2023 Integrated Resource Plan (IRP)

Public Stakeholder Meeting #3

June 28, 2022

Santee Cooper
Resource Adequacy Studies

Astrapé Consulting

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Topics of Discussion

- **Planning Reserve Margin (PRM) Study Results**
- **ELCC Study Results**
- **Solar Integration Study Update**

Planning Reserve Margin (PRM) Study Results

SERVM Framework

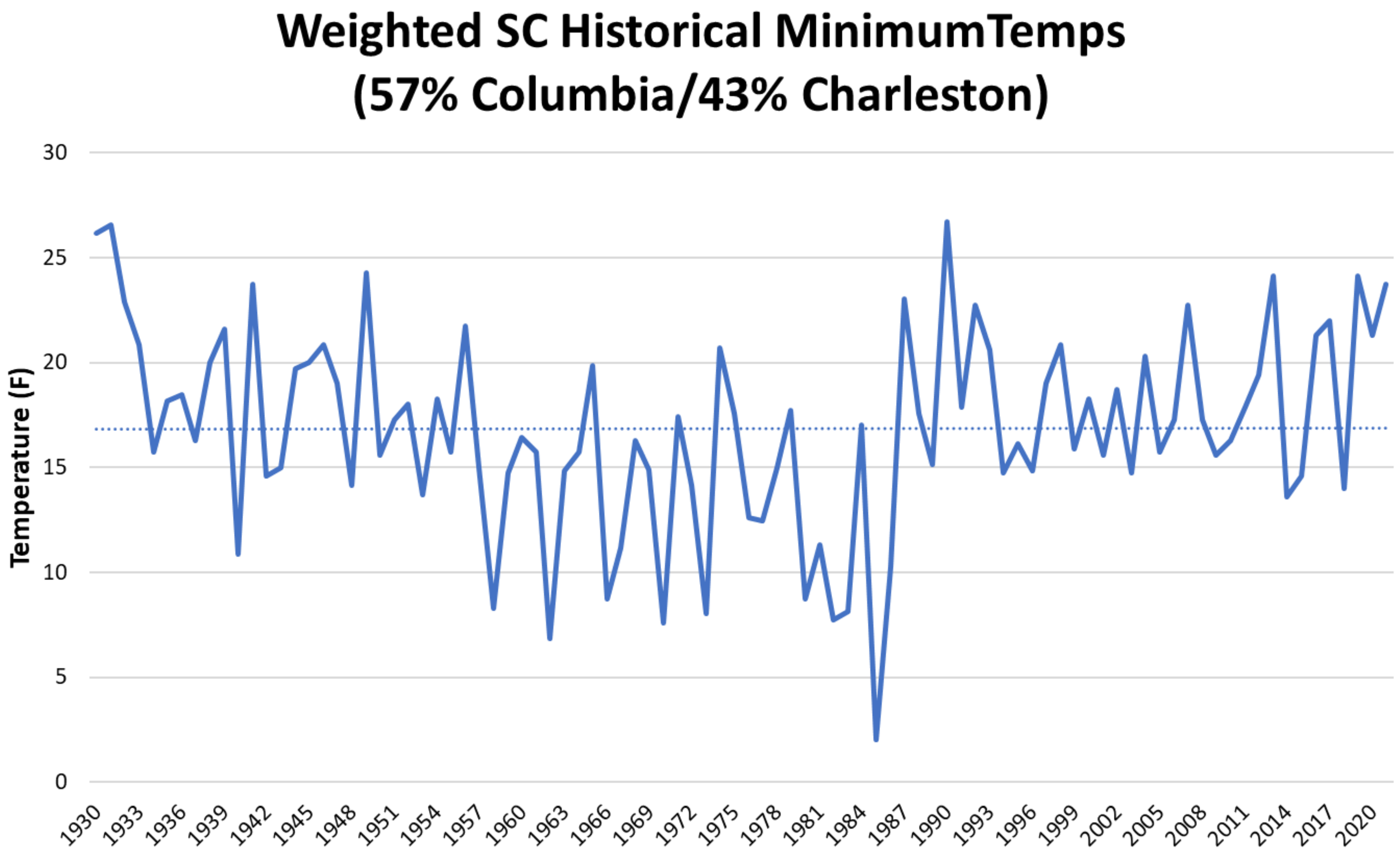
- **Capture Uncertainty in the Following Variables**
  - Weather: 41 years of weather history (1980-2020) with equal probability of occurrence
    - Impact on Load and Resources (hydro, wind, PV, temp derates on thermal resources)
  - Economic Load Forecast Error: Distribution of 5 points with varying probabilities of occurrence
  - Unit Outage Modeling (25+ iterations for each load scenario)
- **Multi-Area Modeling – Pipe and Bubble Representation**
- **Total Base Case Scenario Breakdown**

41 **Weather Years** (Equal Probability)	x	**5** **LFE Points** (Associated Probabilities)	=	**205** **Load Scenarios** (Associated Probabilities)
205 **Load Scenarios**	x	**25** **Unit Outage Draws**	=	**5,125** **8760 Hour Simulations**

Major Study Parameters

- **Study Years: 2026 & 2029**
- **Historical Weather Years: 1980-2020**
- **Regions (Balancing Authority Areas) Modeled**
  - Santee Cooper
  - Southern Company (SOCO)
  - Duke Energy Carolinas (DEC)
  - Duke Energy Progress (DEP)
  - Dominion Energy South Carolina (DESC)
  - Target 0.1 LOLE for neighboring regions
- Maintain minimum regulating reserves of 100 MW during firm load shed events
- **Target LOLE:** 0.1 Days/Year = 1 firm load shed event in 10 years

Minimum Annual Temperatures Since 1930



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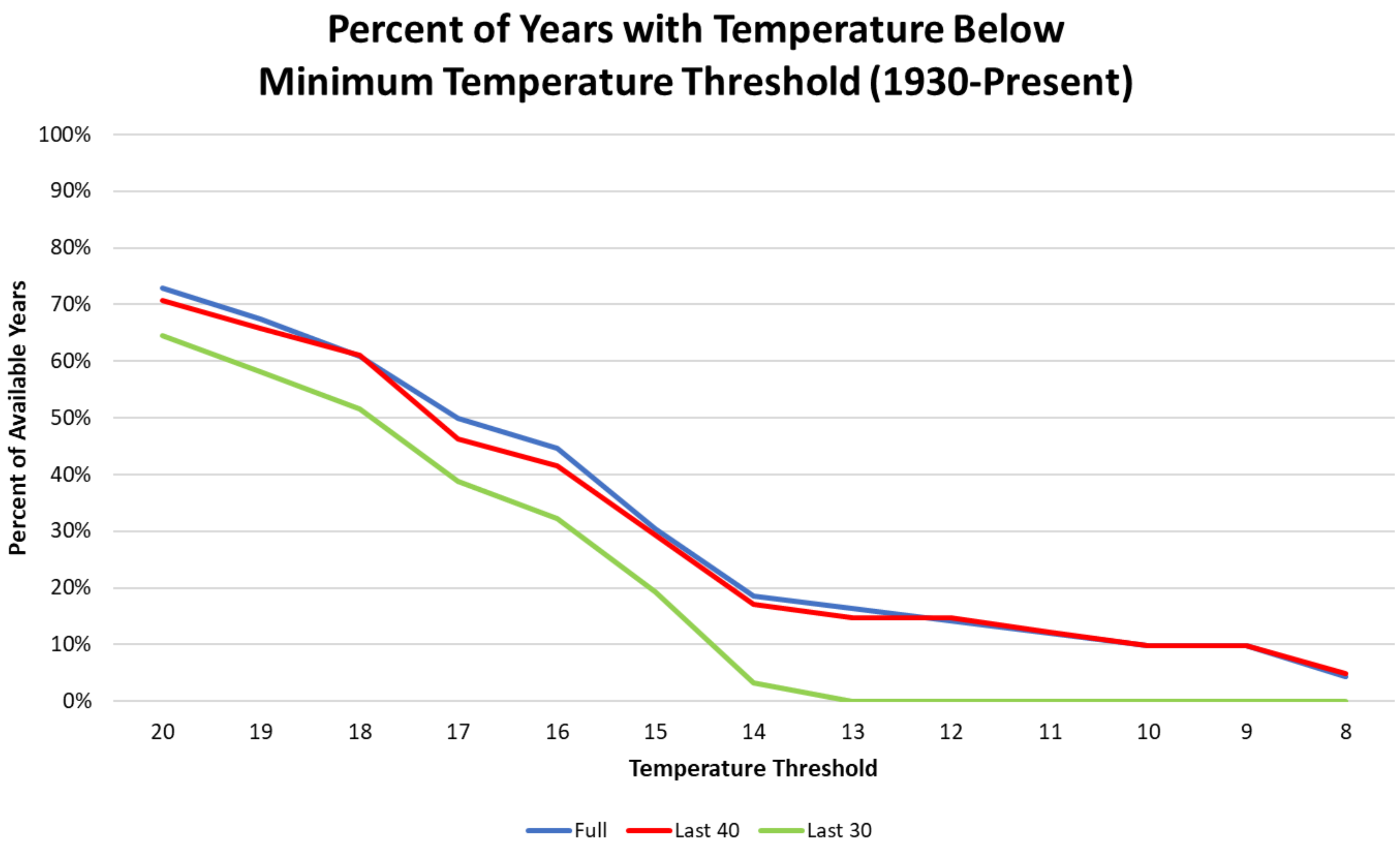
Historical Minimum Temperatures – Percent of Years



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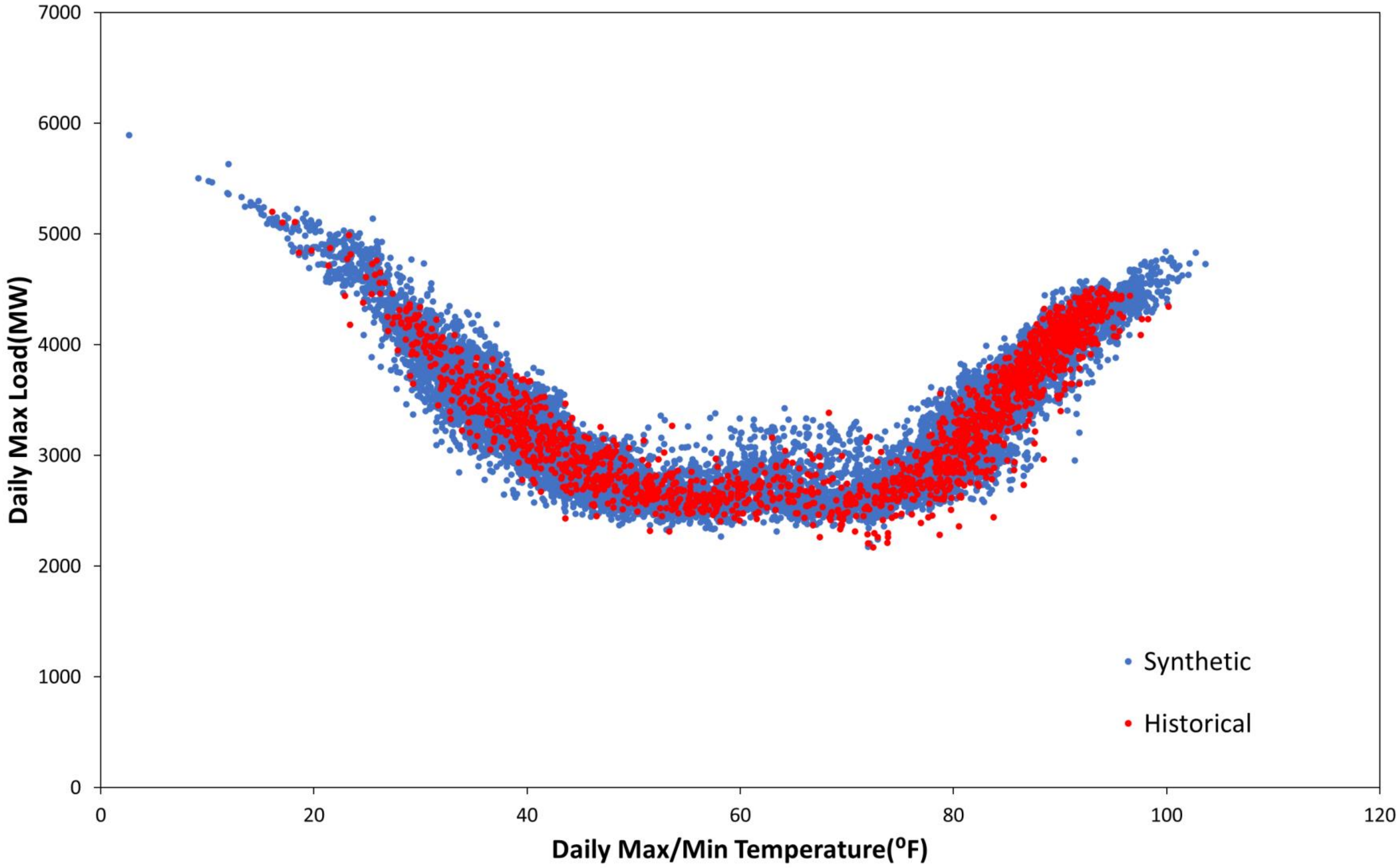
Daily Max/Min Temperatures vs Daily Max Load



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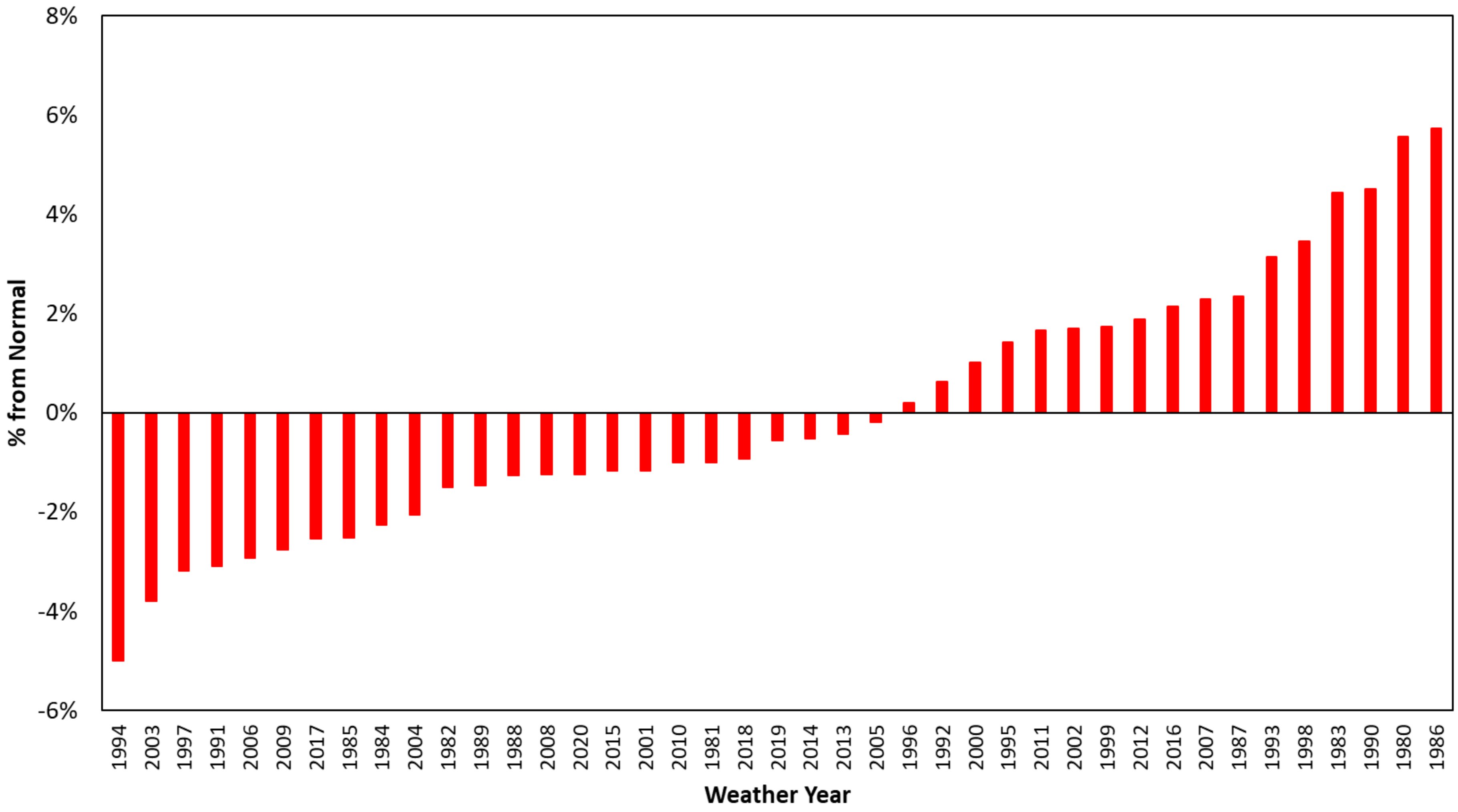
Summer Peak Load Variability



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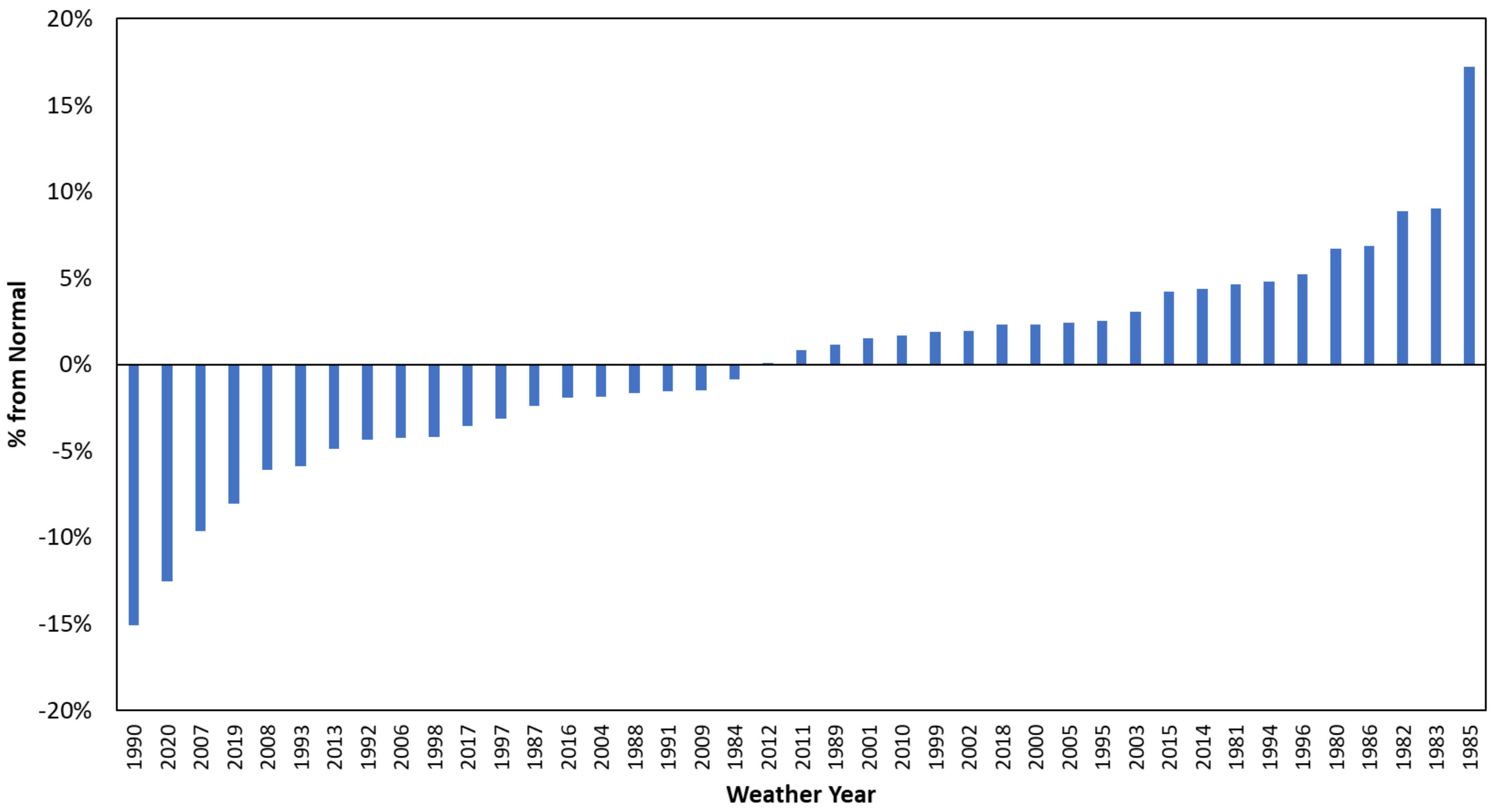
Winter Peak Load Variability



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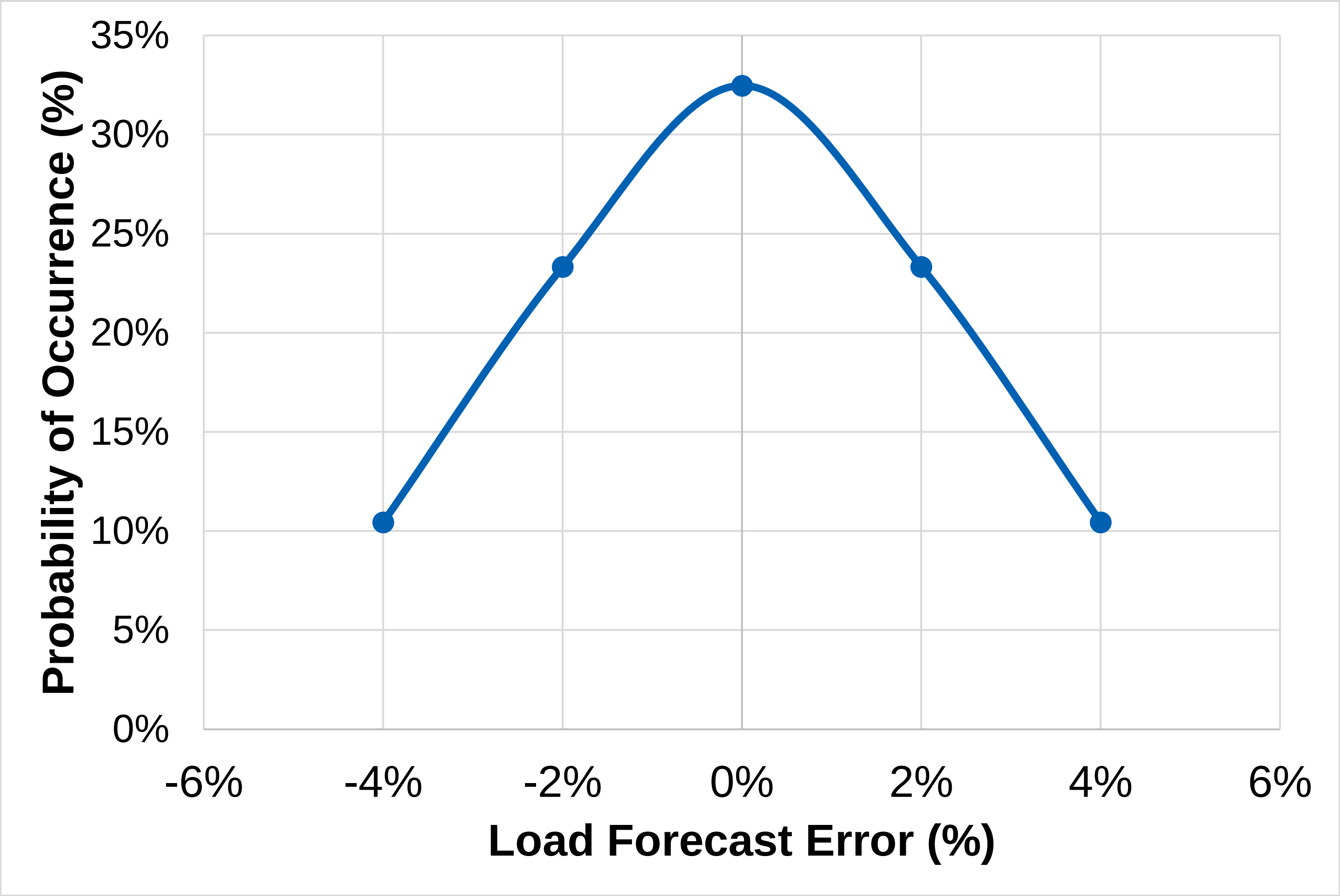
Economic Load Forecast Uncertainty



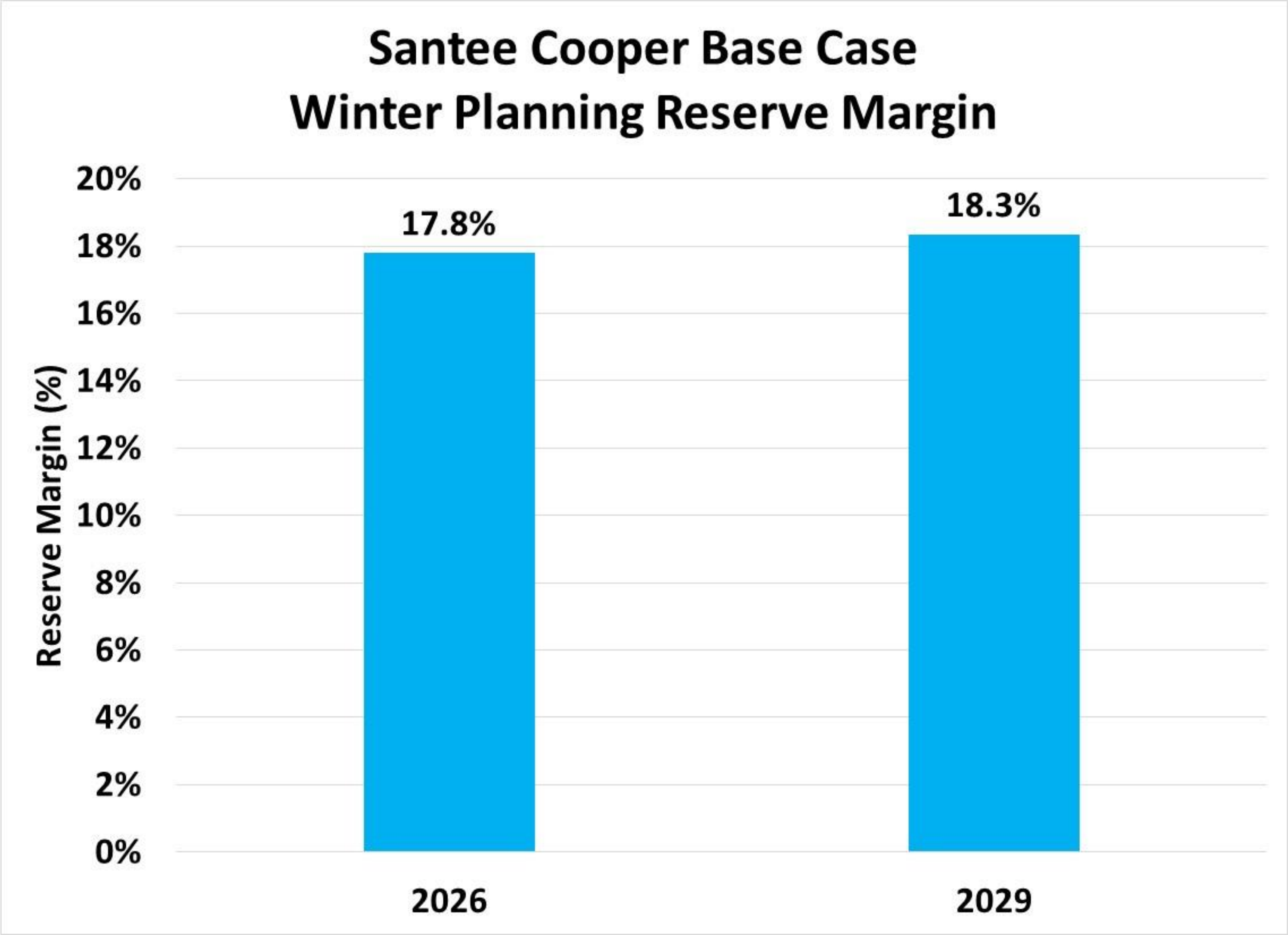
LFE	Probability
-4%	10.4%
-2%	23.3%
0%	32.5%
2%	23.3%
4%	10.4%

Derived from Congressional Budget Office GDP forecast error over last 30 years. GDP Load forecast error multiplied by 40% to reflect electric load growing less than GDP.

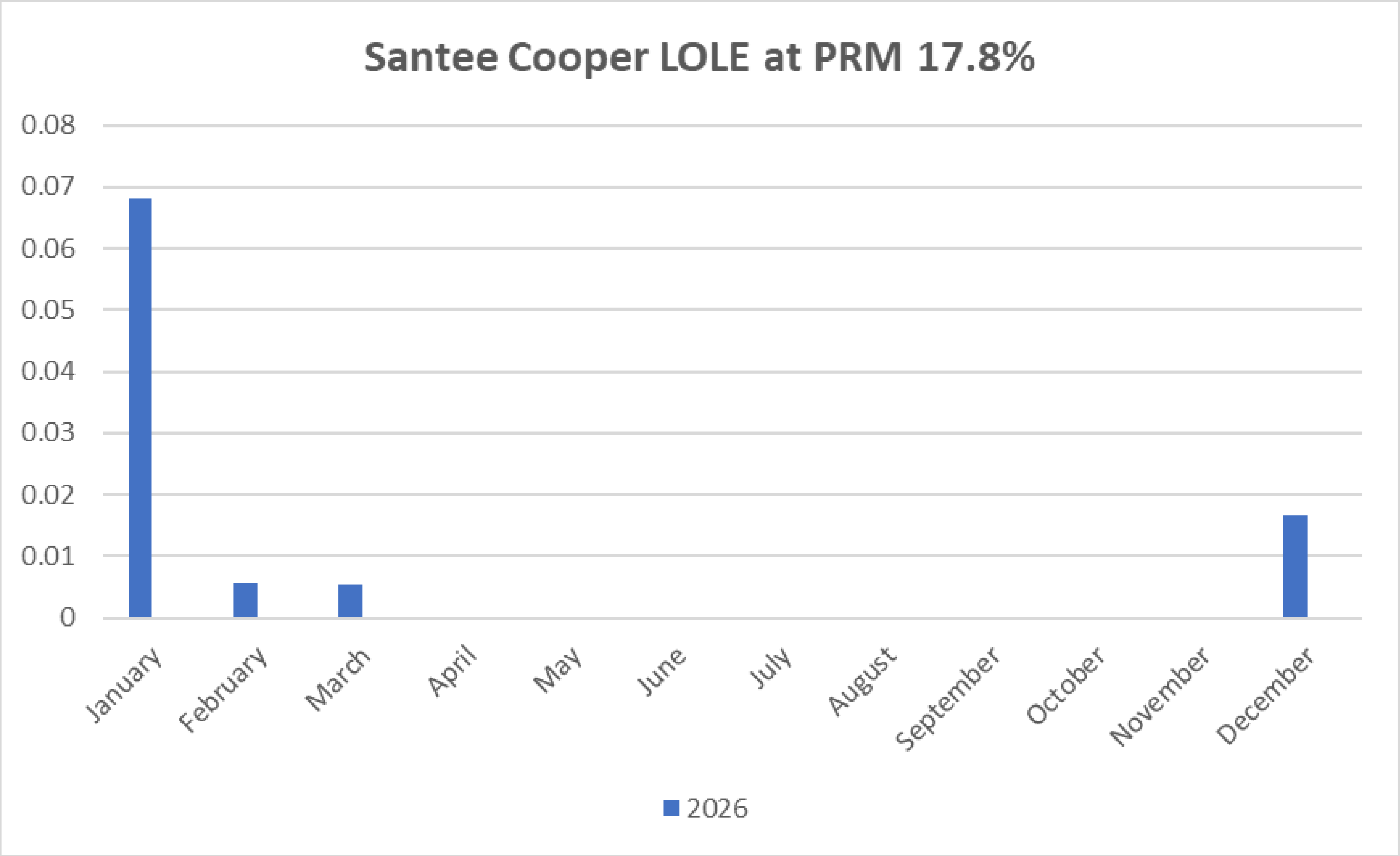
Generator Outage Data

- **NERC Generating Availability Data System (GADS) is Confidential**
  - EFORs based on 5 years of historical GADS data captured as annual outage rates
  - EFORs subject to adjustments made by SC Management on forward looking expectations
  - Planned maintenance rates based on future planning
    - Optimized by SERVM based on net load over the 41 weather years
- Astrape analyzed recent cold weather events in the GADS data and thermal generation performed well so no incremental cold weather outages were modeled for Santee Cooper

Winter Base Case Results



LOLE by Month



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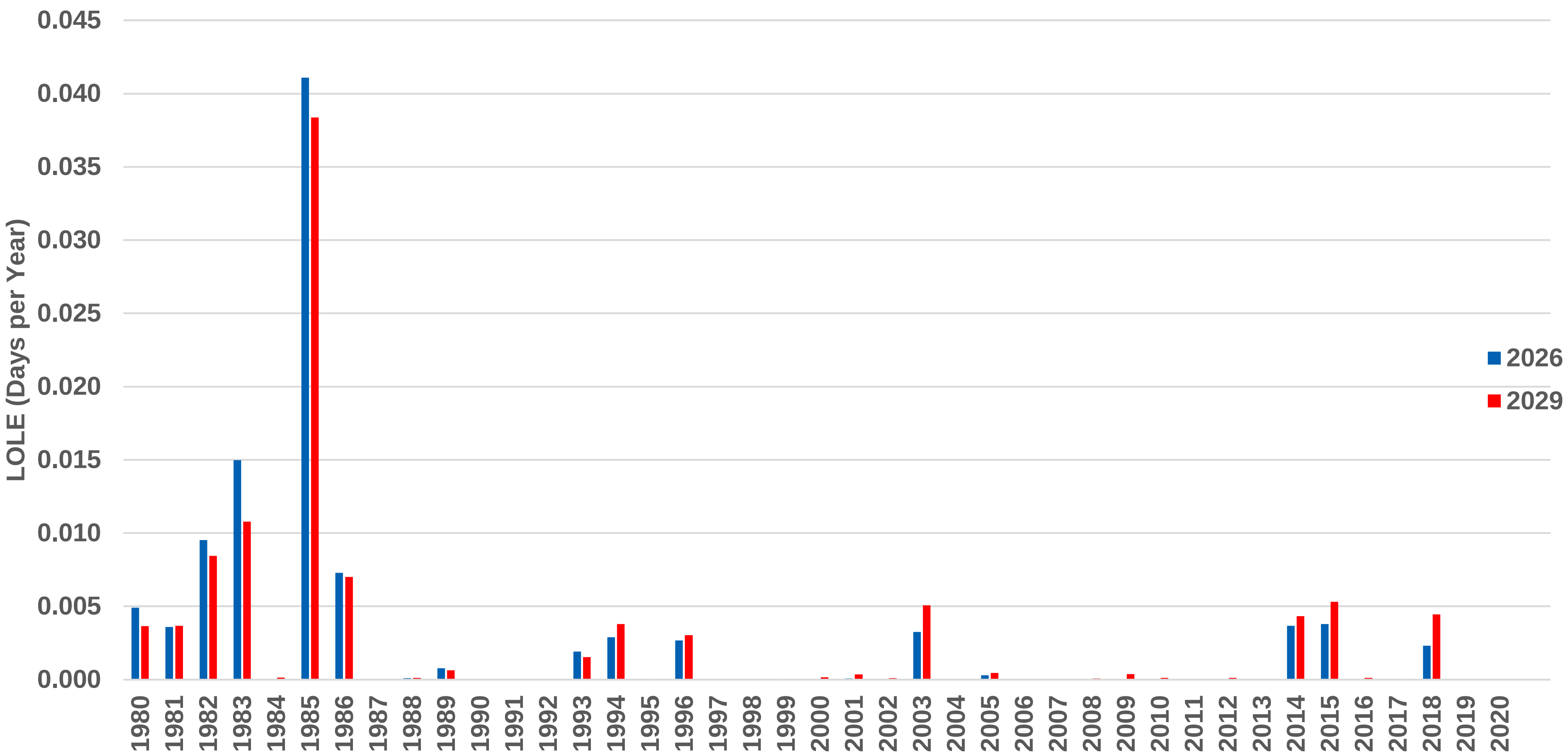
LOLE By Weather Year



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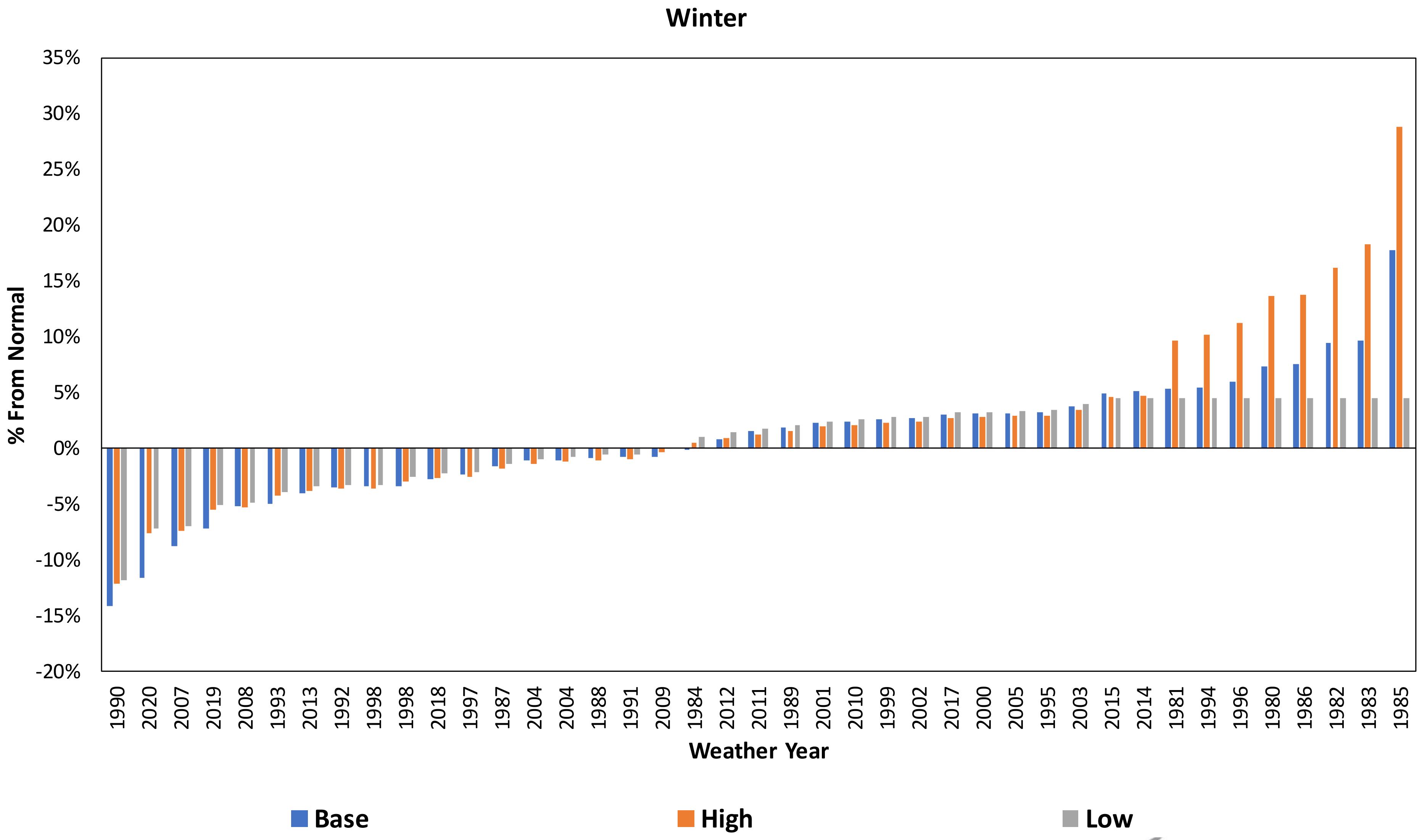
Sensitivities

1. **Island Case**
   – Assumes no market exists around the Santee Cooper system
2. **Climate Change Sensitivity**
   – Adjust temperatures 0.3°/Decade per NOAA Climate Change Study
3. **2 Load Sensitivities**
   - LOW: Cap Winter Loads at highest value in historical data
   - HIGH: Adjust load response until winter volatility reaches 30% (similar to recent ERCOT experience)
4. **Transmission Sensitivity**
   – Constraint the combined DESC/SC import to 1,500 MW

Load Sensitivity Inputs



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Summary of Sensitivity Results

Winter	2026	2029
Base Case Market	17.8%	18.3%
Base Case Island	27.1%	27.7%
Climate Change	16.8%	17.2%
High Load Response	22.0%	22.9%
Low Load Response	14.2%	15.2%
Transmission Import	17.8%	18.5%

Summer Reserve Margin

- Base case shows almost all LOLE is in the winter (0.0904 Winter / 0.0004 Summer)
  - Neighboring utilities are all long in summer, providing substantial market support
  - This is likely real-world reality
- Allowing LOLE in the summer months to rise to the 0.01-0.02 range would establish a reasonable summer PRM without significantly raising annual LOLE
- Resulting summer PRM would be in the 14%-16% range

Recommendation

- Study supports a winter reserve margin of 17%-18%
  - Recommendation:
    - Adopt a 17% winter reserve margin
    - Target to achieve by 2026
- Study supports a summer reserve margin of 14%-16%
  - Recommendation:
    - Maintain a 15% summer reserve margin

ELCC Results for Solar and Storage

Seasonal ELCC Methodology Details

- Start with System at approximately 0.1 LOLE with no renewable resources
  - Record Winter LOLE (Jan, Feb, Dec) as Winter target
  - Record Summer LOLE (Jun-Sep) as Summer target
- Add renewable tranche to system
- For each season, iteratively add load until that season’s LOLE returns to target
- ELCC is the load added divided by the nameplate of the renewable tranche

ELCC Portfolio Matrix to be Evaluated

	BESS MW				
Solar MW ->	0	1,000	1,250	1,500	2,000
	200			200\1,500	
	400				400\2,000

Capturing solar and battery together will ensure any synergistic value of the two resources is considered

ELCC

Raw Capacity Value (MW) Winter

BESS\Solar	0	1000	1250	1500	2000
0		20	23	27	28
200	200			279	
400	352				405

Raw Capacity Value (MW) Summer

BESS\Solar	0	1000	1250	1500	2000
0		393	458	490	537
200	200			708	
400	379				972

Portfolio ELCC Winter

BESS\Solar	0	1000	1250	1500	2000
0		2.0%	1.8%	1.8%	1.4%
200	100.0%			16.4%	
400	88.0%				16.9%

Portfolio ELCC Summer

BESS\Solar	0	1000	1250	1500	2000
0		39.3%	36.6%	32.7%	26.9%
200	100.0%			41.6%	
400	94.8%				40.5%

Allocated Portfolio ELCC Winter

BESS\Solar	0	1000	1250	1500	2000
0		2.0%	1.8%	1.8%	1.4%
200	100.0%			100.0%/5.3%	
400	88.0%				93.8%/1.5%

Allocated Portfolio ELCC Summer

BESS\Solar	0	1000	1250	1500	2000
0		39.3%	36.6%	32.7%	26.9%
200	100.0%			100.0%/33.9%	
400	94.8%				100.0%/28.5%

ELCC Additional Thoughts

- Ensure resources are on equal playing field with new thermal generation for capacity expansion decisions
  - New Gas EFOR less than 5%
  - Storage/Solar EFORs are more uncertain
  - Santee Cooper and Astrape are discussing ways to ensure storage and solar ELCCs are treated fairly to account for EFORs on new thermal resources
  - Cold weather correlated outages were not seen in outage history which demonstrates plants are winterized

Solar Integration Study Update

Schedule

- Finalized thermal resource inputs - Mid June
- Started Simulations in late June
- Expect Draft Results in July/August

Scope of Study

- **Solar Tranches Evaluated**

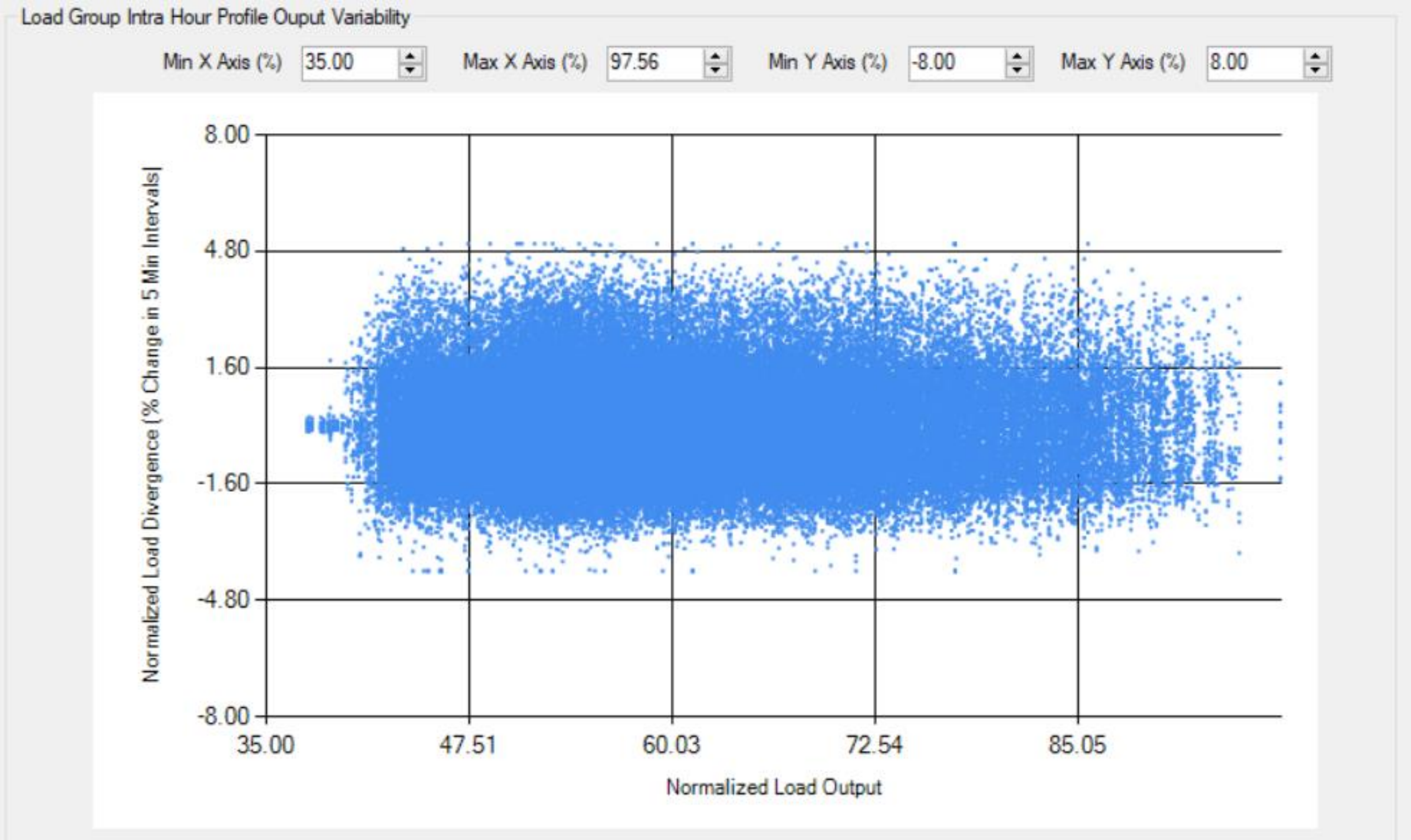
	Santee Cooper Solar
Tranche 1 MW	500
Tranche 2 MW	1,000
Tranche 3 MW	1,500
Tranche 4 MW	2,000

- **Scenarios Evaluated**
  - Base Scenario: 2x1 CC
  - Alternative Scenario 1: 1x1 CC with 2 Oil CTs
  - Alternative Scenario 2: 1x1 CC with 1 Oil CT and 150MW of BESS

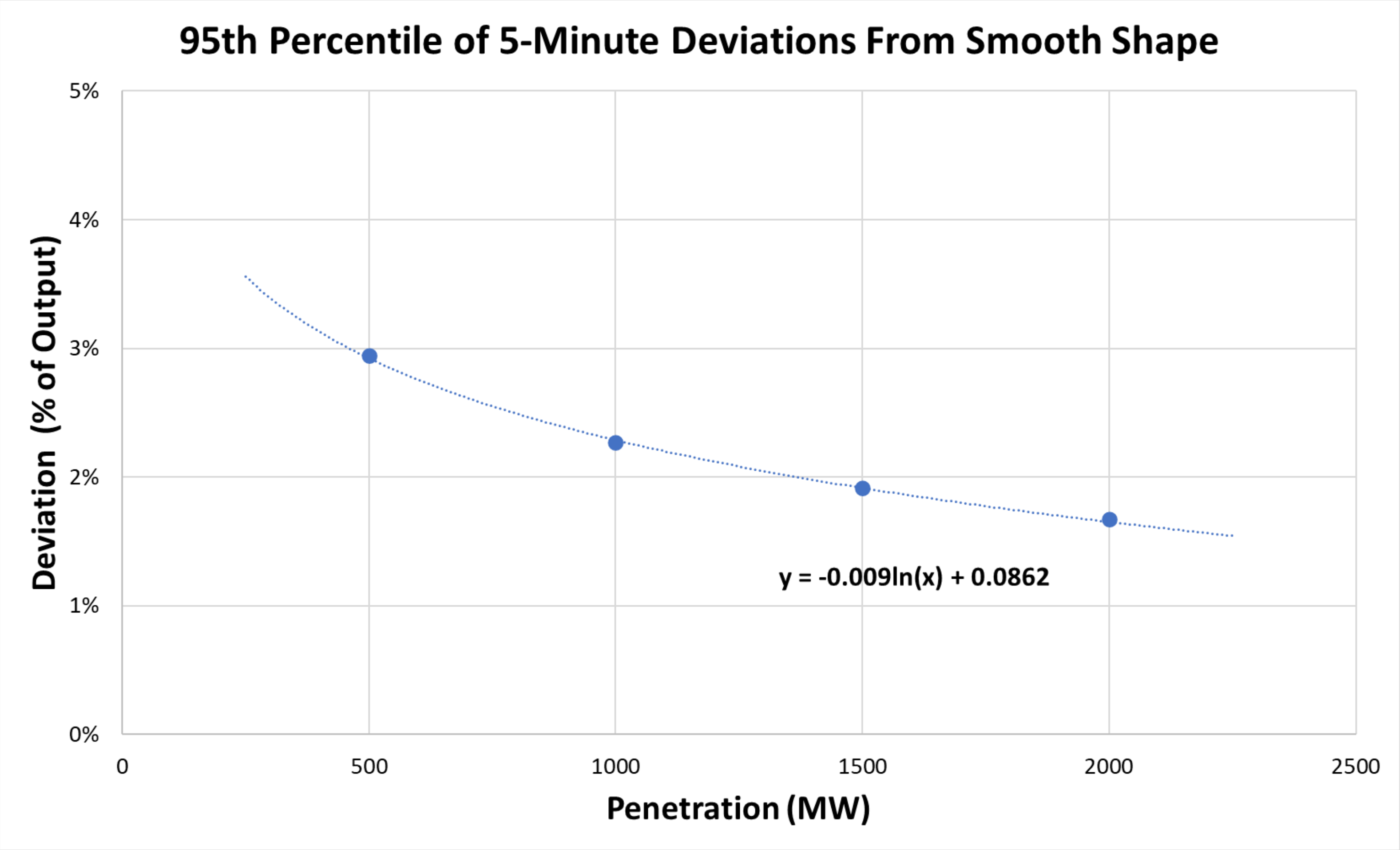
Study Procedure

- **Step 1:Run Base Case:**
  - Establish a non-renewables base case at 0.1 LOLE
  - Simulate with reasonable operating reserves to determine flexibility violations without solar (e.g. no solar case produced 3 flexibility events per year)
- **Step 2: Add Solar:**
  - Return system to 0.1 LOLE
  - As solar is added flexibility violations increase due to the increase in net load volatility
  - Determine the hours where flexibility violations occur
- **Step 3: Add operating reserves:**
  - Add additional operating reserves in the form of load following to get back to the number of flexibility violations in the base case
  - Target hours where flexibility violations occur
  - By using a set violation target, the model is allowed to make use of periods where reserves are already high due to unit commitment and peak and off peak loads
- **Step 4: Calculate the solar integration cost:**
  - Calculate the cost increase of the operating reserves between Step 2 and Step 3. Then divide by the incremental solar generation to calculate the solar integration cost

Load Intra-Hour Volatility – Included in all simulations

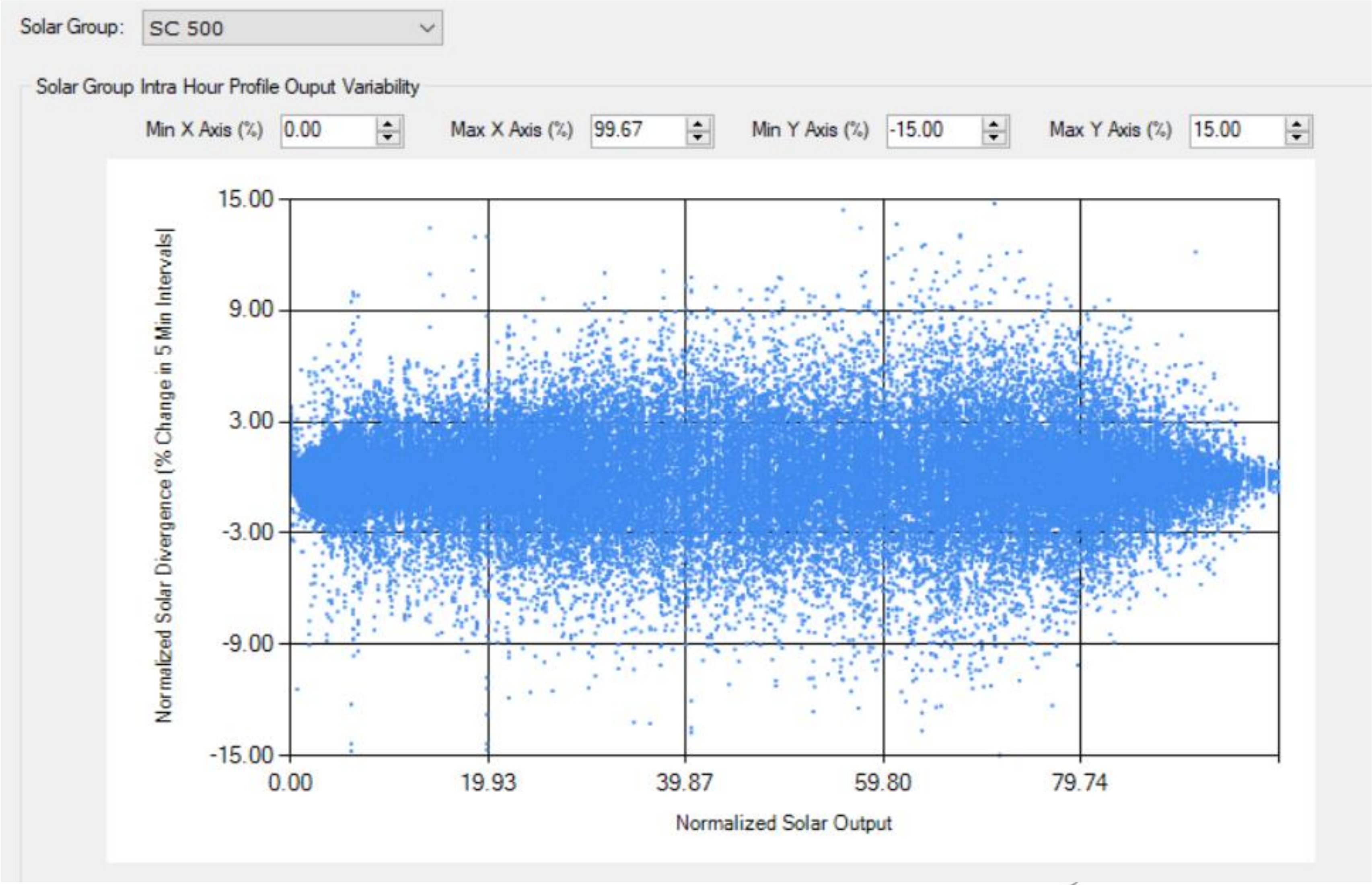


Solar Volatility as a Function of Penetration



- **Relying on historical solar data**
  - Compare volatility across a range of solar penetration levels
  - See significant diversity benefit from solar tranches
  - Hourly profiles are the same as the reserve margin study

Solar Intra-Hour Volatility – 500MW Tranche



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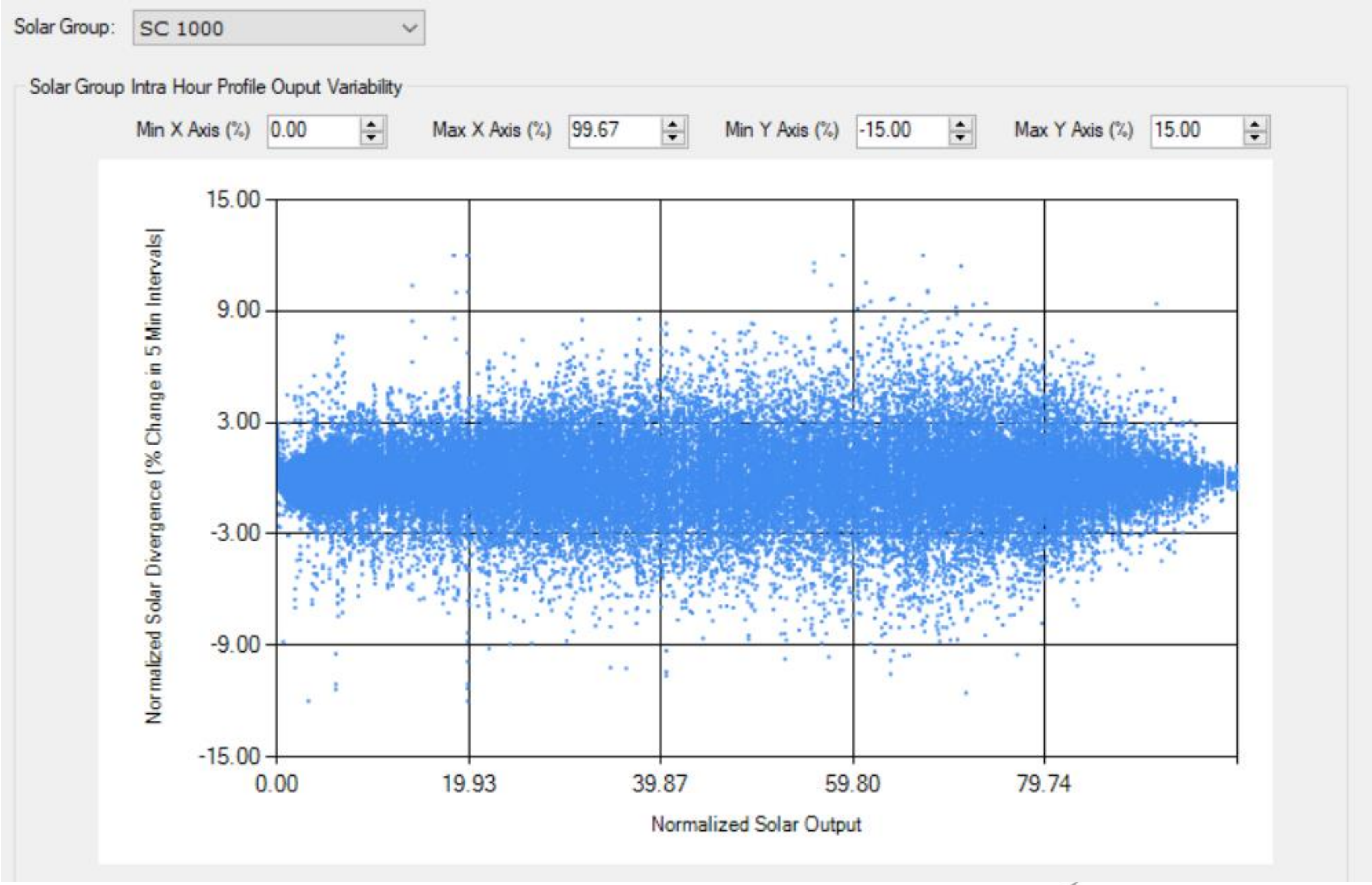
Solar Intra-Hour Volatility – 1000MW Tranche



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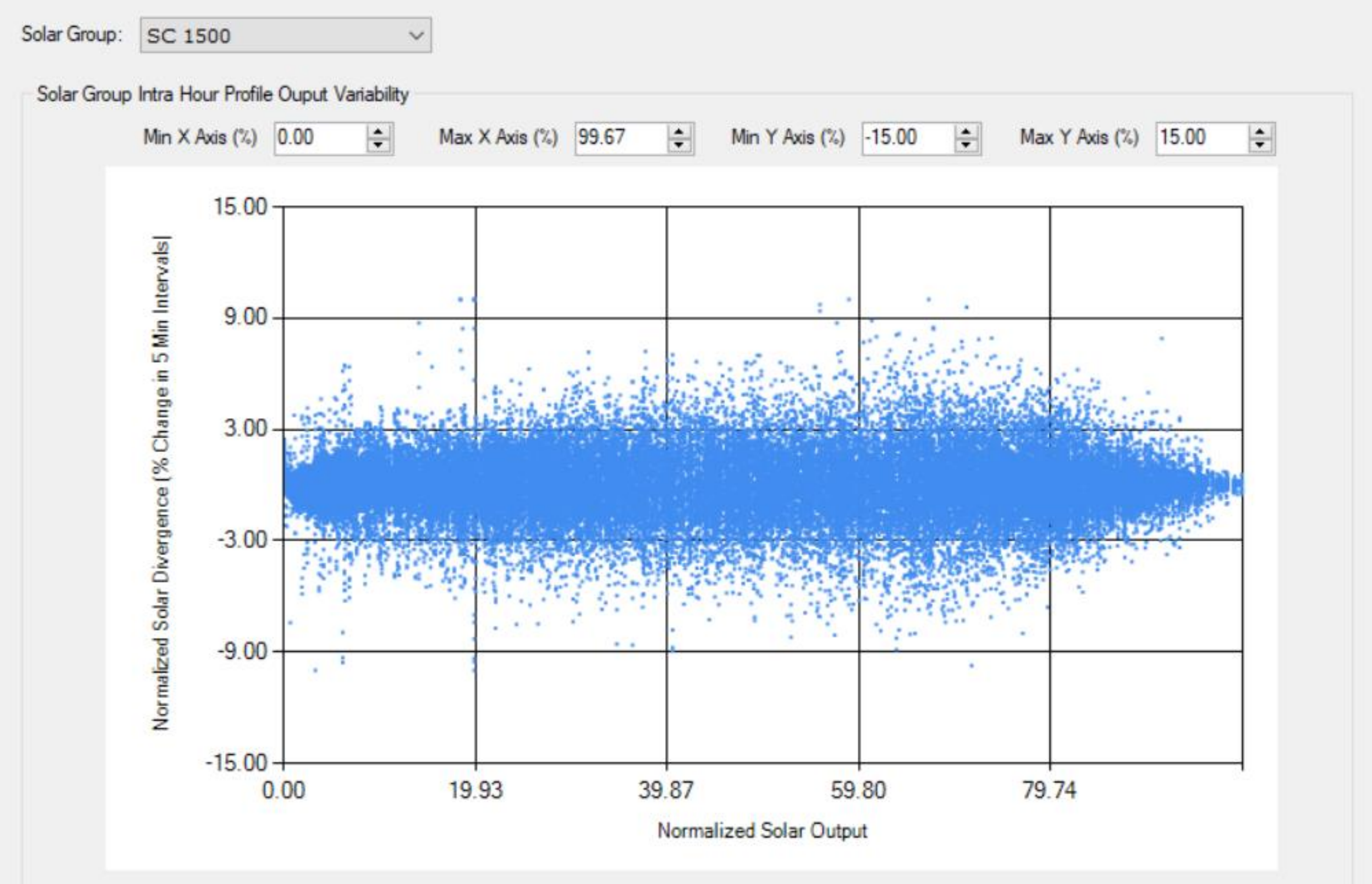
Solar Intra-Hour Volatility – 1500MW Tranche



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Solar Intra-Hour Volatility – 2000MW Tranche