Santee Cooper Resource Planning

Stakeholder Working Group Meeting #10

April 9, 2026

Welcome and Agenda

Stewart Ramsay, Facilitator, VANRY Associates

Meeting Agenda

10:00 – 10:10	**Welcome and Agenda**	**Stewart Ramsay, VANRY**
10:10 – 10:25	**Working Group Business**	**Will Brown**
10:25 – 11:00	**2026 Load Forecast Update**	**Carl Ciullo**
11:00 – 11:30	**Wind Study Results**	**Daniel Pardo, DNV**
11:30 – 12:00	**LUNCH BREAK**	
12:00 – 12:50	**2026 Reserve Margin and ELCC Results**	**Joel Dison, PowerGEM**
12:50 – 1:30	**2026 Integration Study Update**	**Joel Dison, PowerGEM**
1:30 – 1:40	**BREAK**	
1:40 – 2:20	**Market Potential Study Results**	**Steven Roys**
2:20 – 2:40	**2025 IRP Update**	**Will Brown & Bob Davis**
2:40 – 3:30	**2026 Triennial IRP**	**Will Brown & Bob Davis**
3:30 – 3:40	**Meeting Closeout**	**Stewart Ramsay, VANRY**

Guest Speakers

Carl Ciullo
Financial Analyst, Santee Cooper

Daniel Pardo
Project Manager, DNV

Guest Speakers

Joel Dison
Project Lead, PowerGEM

Steven Roys
Manager Program Development, Santee Cooper

Working Group Business

Will Brown, Manager Resource Planning

Review of Action Items

Meeting Identified	Action Item	Progress
Meeting 9	Discuss Act 41 IRP impacts and plans to incorporate in future SWG meetings	After internal review, we have determined that the only addition to the 2026 Triennial IRP is the new requirement under (B)(1)(j)
Meeting 9	Consider the review of distributed or non-traditional turbines, such as ducted lower-height units, as part of the Wind Study	To be addressed in the Wind Study section
Meeting 9	Consider internally an increase in the opportunity for input/feedback into the Wind Study	To be addressed in the Wind Study section
Meeting 9	Confirm the wind hub heights that are being studied	To be provided in the Wind Study section
Meeting 9	Discuss with the load forecast team the potential impact considerations of data center load discussed in SWG meeting 9	Shared with the Load Forecast team on 10/15/2025
Meeting 9	Discuss internally the level of “flexibility violations” seen currently	Joel to discuss in the Solar Integration section

SWG Schedule – Preliminary Proposal

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Sept. 16, 2025 Filed IRP Update

General Notice Meeting 3
Dec. 3, 2025

2026

General Notice Meeting 4
June 11, 2026

Sept. 30, 2026
File Triennial IRP

2027

SWG Meeting 10
April 9, 2026
- 2026 Load Forecast
- 2025 Wind Study Results
- 2025 Reserve Margin and ELCC Study Results
- 2026 Integration Study Update
- 2026 MPS Final Results
- 2025 IRP Update Order
- 2026 Triennial IRP

Coal Retirement Tech. Mtg 4
April 30, 2026
- Transmission Studies
- Review final methodology including assumptions and EnCompass runs

SWG Meeting 11
June 3, 2026
- Final 2026 Load Forecast
- 2026 Triennial IRP Final Assumptions and Modeling Strategy
- Modeling DSM in the 2026 IRP
- Update on integration cost methodology and modeling operating reserves
- Benchmarking EnCompass
- Portfolio Reliability Assessment Process
- 2026 Integration Study Results

SWG Meeting 12
Date TBD

2025 IRP Update Commission Proceeding

2026 Load Forecast

2026 Market Potential Studies

2026 PRM and ELCC Study, Integration Study

2026 IRP Commission Proceeding

SWG – Stakeholder Working Group
ELCC – Effective Load Carrying Capability

2026 Stakeholder Sessions

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2027

PSC Proceeding for 2026 Triennial IRP

January 29
Coal Retirement Technical Mtg #3

April 9
SWG Mtg #10

April 30
Coal Retirement Technical Mtg #4

June 3
SWG Mtg #11

June 11
General Notice Mtg #4

August 31
NDAs available to those stakeholders interested in modeling data

September 29
Santee Cooper Board Meeting

September 30
File 2026 Triennial IRP

SWG Mtg #12
TBD

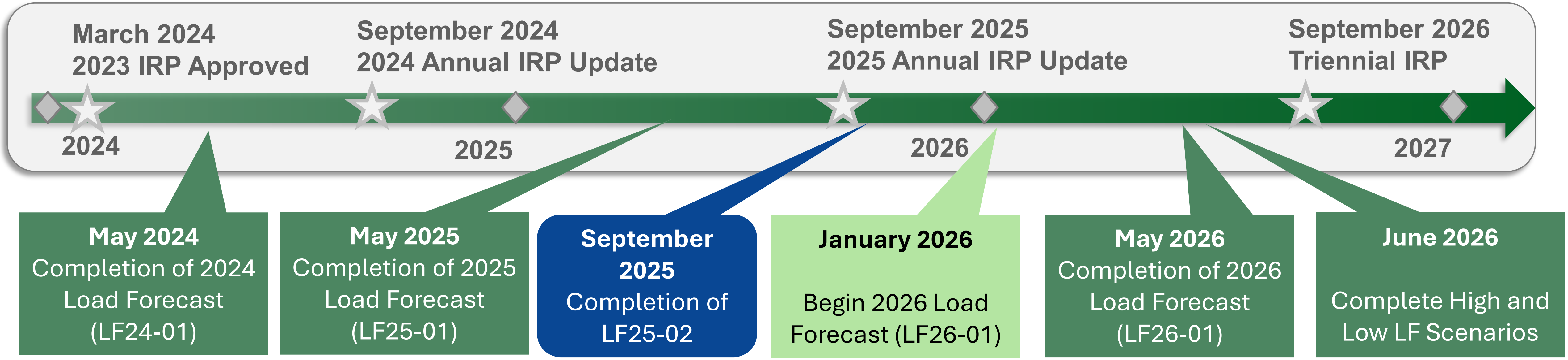
Post-Filing
Modeling files available within 1 week and results file within 2 weeks

SWG – Stakeholder Working Group
MPS – Market Potential Study
PSC – Public Service Commission

2026 Load Forecast Update

Carl Ciullo, Financial Analyst III

Load Forecast | Timeline



- 2026 IRP Load Forecast (26-01) is currently underway and will be completed in May.
- Load scenarios will be completed in June.
- Having received no Load Forecast feedback following the December General Notice Meeting, Santee Cooper is moving forward without major changes to methodology.
- Feedback from this meeting will be assessed against 2026 Load Forecast deadline.

Load Forecast | Methodology Highlights

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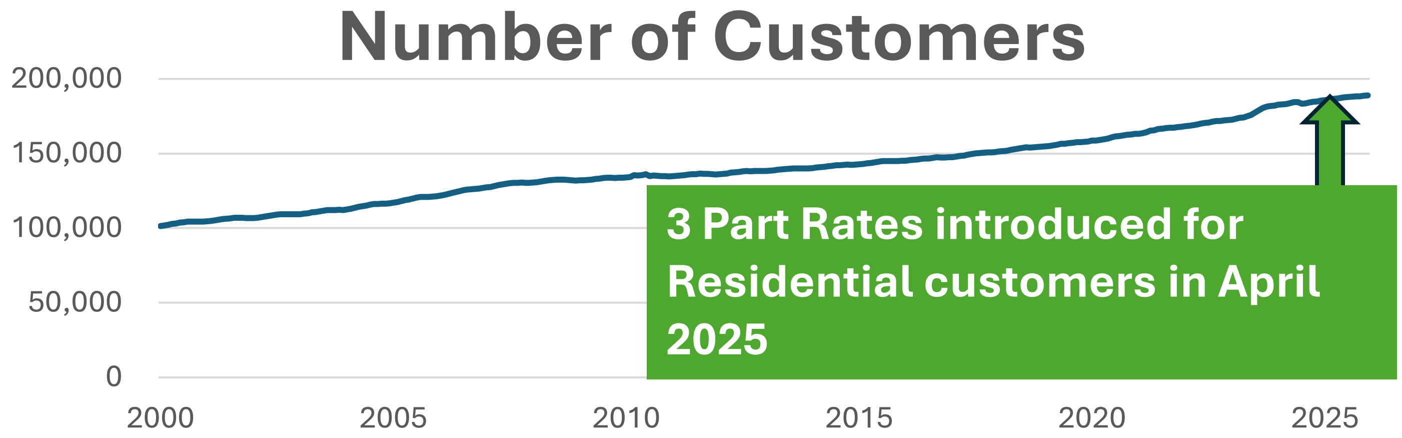
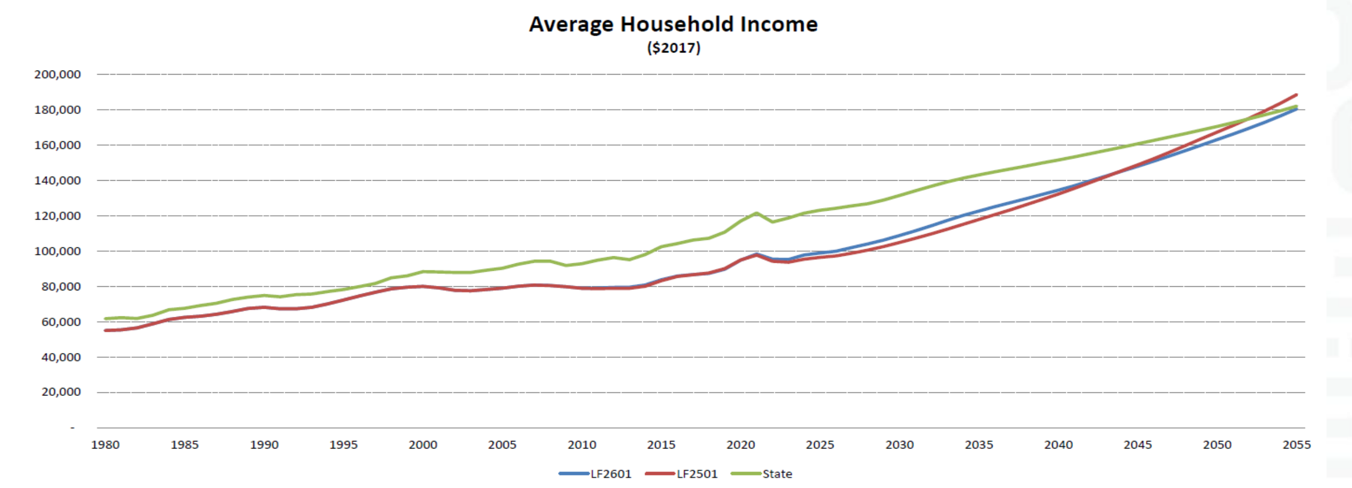
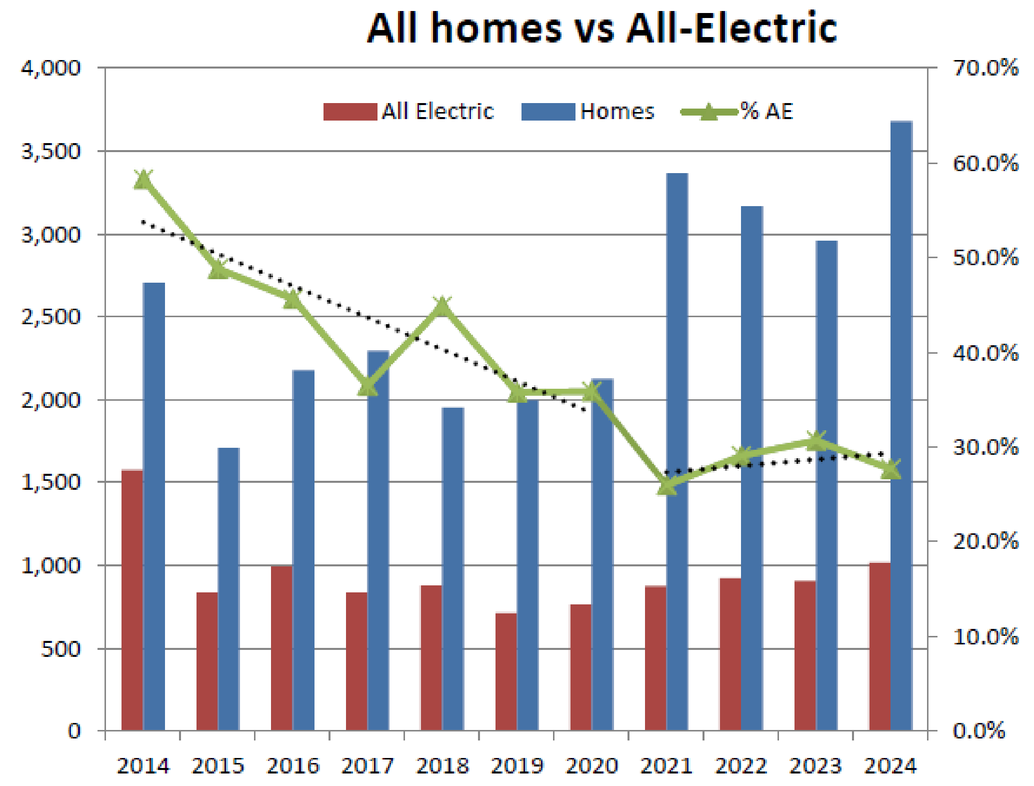
Load Forecast Segment	2025 IRP Methodology	2026 IRP Tentative Changes
Residential and Commercial	Statistically Adjusted End–Use and Econometric models prepared by GDS	Assumptions update only
Electric Vehicle	Internally generated EV Forecast using EPRI EV forecast and NREL load shape	Uses actual load data for usage and load shape and EIA AEO EV forecast
Rooftop Photovoltaic	Internally generated PV Forecast using EIA AEO solar forecast and NREL load shape	Uses actual load data for usage and load shape
Industrial	Internally generated forecast using customer contract, historical usage, and discussions with customer	Assumptions update only
Central Member Cooperatives	Central staff prepared Statistically Adjusted End–Use model	Assumptions update only
Potential New Large Loads	Internally generated Stochastic model	Assumptions update only

Load Forecast | Assumption Update – Residential and Commercial



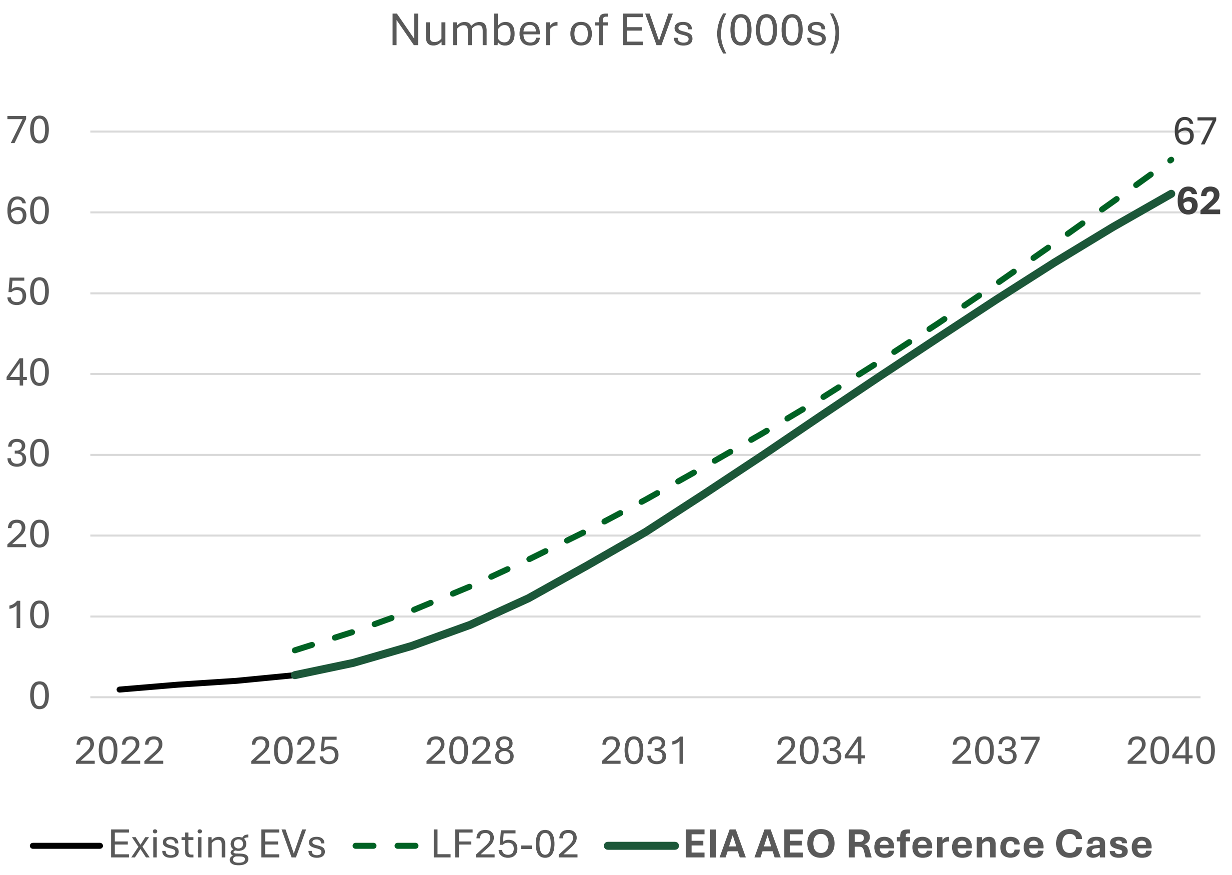
AVERAGE HOUSEHOLD INCOME

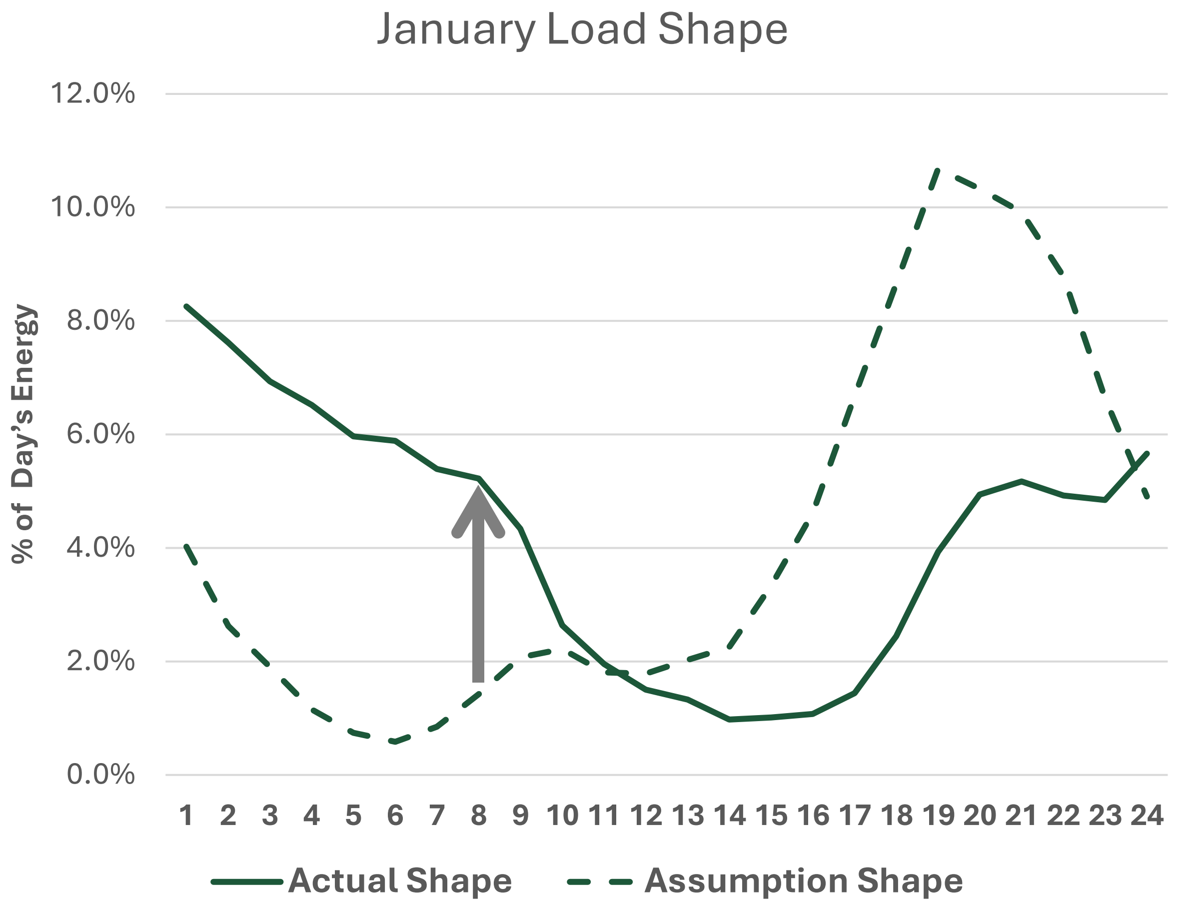




SC Supreme Court has ruled on Dominion's proposed natural gas pipeline. Further natural gas penetration expected to resume.

EV Load = # Electric Vehicles X Usage per Vehicle





All figures are PRELIMINARY

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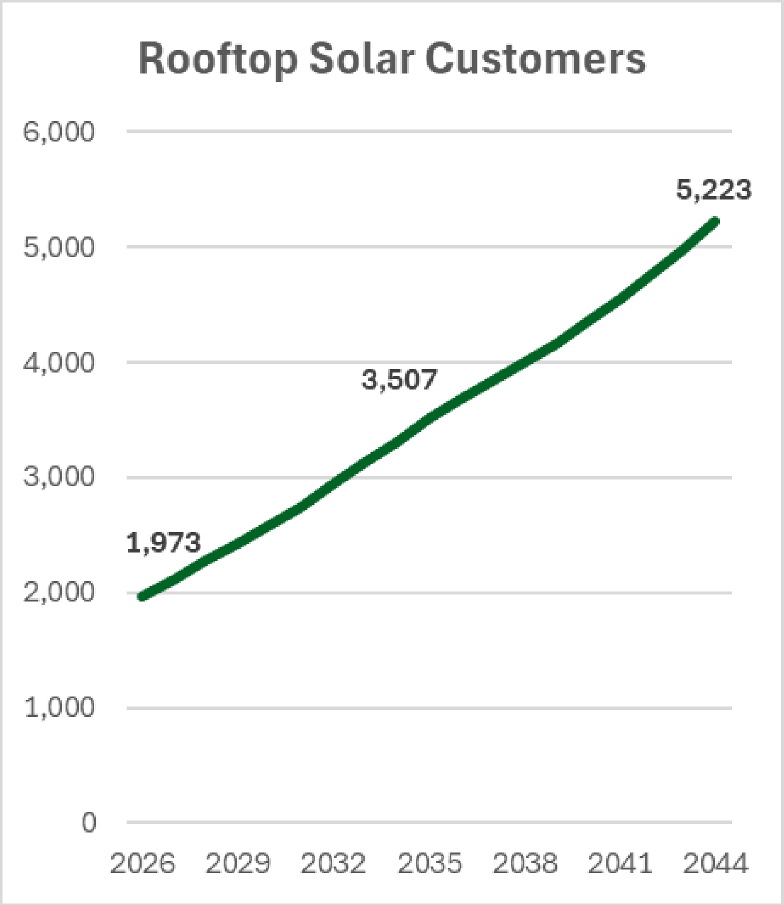
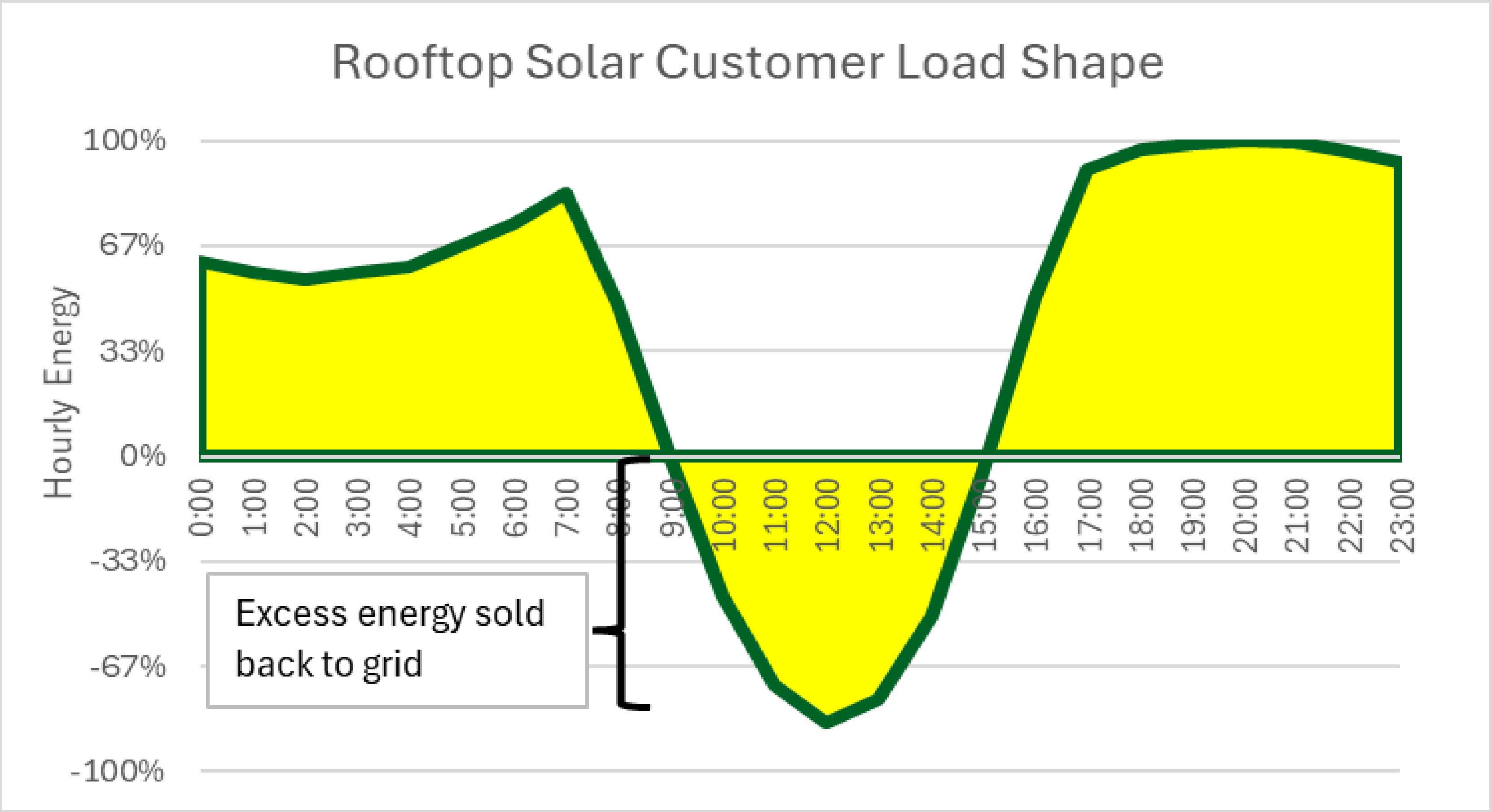
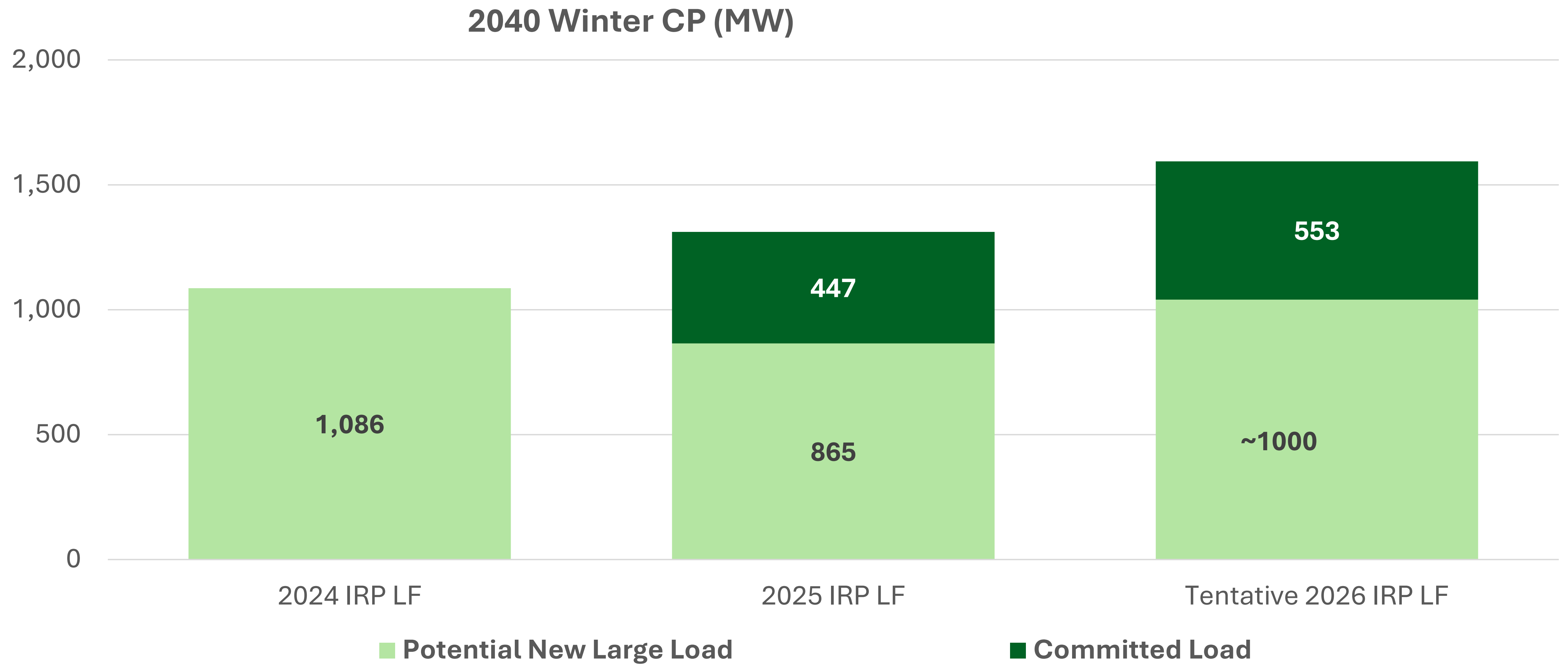
PV Load = # Solar Installations **X** Generation per install





All figures are PRELIMINARY

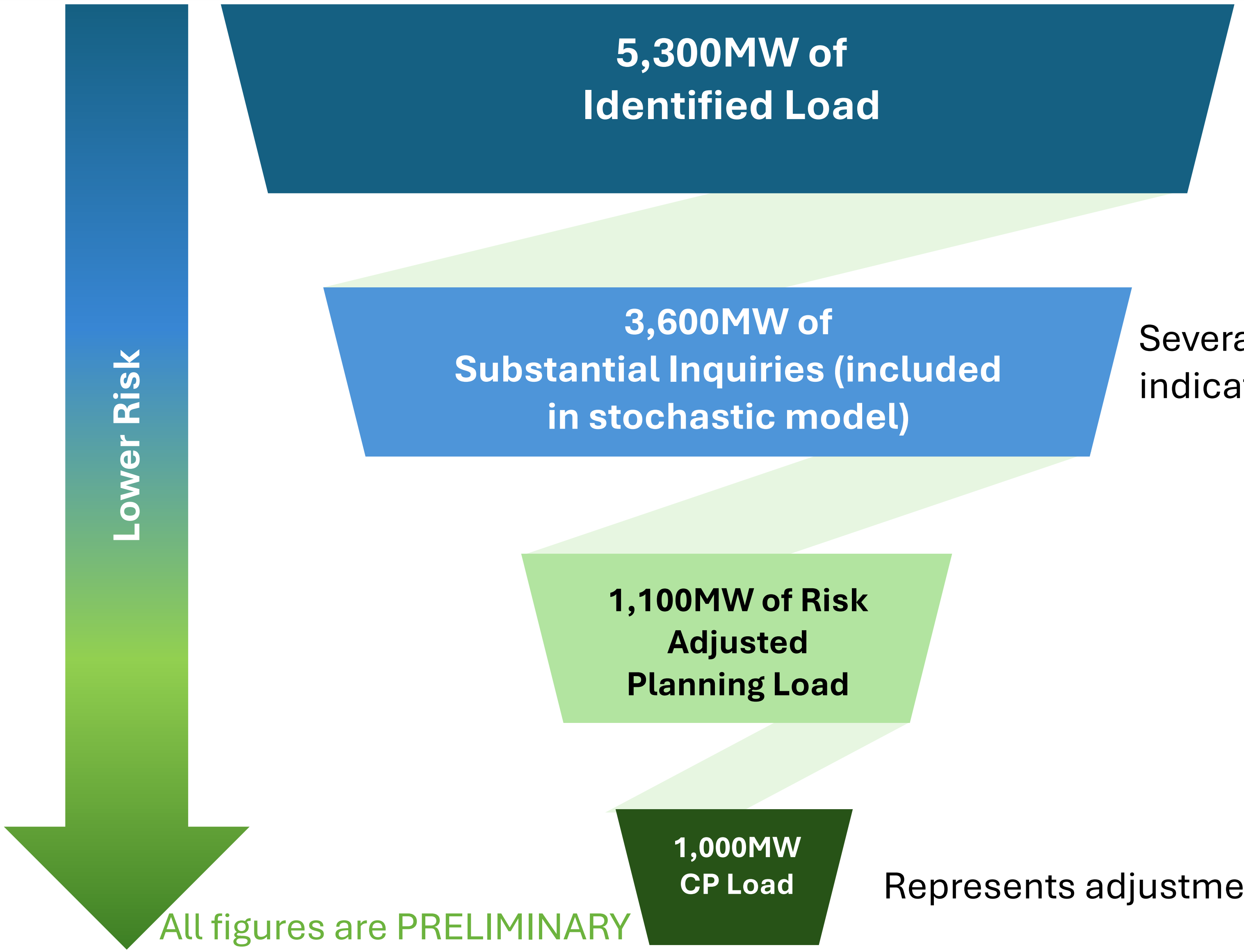
Load Forecast | Assumption Update – Potential New Large Loads



Committed load represents loads included in Potential New Larges load in a previous forecast who have signed contracts

All figures are PRELIMINARY

Load Forecast | PRELIMINARY PNLL Model Output



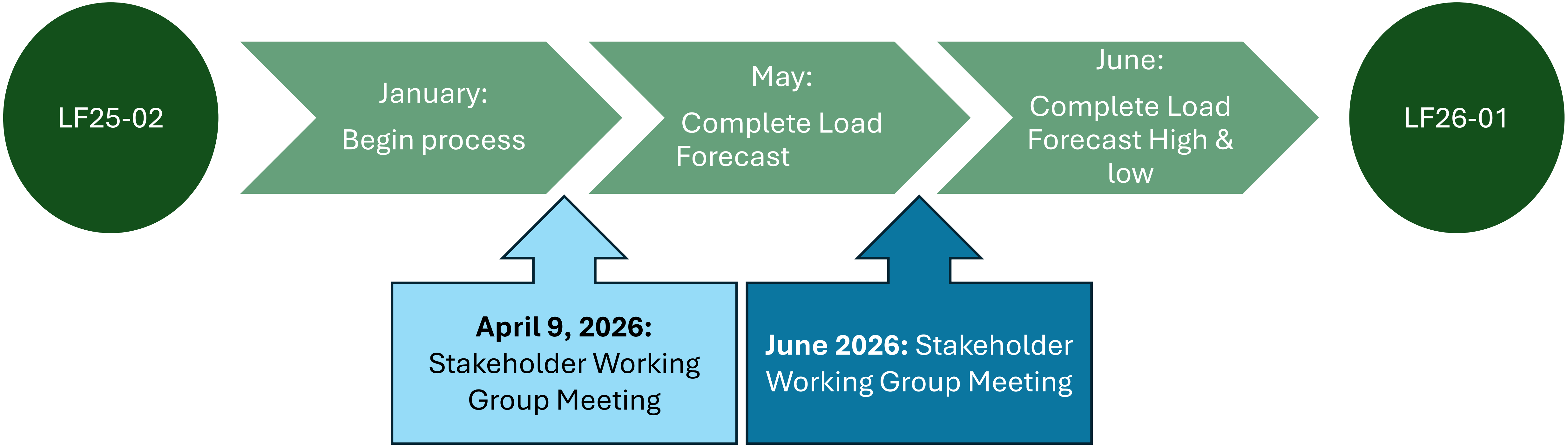
Notes

Several potential new large loads have indicated interest in non-firm service.

Represents adjustment from NCP to CP

All figures are PRELIMINARY

Load Forecast | 2026 Triennial IRP Load Forecast (LF26-01)



Feedback is needed by April 16th to allow adequate time to incorporate or respond to.

Wind Study

Daniel Pardo, Project Manager, DNV

WHEN TRUST MATTERS

Santee Cooper's 2025 Wind Study

www.dnv.com

DNV

Wind Study Overview

- Santee Cooper engaged DNV Energy USA, INC (“DNV”) to perform a feasibility assessment for onshore wind energy development in South Carolina
- Scope of Work Summary
  - Feasibility assessment of potential wind development in South Carolina
  - Project development timeline assessment
  - Capital and operating cost benchmarking
  - Provide wind production profiles for South Carolina
- Study Overview and Results

Wind Study | Multi-criteria assessment

Item	Notes
Area of interest	Within 20 miles of Santee Cooper's Transmission System
Individual target site	Minimum 50 MW capacity
Wind resource	Minimum 5 m/s at 115 m hub height DNV used high-resolution baseline + proprietary calibration, downscaling, and long-term correction methods
Areas avoided	Federal, State and local protected areas Other conservation easements Wetlands, waterbodies, and flood hazard zones
Terrain complexity	Only areas with less than 15% slope
Setbacks	Urban areas: 1 mile Coastline: 1 mile Highways and railways: 800 ft Transmission lines: 800 ft
Ordinances	Georgetown and Darlington Counties

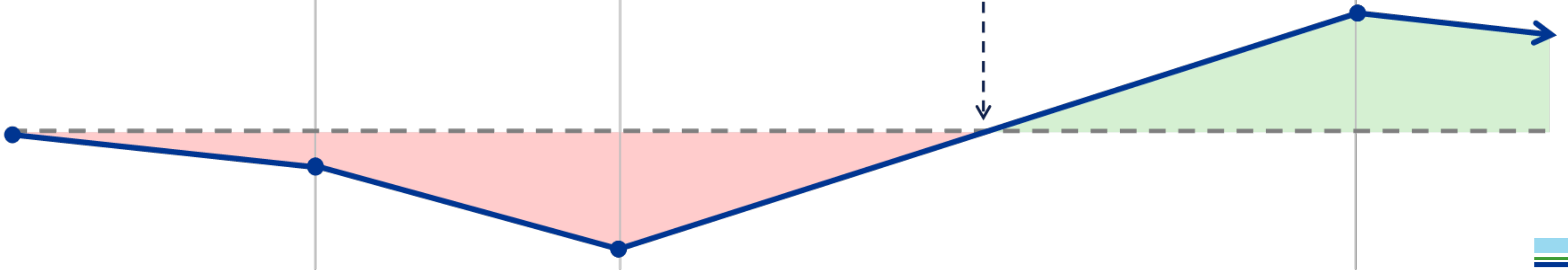
Wind Study | Results Overview

- 41 sites identified for potential development
- Average capacity per site: 190 MW
- Wind speeds from 5.4 to 6.2 m/s
- For each site, DNV estimated:
  - Land cover % (e.g. open, crops, pasture, forested)
  - Environmental sensitivities (distance to national parks, wildlife management areas, etc.)
  - FEMA hurricane risk index
  - Distances to military and airspace systems
- Results use a scoring system that can be modified by Santee Cooper

Wind Study | Development timeline

	Development	Construction	Operations		Decommissioning
Duration	~2 – 4+ Years	~1.5 – 2 Years	~25 - 35 years		~0.5 years
Milestones	**FNTP** Full Construct NTP **Financial Close** Construction loan Tax equity commitment	**COD** MC → Energization → **SC** →FC Term conversion Investor equity funding	**Flip Date** Investor reach target return Refinancing, Equity investment	**Decom** Decom and remediation or Repower	
Revenue / Costs	Pre-Revenue DevEx	Pre-Revenue Upfront CapEx	Contracted Revenue + PTCs OpEx + Loan Service	Contracted / Merchant Revenue OpEx	Post-Revenue CapEx
Source of Funding	Equity (“Balance Sheet”) / DevEx debt (Parent-level credit, Borrowing-base facility etc)	Construction loan drawdowns. Pre-con tax equity commitments at NTP and MC (sometimes).	Tax equity, term loan, back-leverage debt	Unlevered / Refinancing	Reserve / Bond
Risk / Return	High Risk / Low Investment Investors expect >15% return	Medium Risk / High Investment Investors expect 10-15% return	Low - Medium Risk / Medium Return Investors expect <10% return	Low Risk / High Return	Low Risk / Low Investment

Cumulative Cash Flows



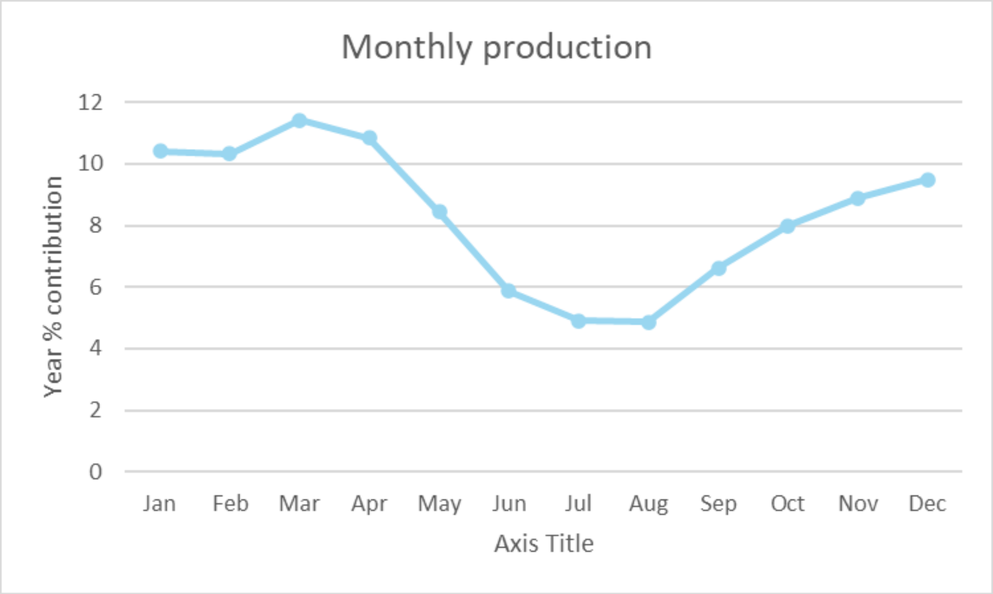
Wind Study | CapEx and OpEx

Cost category	2026	2034	2035
Base Case			
TSA	$ 1,244	$ 1,144	$ 1,132
BoP	$ 592	$ 545	$ 539
Others	$ 375	$ 345	$ 342
All-in CapEx	**$ 2,211**	**$ 2,035**	**$ 2,013**
High Case			
TSA	$ 1,384	$ 1,274	$ 1,260
BoP	$ 686	$ 631	$ 624
Others	$ 482	$ 443	$ 439
All-in CapEx	**$ 2,552**	**$ 2,348**	**$ 2,323**

Case		20-year total	Annual average
Base	Turbine O&M scheduled	$ 255,500	$ 12,775
	Turbine O&M unscheduled	$ 414,700	$ 20,735
	Balance of plant O&M	$ 105,400	$ 5,270
	Total O&M	**$ 776,200**	**$ 38,810**
High	Turbine O&M scheduled	$ 302,500	$ 15,125
	Turbine O&M unscheduled	$ 613,900	$ 30,695
	Balance of plant O&M	$ 125,200	$ 6,260
	Total O&M	**$ 1,041,700**	**$ 52,085**

- Results presented in U.S. 2025 $/kW
- TSA = Turbine supply agreement
- BoP = Balance of Plant

Wind Study | Production Estimates



- Two sites: 55 MW each
- Turbine "a": 12 units
- Turbine "b": 9 units
- Turbines perform differently per site

Site ID	Net energy (GWh/annum)	Net capacity factor
EFD1 – turbine "a"	137.9	29.1%
EFD1 – turbine "b"	112.3	23.3%
HRY2 – turbine "a"	146.9	31.0%
HRY2 – turbine "b"	121.2	25.2%

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- Santee Cooper Learnings
  - Determined onshore wind is technically feasible in South Carolina
  - Validated onshore wind resource modeling assumptions and development timelines assumed in our IRPs
  - Identified production profiles
  - Identified sites generally favorable for future wind resource research and development activities
- Next steps
  - Continue to evaluate onshore wind as a resource option in IRPs
  - When appropriate based on selection in IRPs and considering development timelines, evaluate selecting sites to collect actual wind speed data
  - Continue to monitor and evaluate wind technologies
  - Continue to include wind research and development as a topic in future stakeholder meetings

Lunch Break

Returning at 12:00

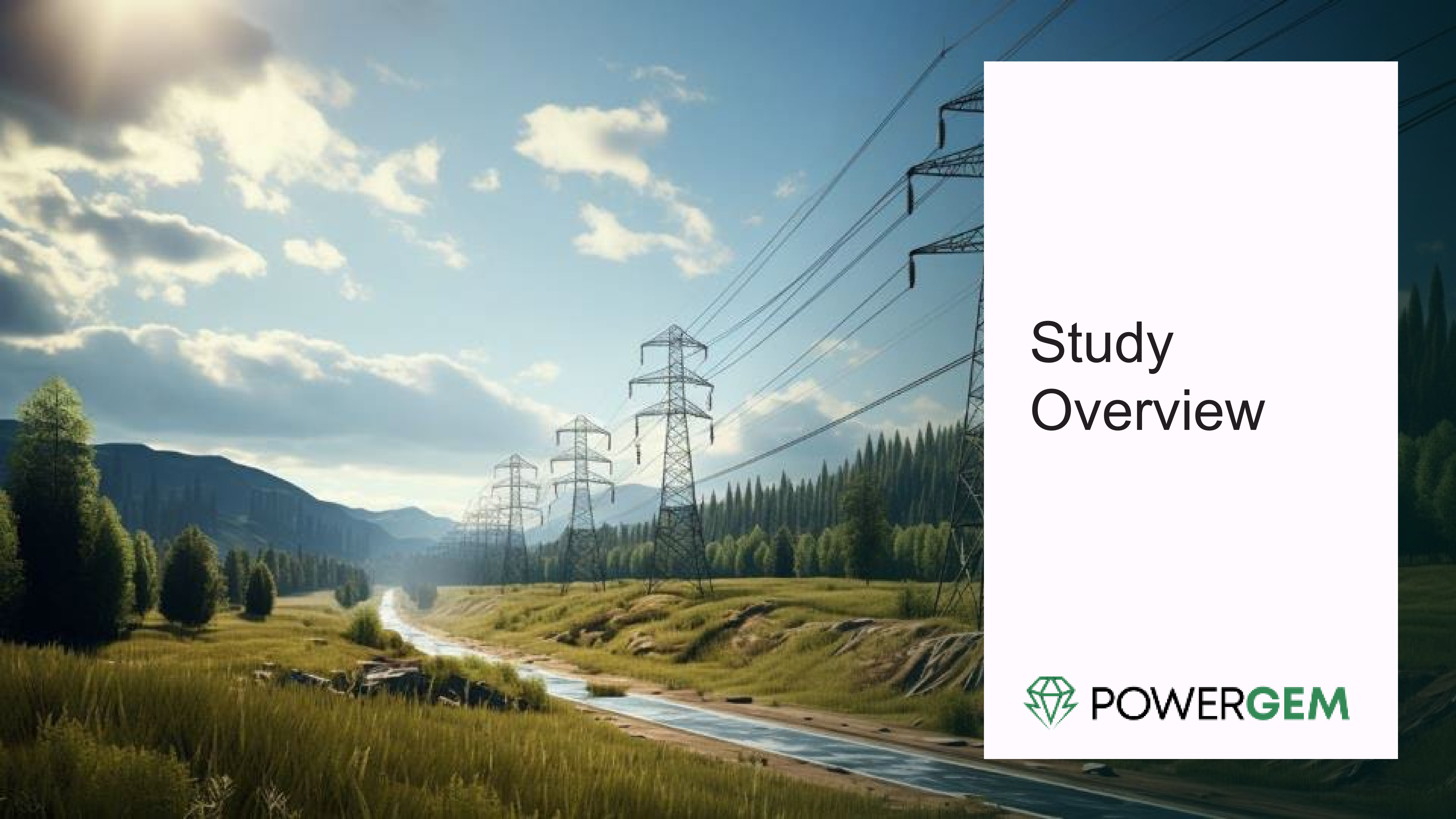
2026 Reserve Margin Study & ELCC Results

Joel Dison, Project Lead PowerGEM

Santee Cooper Reserve Margin Analysis

Project Results

POWERGEM

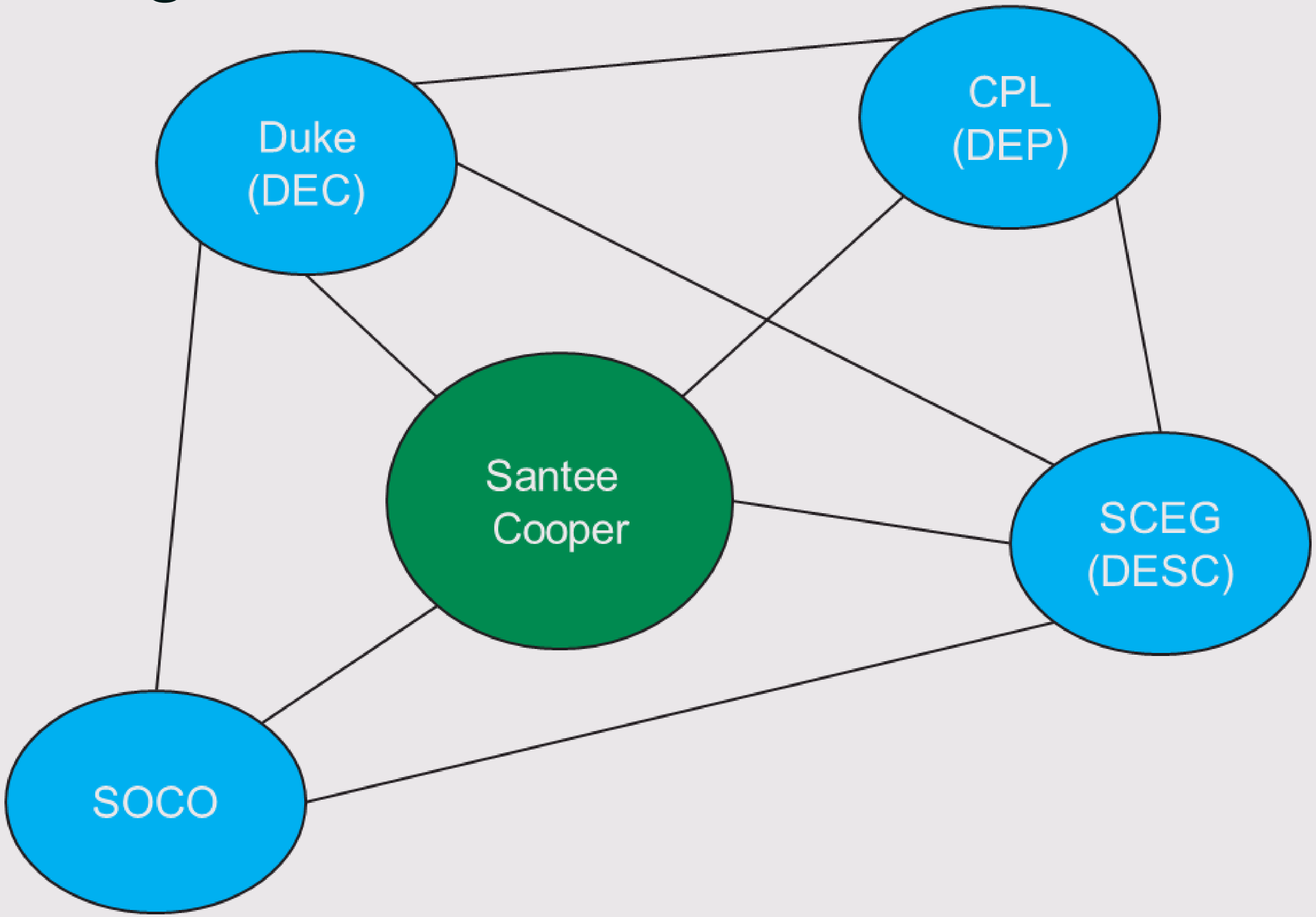


Study Overview

Study Parameters

- Study Year: 2030
- Historical Weather Years: 1980-2023
- Regions (Balancing Authority Areas) Modeled
  - Santee Cooper
  - Southern
  - Duke Energy Carolinas
  - Duke Energy Progress
  - Dominion Energy of SC
- Assumed resource generation mix from 2024 IRP Update by 2030
  - Existing Resources, 240 MW BESS, Central 672 MW NSR PPAs, 1,500 MW Solar additions
- Load Curtailment: Maintain Minimum Regulating Reserves of 100 MW

System Configuration



SERVM Framework

- **Capture Uncertainty in the Following Variables**
  - Weather (44 years of weather history: 1980-2023)
    - Impact on Load and Resources (hydro, PV, temp derates on thermal resources)
  - Economic Load Forecast Error (distribution of 5 points)
  - Unit Outage Modeling (1000s of iterations)
- **Multi-Area Modeling – Pipe and Bubble Representation**
- **Total Base Case Scenario Breakdown:**

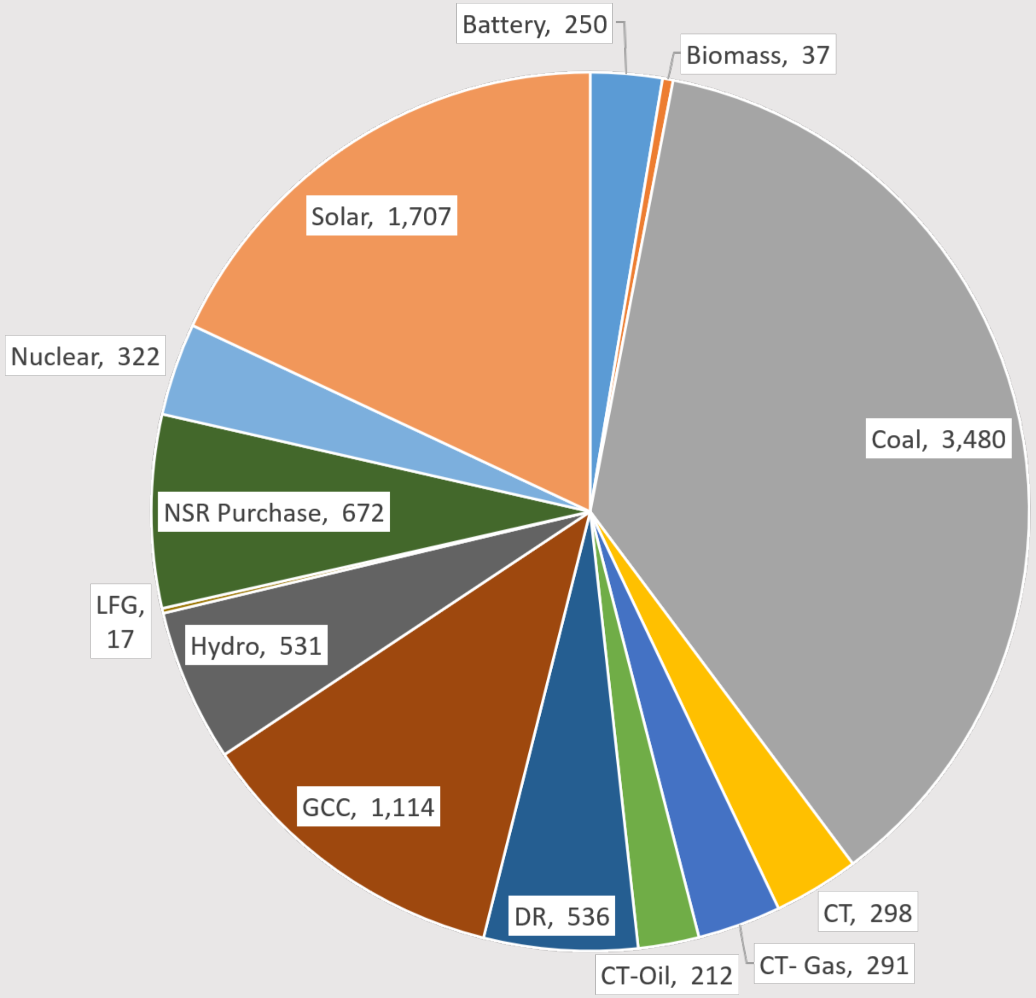
44 **Weather Years** (Equal Probability)	x	**5** **LFE Points** (Associated Probabilities)	=	**220** **Load Scenarios** (Associated Probabilities)
220 **Load Scenarios**	x	**100** **Unit Outage Draws**	=	**22,000** **8760 Hour Simulations**

Significant Changes Since Prior Reserve Margin Study

- Loads
  - Updated to include historical load data, 2021-2023 added to historical load data
  - Utilized the LF25-01 load forecast as base forecast
    - Includes an increase in non-firm load of ~142 MW
- GADS (Generation Availability Data System)
  - Updated generation outage assumptions to consider GADS data and Santee Cooper SME input
- Load Scaling
  - Load scaling to consider both Santee Cooper and Central load forecasting historical sample size of 25 years (Santee Cooper assumes 20 years historical and Central assumes 30 year historical)
- Data Centers
  - Potential data center load treated as separate load shape, does not increase under weather events as compared to the native load

Modeled Resource Mix (2030)*

Unit Type	Nameplate (MW)
Battery	250
Biomass	37
Coal	3,480
CT	298
CT- Gas	291
CT-Oil	212
DR	536
GCC	1,114
Hydro	531
LFG	17
NSR Purchase	672
Nuclear	322
Solar	1,707
Total	9,467



*Based on Winter Ratings (Hydro is nameplate)

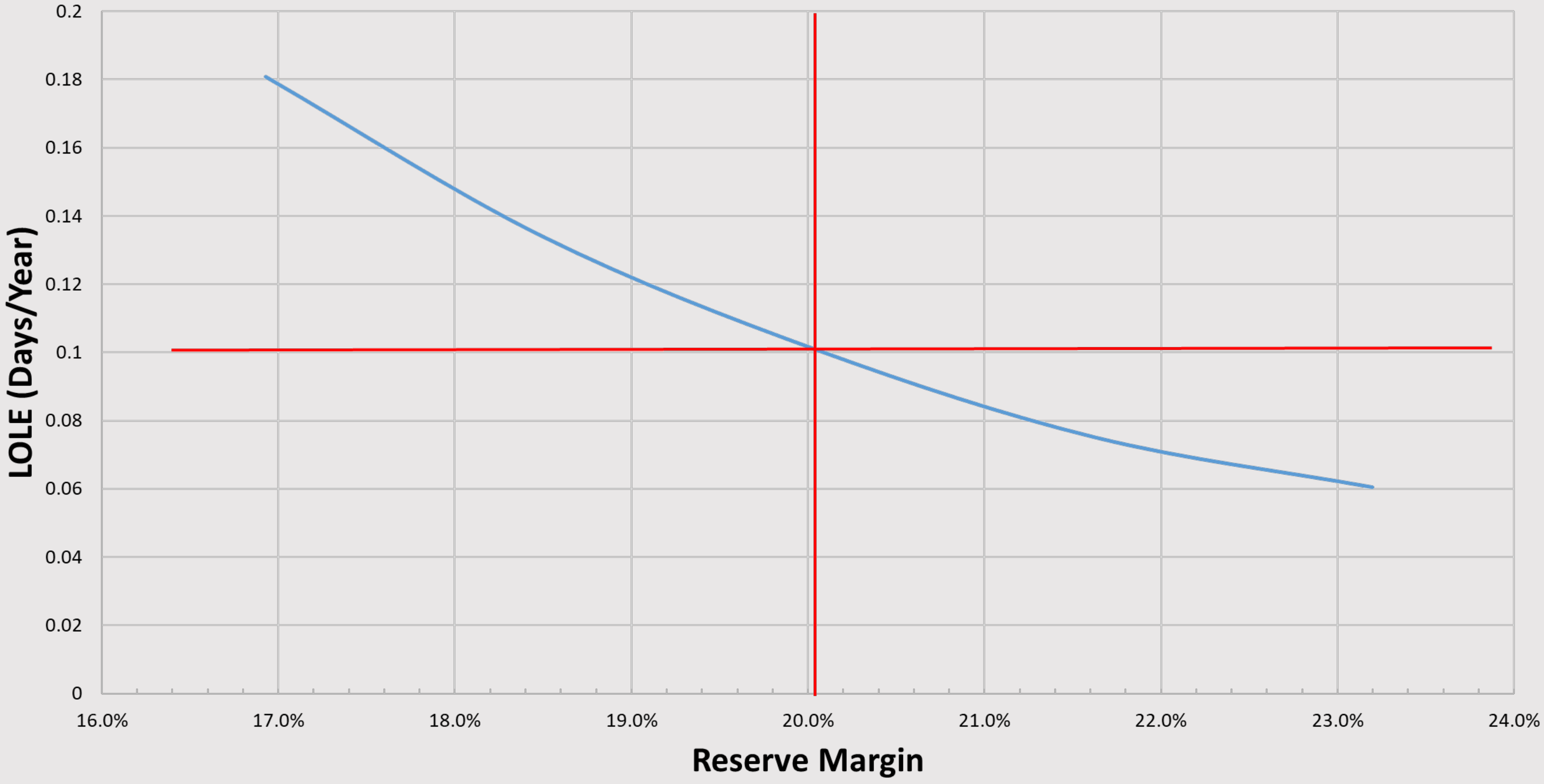
Study Results

Reserve Margin Summary

	Nameplate	ELCC	Reliable
ICAP Capacity*	7,469		7,469
ELCC Capacity	1,957	12.99%	254
MW Adjustment			(62)
Total Capacity	9,728		7,662
Load (BAU+EV+LgLd)			6,382
Reserves			1,280
PRM			20.1%

*ICAP capacity is winter ratings for thermal and DR. Hydro is accredited at its average winter available capacity

Winter Reserve Margin vs. LOLE



Loss of Load Expectation (LOLE)

Summer Reserve Margin vs. LOLE

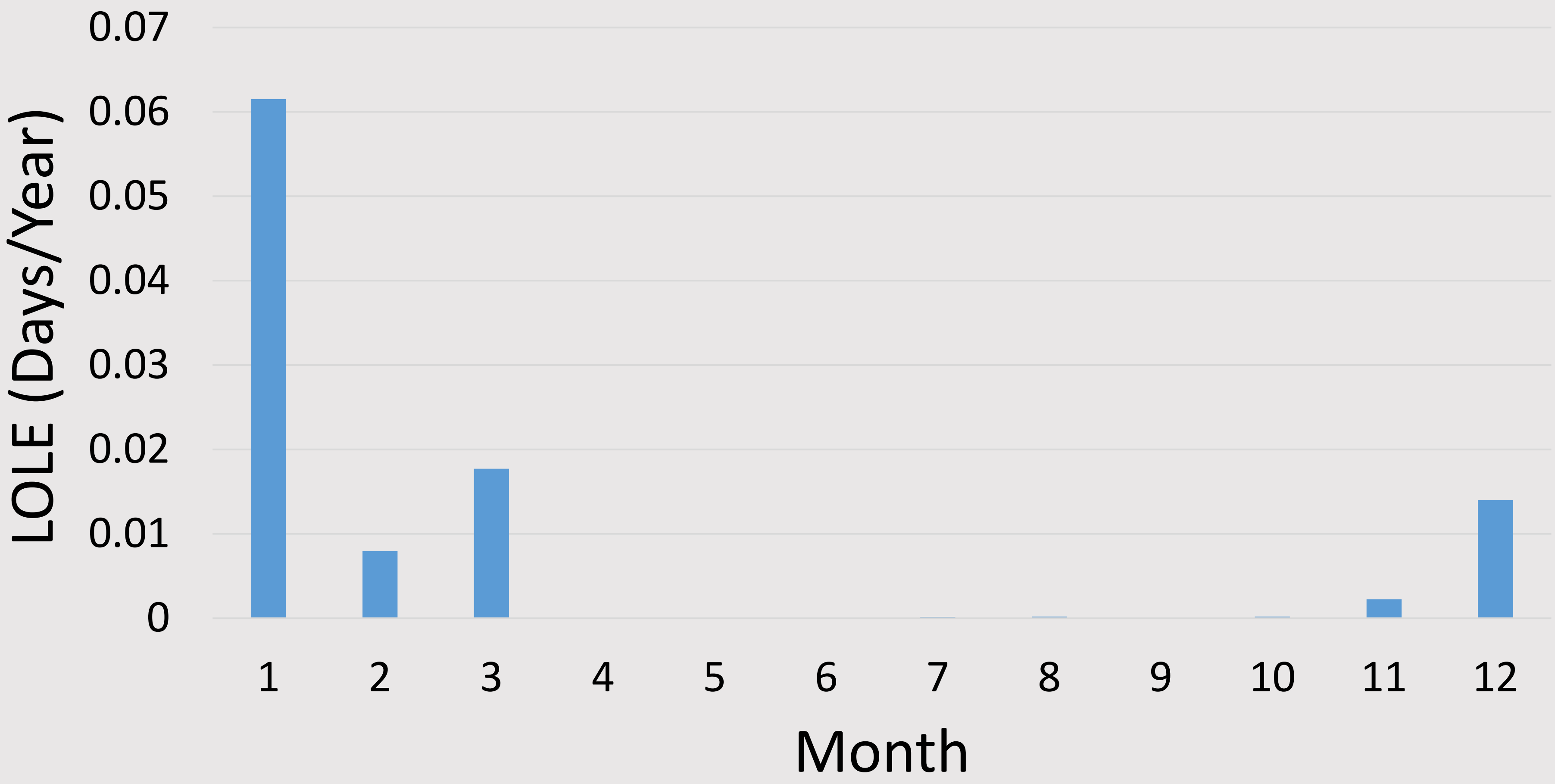
Loss of Load Risk Profile

Chart shows the greatest risk of where EUE would occur in the event of a loss of load event.
It does not show the probability of such an event happening.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	1.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	2.3%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	4.3%	0.1%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	6.6%	0.1%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	10.4%	0.3%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
6	12.8%	0.7%	2.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.9%
7	17.2%	1.5%	4.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	2.1%
8	19.8%	0.9%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%
9	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
18	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
19	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
20	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
21	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
22	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
23	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
24	0.6%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

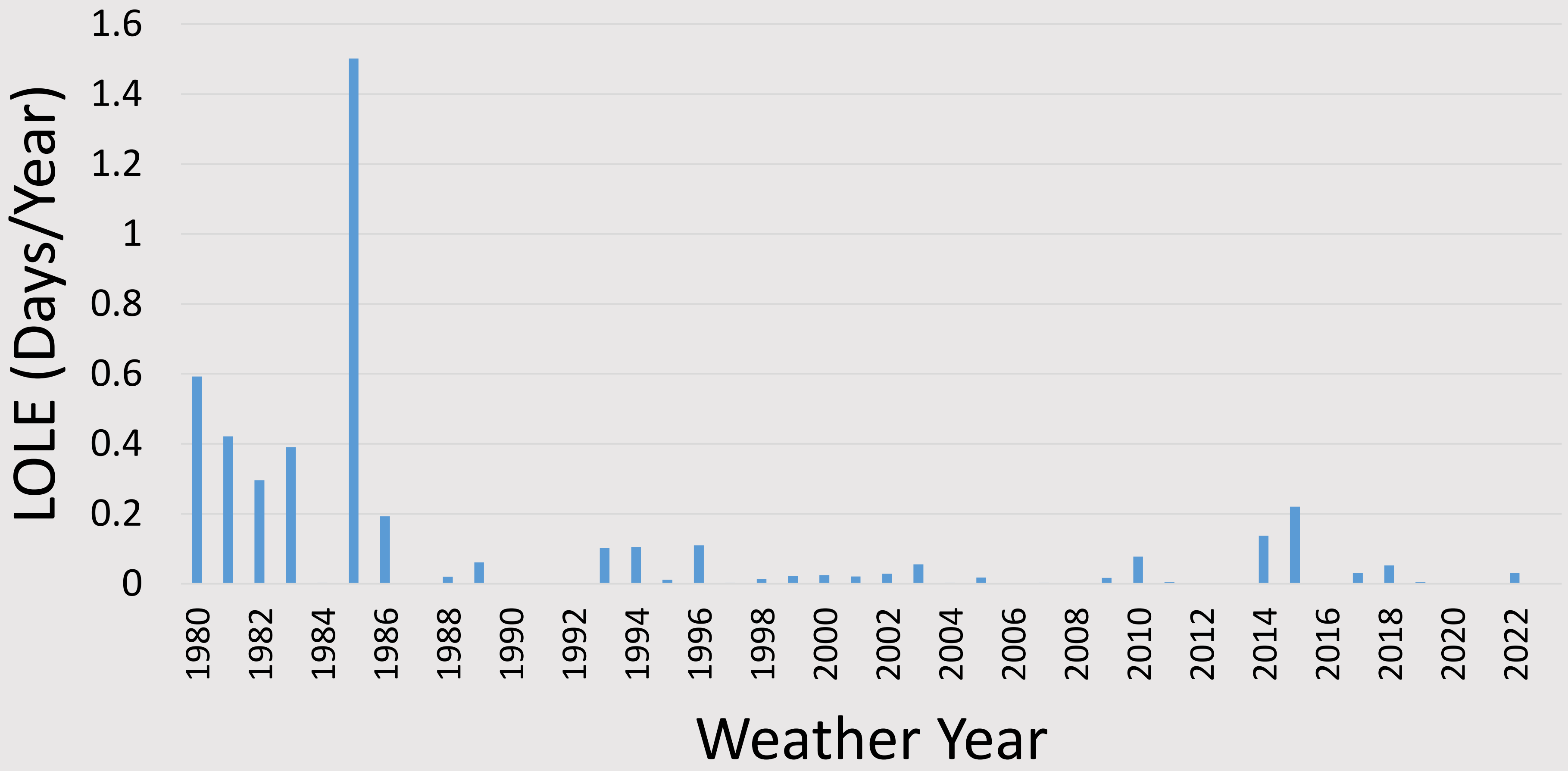
LOLE by Month

Chart shows the breakdown of the 0.1 Days/Year Annual LOLE across months



LOLE by Weather Year

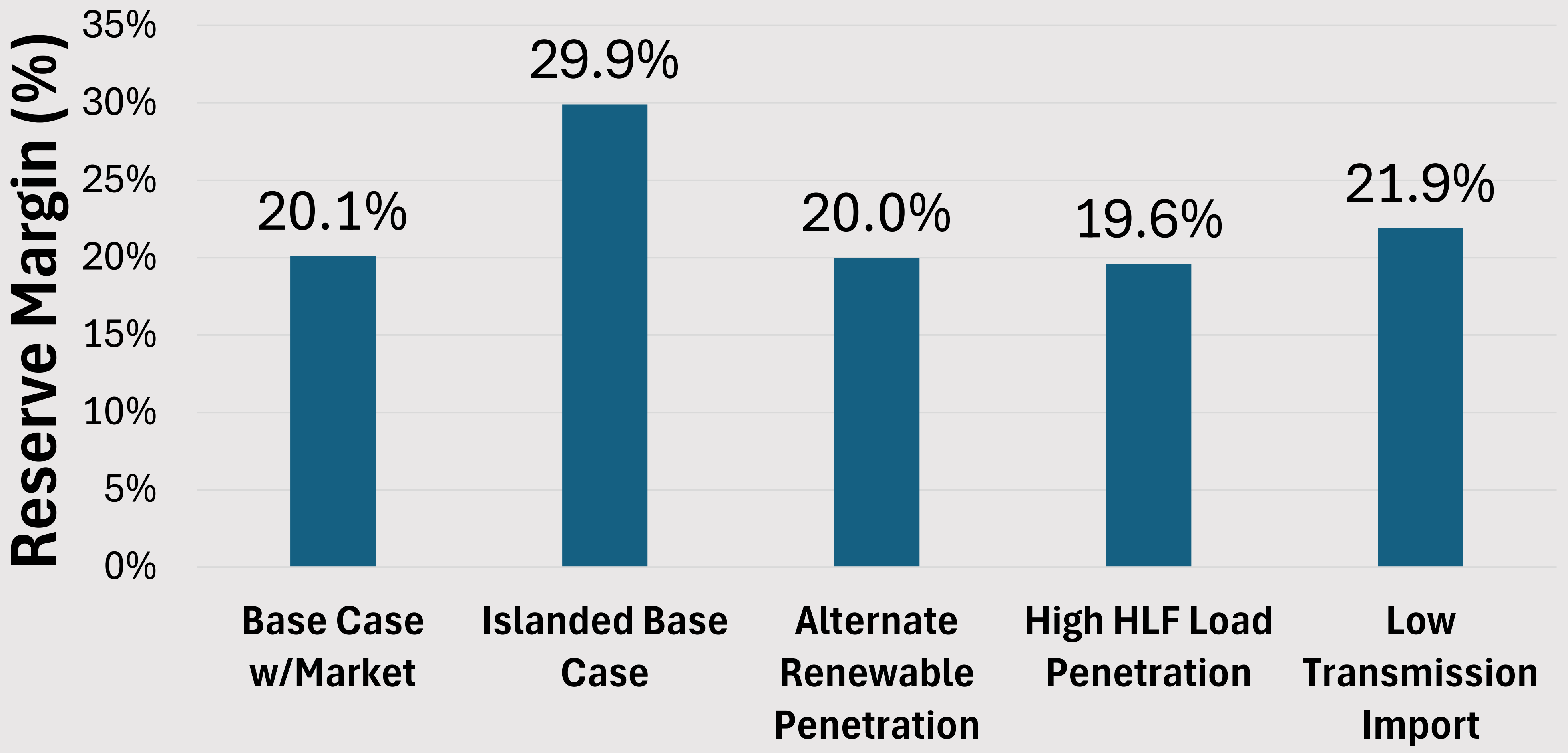
Chart shows the likelihood (in Days/Year) that a loss of load event would happen if the weather from the associated year were to be repeated.



Sensitivities

- Islanded System
- Alternate Renewable Penetration
  - Tests robustness associated with uncertainty of future renewable buildout
  - Solar: 750 MW (~50% reduction)
  - Battery: 300 MW
- High HLF Load Penetration
  - Tests robustness associated with uncertainty of future datacenter loads
  - Double SC HLF Penetration: 352 MW
- Low Transmission Import (Low XM)
  - Tests robustness associated with uncertainty of transmission import capability
  - Santee Cooper import capability reduced by 50%

Sensitivities



ELCC Results

Scope of ELCC Analysis

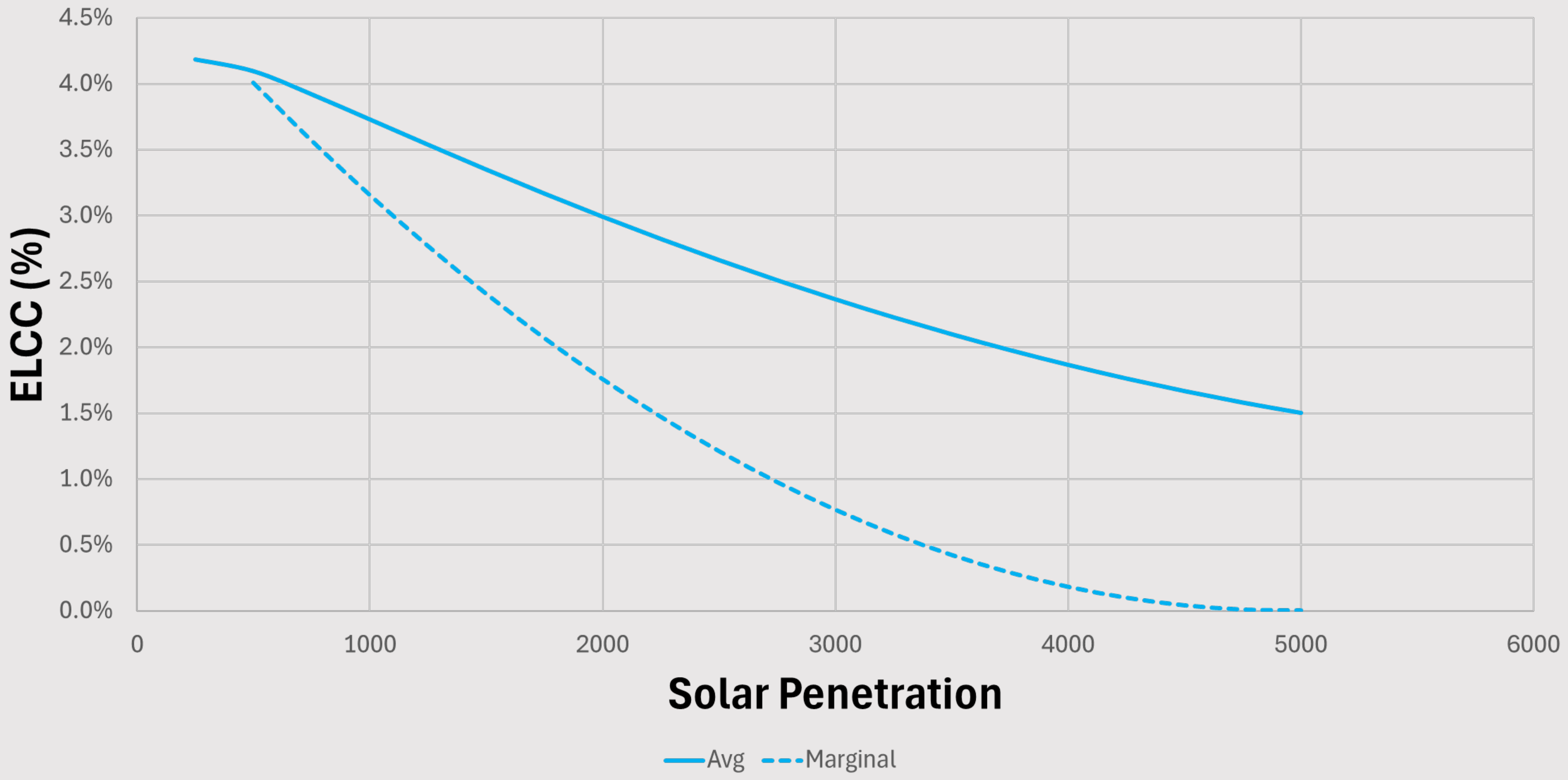
- Solar-BESS Combinations
  - Solar up to 5,000 MW
  - BESS up to 2,250 MW
- Solar-On Shore Wind
  - Solar up to 5,000 MW
  - Wind up to 2,500 MW
- Solar-Off Shore Wind
  - Solar up to 5,000 MW
  - Wind up to 2,500 MW

ELCC Methodology

- Using SERVM, calculate discreet ELCCs for a subset of single and multi-tech combinations of renewable penetrations
  - *E.g., combinations of solar and battery at various penetrations up to the maximum scoped values*
- Use proprietary techniques to create a portfolio ELCC surface for all possible combinations within the scope of penetrations evaluated
- Use integration techniques to determine the technology specific average and marginal ELCCs at any point on the surface.

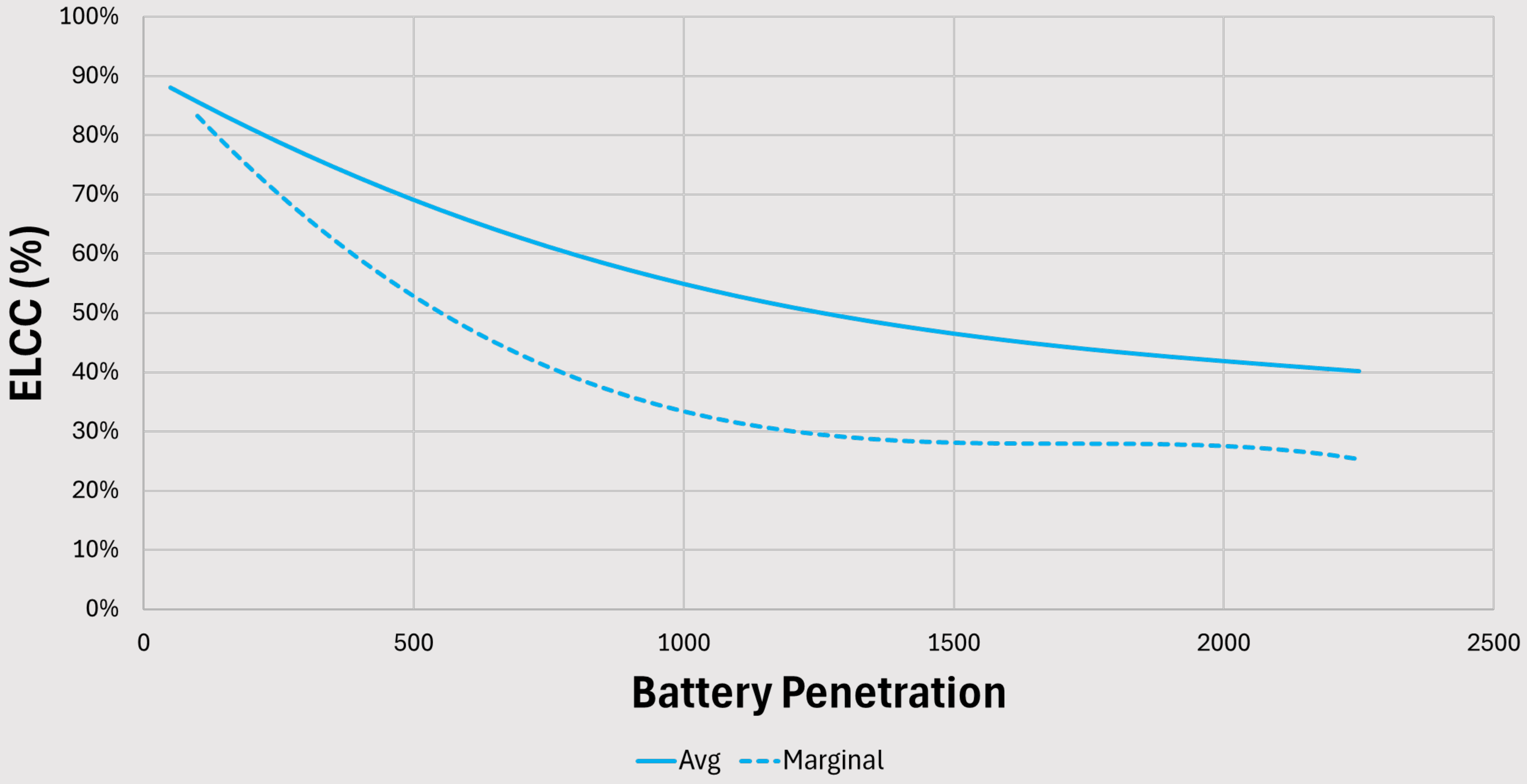
Single Tech Solar ELCC

Chart shows the average and marginal ELCC of solar with no battery or wind on the system.



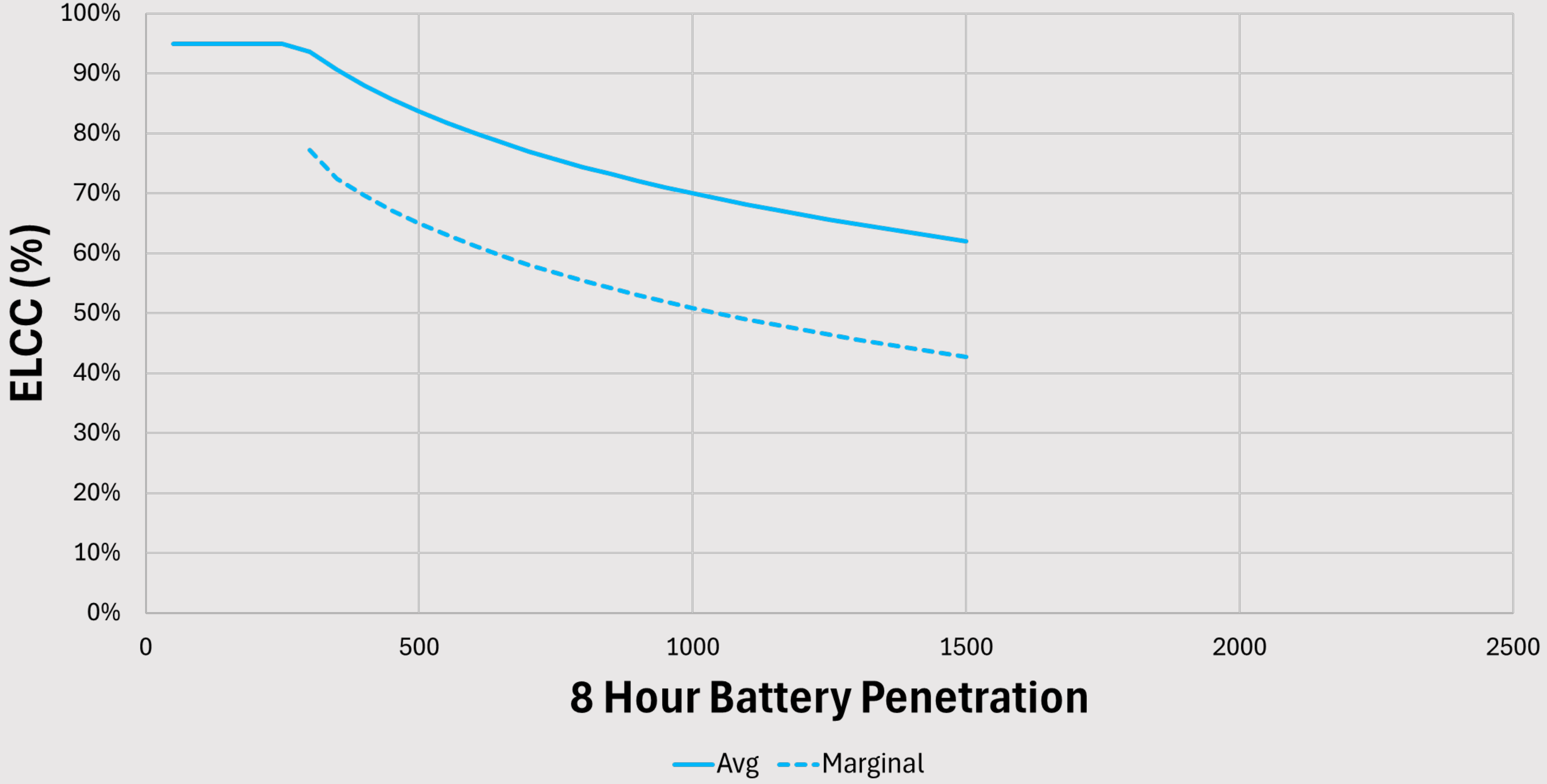
Single Tech BESS ELCC

Chart shows the average and marginal ELCC of battery with no solar or wind on the system.



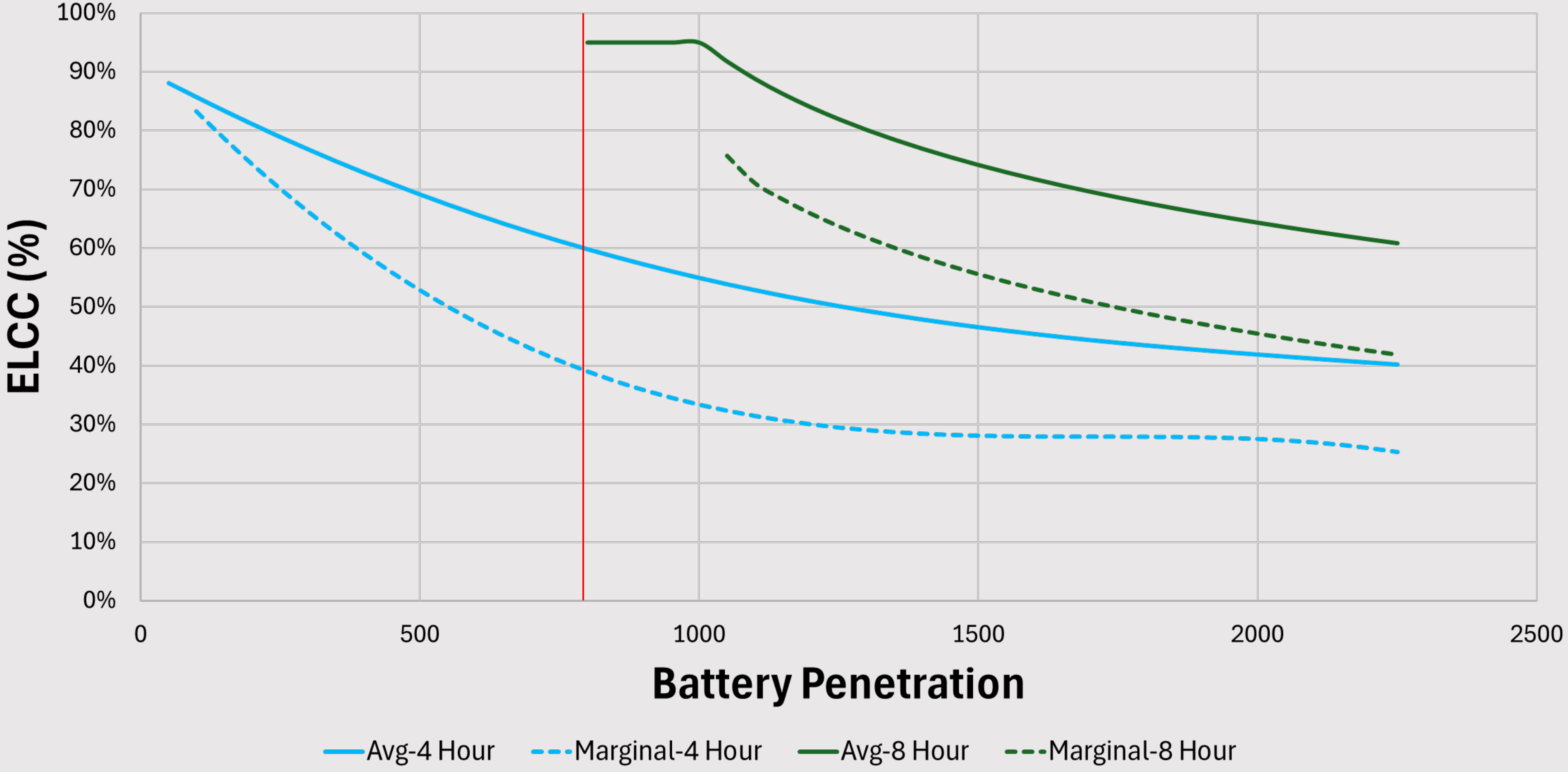
Single Tech BESS ELCC-8 hour

Chart shows the average and marginal ELCC of 8hr battery with an underlying 1700MW of solar and 750MW of 4-hour battery.



Single Tech BESS ELCC-Combined 4hr and 8hr

Chart shows the average and marginal ELCC of 8-hour battery relative to 4-hour battery as a function of total storage on the system.



Solar ELCC as a function of Battery Penetration

Average

		Solar					
		250	**500**	**750**	**1000**	**1500**	**2000**
	0	4.3%	4.2%	4.0%	3.8%	3.4%	3.1%
Battery	**250**	4.5%	4.3%	4.1%	3.9%	3.5%	3.2%
	500	4.6%	4.5%	4.3%	4.1%	3.6%	3.3%
	750	4.7%	4.6%	4.4%	4.2%	3.8%	3.4%
	1000	4.8%	4.7%	4.5%	4.3%	3.9%	3.5%
	1500	5.0%	4.9%	4.6%	4.5%	4.1%	3.8%
	2000	5.2%	5.1%	4.9%	4.8%	4.4%	4.0%

Marginal

		Solar					
		250	**500**	**750**	**1000**	**1500**	**2000**
	0	4.3%	4.1%	3.6%	3.2%	2.5%	1.8%
Battery	**250**	4.7%	4.3%	3.9%	3.4%	2.7%	2.0%
	500	4.9%	4.6%	4.1%	3.7%	2.9%	2.2%
	750	5.1%	4.8%	4.3%	3.9%	3.1%	2.5%
	1000	5.2%	5.0%	4.6%	4.1%	3.4%	2.7%
	1500	5.5%	5.4%	4.8%	4.6%	3.8%	3.1%
	2000	5.7%	5.7%	5.0%	5.0%	4.2%	3.5%

4 hr. Battery ELCC as a function of Solar Penetration

Average

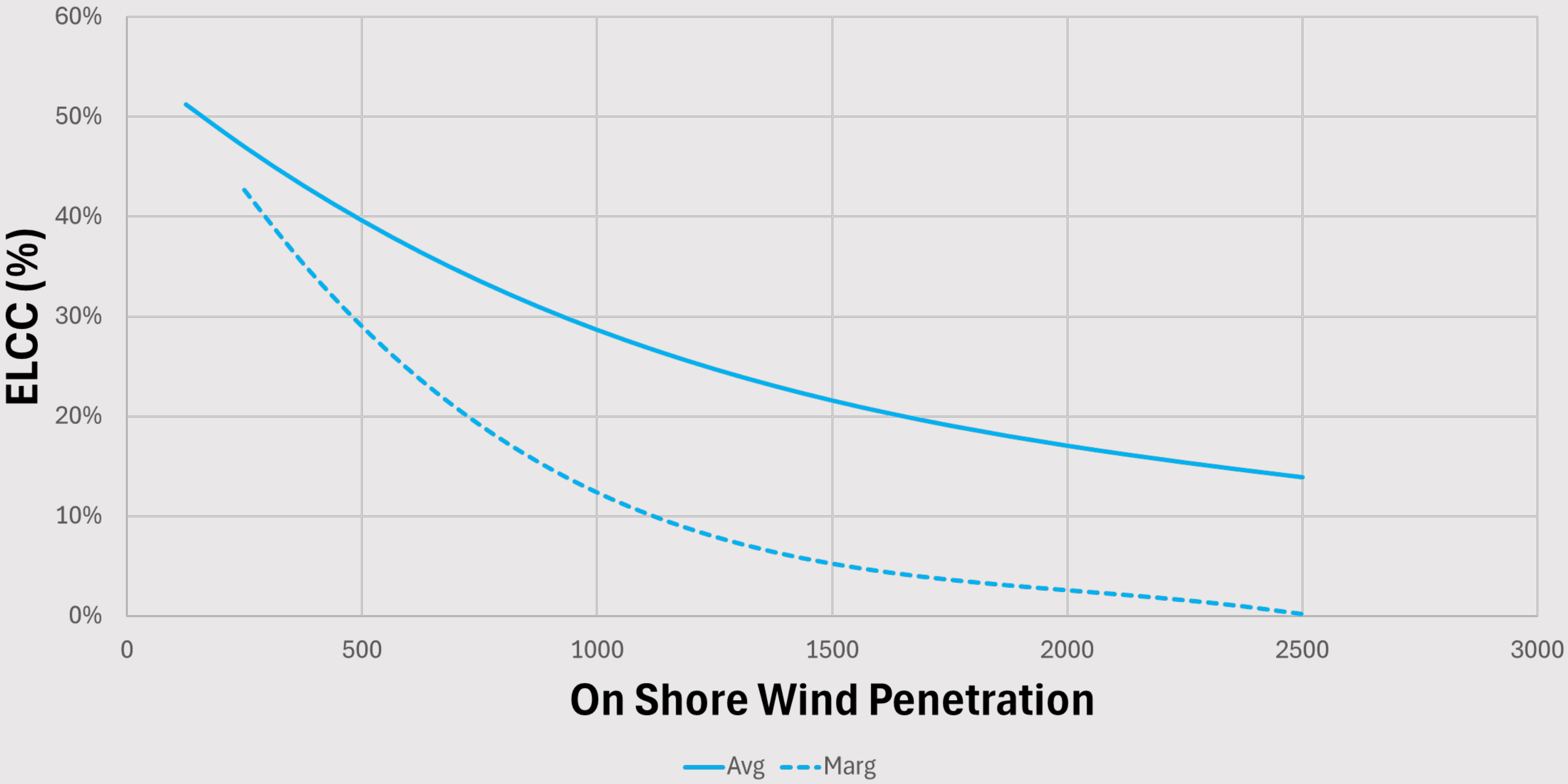
		Solar						
		0	250	500	750	1000	1500	2000
Battery	250	78.9%	79.0%	79.2%	79.3%	79.5%	79.7%	79.9%
	500	69.1%	69.2%	69.4%	69.5%	69.6%	69.9%	70.1%
	750	61.2%	61.3%	61.4%	61.5%	61.6%	61.9%	62.1%
	1000	54.9%	55.0%	55.1%	55.2%	55.3%	55.6%	55.8%
	1500	46.5%	46.6%	46.7%	46.8%	46.9%	47.1%	47.3%
	2000	41.8%	41.9%	42.0%	42.1%	42.2%	42.4%	42.6%

Marginal

		Solar						
		0	250	500	750	1000	1500	2000
Battery	250	70.1%	70.4%	70.7%	70.9%	71.1%	71.6%	72.0%
	500	52.9%	53.1%	53.3%	53.5%	53.8%	54.2%	54.7%
	750	40.9%	41.1%	41.3%	41.5%	41.7%	42.2%	42.7%
	1000	33.4%	33.6%	33.7%	34.0%	34.2%	34.7%	35.1%
	1500	28.1%	28.3%	28.4%	28.6%	28.8%	29.2%	29.7%
	2000	27.6%	27.7%	27.9%	28.1%	28.3%	28.6%	28.9%

Single Tech On-Shore Wind ELCC

Chart shows the average and marginal ELCC of On-Shore Wind with no solar or battery on the system.



Solar ELCC as a function of On-Shore Wind Penetration

Average

		Solar					
		250	500	750	1000	1500	2000
	0	4.3%	4.2%	4.0%	3.8%	3.4%	3.1%
On-Shore Wind	250	4.6%	4.5%	4.3%	4.0%	3.6%	3.3%
	500	4.9%	4.7%	4.5%	4.3%	3.8%	3.5%
	750	5.1%	4.9%	4.7%	4.5%	4.1%	3.7%
	1000	5.2%	5.1%	4.9%	4.7%	4.3%	3.4%
	1500	5.5%	5.4%	5.2%	5.0%	4.7%	4.4%
	2000	5.7%	5.6%	5.5%	5.3%	5.0%	4.8%

Marginal

		Solar					
		250	500	750	1000	1500	2000
	0	4.3%	4.1%	3.6%	3.2%	2.5%	1.8%
On-Shore Wind	250	4.9%	4.6%	4.0%	3.6%	2.8%	2.2%
	500	5.3%	5.0%	4.5%	4.0%	3.3%	2.7%
	750	5.6%	5.3%	4.8%	4.4%	3.7%	3.2%
	1000	5.8%	5.6%	5.2%	4.8%	4.2%	3.7%
	1500	6.1%	6.0%	5.7%	5.4%	4.9%	4.6%
	2000	6.4%	6.4%	6.1%	5.8%	5.3%	5.1%

On-Shore Wind ELCC as a function of Solar Penetration

Average

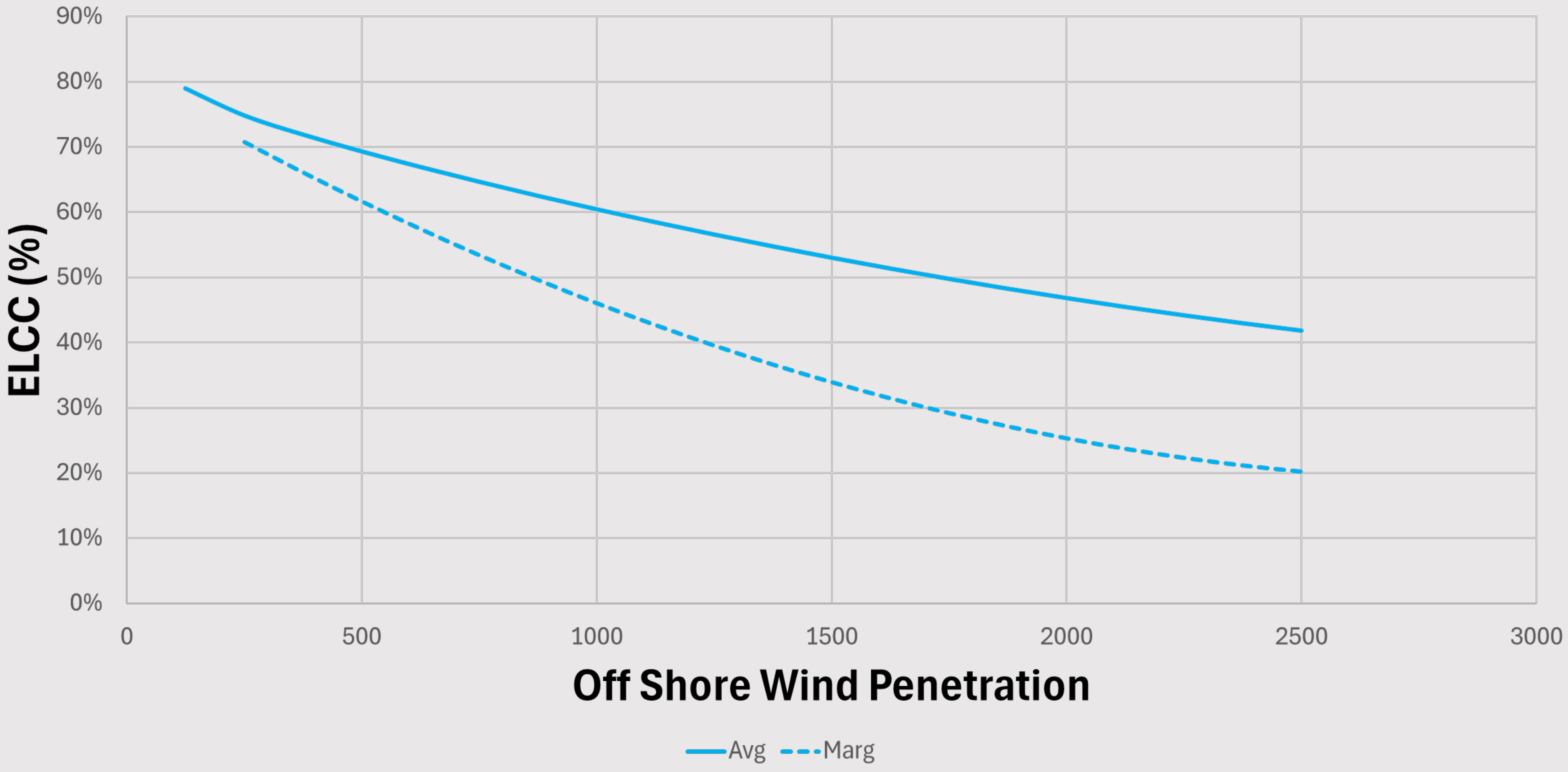
		Solar						
		0	250	500	750	1000	1500	2000
On-Shore Wind	250	46.8%	47.0%	47.3%	47.5%	47.8%	48.2%	48.6%
	500	39.5%	39.7%	40.0%	40.2%	40.4%	40.8%	41.3%
	750	33.5%	33.7%	33.9%	34.1%	34.3%	34.7%	35.2%
	1000	28.6%	28.8%	28.9%	29.1%	29.3%	29.7%	30.1%
	1500	21.5%	21.6%	21.8%	21.9%	22.1%	22.4%	22.8%
	2000	17.0%	17.1%	17.2%	17.3%	17.5%	17.7%	18.0%

Marginal

		Solar						
		0	250	500	750	1000	1500	2000
On-Shore Wind	250	39.0%	39.5%	39.9%	40.3%	40.7%	41.5%	42.4%
	500	26.5%	26.9%	27.3%	27.6%	28.0%	28.9%	29.9%
	750	17.8%	17.7%	18.1%	18.4%	18.8%	19.6%	20.6%
	1000	11.3%	11.4%	11.7%	12.0%	12.4%	13.1%	14.1%
	1500	4.9%	5.0%	5.2%	5.4%	5.6%	6.2%	6.8%
	2000	2.6%	2.7%	2.9%	3.1%	3.2%	3.5%	3.8%

Single Tech Off-Shore Wind ELCC

Chart shows the average and marginal ELCC of Off-Shore Wind with no solar or battery on the system.



Solar ELCC as a function of Off-Shore Wind Penetration

Average

		Solar					
		250	500	750	1000	1500	2000
	0	4.3%	4.2%	4.0%	3.8%	3.4%	3.1%
Off-Shore Wind	250	4.3%	4.2%	4.0%	3.8%	3.4%	3.1%
	500	4.4%	4.3%	4.1%	3.9%	3.4%	3.0%
	750	4.4%	4.3%	4.1%	3.9%	3.5%	3.1%
	1000	4.4%	4.3%	4.1%	3.9%	3.5%	3.1%
	1500	4.4%	4.3%	4.1%	3.9%	3.5%	3.1%
	2000	4.4%	4.3%	4.1%	3.9%	3.5%	3.1%

Marginal

		Solar					
		250	500	750	1000	1500	2000
	0	4.3%	4.1%	3.6%	3.2%	2.5%	1.8%
Off-Shore Wind	250	4.3%	4.2%	3.7%	3.3%	2.4%	1.8%
	500	4.4%	4.2%	3.8%	3.3%	2.4%	1.7%
	750	4.4%	4.3%	3.8%	3.3%	2.4%	1.7%
	1000	4.4%	4.3%	3.8%	3.3%	2.4%	1.7%
	1500	4.4%	4.2%	3.7%	3.3%	2.4%	1.7%
	2000	4.4%	4.2%	3.7%	3.3%	2.4%	1.8%

Off-Shore Wind ELCC as a function of Solar Penetration

Average

		Solar						
		0	250	500	750	1000	1500	2000
Off-Shore Wind	250	74.2%	74.2%	74.2%	74.3%	74.3%	74.4%	74.4%
	500	69.2%	69.2%	69.2%	69.3%	69.3%	69.3%	69.3%
	750	64.6%	64.6%	64.6%	64.6%	64.7%	64.7%	64.7%
	1000	60.4%	60.4%	60.4%	60.4%	60.4%	60.4%	60.5%
	1500	53.0%	53.0%	53.0%	53.0%	53.0%	53.0%	53.0%
	2000	46.8%	46.8%	46.8%	46.8%	46.8%	46.8%	46.8%

Marginal

		Solar						
		0	250	500	750	1000	1500	2000
Off-Shore Wind	250	69.1%	69.2%	69.2%	69.3%	69.3%	69.3%	69.2%
	500	59.8%	59.8%	59.9%	59.9%	59.9%	59.9%	59.9%
	750	51.6%	51.6%	51.6%	51.6%	51.6%	51.7%	51.7%
	1000	44.5%	44.5%	44.5%	44.4%	44.4%	44.5%	44.5%
	1500	33.0%	33.0%	32.9%	32.9%	32.9%	32.9%	32.9%
	2000	24.8%	24.8%	24.8%	24.8%	24.8%	24.8%	24.8%

2026 Integration Study Update

Integration Study Fundamentals

- Objective of a flexibility analysis
  - Determine the amount of operating reserves needed to integrate intermittent resources/loads
  - Impact measured by the system’s ability to meet NERC CPS1 requirements
- NERC CPS1
  - A metric under BAAL-01
  - Measures the ability of a system to maintain frequency within a bandwidth over a period of time
  - Deviations from Area Control Error (ACE), combined with the system’s frequency bias ratio (β), determine momentary deviations in system frequency that are accumulated over time.

Traditional Approach to Evaluation

- "Flex violations" can be determined as a 5-minute inability to meet load due to ramping or other flexibility limitation – measured in SERVM as Flex Violations in days/year
- Determine a targeted number of "flex violations" in a reference case
  - Traditionally, a future study year with no solar and (usually) no batteries
- Add tranches of solar – Flex Violations increases
- Add load following until Flex Violations returns to the reference case target
  - Can be done as a single number or hourly to attempt optimization
  - Results presented in realized operating reserves instead of targeted operating reserves

Modeling World vs. Real Time Operations

1. Modeling world cannot replicate real time CPS1 results
   a. SERVM can determine the inability of system to ramp to its targeted 5-minute load given intra-hour load and resource uncertainties, but that is not a perfect match to historical ACE
   b. SERVM simulation has perfect 5-minute knowledge vs. the instantaneous chasing of real time load
   c. Expectation will always be that the modeling world results in less violations
2. Modeling world cannot model interconnection frequency
   a. A key component of CPS1

Goal:
Find a metric that suits the modeling world *and* accomplishes the same objectives as CPS1

CPS1 Compliance Factor

- The CPS1 compliance factor is a portion of the overall CPS1 metric that is accumulated over time to determine the negative impact that a BAA's operations may have on system frequency
- Given:
  - "α" is the clock-minute average MW deviation from ACE
  - "β" is the system's frequency bias ratio constant
  - Δf is the clock-minute average frequency deviation
- The CPS1 compliance factor (CF) from BAAL-01 is determined by the formula

$$CF = ((\alpha/-10\beta) * \Delta f)$$

Concepts for a SERVM CPS1 Stress Index

- A five-minute shortfall in SERVM is equivalent to a normalized ACE deviation, α
- SERVM cannot simulate Δf
- However, assuming a linear frequency response relationship, α is proportional to Δf
- Therefore, we can develop a CPS1 Stress Contribution that is correlated and proportional to the CPS1 Compliance Factor

$$\text{CPS1 Stress Contribution} = (\alpha^2/10\beta)$$

- The Stress Index would be the accumulation of the CPS1 Contribution across the simulation/study
- CPS1 doesn't just look at ACE deviations or frequency deviations, it combines the two concepts such that larger deviations are penalized more
  - Δf answers the question "how much did frequency move"
  - α answers the question "how big is the imbalance"
  - $\alpha/(-10^* \beta)^*\Delta f$ answers the question "how much frequency harm is associated with that imbalance"
  - $\alpha^2/(10^* \beta)$ provides the same information proportionally and preserves the key concepts intended by CPS1

Calculating a CPS1 Stress Index from SERVM

Given system frequency bias (β)

1. Determine the 5-minute average shortfall in MW (via the SERVM model)
   - This represents a 1-minute ACE deviation (α)
2. Calculate the CPS1 Stress Contribution (ρ) as: $\rho \approx \alpha^2/(10*\beta)$
3. Multiply ρ by 5 to get a 5-minute CPS1 Stress Contribution for that interval
4. The CPS1 Stress Index for that 8760 simulation = The sum of each 5-minute interval stress contribution values in the simulation
5. The study-wide CPS1 Stress Index = the weighted average across all simulations

Santee Cooper Integration Study

- Determine integration requirements based on three simultaneous metrics
  1. Traditional Flex Violations (Days/Year)
  2. Total Flex Violations
  3. CPS1 Stress index
- Benchmark Study: 2030 study year: No Solar and No BESS
  - Metrics from benchmark would define the target
  - Anything below those targets would represent "existing headroom on the system"
  - Anything above those targets would require additional operating reserves
- Operating Reserves for this case study
  1. No-Solar/No BESS Benchmark to be calibrated to 2021 levels*
  2. Incremental "target" operating reserves to be added to all hours.
  3. Results to be reported as incremental "realized" operating reserves.

*represents the available historical year closest to the no solar condition

Break

Returning at 1:40

Market Potential Study Results

Steven Roys, Manager Program Development

Market Potential Study Process

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- Completed 2 separate Market Potential Studies (MPS)
  - Energy Efficiency MPS
  - Demand Response MPS

- In coordination with SC Code 58-37-40-(B)(1)(e) Santee Cooper developed a low, medium, and high case scenario for each potential study.

DSM Market Potential Studies

EPA – National Guide for Resource Planning

Stakeholder Process

- 3 technical working sessions
- Documents provided:
  - Study plan and measure list
  - Forecast disaggregation and measure parameters
  - Technical potential
  - Economic potential
  - Achievable potential

EE Achievable Potential Scenarios

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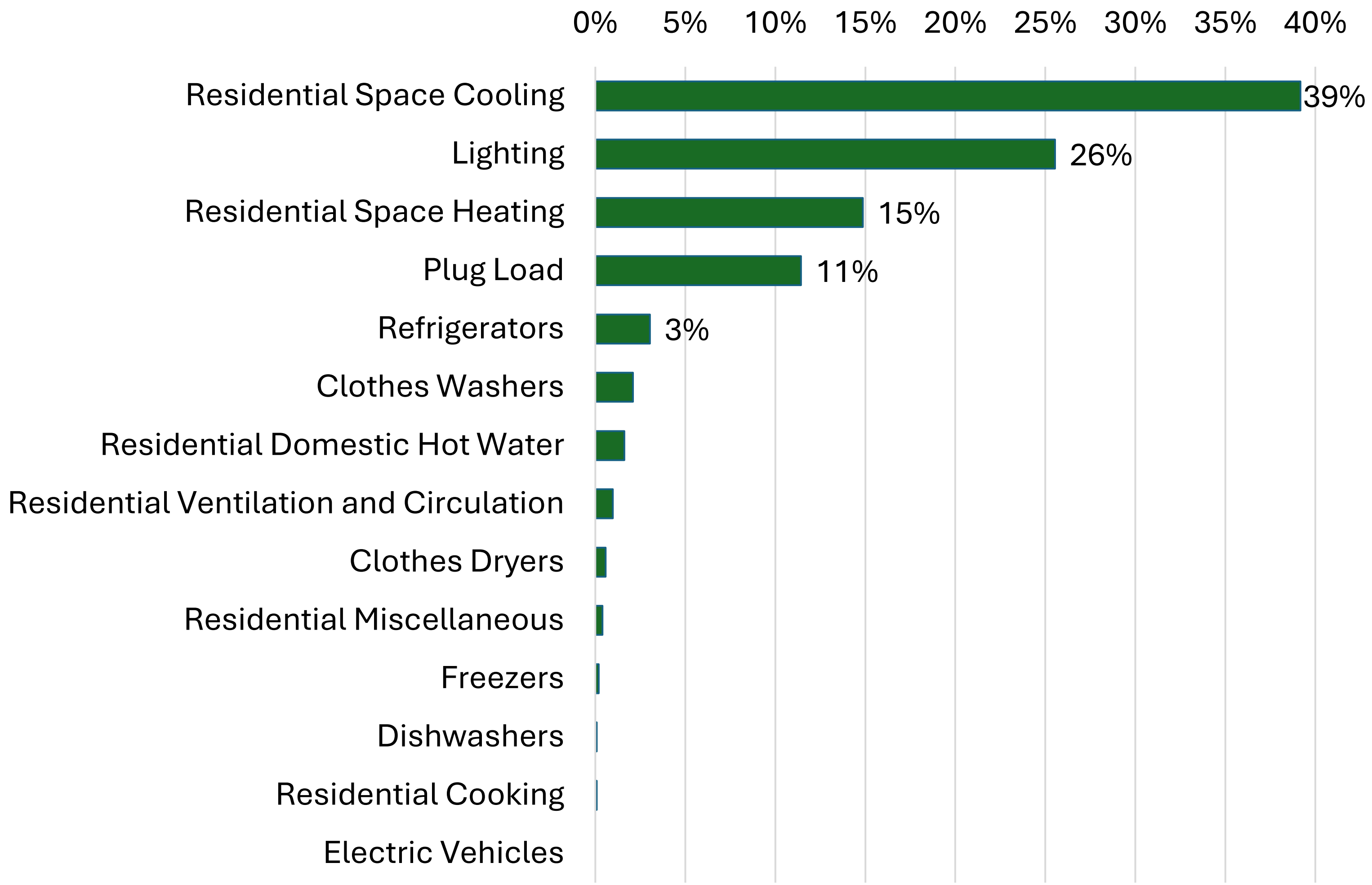
Summary of 20-Year Cumulative AP Results by Scenario *(w. Roll-Off)*

	Residential	Commercial	New Technology EVs	System
2026 Base Load (MWh)	2,171,150	1,962,867	32,174	4,166,191
Low Scenario AP (MWh), *% of first-year base load*	69,793 *3%*	135,595 *7%*	0.38 *0%*	205,389 *5%*
Med Scenario AP (MWh), *% of first-year base load*	90,237 *4%*	172,182 *9%*	36 *0.1%*	262,456 *7%*
High Scenario AP (MWh), *% of first-year base load*	177,701 *8%*	258,997 *13%*	36 *0.1%*	436,734 *10%*

- Low/Base Scenario: Incentives of 30% of the incremental costs, measures are screened at UCT ≥ 1.0;
- Medium Scenario: Incentives are increased up to 50% of the incremental costs*, UCT threshold is reduced to 0.7 as proxy for program-level screening;
- High Scenario: Incentives are increased up to 75% of the incremental costs*, UCT threshold is reduced to 0.7, Avoided marginal energy costs are increased by 50%.

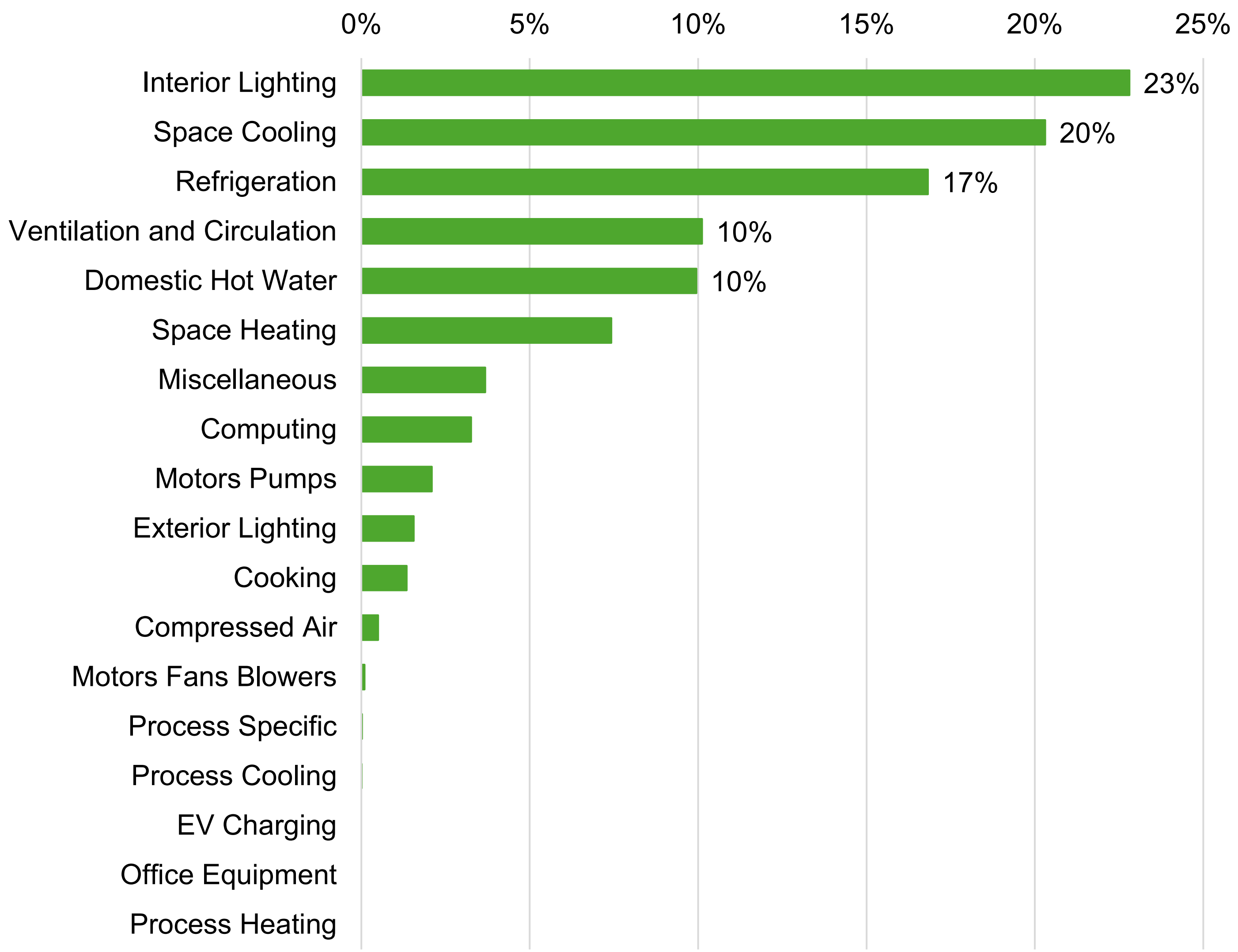
* Incentive rates for individual measures will be capped to maintain passing UCT result, if less than targeted rate.

Residential Potential by End Use



- The top five end uses contribute 94% of residential savings opportunities.
  - Residential Space Cooling
  - Lighting
  - Residential Space Heating
  - Plug Load
  - Refrigerators
- We expect fewer savings opportunities from the water heating end use due to new federal regulations. Updated DOE energy conservation standards for residential water heaters will take effect on May 6, 2029.

Commercial Potential by End Use



- The top five end uses contribute 80% of commercial savings opportunities.
  - Interior Lighting
  - Space Cooling
  - Refrigeration
  - Ventilation and Circulation
  - Domestic Hot Water
- The savings opportunities correlate with the end-use sales distribution from the load disaggregation.

Annual EE Savings by Scenario

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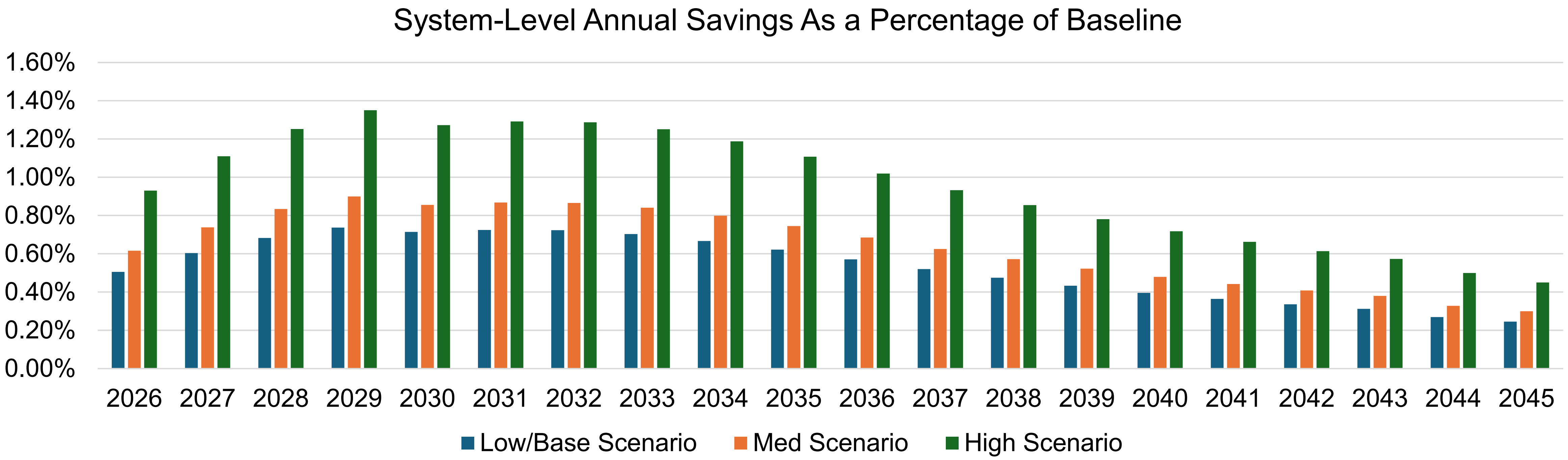

DR Achievable Potential Scenarios

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AP incorporates expected market response to cost-effective measures

- Technology adoption, program enrollment, marketing & customer acquisition

Measures are analyzed based on scenario parameters

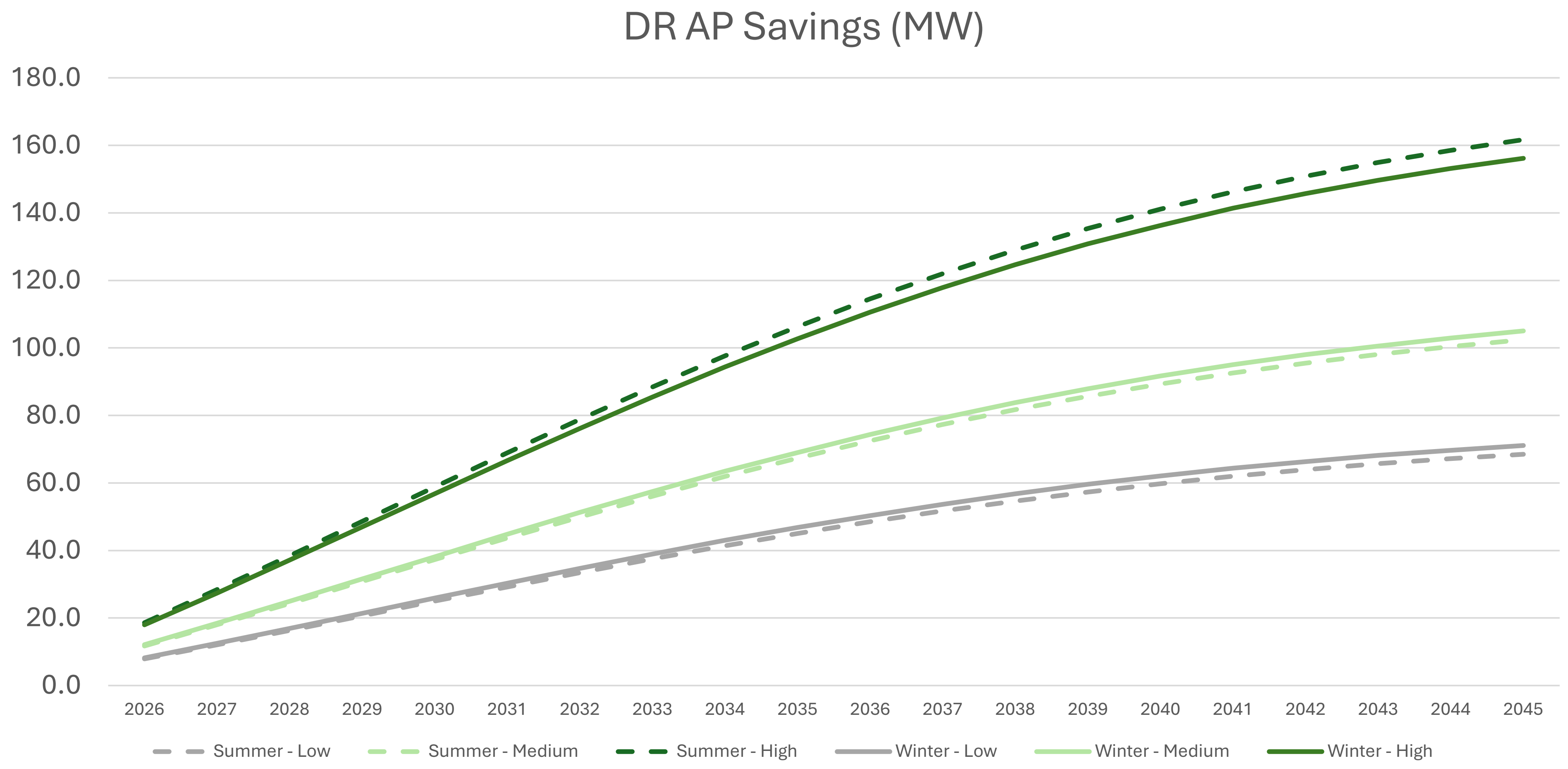
Low Scenario	Medium Scenario	High Scenario
• “Business as usual” • Aligned with existing programs • Residential and SMB Thermostats	• Include all economic loads/ measures • Target cost-effective customer segments • Assume medium incentives, marketing & outreach	• Include all economic loads/measures • Target all customer segments that maintain program cost-effectiveness • Enhanced incentives, marketing & outreach

DR Achievable Potential by Sector

- **Medium scenario:** includes Smart Thermostats, Peak Time Rebates, Pool Pump (Switch), Water Heat (Grid-Enabled), and Behavioral DR

Sector	Season	Achievable Potential (MW)		
		Short-Term (2030)	Medium-Term (2035)	Long-Term (2045)
Residential	Summer	30.2	54.5	83.0
	Winter	34.1	61.7	93.9
Small Commercial	Summer	4.2	7.6	11.5
	Winter	2.4	4.4	6.7
Large Commercial	Summer	2.9	5.2	8.0
	Winter	1.6	2.9	4.4

DR Achievable Potential by Sector



2025 IRP Update

Will Brown, Manager Resource Planning

Commission Procedural Schedule

Schedule Item	Date
Santee Cooper's IRP Update filed with the Commission	September 16, 2025
ORS to File a Report regarding Santee Cooper's IRP Update	December 15, 2025
Intervenors/Other Parties of Record to File Comments Regarding Santee Cooper's IRP Update	January 12, 2026
Santee Cooper's Reply Comments in Response to ORS's Report and All Other Parties' Comments to ORS' Report	January 26, 2026
Proposed Order Due	Santee Cooper filed on February 3, 2026
Commission Issues Final Order	March 5, 2026

- IRP Update PSC Docket: Detail for 2025-18-E
- 2025 IRP Update PSC Order: Order 2026-126

2025 IRP Update Ordering Paragraphs

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- Santee Cooper shall consider all stakeholder feedback from the SWG regarding large-load penetration, and to the extent Santee Cooper determines that the recommended assumptions are consistent with good utility practice and are reasonable in the context of the design, operation, and plans for the Santee Cooper system, Santee Cooper shall incorporate those assumptions into its new reserve margin studies for the 2026 IRP. In addition to addressing its reserve margin in the 2026 IRP, Santee Cooper must similarly update its ELCC studies, incorporating those recommended assumptions from the SWG that Santee Cooper determines are reasonable and consistent with good utility practice.
- Consistent with Order No. 2025-244, in future Comprehensive triennial IRPs and annual IRP Updates, Santee Cooper shall report on potential new large load and the impact these loads have on the load forecast, including explanations of variances from prior forecasts.
- Santee Cooper shall include a comprehensive assessment of coal retirements, including the Cross generation station, in its 2026 Comprehensive IRP.
- Santee Cooper shall discuss resource option assumptions for the 2026 IRP, including the potential to include a 2x1 NGCC resource option, with the SWG. Further, Santee Cooper shall provide an evaluation of new resource additions.

2025 IRP Update Ordering Paragraphs

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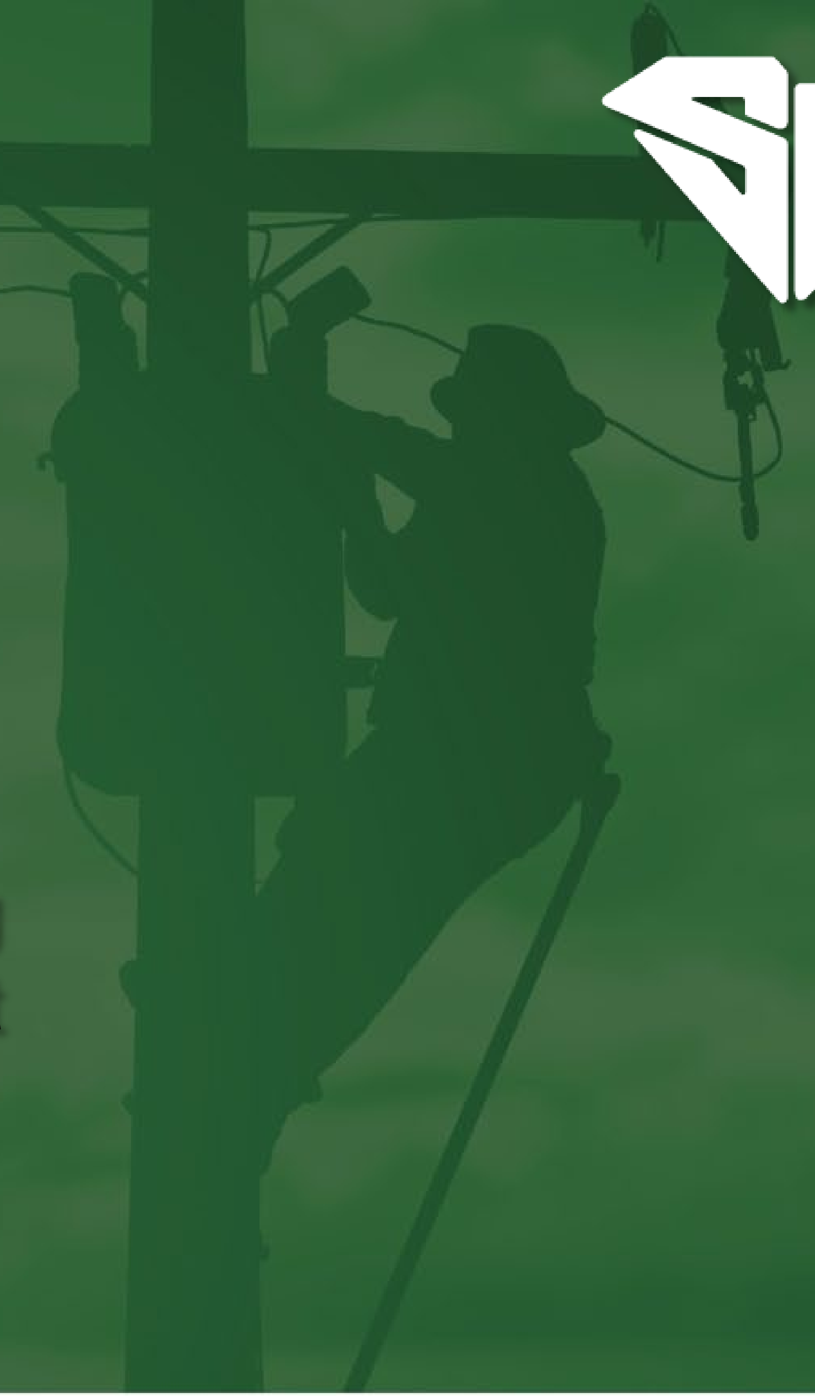
- Santee Cooper shall include information about the Fairfield Nuclear Project in the 2026 IRP to the extent it is available and relevant.
- Santee Cooper shall include its latest assessment of transmission planning and short-term resource considerations in its 2026 IRP.
- Except for those ORS recommendations for Santee Cooper to address specific matters in its Reply Comments in this docket and those recommendations addressed in Ordering Paragraphs 2 through 7 above, Santee Cooper should consider and address any recommendations raised by the ORS Report as well as the comments from all parties in either the SWG or its 2026 IRP as appropriate. Santee Cooper may address such recommendations and comments via its filed IRP or IRP update, filed testimony, filed comments, or any other that it deems appropriate.
- All requirements or ordering provisions from the Santee Cooper 2023 IRP Decision, Order No. 2024-171, and the Santee Cooper 2024 IRP Decision, Order No. 2025-244 shall be addressed in ongoing stakeholder engagement, potential negotiations, or filings for Santee Cooper's 2026 IRP as appropriate.

2026 Triennial IRP

Will Brown, Manager Resource Planning

Bob Davis, Executive Consultant, nFront



2026 Triennial IRP

- Thermal Resources
  - Considering not including 2x1 Natural Gas Combined Cycle (NGCC) as a resource option
  - Planning to not include 3 1x1 NGCC as a resource option
- Renewable Resources
  - Will utilize production profile from Wind Study for Onshore Wind resource option
- Storage Resources
  - Considering assuming an energy community tax credit of 10% through 2035 for BESS resource options
  - Evaluating including a Long Duration Energy Storage resource option
- Considering not modeling hydrogen as an alternative fuel option
- Planning to model large loads as separate load group in EnCompass

2026 Triennial IRP

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- IRP will consider Santee Cooper Market Potential Study results and Cooperative DSM programs will be reflected in the Central load forecast
- Planning to model incremental operating reserves for intermittent resources based on results from the Integration Study
- Planning to run portfolios through reliability verification process utilizing SERVM and report metrics
- Planning to run the same portfolios as the 2023 IRP
  - Monitoring GHG regulations
- EnCompass benchmarking

Meeting Closeout

Stewart Ramsay, Facilitator, VANRY Associates

Meeting Closeout

- Review and agreement for meeting action items
- Vanry will send the meeting summary to members for review
- Upcoming Coal Retirement Technical Meeting #4 will be April 30, 2026
- Next working group meeting
  - Targeting June 3, 2026
  - Please let us know if a member would like to present on a topic
- Next general notice meeting targeted for June 11, 2026

Thank you!

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