ESIG Transmission Resilience Task Force

ESIG 2023 Fall Working Group – October 2023

ESIG
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Study Objectives & Key Findings (Phase 1)

Objectives

1. **Identify high priority, prudent additions to total transfer capability between regions to support reliability**

2. **Develop a weather dataset and regional capacity margins (load, wind, solar, thermal outages) that can be used to represent neighboring regions within a probabilistic RA assessment**

Out of Scope

- ACPF transfer capability (used historical flows to inform interregional limits)
- Probabilistic Resource Adequacy analysis (intended to augment those studies with a better, yet simplified, view of interregional imports

Key Findings

A Framework for Planners
This methodology can be used to augment a region's probabilistic RA framework to investigate where their region may see the most resilience benefits for expanding interregional transmission capabilities.

Identification of Priority Lines
Planning transmission with regards to resilience should consider geographically diverse areas with complementary resource mixes, uncorrelated outage and load risks.

Data needs are critical
We have limited availability of consistent, correlated, hourly time series of load, wind, solar, and weather-dependent outages and we are missing extreme events.

Study Phases Recap

Phase 1 Objective: Identify high priority, prudent additions to total transfer capability between regions to support reliability

Determine current interregional transfer limits

Phase 1

Evaluate Weather & Geographic Diversity During Extreme Events

Phase 2

Probabilistic Resource Adequacy Analysis

Detailed Power Flow & Transmission Analysis

Evaluate Weather & Geographic Diversity During Extreme Events

Phase 1 Objective: Identify high priority, prudent additions to total transfer capability between regions to support reliability

Determine interregional transfer limits

- Develop Regions & Portfolios
- Solar & Wind Dataset
- Load & Electrification
- Weather Dependent Outages
- Regional Net Load & Margin
- Future Transfer Limits

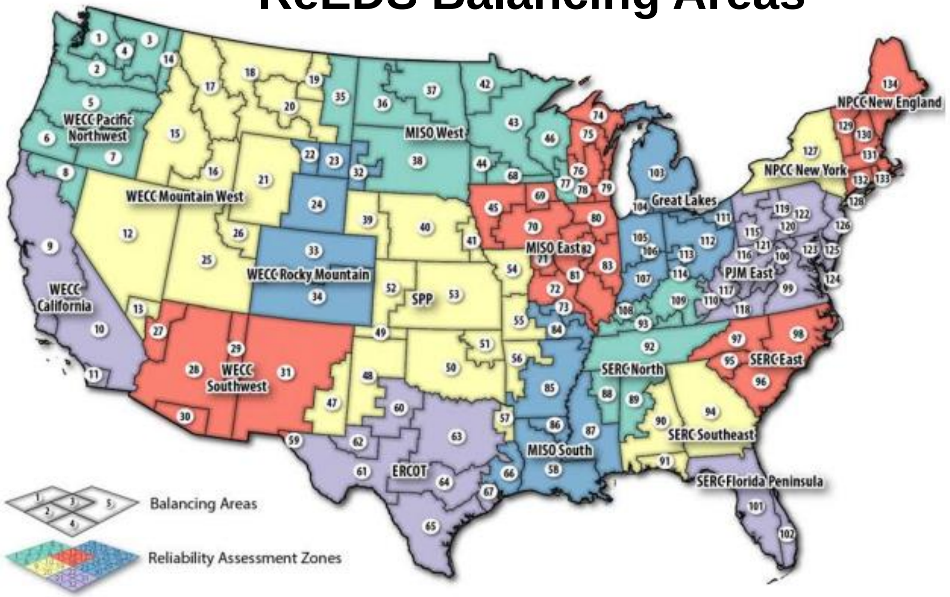
Probabilistic Resource Adequacy Analysis

Detailed Power Flow & Transmission Analysis

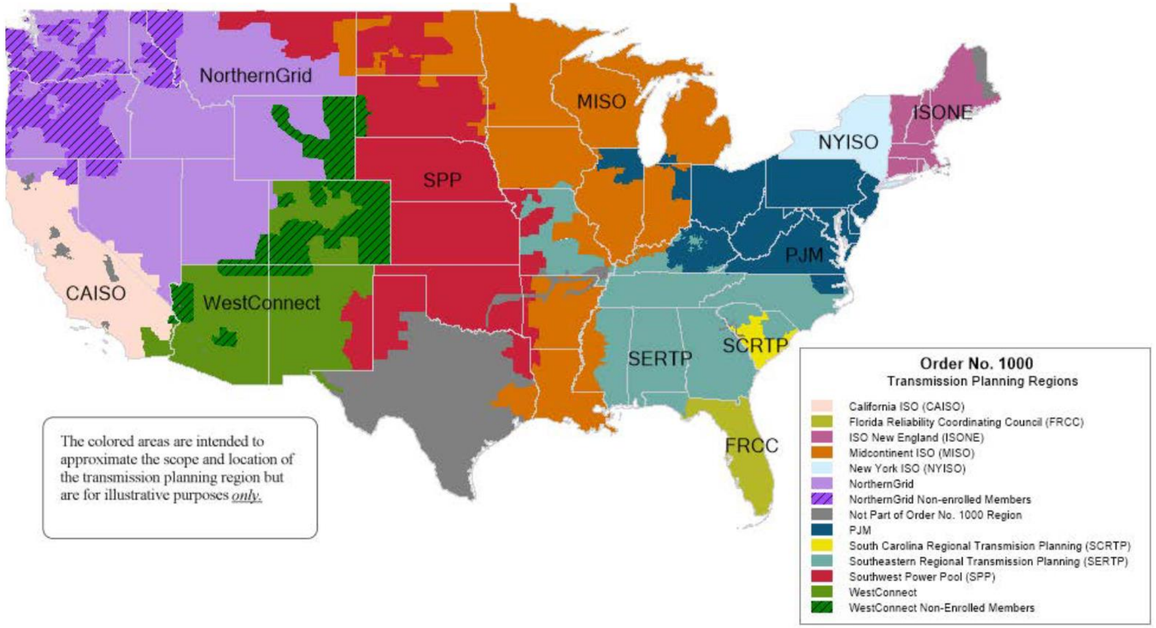
Regional Topology Selection

NREL ReEDS Balancing Areas aggregated up to FERC Order 1000 planning regions, with some adjustments

ReEDS Balancing Areas



FERC Order 1000 Regions



ReEDS and Cambium datasets are developed by NREL at a national scale and were used to develop future portfolios (capacity expansion), load profiles, and wind and solar profiles for this study

Adjustments:

- SCRTP is rolled into SERC East
- FPL Northwest now in FRCC
- Non-FERC Order 1000 regions in California (LDWP, BANC, IID, TIDC) included in CAISO region
- Two BAs in Missouri moved into SERC Central
- All of Indiana falls into MISO, no way to split into PJM/MISO

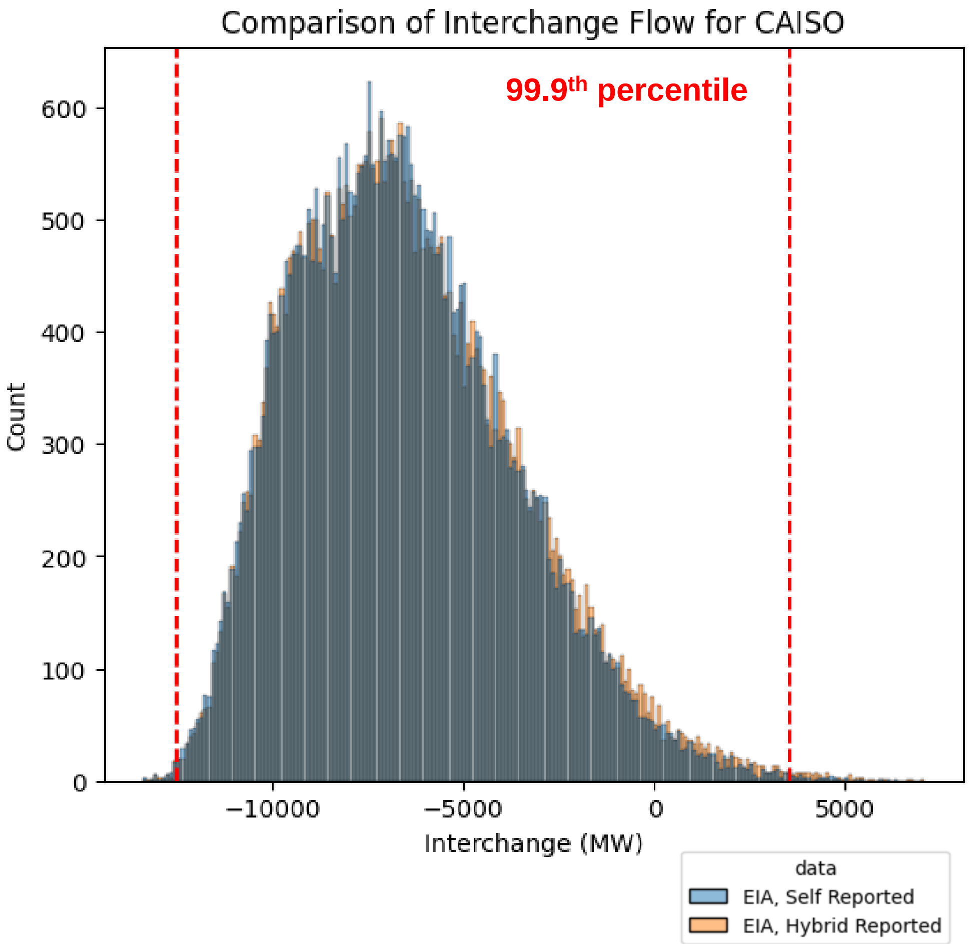
Existing Interregional Transfer Limits

Transfer limits between FERC Order 1000 planning regions based on **actual** aggregating hourly EIA 930 data from 2019 – 2023.

Values used represent the **99.9th percentile** after controlling for outliers due to data quality issues.

Includes both from and to directions

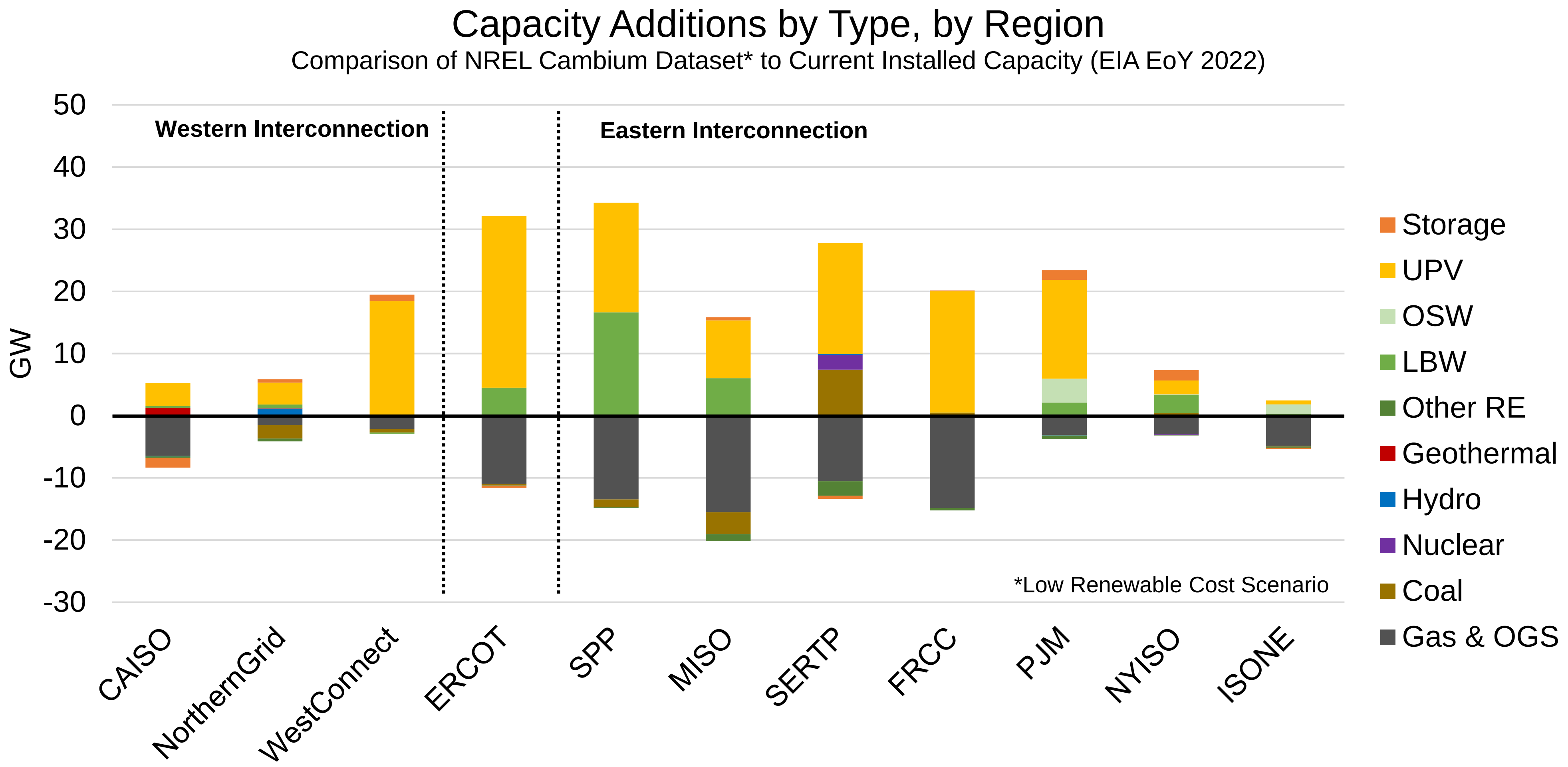
Does not rely on ACPF capability analysis



Historical Non-Coincident Interchange Capability by Region

FERC 1000 Region	Existing Interchange Capability (MW)
CAISO	15,934
NorthernGrid	10,198
WestConnect	10,819
ERCOT	1,034
SPP	6,740
MISO	17,673
SERTP	13,982
FRCC	2,862
PJM	16,919
NYISO	5,559
ISONE	1,814

Regional Capacity Mix & Portfolios based on NREL Cambium buildout



Cambium spreads renewable resource additions in each ReEDS BA by resource class based on geographic limitations and transmission estimates to reach optimal locations

Includes hourly data for weather years 2007 – 2013 for wind, solar, and load under future growth scenarios

Accounts for planned and age-based retirements and new generation resources required to meet planning criteria to capture the changing regional mix of dispatchable generation and renewable generation

Weather Year Load Dataset

Multiple Weather Year Load Profiles Scaled to Future Load Growth

Purpose: Provide load profiles that reflect historical weather conditions for future load growth scenarios to assess load diversity benefits and correlated risks due to weather systems

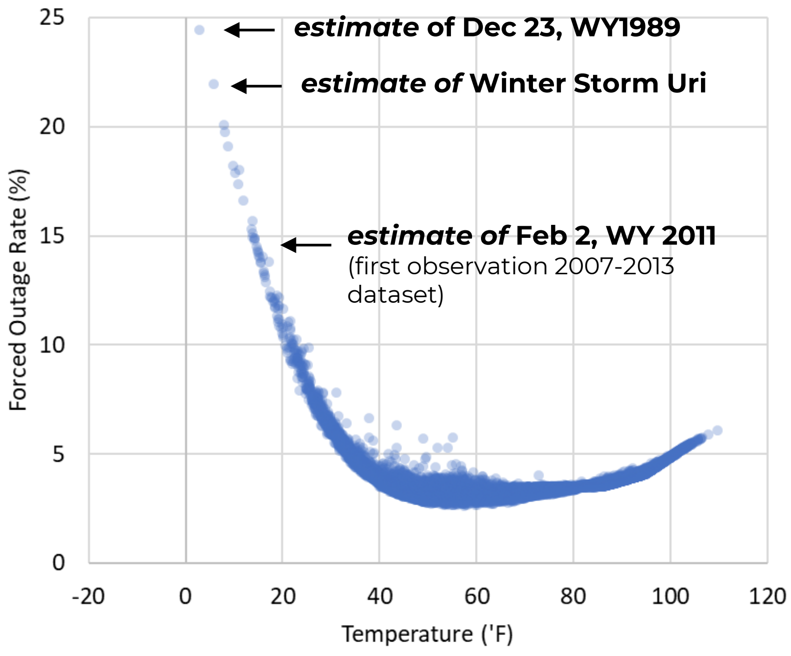
Selected Data Source: NREL Cambium standard scenarios reference load growth with some modifications

- Base weather year load profiles scaled to closely match near-term forecasted P50 peak loads or (2019-2023) peak load events depending on data availability
- Next Step: future load from NREL Cambium scenarios will include chronological impacts of weather and electrification of end-uses

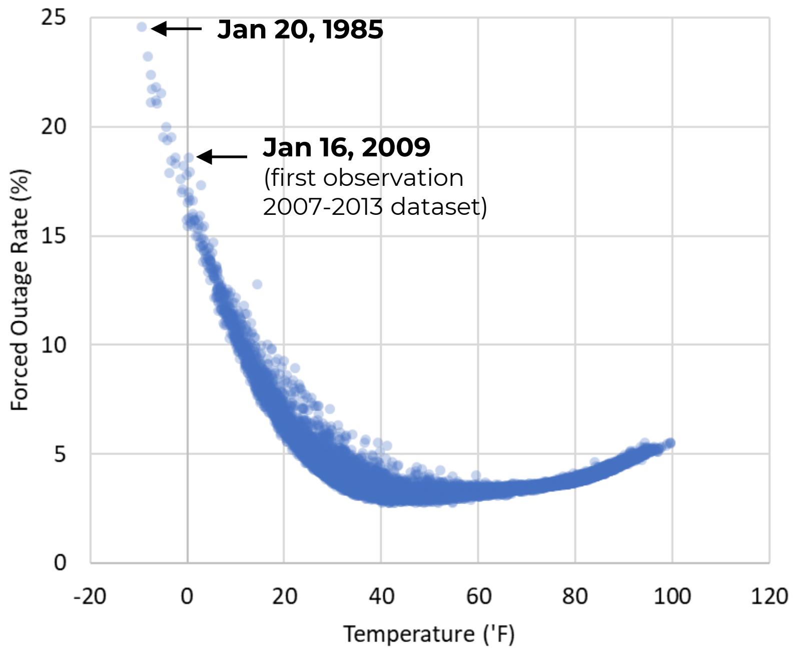
Property	CAISO	Northern Grid	West Connect	ERCOT	SPP	MISO	SERTP	FRCC	PJM	NYISO	ISONE
7-yr Avg Peak Load (MW)	59,863	48,172	38,748	83,851	54,466	131,014	128,021	51,115	150,448	32,297	25,734
Max Peak (MW)	62,168	50,945	38,981	84,731	55,942	136,393	132,788	56,952	160,223	33,537	27,106

Results of the weather dependent outages are still below recent observations

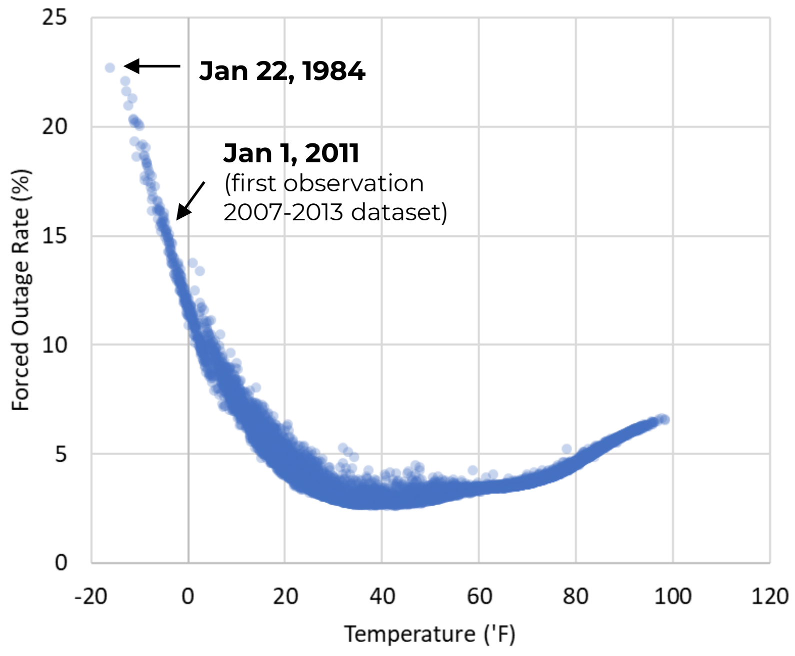
ERCOT



MISO



ISONE



- Utilized weather dependent outage (WDO) functions for each technology, based on temperature-outage rate relationship from S. Murphy, et al., 2019 (Originally developed for PJM, but applied nationally with adjustments)
- Implemented as a time-varying, daily UCAP derate by technology (deterministic, no probabilistic sampling)
- A time series was developed for each technology type, for each, NREL ReEDS balancing authority, then aggregated up to the FERC Order 1000 region

Hourly Regional Margin Calculation

Objective: To determine periods of high-risk events, an **hourly available capacity margin** for each FERC 1000 region was developed

✓ Allows for quick regional assessments of expected resource availability

✓ Captures hourly variability in wind and solar output against thermal availability

× Does not assess actual system dispatch or economic transfers

× Simplifies hydro availability with seasonal capacity ratings. Does not capture energy limitations of hydro.

Hourly Margin Calculation across Seven Weather Years

+ Available Wind & Solar
+ Seasonal Hydro Capacity
+ Available Thermal
– Weather Dependent Outages
– Expected Maintenance
+ Recallable Maintenance
+ Storage Net Gen
– (Load + 6% Reserves)

Regional Available Capacity Margin

Notes:

1. Storage is dispatched to arbitrage hourly net load within a day
2. Operating Reserves (spin and regulation) are set at 6% of the load
3. In later steps (Slide 16), interregional transmission flows are only modeled for reliability/resilience objectives, and flow when reserves drop below 10% of load.

Visualizing the Data

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Visualizing the Data: Timeseries

Identify periods of tight margin conditions and the underlying stressors (load, renewables, or outages)

Placeholder image for interactive visual

Visualizing the Data: Correlation Matrices

Quantify the correlation between regional periods of high stress (low margin) to determine which regions will experience tight margin conditions at the same time (quantifies geographic diversity)

Minimum Daily Margin Correlation by FERC 1000 Region (All Hours of Year)

	CAISO	NorthernGrid	WestConnect	ERCOT	SPP	MISO	SERTP	FRCC	PJM	NYISO
NorthernGrid	0.56									
WestConnect	0.63	0.42								
ERCOT	0.43	0.25	0.6							
SPP	0.42	0.42	0.57	0.62						
MISO	0.34	0.29	0.58	0.56	0.61					
SERTP	0.23	0.21	0.48	0.45	0.41	0.71				
FRCC	0.16	−0.21	0.4	0.42	0.12	0.4	0.44			
PJM	0.29	0.39	0.36	0.36	0.42	0.72	0.73	0.16		
NYISO	0.25	0.16	0.31	0.25	0.21	0.45	0.45	0.31	0.63	
ISONE	0.34	0.38	0.25	0.24	0.25	0.41	0.39	0.11	0.71	0.8

Bottom 1400 Margin Hours Correlation by FERC 1000 Region (Lowest 2.2% of Margin Hours)

	CAISO	NorthernGrid	WestConnect	ERCOT	SPP	MISO	SERTP	FRCC	PJM	NYISO	ISONE
CAISO	1	0.08	0.29	0.1	0.11	−0.08	0.06	−0.1	−0.11	0.03	−0.03
NorthernGrid	0.25	1	0.32	0.13	0.09	−0.05	0	−0.11	0.04	0.11	0.05
WestConnect	0.19	−0.02	1	0.05	0.04	0.06	−0.08	−0.19	−0.03	0.1	0.1
ERCOT	0.12	0.05	0.2	1	0.23	0.26	−0.02	−0.03	0.01	0.14	0.11
SPP	0.02	0.03	0.04	0.07	1	0.27	−0.03	−0.01	0.02	0.11	−0.02
MISO	0.04	0.03	0.03	−0.02	0.29	1	0.06	0.01	0.24	0.25	0.22
SERTP	0	−0.1	0.08	0.1	0.26	0.3	1	0.22	0.28	0.14	0.22
FRCC	0.09	−0.07	0.16	0.03	0.12	0.1	0.22	1	0.02	0.08	0.12
PJM	0.02	−0.02	0.01	0	0.25	0.36	0.18	0.13	1	0.45	0.44
NYISO	0.06	−0.14	0.03	−0.09	0.11	0.15	−0.03	−0.06	0.26	1	0.58
ISONE	0.09	−0.1	0.07	−0.03	0.06	0.07	0.03	−0.06	0.38	0.58	1

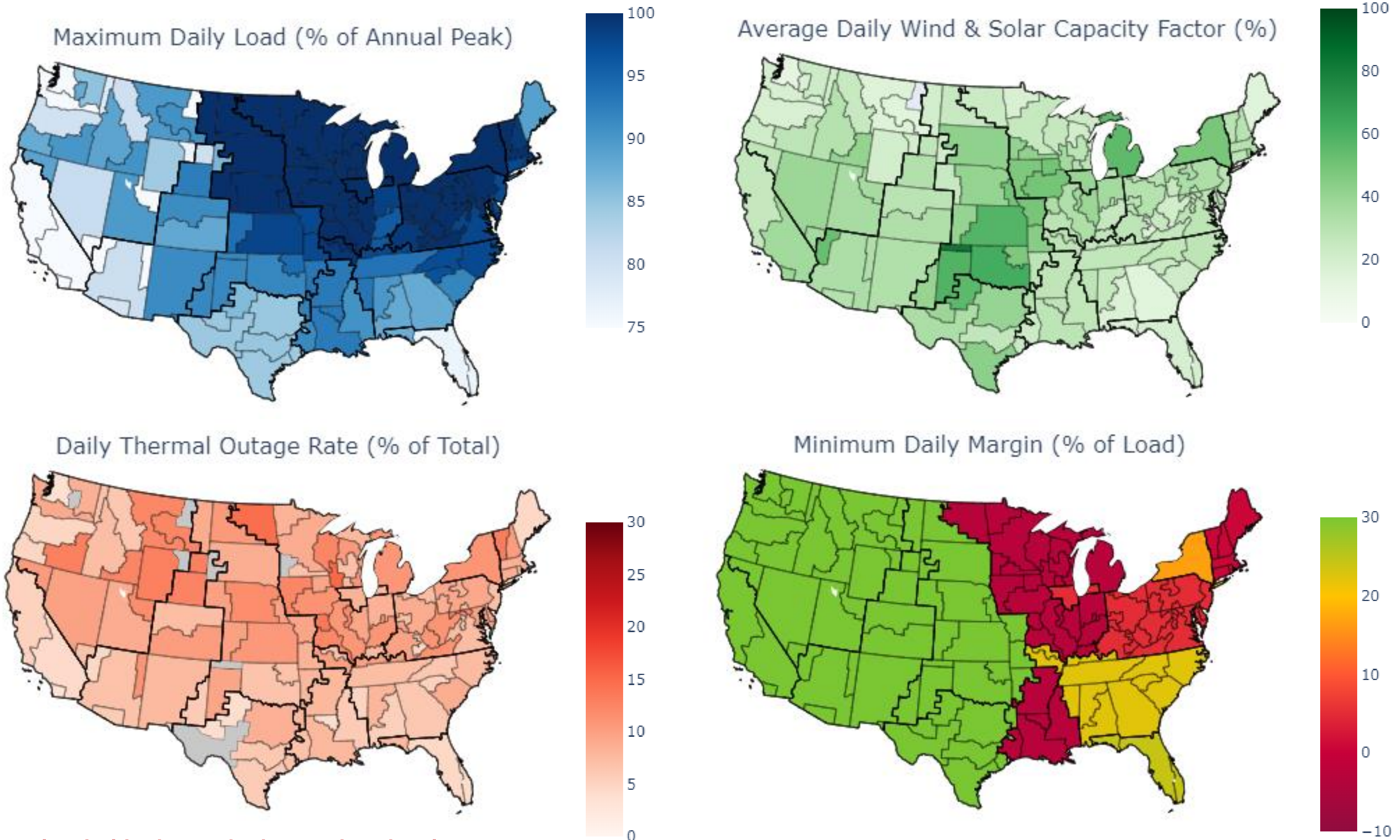
Visualizing the Data: Regional Maps & Events

Deep dive into interesting periods of tight margin to visualize geographic diversity.

Particularly helpful in showing the movement and regional concentration of events to identify priority regional connections

e.g., heat wave in Midwest and mild temperatures and load in the Southwest

July 14, Weather Year 2012



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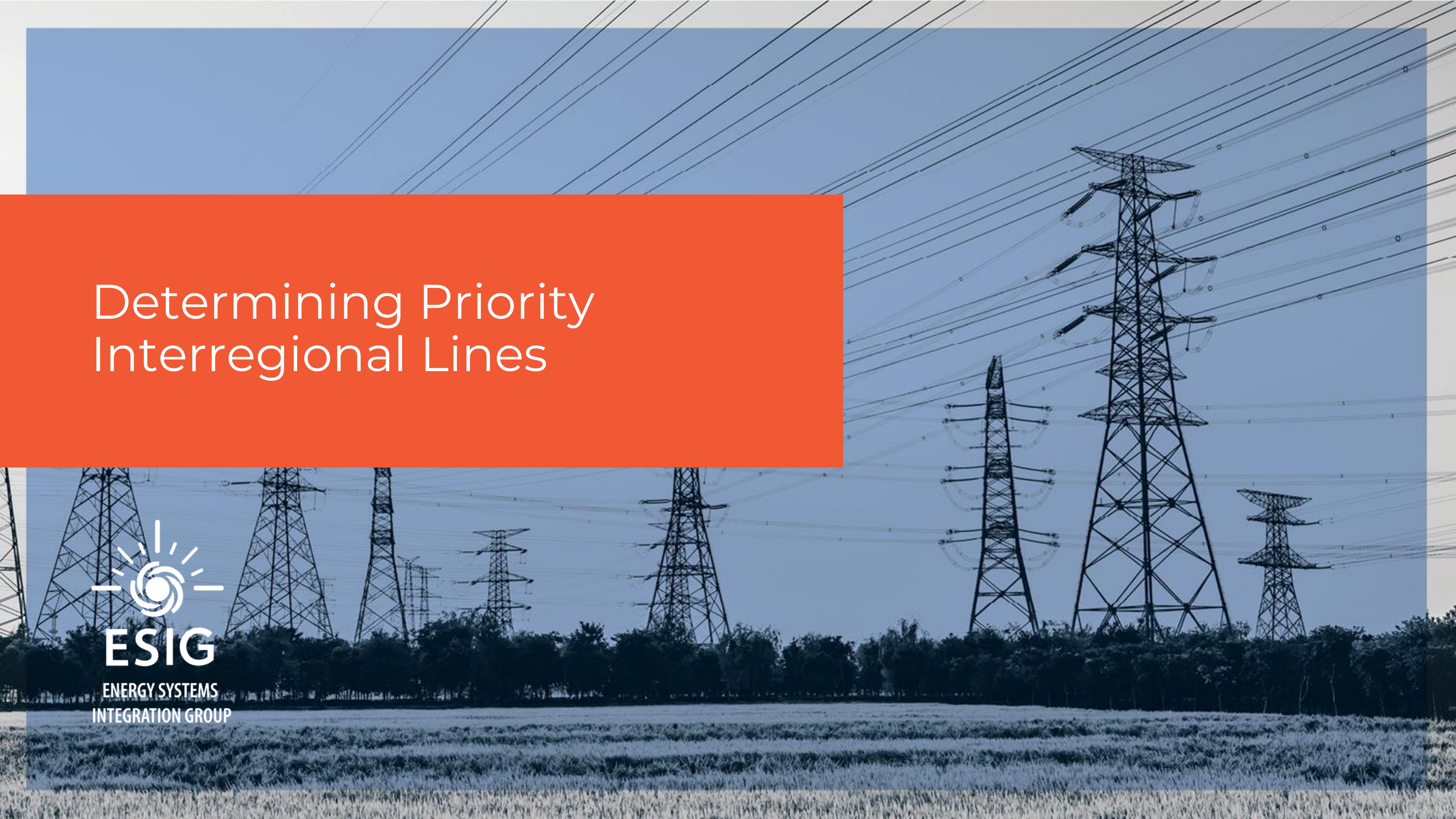

Determining Priority Interregional Lines

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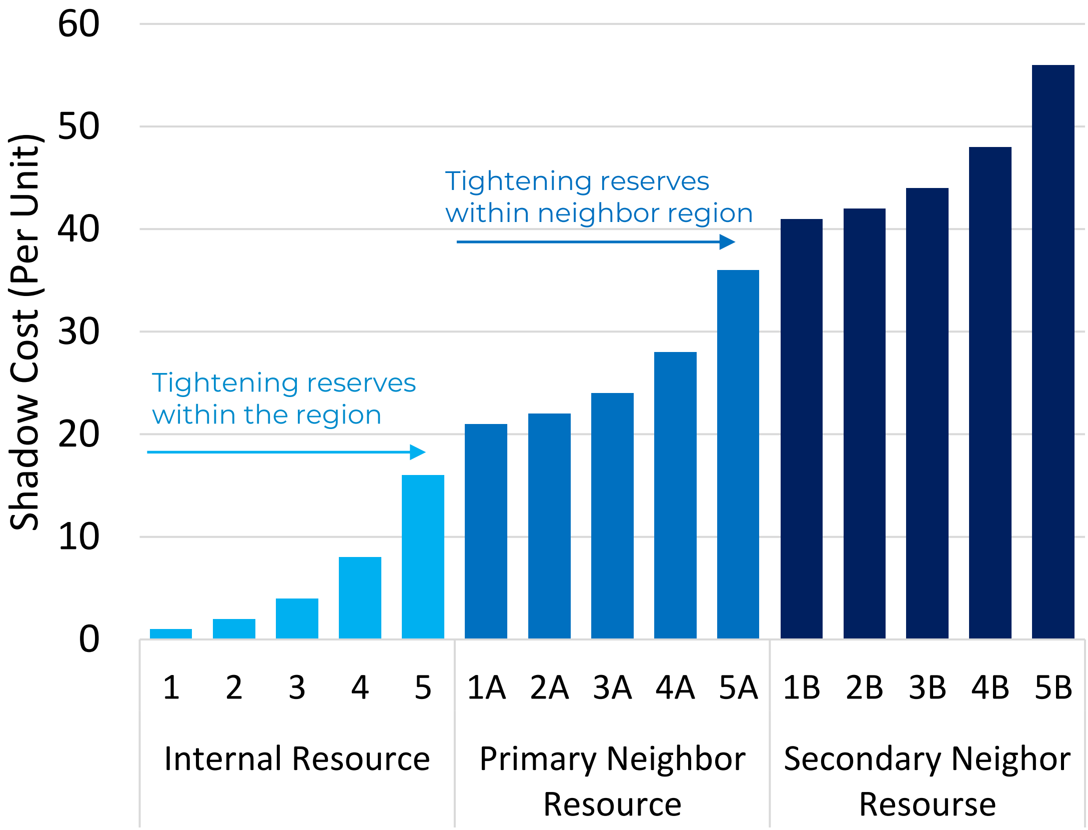
How should we prioritize interregional line expansion for **reliability & resilience**?

1. Prioritize imports from regions that have more surplus resources and low correlation of tight margin conditions

2. Prioritize closer immediate neighbors

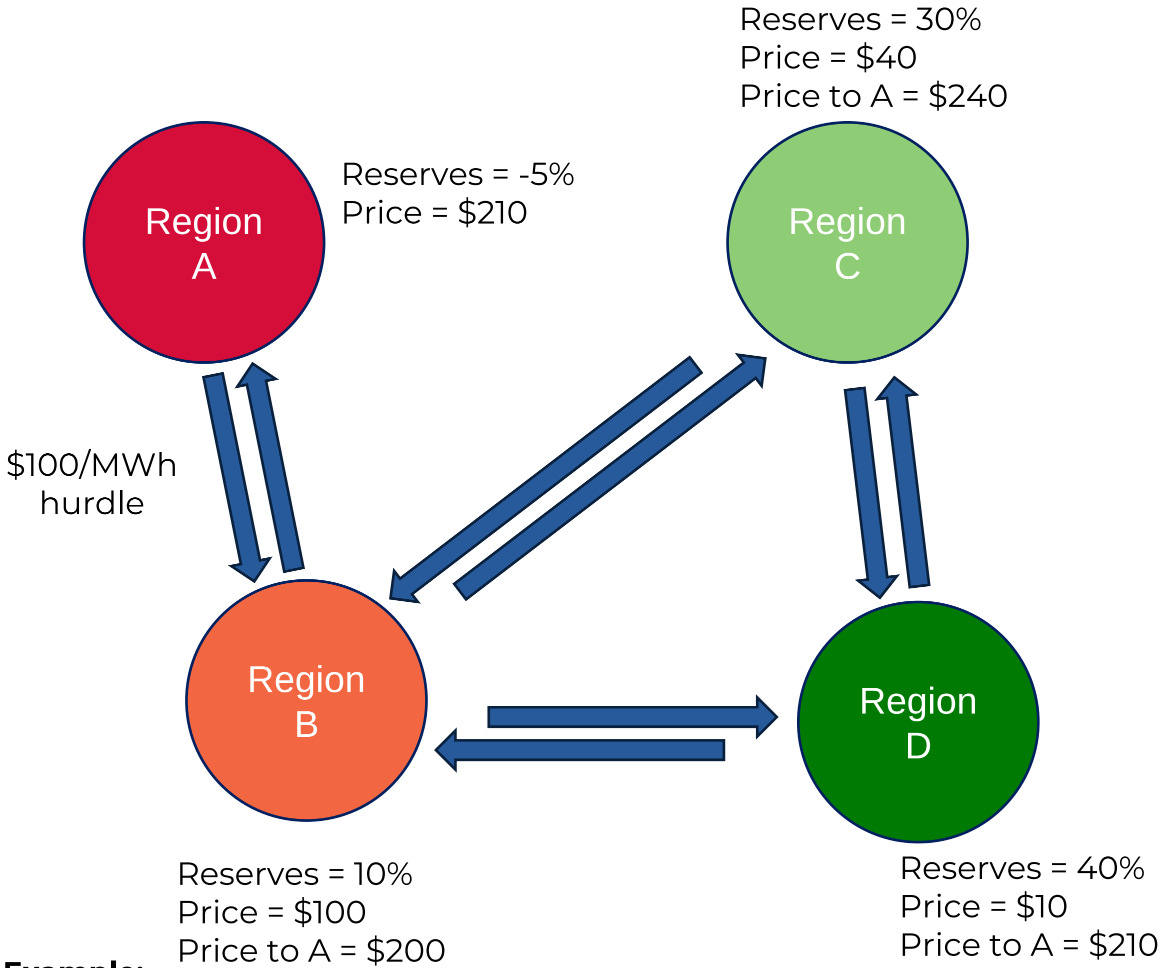
3. Allow for flow from “neighbors-neighbor”

Example Region Shadow Cost



Methodology for Identifying High Priority Interregional Lines **for Reliability & Resilience**

- Represent each FERC 1000 region with their expected available capacity and load across 7-years and include existing interregional transfer capabilities.
- Regions with margin below 10% of load will draw from neighbors for support.
- Transmission flows will be limited to reliability hours only by a high hurdle rate (e.g., 100 $/MWh) to force each region to serve its own load first.
  - The hurdle rate and the increased resource cost at tighter reserves (previous slide) both create a shadow price on the interregional lines
  - When transmission was needed to reach 10%, 20%, and 30% of peak demand, it was added in proportion to the shadow cost on the line
  - Transfer capacity was added where it would reduce 'congestion' for reliability imports only
- **Objective is to identify regions where transfer capabilities limit the support from neighbors, likely indicating a high-value, high priority path to increase transfer capabilities incrementally until the shortfalls are resolved.**



Example:
Region A is short and will be supported by Region D because it has high reserves (low price), and Region B cannot go below 10% reserves.

Results of Priority Lines for Minimum Interregional Transfer Capability Scenarios

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Bi-directional Tie Line Capability (maximum of From/To ratings)

Path Name	Base Tx	Incremental Tx to get to 10% ITC	Incremental Tx to get to 20% ITC	Incremental Tx to get to 30% ITC	Delta 30% ITC to Base (%)
NorthernGrid <---> CAISO	8,026	0	0	2,237	28%
WestConnect <---> CAISO	7,908	0	0	479	6%
MISO <---> NorthernGrid	-	0	4,667	13,760	N/A
SPP <---> NorthernGrid	200	0	2,372	7,967	3983%
WestConnect <---> NorthernGrid	1,872	0	0	0	0%
ERCOT <---> WestConnect	-	2,680	5,151	13,624	N/A
SPP <---> WestConnect	939	0	1,483	1,483	158%
MISO <---> ERCOT	-	2,403	6,286	7,289	N/A
SPP <---> ERCOT	834	2,356	4,475	4,475	537%
MISO <---> SPP	3,283	0	1,439	2,197	67%
SERTP <---> SPP	1,484	0	7,121	14,480	976%
PJM <---> MISO	8,864	0	0	0	0%
SERTP <---> MISO	5,326	0	1,848	3,286	62%
FRCC <---> SERTP	2,862	2,833	8,528	14,224	497%
PJM <---> SERTP	4,310	0	3,153	7,297	169%
NYISO <---> PJM	3,745	0	1,148	4,502	120%
ISONE <---> NYISO	1,814	897	3,607	3,607	199%

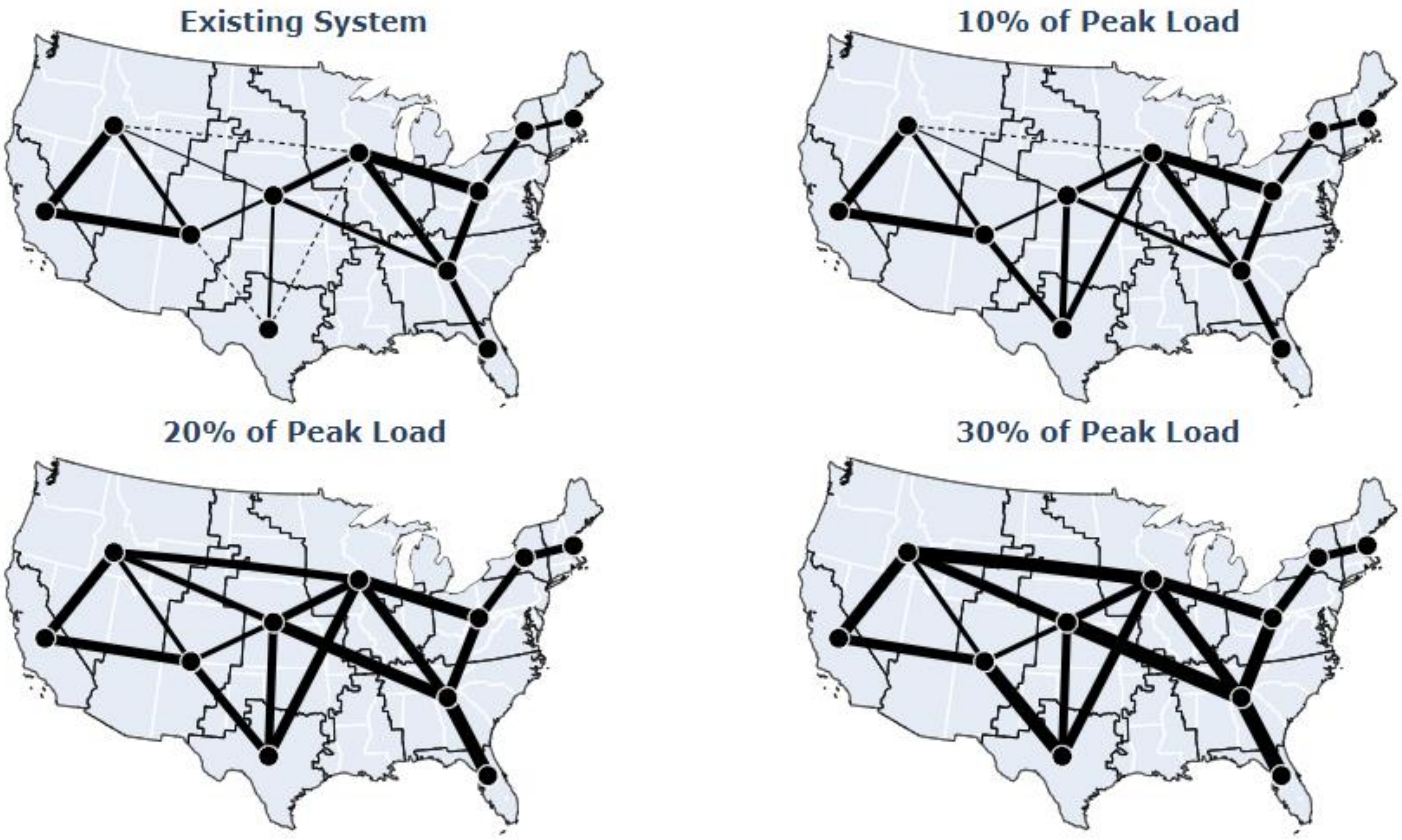
Results show which interregional paths should be expanded by incrementally meeting increasing minimum ITC targets.

Paths where the existing capability was congested due to margin targets or higher reserve surpluses were expanded

Results capture the “neighbor’s neighbor” effect of flowing power across multiple regions

Visualizing Priority Lines

Bidirectional Tie Line Capability (maximum of From/To ratings)



Key Findings

A Framework for Planners

This methodology can be used to augment a region’s probabilistic RA framework to investigate where their region may see the most resilience benefits for expanding interregional transmission capabilities.

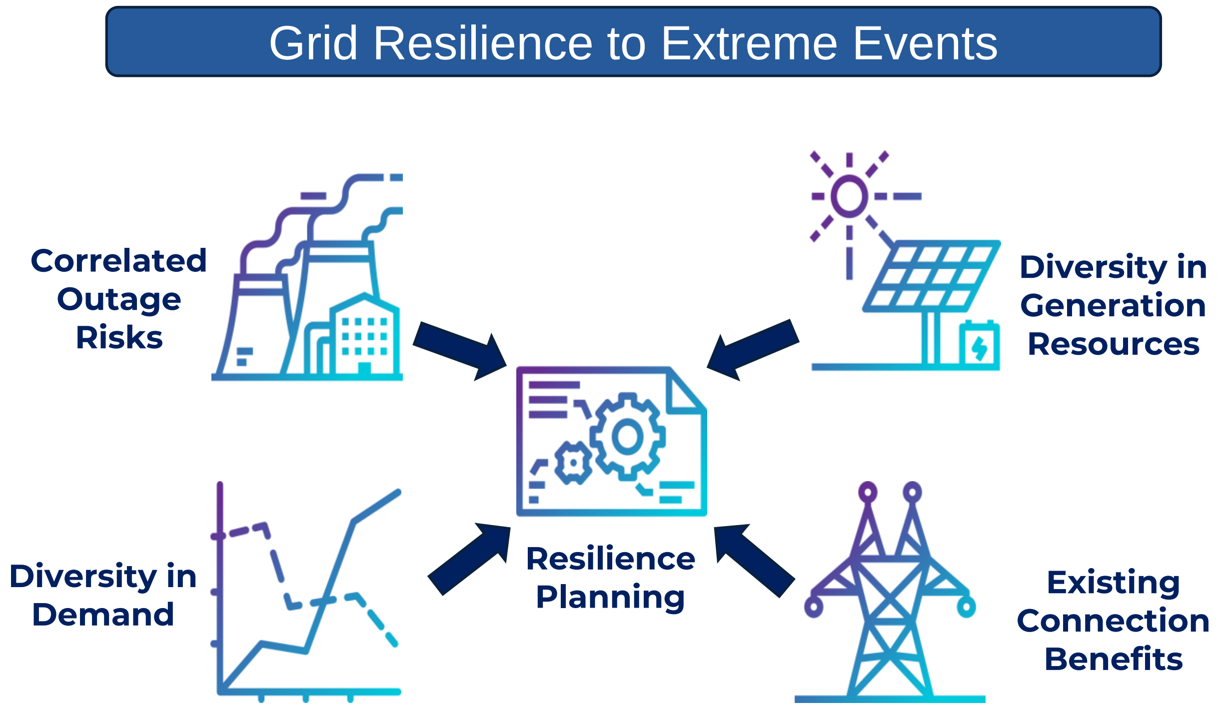
Identification of Priority Lines

Planning transmission with regards to resilience should consider geographically diverse areas with complementary resource mixes, uncorrelated outage and load risks.

Data needs are critical

We have limited availability of consistent, correlated, hourly time series of load, wind, solar, and weather-dependent outages and we are missing extreme events.

New ESIG Report on need for weather data!



Future Analysis Modeling More Extreme Events

Based on feedback from the study task force we are looking to extend the analysis to include some of the most extreme events seen in recent years. There is also room for potentially updating some of underlying data.

Next Steps:

- Use the margin framework to assess two recent extreme weather events like Winter Storm Uri/Elliott and the Southwest heat dome
- Add additional quantification of resilience benefits by reviewing the reduction in magnitude and duration of low margin periods
- Incorporate the methodology into a regional probabilistic RA framework to represent potential availability imports from neighbors

Backup Slides

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Inputs & Assumptions Recap

Develop Regions → Capacity Forecast → Solar & Wind Dataset → Load & Electrification → Weather Dependent Outages → Regional Net Load & Margin → Future Transfer Limits

	Source	Description	Status
Regions	FERC	FERC Order 1000 regions with small modifications	Complete
Transmission Capability	ESIG	Based maximum historical transfers reported in EIA hourly data	Complete
Capacity Forecast	NREL	Standard Scenario capacity expansion for near-term study year	Complete
Wind and Solar Dataset	NREL	Hourly wind and solar available generation by weather year (2007-2013) by ReEDS balancing authority	Complete
Load	NREL	Standard scenario hourly data by weather year (2007-2013) includes load growth from end use electrification, but not weather dependent hourly profile	Complete
Weather Dependent Outages	S. Murphy, Telos Analysis	Daily minimum/maximum temperature observations applied by technology type, by balancing authority. Modeled as a deterministic capacity derate (2007-2013)	Complete
Hydro	NREL	ReEDS monthly max rating, assumes no energy limitations during tight margin conditions	Complete
Storage	Telos Analysis	Storage scheduled to arbitrage net load curve by region	Complete

Solar, Wind, and Resource Build Dataset

Multi-Year Solar and Wind Dataset and

Purpose: Provide a geographically diverse timeseries of wind and solar output across the study topology.

Selected Data Source: NREL Cambium standard scenario 2020s low-cost renewable resource mix

- Includes the **capability to assess weather years for 2007 – 2013** for wind, solar, and load under future growth scenarios
- Cambium spreads renewable resource additions in each ReEDS BA by resource class (best to worst solar) based on geographic limitations and transmission estimates to reach optimal locations

Future Resource Buildout

Purpose: Account for planned retirements and new generation resources required to meet planning criteria to capture the changing regional mix of dispatchable generation and renewable generation

- Buildout scenarios – less focus needed on the years, more emphasis will be placed on evaluating a “close to existing” system with higher penetrations of wind and solar across the country.

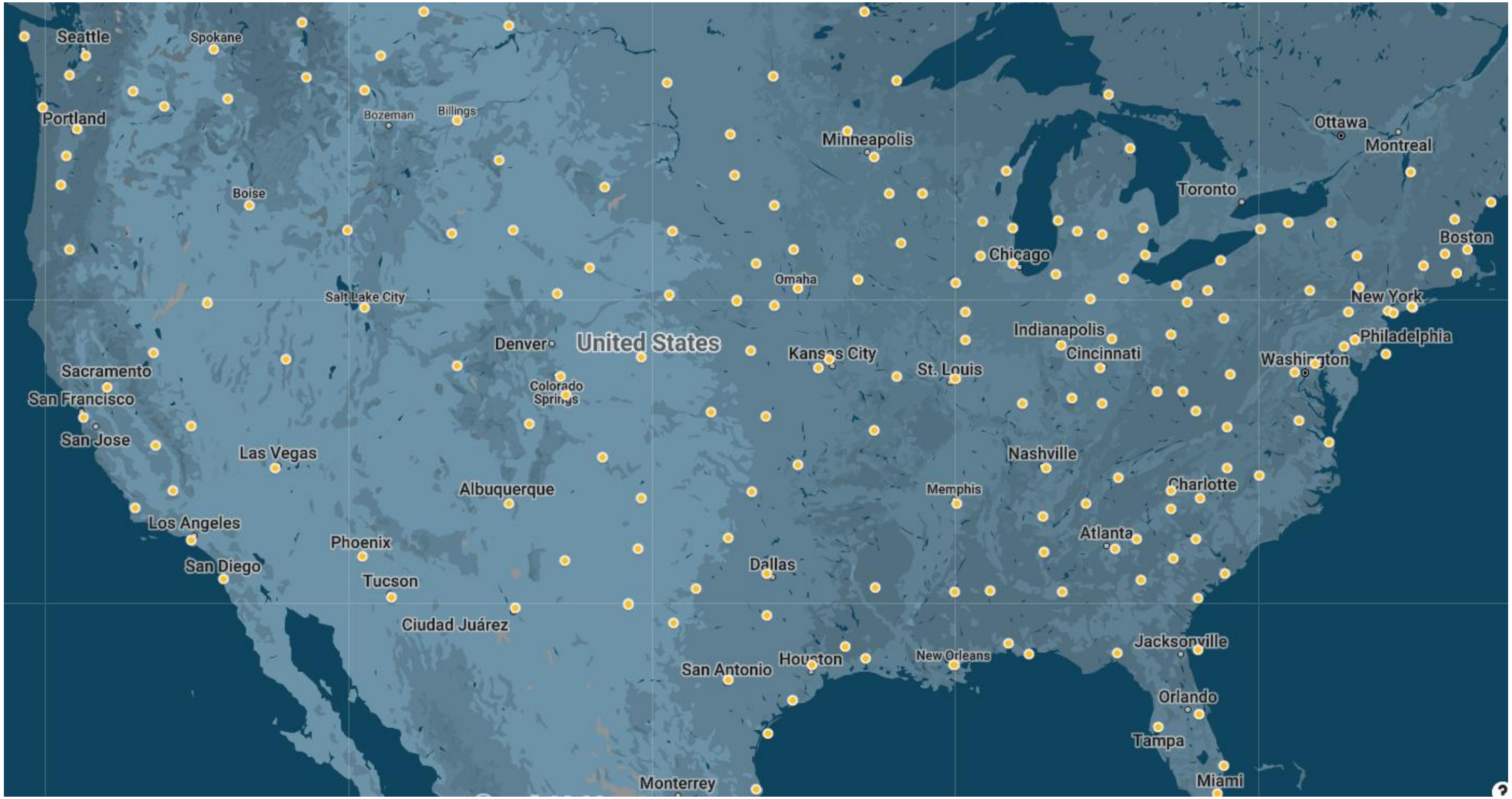
Resource Capacity by Region

Leverages near-term NREL Cambium low-cost renewable expansion scenario for resource mix by FERC 1000 region and includes near-term retirements (planned and age-based) embedded in expansion results

- Emphasis is on evaluating a system close to the existing one with high levels of renewable resources where correlation with weather may emphasize resilience needs

Summer Capacity (MW)	CAISO	ERCOT	FRCC	ISONE	MISO	NYISO	PJM	SERTP	SPP	Northern Grid	WestConnect
Batteries	3,202	1,728	669	133	51	1,858	1,764	135	13	858	1,158
Biomass	835	111	743	1,069	923	395	1,252	645	34	319	65
Coal	0	14,767	5,043	439	51,707	445	40,803	36,170	21,203	7,986	11,285
Solar	35,160	39,678	27,346	7,282	17,350	5,538	28,745	32,043	20,329	12,449	25,956
LBW	6,476	35,692	0	1,836	37,576	5,070	7,343	237	58,016	11,186	10,603
OSW	0	0	0	1,546	0	130	3,869	0	0	0	0
Gas CC	19,789	34,331	32,719	12,900	38,691	9,762	59,044	35,015	11,820	13,675	15,189
Gas CT	10,753	7,946	3,371	2,257	20,130	2,825	28,909	20,650	7,376	3,694	5,639
Geothermal	3,106	0	0	0	0	0	0	0	0	785	0
Hydro	10,098	563	55	1,958	3,154	4,551	3,194	12,116	3,397	37,938	3,863
Nuclear	2,240	4,980	3,666	3,321	13,478	3,203	30,853	28,123	1,995	1,151	3,937
Oil-Gas-Steam	995	9,933	0	2,438	12,423	10,651	9,802	1,212	153	617	1,118
PSH	3,912	5	0	1,546	0	130	5,233	6,396	444	314	797

Locations of temperature data for weather dependent outages



190 weather stations (airports)

41 weather years (1981-2022)

Daily observations, min/avg/max temp

Each NREL ReEDS balancing area mapped to temperature observation

Special thanks to Erik Smith (EPRI) for providing data

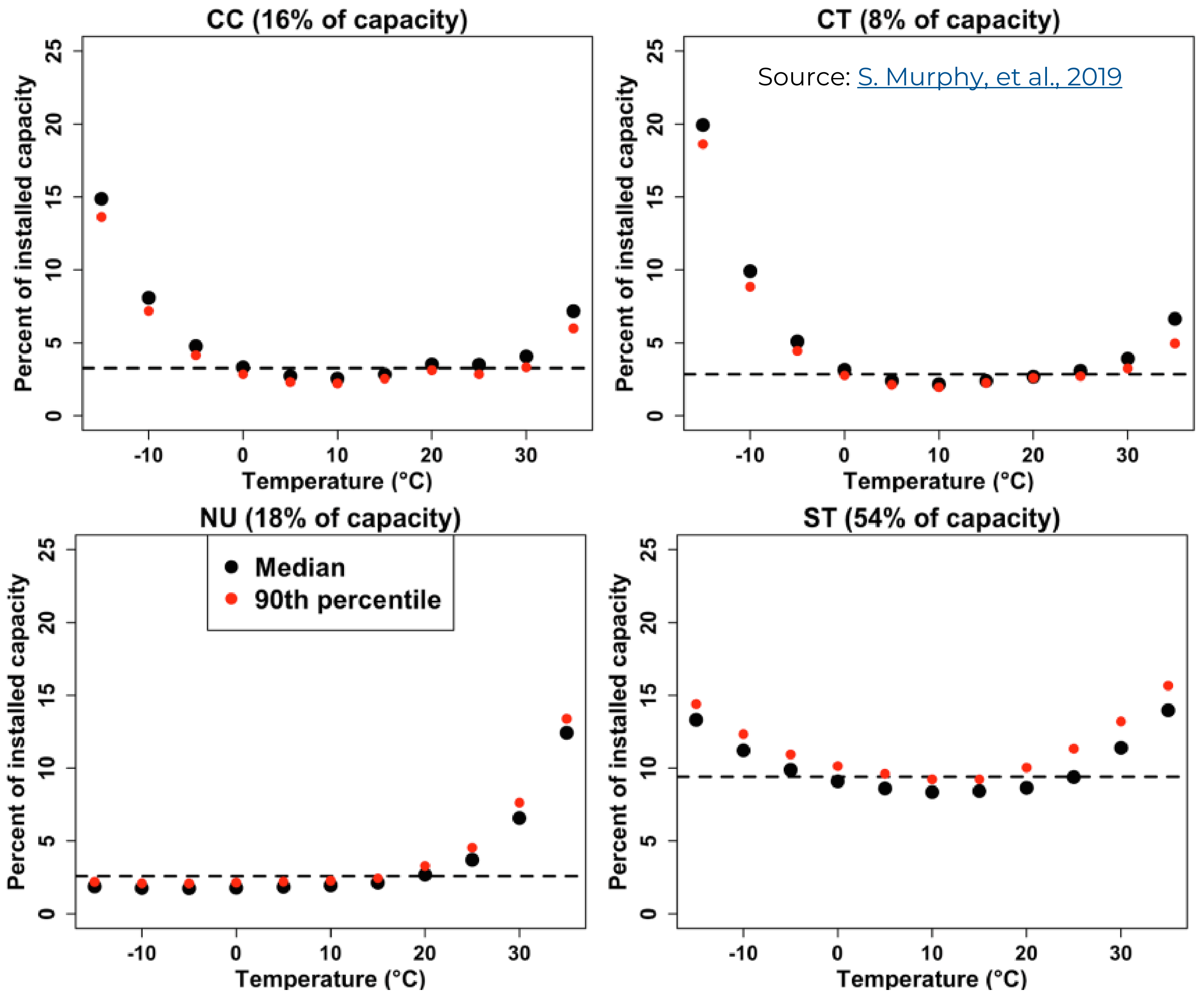
Incorporating weather dependent outages by region

Method: utilize weather dependent outage (WDO) functions for each technology, based on temperature-outage rate relationship from S. Murphy, et al., 2019

Originally developed for PJM, but applied nationally with adjustments (see following slides)

Implemented as a time-varying, daily UCAP derate by technology (deterministic, no probabilistic sampling)

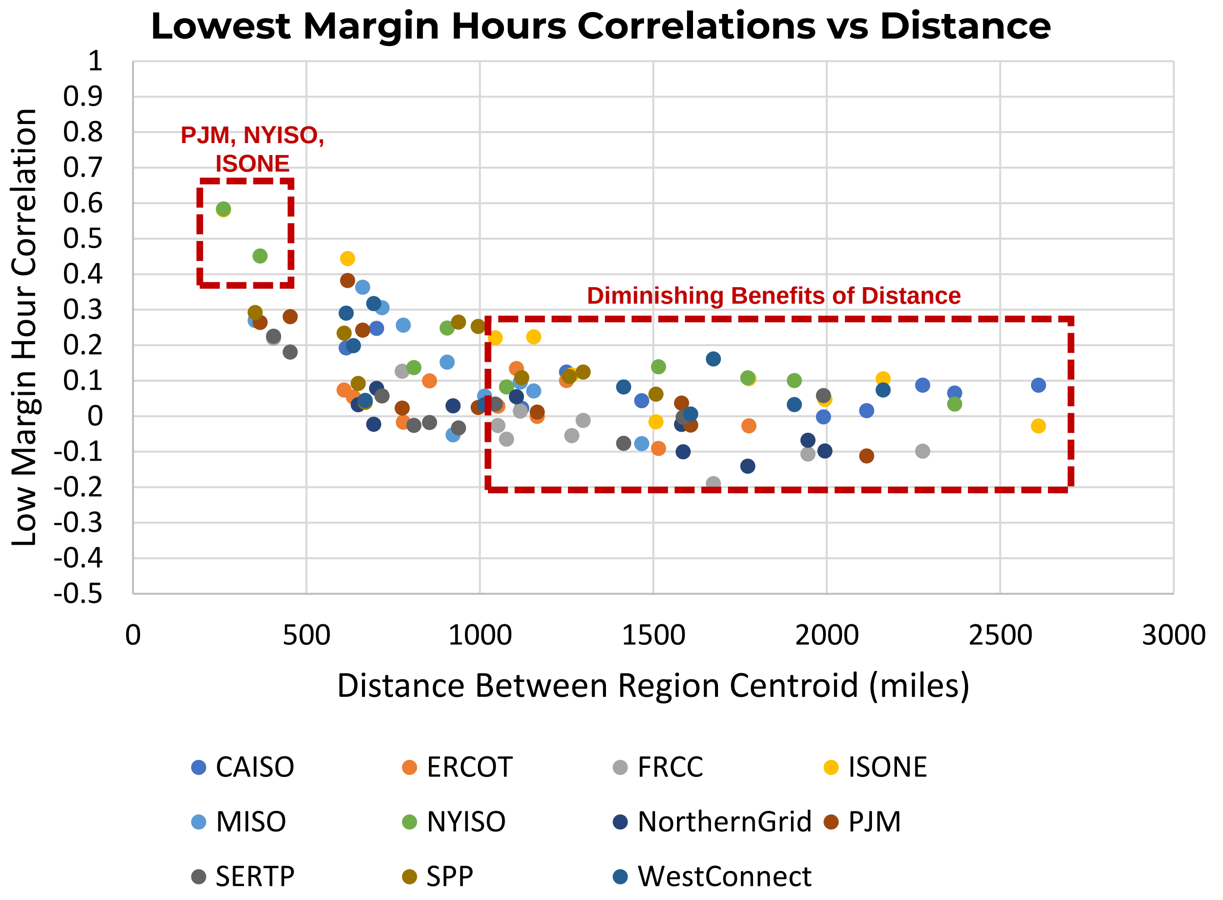
A time series was developed for each technology type, for each, NREL ReEDS balancing authority, then aggregated up to the FERC Order 1000 region



Visualizing the Data: Correlations vs Distance

Correlation Visualizations: Shows correlation between each region across the lowest 1,400 hours of margin in the 2007 – 2013 period. Plotting as a function of distance between region shows some regions have lower correlation of low margin hours regions further away.

- Regionally concentrated and small regions (ISONE & NYISO) show higher correlations of low margin hours
- Most regions show relatively low correlation during low margin hours (<0.5) and high potential for sharing
- Geographic distances greater than 1,000 miles show there can be **diversity with less cost (shorter distance)**



Frequency of Low Margin Events w/o Transmission

Periods of low margin (<10%) appear seldomly in the 2007 – 2013 period. This is driven by a lack of extreme events like recent heat domes or Uri/Elliott in the dataset and the use of expected available capacity which may miss outlier but extreme outage events.

- Current assumptions are that interregional transfers would occur during hours when margin is below 10% of a regions load.

Low Margin Results	CAISO	ERCOT	FRCC*	ISONE	MISO	NYISO	PJM	SERTP	SPP	Northern Grid	WestConnect
Hours Margin <10%	1,072	21	1,998	259	451	57	36	60	11	0	0
Hours Margin <0%	308	0	364	47	27	0	0	0	1	0	0
Minimum Margin (MW)	-11,705	1,103	-12,744	-2,540	-3,283	1,391	4,539	81	-244	5,915	4,339
Historical Max Transfer (MW)*	15,934	821	2,860	1,814	15,853	5,555	15,686	13,951	5,601	9,892	10,591

*Historical max transfer shown is the 99.9th percentile non-coincident transfers between regions and does not include regions external to the U.S.
*FRCC results show drastic shortfalls due to the retirements assumed in the ReEDS expansion results and showing historical transfer capabilities versus expanded transfers

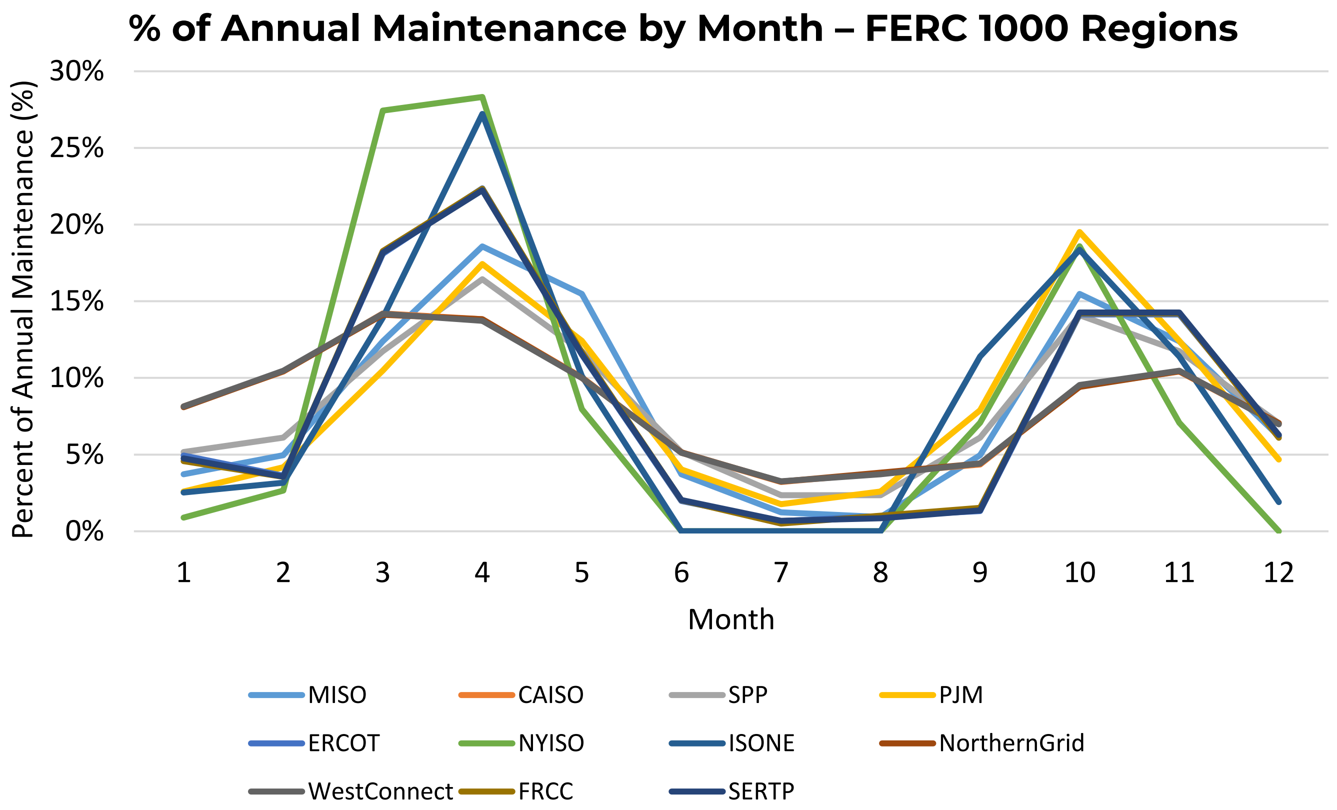
Expected Maintenance Implementation

Maintenance shapes for each region are based on recent published monthly maintenance data (market monitor, ISO reports, etc.) or uses a neighbors' maintenance shape if no data is available.

Annual maintenance by unit type (Coal, Gas CC, Gas CT, etc.) is based on NERC GADS fleetwide data.

- Planned Outage Factor (POF)
- Maintenance Outage Factor (MOF)

Assumed that 20% of maintenance is recallable to reduce expected capacity on outage to account for emergency operations.



Visualizing the Data: Low VRE Trends

Low VRE Visualizations: Identifying periods of correlated low renewable output across large regions in terms daily renewable energy output as a % of load. Clear seasonal differences between areas with different VRE builds and resource potential. Useful for identifying low VRE periods for detailed analysis and including regional availabilities (e.g., wind drought but solar deluge).