	(57)	(37)	(17)	2	21	39
$100	(13)	28	68	108	146	183	220
$150	52	113	173	232	290	346	401
$200	116	198	278	357	434	509	582
$250	180	283	383	481	577	671	763
$300	245	368	488	606	721	834	944
$350	309	453	593	731	865	996	1,125
$400	374	538	698	855	1,009	1,159	1,306

Base Case Assumption

Battery Financials – 800 MW x 4 hours

Financial Analysis

Brandon Shores Retirement Analysis

BESS Financials Update

February 13, 2023

TELOS ENERGY

GridLAB

Replacement Portfolio Financial Analysis

Replacement Portfolio for Brandon Shores Retirements

Assumptions Update – 800MW/3,200MWh @ 59% ELCC Credit

Overview of Financial Analysis

- A 3-part NPV analysis was performed to determine the net impacts of a BESS investment as a replacement for Brandon Shores
- The cost of a BESS investment with corresponding incremental transmission was netted against the savings associated with a reduction in reliability-must-run payments to Brandon Shores to determine the overall investment NPV

1 BESS Standalone Investment

- 800MW/ 3,200 MWh BESS is placed in service on 6/30/27 at the Brandon Shores bus
- Revenues from energy arbitrage, capacity, and ancillary services are netted against capital and operating costs to determine investment NPV

2 Incremental BESS Transmission Upgrades

- $31mm incremental transmission investment is made for BESS grid connections
- Levelized revenue requirement is calculated such that the investment NPV is zero
- NPV of this revenue requirement is used to determine investment NPV

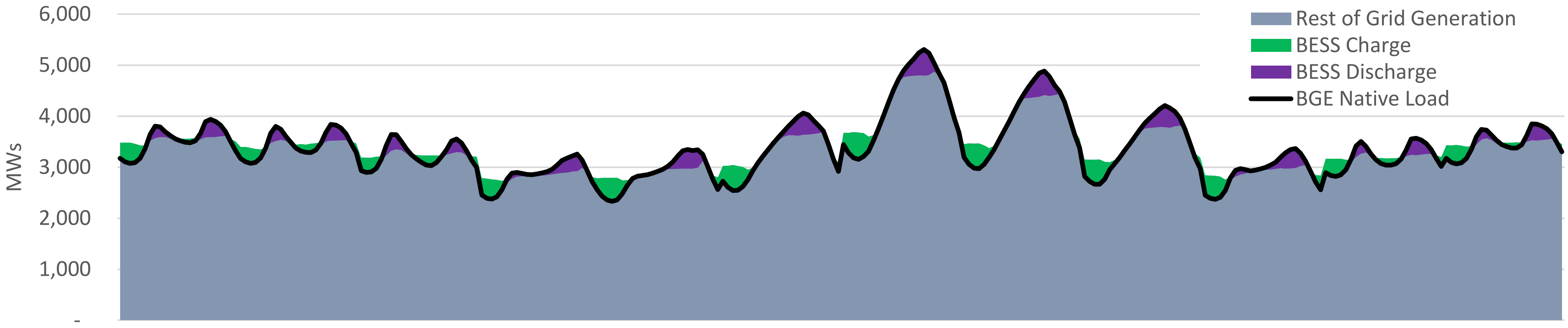
3 Incremental Savings from Earlier Reliability Must-Run End Date

- Assumes that BESS COD coincides with the end of reliability must-run payments to Brandon Shores
- $200mm/year of incremental RMR savings are realized between the time of BESS COD (6/30/27) and the time of large-scale transmission COD (12/31/28 base case assumption)

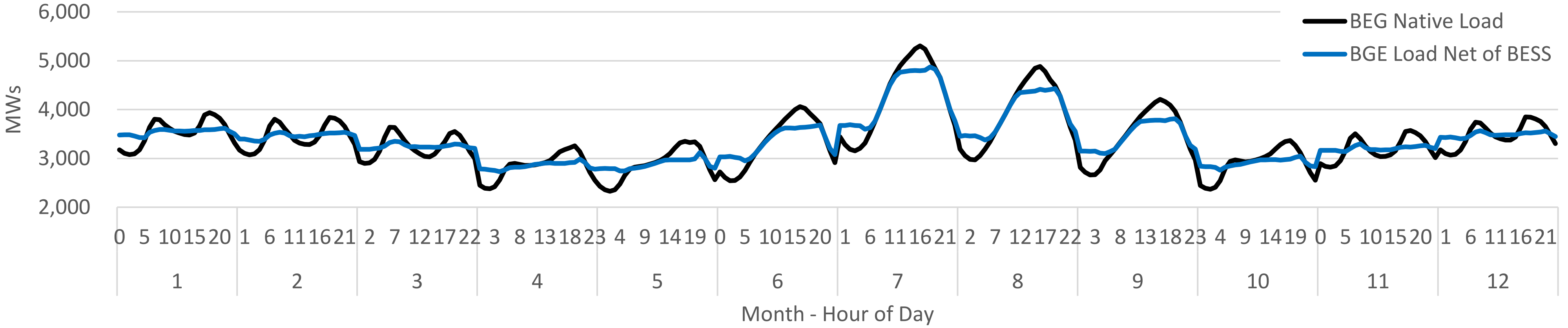
1 BESS Operations Optimized for BGE Peak Shaving

- BESS operations were optimized daily to shave BGE's peak loads – this analysis was performed using BGE's 2023 hourly load profile
- This process generated charge, discharge and state of charge (SoC) parameters for the BESS which were used to estimate revenues relating to energy arbitrage and reserve provisions

2023 Average Day Per Month BESS Operating Profile



2023 Average Day Per Month Net Load Resulting from BESS Operations

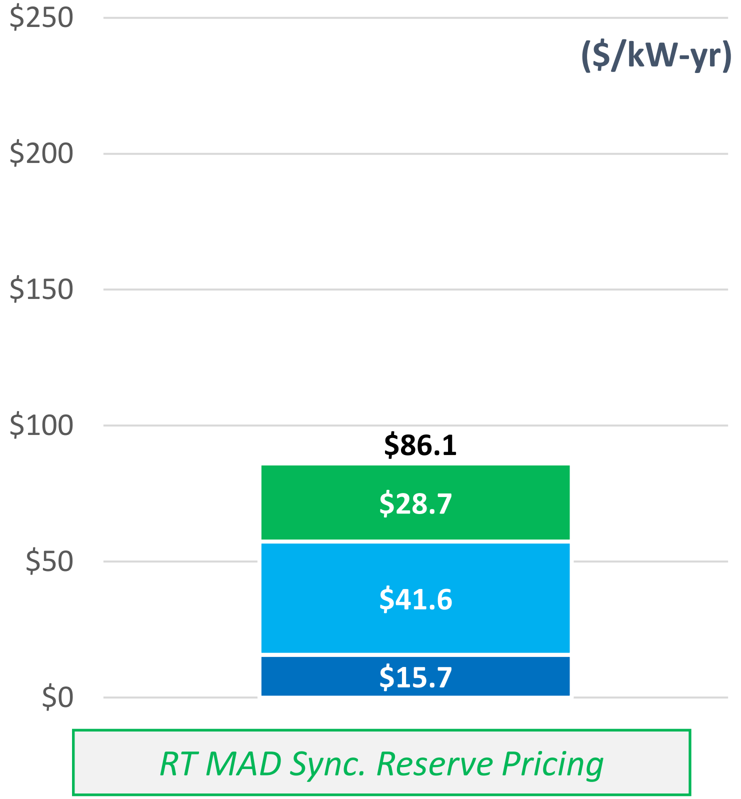


1 BESS Revenues by Source

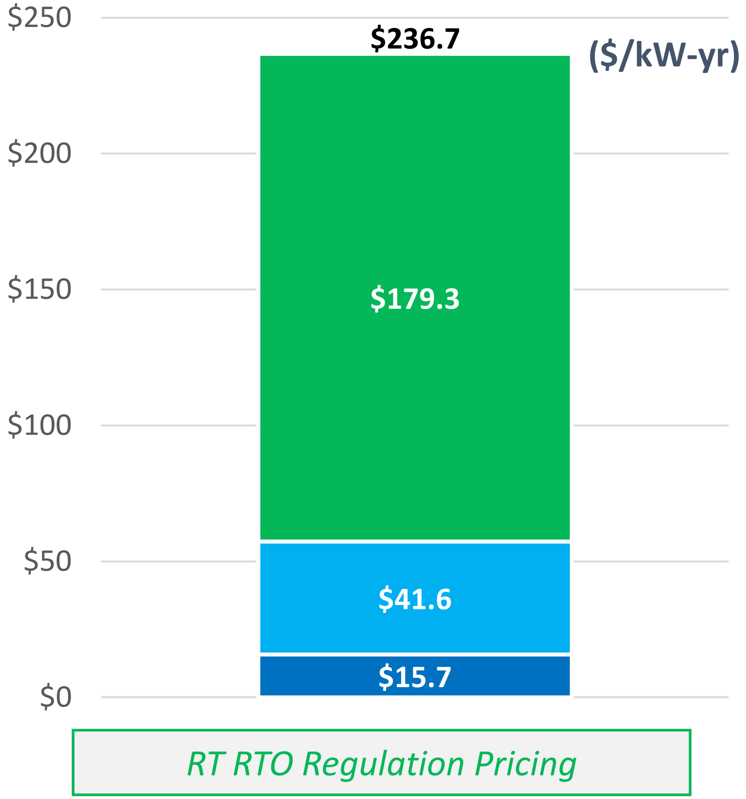
Source & Methodology

- **Ancillary Services:** Peak shaving optimization generated 8760 'available provisions' profiles based on BESS's charge, discharge and SoC for 2022 and 2023. These profiles were applied against the corresponding 2022/23 ancillary service pricing profile to calculate revenues; the two years were averaged together
- **Net Energy Arbitrage:** Peak shaving optimization generated 8760 charge/discharge profiles for 2022 and 2023. These profiles were applied against 2022/23 8760 LMP profiles at the Brandon Shores bus to determine charging cost and generation revenues; two years were averaged together
- **Capacity:** Based on BGE's 2024/25 BRA pricing ($73/MW-day), assuming 59% ELCC capacity credit from the preliminary 25/26 class ratings

Revenue by Source Assuming SYNCHRONOUS RESERVE Pricing



Revenue by Source Assuming REGULATION Pricing



■ Capacity ■ Net Energy Arbitrage ■ Ancillary Services

1 Detailed BESS Inputs and Assumptions

Input	Units	Assumption	Notes
Storage Specifications:			
COD Date	Date	6/30/2027	Project-specific Assumption
CapEx Deployment Date	Date	6/30/2026	Assumed to be 1-year prior to COD
Economic Life	Years	20	Project-specific Assumption
Storage Capacity	MW	800	Project-specific Assumption
Storage Energy	MWh	3200	Calculated
ELCC Capacity Credit	%	59%	2025/26 BRA Class Rating for 4-hour BESS
CapEx Assumptions:			
Energy	$/kWh	263	NREL 2023 ATB, (2021$) for a 2027 Install
Power	$/kW	290	NREL 2023 ATB, (2021$) for a 2027 Install
Total CapEx	$/kWh	336	Calculated
% Capex Subsidized	%	40%	IRA Subsidies: ITC 30% + Assumed 10% for 'Siting in Energy Community'
OpEx Assumptions:			
Fixed O&M Cost	$/kW-y	33.6	NREL 2023 ATB, (2021$) for a 2027 Install
Financing Assumptions:			
Date Used for Discounting	Date	12/31/2024	Project-specific Assumption
Discount Rate (Nominal)	%	6.8%	PJM Constructability & Financial Analysis Report 2022 RTEP Window 3
Long-term Inflation Rate	%	2.1%	PJM Constructability & Financial Analysis Report 2022 RTEP Window 3
Discount Rate (Real)	%	4.6%	Calculated
Other Financing Assumptions:			
Tax Rate	%	29.3%	21% Federal + 8.25% for Maryland
MACRS Depreciation	Yrs	5	NREL 2023 ATB
Grid Revenues:			
Arbitrage Revenue	$/kW-y	41.63	Peak Shaving Optimization Profile Coupled with Brandon Shores Bus LMPs (2022 & 2023 Avg.)
Capacity Revenue	$/kW-y	15.72	2024-2025 BRA Capcity Price for BGE Zone Adj. for ELCC Credit
Reserve Revenue	$/kW-y	28.75	Peak Shaving Optimization Profile Coupled with MAD SR MCP (Capped) (2023 & 2023 Avg.)

1 Standalone BESS Investment: NPV Analysis

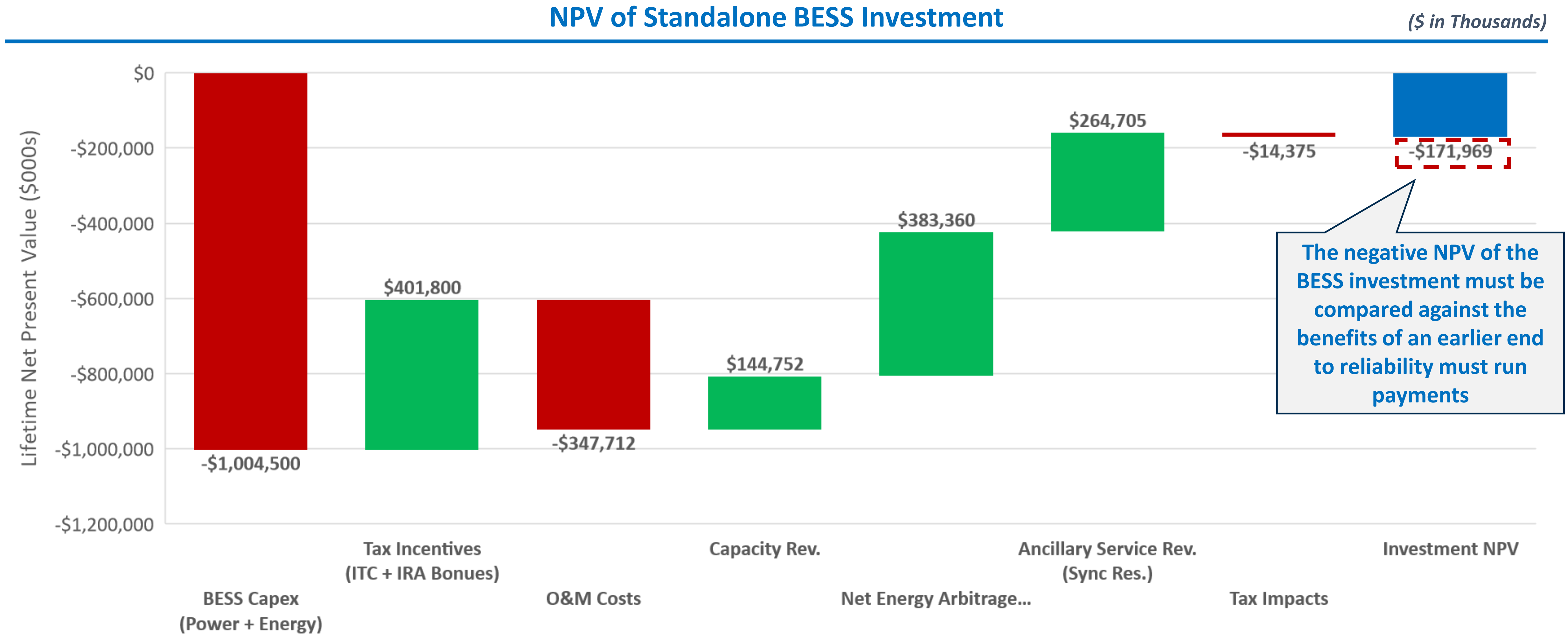
Key Assumptions:

- All figures are in real $2023 dollars with no real dollar escalation; revenue and O&M costs are held constant over the projection period
- Storage O&M costs include the levelized cost of storage augmentation
- Project qualifies for 30% ITC + 10% IRA bonus for 'Siting in Energy Community; this is applied to both energy and power-related capex
- Analysis is performed on an unlevered basis; NPV is calculated using a 4.6% real WACC/discount rate – all NPVs are calculated as of 12/31/2024

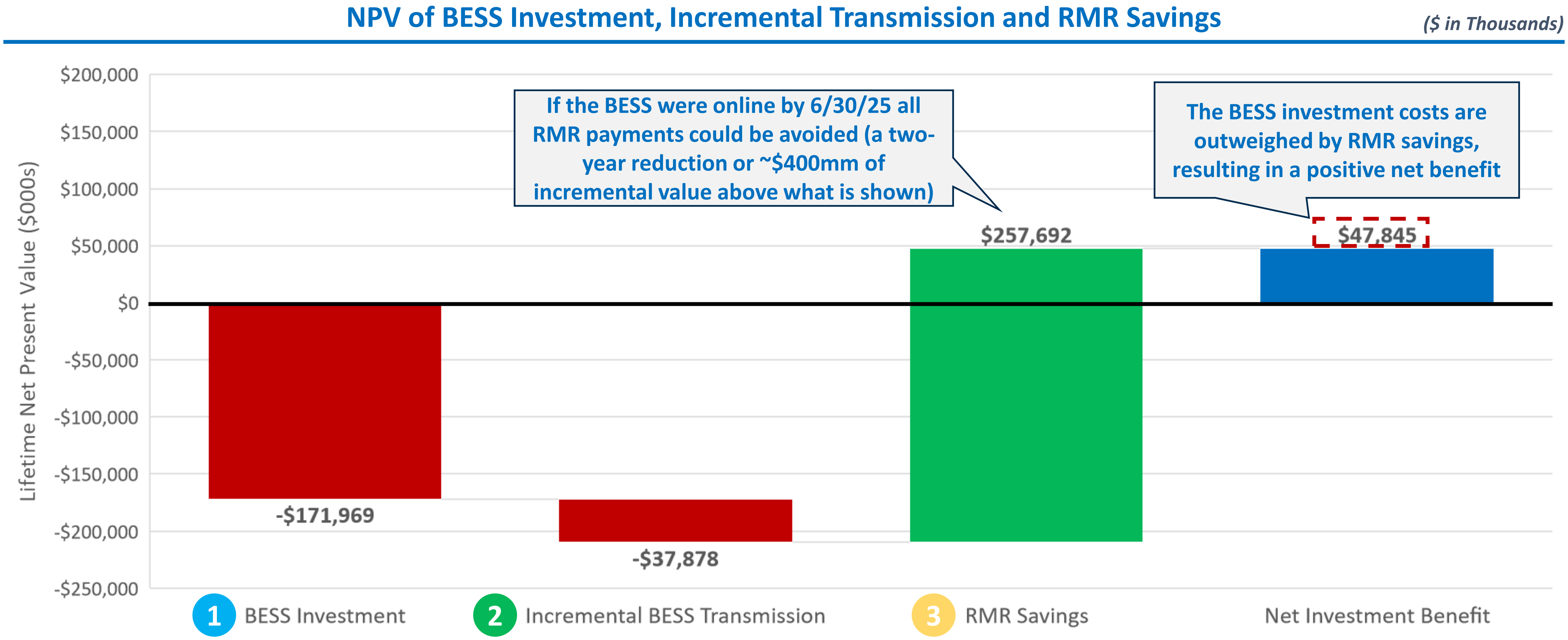
($ in Thousands)

Period Length Period End		Quarterly 6/30/26	Quarterly 9/30/26	Quarterly 12/31/26	Quarterly 3/31/27	Quarterly 6/30/27	Quarterly 9/30/27	Quarterly 12/31/27	Annual 12/31/28	Annual 12/31/29	Annual 12/31/30	Annual 12/31/44	Annual 12/31/45	Annual 12/31/46
Investment P&L														
Capacity	-	-	-	-	-	-	3,144	3,144	12,576	12,576	12,576	12,576	12,576	12,576
Net Energy Arbitrage	-	-	-	-	-	-	8,327	8,327	33,307	33,307	33,307	33,307	33,307	33,307
Ancillary Service (Sync Res.)	-	-	-	-	-	-	5,750	5,750	22,998	22,998	22,998	22,998	22,998	22,998
Total Revenue	-	-	-	-	-	-	**17,221**	**17,221**	**68,882**	**68,882**	**68,882**	**68,882**	**68,882**	**68,882**
Storage O&M	-	-	-	-	-	-	(7,553)	(7,553)	(30,210)	(30,210)	(30,210)	(30,210)	(30,210)	(30,210)
Total Operating Cost	-	-	-	-	-	-	**(7,553)**	**(7,553)**	**(30,210)**	**(30,210)**	**(30,210)**	**(30,210)**	**(30,210)**	**(30,210)**
EBITDA	-	-	-	-	-	-	**9,668**	**9,668**	**38,672**	**38,672**	**38,672**	**38,672**	**38,672**	**38,672**
MACRS D&A	-	-	-	-	-	-	(64,476)	(64,476)	(206,324)	(123,795)	(74,277)	-	-	-
EBIT	-	-	-	-	-	-	**(54,808)**	**(54,808)**	**(167,652)**	**(85,123)**	**(35,605)**	**38,672**	**38,672**	**38,672**
Cash Taxes Paid	-	-	-	-	-	-	-	-	-	-	-	**(9,359)**	**(11,312)**	**(11,312)**
Cash Net Income	-	-	-	-	-	-	**(54,808)**	**(54,808)**	**(167,652)**	**(85,123)**	**(35,605)**	**29,313**	**27,360**	**27,360**
Free Cash Flows														
Energy Cost	-	(842,431)	-	-	-	-	-	-	-	-	-	-	-	-
Energy Cost Tax-Credits	-	336,972	-	-	-	-	-	-	-	-	-	-	-	-
Power Cost	-	(232,174)	-	-	-	-	-	-	-	-	-	-	-	-
Power Cost Tax-Credits	-	92,870	-	-	-	-	-	-	-	-	-	-	-	-
Capital Investment (Post Tax-Credits)	-	**(644,763)**	-	-	-	-	-	-	-	-	-	-	-	-
EBITDA	-	-	-	-	-	-	9,668	9,668	38,672	38,672	38,672	38,672	38,672	38,672
Taxes Paid	-	-	-	-	-	-	-	-	-	-	-	(9,359)	(11,312)	(11,312)
Capital Investment (Post Tax-Credits)	-	(644,763)	-	-	-	-	-	-	-	-	-	-	-	-
After-Tax Free Cash Flows	-	**(644,763)**	-	-	-	-	**9,668**	**9,668**	**38,672**	**38,672**	**38,672**	**29,313**	**27,360**	**27,360**
Investment Returns Summary														
Project NPV	**(171,969)**													

1 Standalone BESS Investment: NPV Waterfall



1 2 3 Full Project Investment Impacts: NPV Waterfall



Impacts of Large-Scale Transmission COD & Ancillary Service Revenues on Investment NPV

NPV of BESS Investment, Incremental Transmission and RMR Savings

($ in Millions)

Additional BESS Value as a Result of Transmission Delays

$/KW-yr revenues assuming avg. of 2022/23 Synchronous Reserve pricing

$/KW-yr revenues assuming avg. of 2022/23 Regulation Reserve pricing

Ancillary Service Revenues ($/KW-yr)	Large Scale Transmission COD (RMR End Date Absent BESS)						
	12/31/2028	**6/30/2029**	**12/30/2029**	**6/30/2030**	**12/30/2030**	**6/30/2031**	**12/30/2031**
$0.00	(202)	(120)	(40)	38	115	190	263
$25.00	20	102	183	261	338	413	486
$28.75	48	130	210	289	365	440	514
$50.00	199	281	361	440	516	591	665
$75.00	370	452	533	611	688	763	836
$100.00	538	620	701	779	856	931	1,004
$125.00	705	787	867	946	1,022	1,097	1,171
$150.00	870	952	1,033	1,111	1,188	1,263	1,336
$175.00	1,035	1,117	1,197	1,276	1,352	1,427	1,501
$179.31	1,063	1,145	1,225	1,304	1,381	1,456	1,529

Base Case Assumption

Incremental BESS Transmission: NPV Analysis

Key Assumptions:

- $31mm of incremental transmission is deployed to support BESS grid interconnection
- Transmission COD matches BESS COD of 6/30/27, Capex is deployed 1-year prior to COD
- O&M costs equal 1% of Capex per year
- Revenue requirements are solved for, such that the project NPV equals zero → the NPV of this revenue requirement is assumed to be the make-whole cost of the investment
- Analysis is performed on an unlevered basis; NPV is calculated using a 4.6% real WACC/discount rate – all NPVs are calculated as of 12/31/2024

($ in Thousands)

Period Length		Quarterly	Quarterly	Quarterly	Quarterly	Quarterly	Quarterly	Quarterly	Annual	Annual	Annual	Annual	Annual	Annual
End Date		6/30/26	9/30/26	12/31/26	3/31/27	6/30/27	9/30/27	12/31/27	12/31/28	12/31/29	12/31/30	12/31/65	12/31/66	12/31/67
Investment P&L														
Levelized Revenue Requirement	-	-	-	-	-	-	**585**	**585**	**2,342**	**2,342**	**2,342**	**2,342**	**2,342**	**1,171**
Transmission O&M	-	-	-	-	-	-	(78)	(78)	(310)	(310)	(310)	(310)	(310)	(155)
Total Operating Cost	-	-	-	-	-	-	**(78)**	**(78)**	**(310)**	**(310)**	**(310)**	**(310)**	**(310)**	**(155)**
EBITDA	-	-	-	-	-	-	**508**	**508**	**2,032**	**2,032**	**2,032**	**2,032**	**2,032**	**1,016**
MACRS D&A	-	-	-	-	-	-	(3,100)	(3,100)	(9,920)	(5,952)	(3,571)	-	-	-
EBIT	-	-	-	-	-	-	**(2,592)**	**(2,592)**	**(7,888)**	**(3,920)**	**(1,540)**	**2,032**	**2,032**	**1,016**
Cash Taxes Paid	-	-	-	-	-	-	-	-	-	-	-	**(594)**	**(594)**	**(297)**
Cash Net Income	-	-	-	-	-	-	**(2,592)**	**(2,592)**	**(7,888)**	**(3,920)**	**(1,540)**	**1,437**	**1,437**	**719**
Free Cash Flows														
Transmission CapEx	-	(31,000)	-	-	-	-	-	-	-	-	-	-	-	-
Capital Investment (Post Tax-Credits)	-	**(31,000)**	-	-	-	-	-	-	-	-	-	-	-	-
EBITDA	-	-	-	-	-	-	508	508	2,032	2,032	2,032	2,032	2,032	1,016
Taxes Paid	-	-	-	-	-	-	-	-	-	-	-	(594)	(594)	(297)
Capital Investment (Post Tax-Credits)	-	(31,000)	-	-	-	-	-	-	-	-	-	-	-	-
After-Tax Levered Free Cash Flow	-	**(31,000)**	-	-	-	-	**508**	**508**	**2,032**	**2,032**	**2,032**	**1,437**	**1,437**	**719**
Revenue Requirement Details														

Project NPV	**$0**
Levelized Revenue Required for $0 NPV	**$2,342**
NPV of Rev. Requirement	**(37,878)**

3 Reliability Must Run: NPV Analysis

Key Assumptions:

- RMR cost of $200mm/year associated with keeping Brandon Shores online
- Without BESS, RMR is paid from 6/30/25 through 12/31/28
- With BESS, RMR is paid from 6/30/25 through BESS COD of 6/30/27 (1.5 year reduction in RMR payments)
- Difference in RMR NPVs with and without the BESS represents incremental savings attributable to BESS investment
- Analysis is performed on an unlevered basis; NPV is calculated using a 4.6% real WACC/discount rate – all NPVs are calculated as of 12/31/2024

($ in Thousands)

Investment Period	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Period Length	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**	**Quarterly**
End Date	12/31/24	3/31/25	6/30/25	9/30/25	12/31/25	3/31/26	6/30/26	9/30/26	12/31/26	3/31/27	6/30/27	9/30/27	12/31/27	3/31/28	6/30/28	9/30/28	12/31/28
RMR Costs Without BESS Addition																	
RMR Costs	-	-	-	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)
NPV	**(629,590)**																
RMR Costs With BESS Addition																	
RMR Costs	-	-	-	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	-	-	-	-	-	-
NPV	**(371,898)**																

Incremental RMR Savings Due to BESS

NPV Without BESS	(629,590)
NPV With BESS	(371,898)
Incremental RMR Savings	**257,692**

Net Incremental Impact of BESS Incestment with BESS Transmission & RMR Reduction

1	NPV of BESS Investment	(171,969)
2	NPV of BESS Transmission	(37,878)
3	NPV of RMR Reduction	257,692
	Overall Investment Savings	**47,845**

Impacts of Large-Scale Transmission COD & Annual RMR Costs on Investment NPV

NPV of BESS Investment, Incremental Transmission and RMR Savings

($ in Millions)

Additional BESS Value as a Result of Transmission Delays

Annual RMR Cost ($MM)	Large Scale Transmission COD (RMR End Date Absent BESS)						
	12/31/2028	6/30/2029	12/30/2029	6/30/2030	12/30/2030	6/30/2031	12/30/2031
$50	(145)	(125)	(105)	(85)	(66)	(47)	(29)
$100	(81)	(40)	0	39	78	115	152
$150	(17)	45	105	164	222	278	333
$200	48	130	210	289	365	440	514
$250	112	215	315	413	509	603	695
$300	177	300	420	538	653	766	876
$350	241	385	525	663	797	928	1,056
$400	306	470	630	787	941	1,091	1,237

Base Case Assumption

What is driving the FPR value?

- FPR is largely driven by the Pool Wide Average Accredited UCAP Factor (0.8020)
  - This factor is a measure of the total Accredited UCAP of the resource fleet relative to the fleet's total ICAP based on the calculation of marginal ELCC Class Ratings

	2025/26 BRA ELCC Class Ratings
Onshore Wind	35%
Offshore Wind	60%
Fixed-Tilt Solar	9%
Tracking Solar	14%
Landfill Intermittent	55%
Hydro Intermittent	36%
4-hr Storage	59%
6-hr Storage	67%
8-hr Storage	69%
10-hr Storage	78%
DR	77%
Nuclear	96%
Coal	85%
Gas Combined Cycle	80%
Gas Combustion Turbine	62%
Gas Combustion Turbine Dual	78%
Diesel Utility	90%
Steam	70%