Interregional Transmission for Resilience

USING REGIONAL DIVERSITY TO PRIORITIZE ADDITIONAL INTERREGIONAL TRANSMISSION

A Report by the
Energy Systems Integration Group's
Transmission Resilience Task Force

June 2024

ESIG
ENERGY SYSTEMS INTEGRATION GROUP

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Interregional Transmission for Resilience: Using Regional Diversity to Prioritize Additional Interregional Transmission

A Report by the Energy Systems Integration Group's Transmission Resilience Task Force

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Suggested Citation

Energy Systems Integration Group. 2024. *Interregional Transmission for Resilience: Using Regional Diversity to Prioritize Additional Interregional Transmission.* Reston, VA. https://www.esig.energy/interregional-transmission-for-resilience.

Design: David Gerratt/NonprofitDesign.com
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Contents

Abbreviations Used

CAISO	California Independent System Operator
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
ISO	Independent system operator
ISONE	Independent System Operator of New England
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
ReEDS	Regional Energy Deployment System
RTO	Regional transmission organization
SPP	Southwest Power Pool
SERTP	Southeastern Regional Transmission Planning
WECC	Western Electricity Coordinating Council

Executive Summary

As extreme weather events become more of a concern for the electric power industry, power system resilience is seen as an increasingly valuable grid quality that offers measurable advantages to consumers. Events such as Winter Storm Uri in 2021, which resulted in widespread outages and loss of life, highlight the critical need for a resilient grid that can withstand and recover from such disruptions. While the industry has well-established standards and procedures for evaluating reliability and resource adequacy needs, the increasing industry focus on grid resilience indicates that these standards may not be sufficient to address the unique challenges posed by high-impact, low-frequency events such as winter storms, summer heat waves, and concurrent power plant outages.

Interregional transmission can increase grid resilience by enabling the transfer of electricity across large geographical areas, thereby mitigating the impacts of local or regional disruptions. Increased transfer capability between regions can help balance supply and demand during periods of stress due to high load, inclement weather, high generator outages, low renewable output, or a combination of these. Interregional transmission improves grid resilience by allowing regions to access diverse resources in other regions that are not simultaneously affected by the same weather conditions.

While the industry has well-established standards and procedures for evaluating reliability and resource adequacy needs, these standards may not be sufficient to address the unique resilience challenges posed by high-impact, low-frequency events.

However, despite the potential benefits, current planning processes often overlook the resilience value of interregional transmission, focusing on local reliability solutions within the local territory or only a small geographical region. This report offers planners a framework for assessing transmission's adequacy and resilience benefits at a national scale and prioritizing transmission investments that offer the greatest benefits for system resilience.

Need for a National-Scale Solution to a Nationwide Risk

Recent extreme weather events have reinforced that these events are often larger than local planning regions and can move across multiple regions as the storms progress, a dynamic that points to the need for a national-scale solution. This need is broadly recognized, as underscored by recent actions by the Federal Energy Regulatory Commission (FERC) and Congress. FERC Order 1920 mandates the consideration of interregional transmission projects in regional planning, and the proposed BIG

WIRES Act, if enacted, would establish a minimum transfer capability between regions as a function of their peak load. And the North American Electric Reliability Corporation (NERC) has been tasked with quantifying existing transfer capabilities and recommending prudent additions to ensure reliability, highlighting the importance of this topic to grid planners and policymakers as uncertainty grows around maintaining grid reliability, adequacy, and resilience in the face of a changing resource mix, new loads, and the effects of climate change.

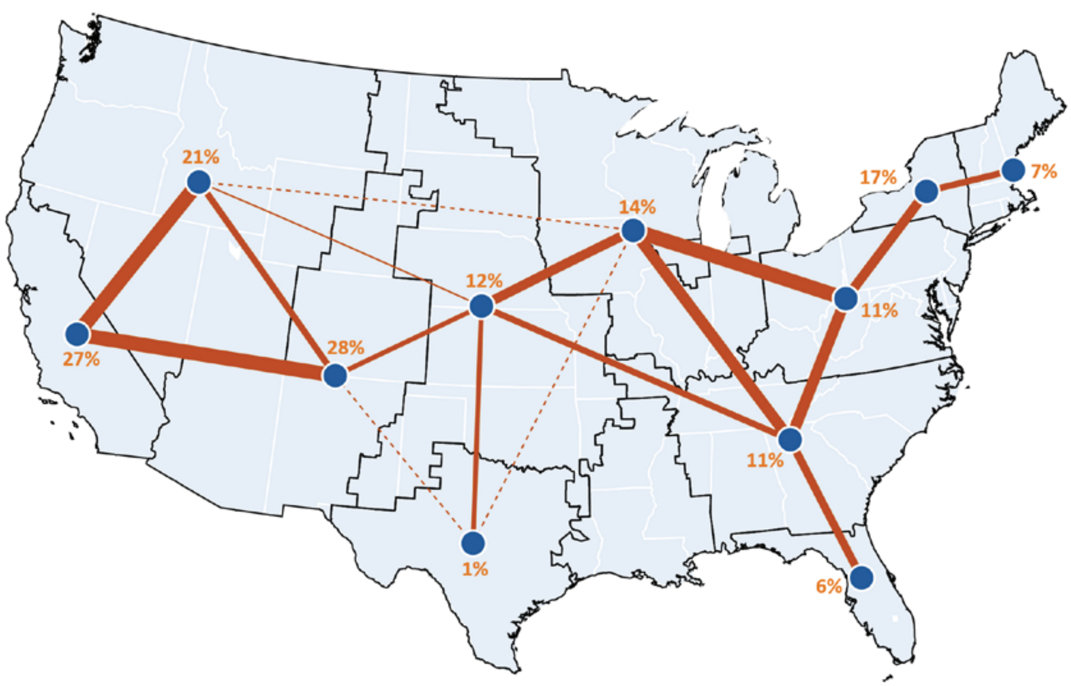
Given the variety of options to improve grid resilience, it is important to have robust procedures to assess expected benefits and allow cost/benefit comparisons of solutions. This study first provides a nationwide assessment of current interregional transmission capability. To date, there is no consistent, rigorous method for planning additional transfer capability between regions. The Energy Systems Integration Group's Transmission Resilience Task Force developed the methodology detailed in this report to aid in evaluating the resilience benefits of interregional transmission, providing planners with a quantitative approach to prioritizing new transfer capability to increase resilience. Future work from the Transmission Resilience Task Force will apply these methods for a specific region to provide more detailed quantification of the benefits that interregional transmission can provide during grid stress conditions.

Today's Interregional Transfer Capability

This study estimated existing interregional transmission capabilities using historical flow data from the Energy Information Administration Form 930, analyzing five years of hourly interchange data (2019-2023) at the FERC Order 1000 level. We evaluated the transfer capability between regions and the total transfer capability for each region. Figure ES-1 shows the magnitude of each region's existing transfer capability with its neighbors as a percentage of the region's peak load modeled in this study.

FIGURE ES-1

Existing Interregional Transmission Paths Across the U.S., by FERC Order 1000 Region



The blue dots represent the FERC Order 1000 regions, with orange lines showing the magnitude of the transfer capability between each pair of regions. Dotted lines represent no existing transfer capability, but the potential for immediate neighbors to create transfer capability. The thickness of the solid lines indicates the relative amount of transfer capability in each case. Note, transfer capabilities for U.S. regions with connections to Canadian regions are not included in these values.

Source: Energy Systems Integration Group; data from Energy Information Administration 930 Hourly Electric Grid Monitor.

These findings show that current transfer capabilities for most regions of the country are below 20% of a region's peak load. Given this assessment of existing interregional transfer capabilities, this study presents a methodology to assess where the potential greatest resilience benefits can be realized when increasing interregional transfer capabilities.

Evaluating Resource Availability by Region to Assess Priorities for Additional Interregional Transmission

To support planners evaluating and designing interregional transmission projects, an assessment is needed of each region in the U.S. in terms of hourly variability in wind and solar resources, the unavailability of thermal generators due to correlated outages and maintenance plans, and each region's ability to import or export power to its neighbors. This study provides an initial methodology that can be adapted to meet an individual planning region's needs with a reasonable representation of the neighboring power systems and markets. The study results also inform national efforts to assess resilience benefits from interregional transmission.

This national assessment of the potential benefits from interregional transmission begins with an evaluation of the diversity in hourly electricity demand and resource availability across multiple weather conditions in all regions with consideration of hourly, weather-dependent inputs on loads and resource availability. To assess the diversity of customer demand and resource availability in regions across the U.S., we looked at both normal operating conditions and extreme conditions within a set of hourly weather data representing weather from 2007 through 2013 on a future grid. This study calculated an hourly energy margin that measured hourly available wind and solar, seasonal hydro capacity, and available thermal capacity after accounting for maintenance and weather-dependent outages. The available capacity was compared against hourly loads, inclusive of a capacity margin as a percentage of hourly load, and storage net generation.

This broad, national assessment of hourly energy margins is meant to be complementary to a region's detailed production-cost and resource adequacy assessments by assessing weather-dependent resource availability across a wide geographical area. This is typically not done for production-cost and resource adequacy assessments due to data, analytical, and computational limitations. Instead, system planners often model their own region in a high degree of detail, while incorporating limited or even no representation of neighboring regions. Calculating the hourly energy margin offers a simplified yet robust view of the surplus or deficit in available resources in each region across every hour of a weather year, enabling planners to identify surplus resources and potential support regions during grid stress events such as extreme heat or cold or low renewable resource output. This level of external awareness is critical for assessing the resilience benefits that increasing interregional transmission capability can provide.

Results presented in this report were developed using seven weather years of data and future resource mixes developed by the National Renewable Energy Laboratory across the continental U.S. In addition, the hourly energy margin calculation is adaptable to any number of weather years, load data, future resource mixes, or other planned system changes, making it a flexible tool for assessing interregional resource diversity.

The hourly energy margin calculation is adaptable to any number of weather years, load data, future resource mixes, or other planned system changes, making it a flexible tool for enhancing transmission grid planning to ensure long-term resilience.

A Case Study to Prioritize the Optimal Locations for Building Interregional Transmission

Using these hourly energy margins, a case study was conducted based on the goal from the proposed Building Integrated Grids With Inter-Regional Energy Supply Act (BIG WIRES) of establishing a minimum interregional transmission capability of up to 30% of a region's peak load. We used the hourly energy margin analysis to determine the preferred connections and magnitude of increased interregional transmission for each region.

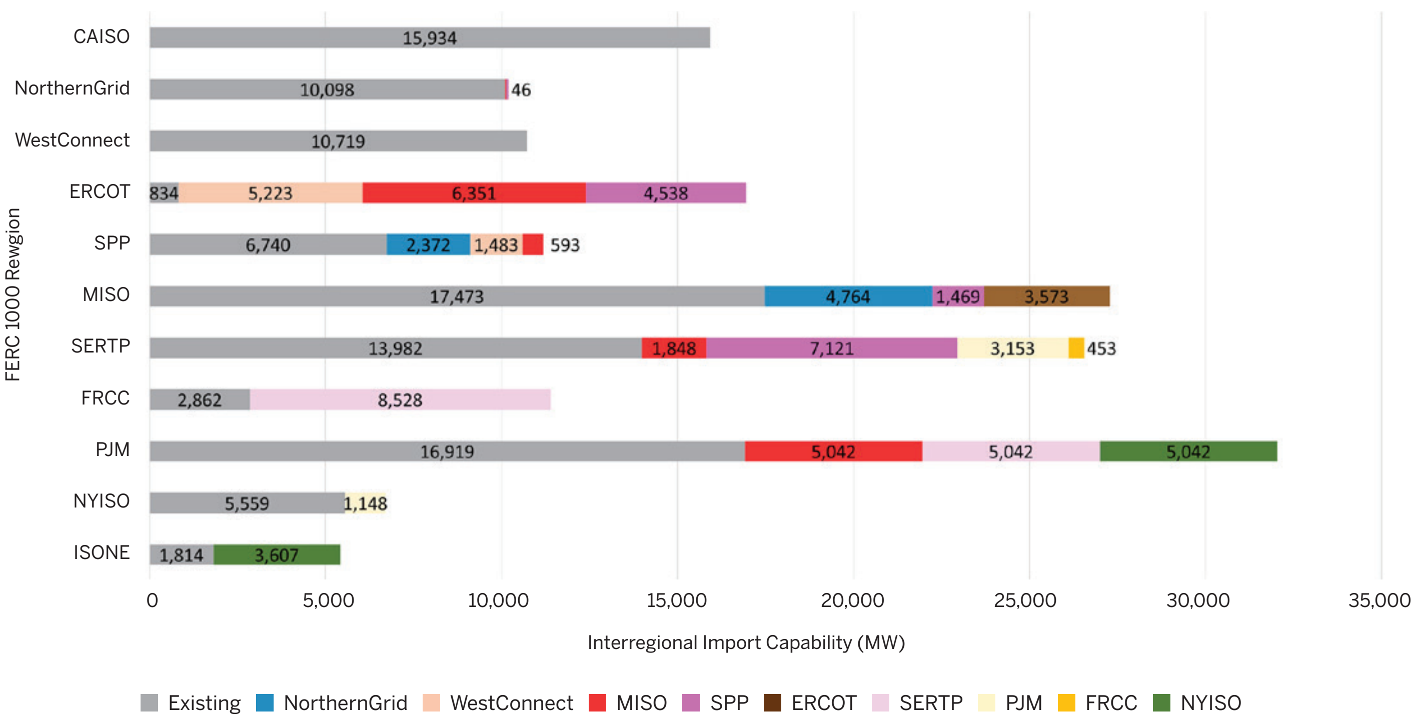
To determine where additional interregional transfer capability should be added, we established a priority dispatch order in which a region first uses its own resources, then resources from its immediate neighbors (if they have surplus), and, lastly, resources from neighbors' neighbors, if they have surplus. This methodology prioritizes transfers for reliability and intentionally only evaluates relative resource surplus or deficits rather than differences in resource costs or electricity prices. The model was thus able to identify which neighboring regions would typically have deeper reserves during a given region's lower-margin periods (having less surplus relative to load). In effect, priority was given to neighbors that offered the greatest access to diversity in resources or load (highest relative energy margin). Results for expanding transfer capabilities to 20% of a region's peak load using this method are shown in Figure ES-2. Gray portions of the bars represent each region's existing transfer capability, and colored portions represent additional capacity from neighboring regions that was prioritized by the model.

All three levels of transfer capability case are shown in Figure ES-3 (p. xi).

Results from the case study indicate that increasing transfer capabilities between the Eastern and Western Interconnections, and between isolated areas like the edges of the Northeast, Southeast, and ERCOT, could significantly enhance regional grid resilience. At the system-wide level, achieving 10%, 20%, and 30% import capability for all FERC Order 1000 regions would

FIGURE ES-2

Interregional Non-Coincident Import Capability Added by the Model, by FERC Order 1000 Region, to Allow Each Region to Import 20% of Its Peak Load

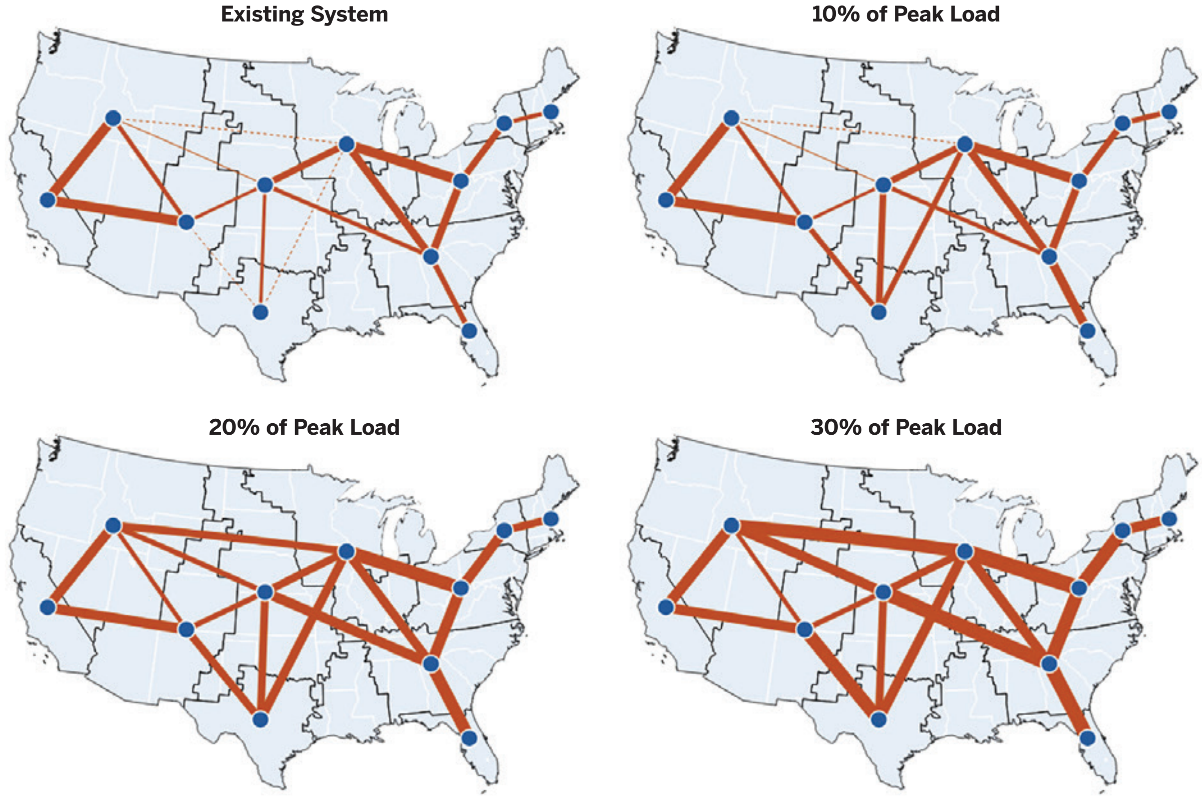


The figure shows the additional interregional transmission capability that would be needed between FERC Order 1000 regions to enable them to import 20% of their peak load, and where the additional capability is coming from. Gray areas of bars represent each region's existing transfer capability. Colored areas of bars represent transfer capability needed between that region and the respective other region(s).

Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; FRCC = Florida Reliability Coordinating Council; ISONE = Independent System Operator of New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; SERTP = Southeastern Regional Transmission Planning; SPP = Southwest Power Pool.

Source: Energy Systems Integration Group.

FIGURE ES-3
Existing U.S. Interregional Transfer Capability Between FERC 1000 Regions, and the Size of Connections Needed for 10%, 20%, and 30% Minimum Transfer Capability



At the top left (existing system), lines connect the center of FERC Order 1000 regions and show where existing interregional transmission connections (solid lines) exist today. Dotted lines represent connections that do not exist today, but where regions are geographical neighbors and connections could be established. The other three maps show modeled increases in transfer capability according to whether a region needed to have sufficient transfer capability to import 10%, 20%, or 30% of its peak load. Lines increase in thickness to show increased transfer capabilities as regions achieve different levels of import capability relative to their peak load. By the 20% scenario, all modeled potential connections exist, and the transfer capability increases steadily as the percentage-of-peak-load requirement goes up.

Source: Energy Systems Integration Group.

require additional transfer capability in the range of 11.4 GW, 71.4 GW, and 149.0 GW, respectively. Most of this increase would be concentrated in ERCOT, MISO, the Southeastern Regional Transmission Planning region, Florida Reliability Coordinating Council, and PJM, given the magnitude of current capabilities.

Suggested Practices

This study demonstrates a framework for planners to assess hourly energy margins for both internal and external systems and to determine resource availability across regions, identifying surplus capacity under diverse weather scenarios to aid interregional transmission planning. The method is intended to be practical and adaptable, allowing for broad nationwide assessments,

The method is applicable on both a regional and a national scale using synthetic historical weather data and future climate change weather data across many different resource mixes to evaluate the timing of surplus and deficits in resource availability.

TABLE ES-1

Four Key Practices for Interregional Transmission Planning

Prioritize regions with less existing interregional transfer capability	Regions with interregional transmission capacity that does not meet the targeted transmission capability as a percentage of their peak load would be prioritized for increasing transfer capability.
Prioritize transfer capability that increases imports from regions with uncorrelated risks	Transmission would be prioritized from regions likely to have a surplus during times of tight supply conditions elsewhere. This requires assessing hourly variations in surpluses and deficits for all regions.
Focus on immediate neighbors	Efforts to increase interregional transmission would focus on connections between geographically closer regions in order to minimize costs.
Allow for power to flow from a neighbor's neighbor	To evaluate interregional transmission, one needs to adequately represent a region's access to load and resource diversity beyond its immediate neighbors and accommodate the movement of power from adjacent regions, establishing a more interconnected and supportive network.

across all hours of the year and across many weather years. The method is applicable on both a regional and a national scale using synthetic historical weather data and future climate change weather data across many different resource mixes to evaluate the timing of surplus and deficits in resource availability. Based on this assessment, Table ES-1 presents four key practices for planners to consider when evaluating interregional transmission plans and their resilience.

Future studies calculating interregional transfer capabilities must recognize that these values are dependent on grid conditions and resource mixes—they are not static. Resource additions and retirements and load growth will affect both transfer capabilities and the availability of diverse resources across regions. Similarly, weather events affect both the availability of renewable resources and the outage risks for conventional thermal generation. This means more scenario modeling is required both to determine transfer capability during high-risk events given load and resource availability and to assess system resilience and reliability during extreme weather events as well as normal conditions. Knowing what transfer capabilities are during stressful grid conditions is crucial for maintaining reliability and ensuring a resilient grid.

Interregional transmission facilitates a more resilient grid by increasing the availability of diverse energy sources to help serve load during critical periods. By prioritizing the expansion and enhancement of interregional connections, we can help ensure that the grid remains capable of meeting the emerging challenges of tomorrow.

Also of note, the results of this study indicate that using FERC Order 1000 regions to define interregional transfers may overstate transfer capabilities and understate the potential risks from extreme grid conditions by underrepresenting internal constraints, especially in very large Order 1000 regions such as WECC-NW and MISO. As such, the size and boundaries of study regions should also be a consideration in developing future assessments of increased interregional transfer capability.

As the industry faces significant uncertainty around future load growth, a changing resource mix, and a changing climate, there is a growing need to ensure that electricity systems remain robust and adaptable. Interregional transmission facilitates a more resilient grid by increasing the availability of diverse energy sources to help serve load during critical periods. These potential benefits underscore the importance of strategic planning and investment in infrastructure that can withstand and adapt to the evolving demands of our climate and societal needs. By prioritizing the expansion and enhancement of interregional connections, we can help ensure that the grid remains capable of meeting the emerging challenges of tomorrow.

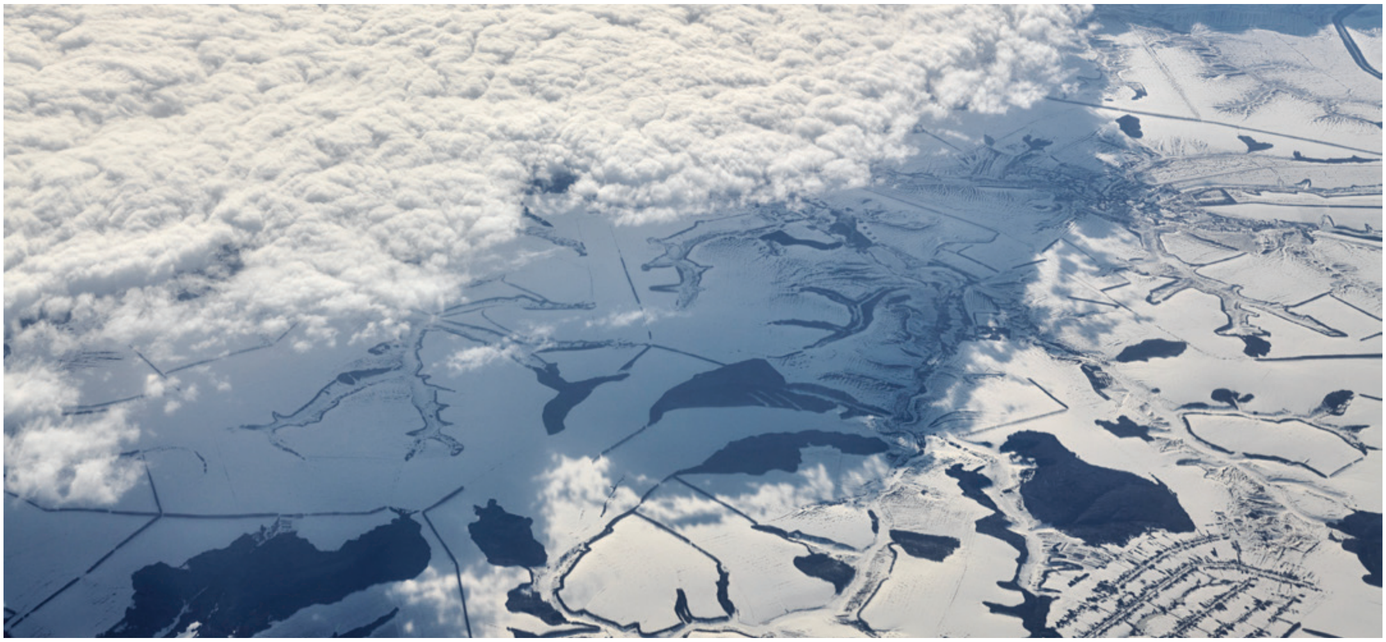
Introduction

As extreme weather events become more of a concern for the electric power industry, power system resilience is seen as an increasingly valuable grid quality that offers measurable advantages to consumers. Extreme weather events can cause prolonged periods of increased energy demand coinciding with disruptions in energy production. These events can result in either grid operators' decisions to implement rolling blackouts or worse, grid collapse, both of which may have severe consequences, disrupting crucial electricity services for homes, businesses, and hospitals. Recent events such as Winter Storm Uri in Texas in 2021 resulted in loss of life due to some consumers' inability to receive power to heat their homes during extreme cold. While the concept of resilience has become established in the industry, a formal definition has not yet been widely agreed upon. One recent study provided a working definition of power system resilience as:

> The ability of the system and its components (both equipment and human) to (1) **prepare for**, (2) **anticipate**, (3) **absorb**, (4) **adapt to**, and (5) **recover from** non-routine disruptions, including high-impact, low-frequency events, in a reasonable amount of time (NATF-EPRI, 2022) [emphasis added]

This working definition points to a wide array of grid capabilities—local as well as regional—that can provide benefits to consumers, including hardening of existing utility assets, improved emergency operational practices, installation of distributed resources or other local generation resources, and interregional transmission.

Two features of the concept of resilience are critical: it is associated with extreme events, and it is distinct from the concepts of reliability and resource adequacy. Whereas reliability standards and resource adequacy analyses are



Whereas reliability standards and resource adequacy analyses are concerned with minimizing loss of load, grid resilience entails preparing for and recovering from the reliability events that do occur.

concerned with minimizing loss of load, grid resilience entails preparing for and recovering from the reliability events that nonetheless occur. While grid reliability and resource adequacy have been a part of grid planning and operations for several decades, efforts to incorporate grid resilience are relatively new.

Planners will need to establish procedures to quantify overall system benefits across a portfolio of potential enhancements that stand to increase grid resilience. Increasing interregional transmission is one important solution that can provide resilience benefits by strengthening connections between regions so that regions can share power across large geographical areas. Increased geographical diversity can mitigate risk during periods of high electricity demand or sustained low wind and solar output, or make up for concurrent power plant outages. While some of this type of support is currently available within the Western and Eastern Interconnections, transmission limits—both between interconnections and within sub-regions—may prevent sufficient support during periods of grid stress. Additionally, the Electric Reliability Council of Texas (ERCOT) interconnection has very limited interregional transmission, exacerbating the risk when extreme weather strikes that region.

While interregional transmission provides many benefits, there is still relatively little new interregional transmission being built in the U.S. today. In part, this is due to the lack of an established methodology for evaluating the grid resilience benefits of interregional transmission, and it can be challenging to prioritize competing, planned upgrades for the greatest resilience benefits. In response to this challenge the Energy Systems Integration Group's Transmission Resilience Task Force undertook an analysis of the availability of resources across the U.S. grid using seven years of historical weather data across the FERC Order 1000 regions, to identify diversity in load and resources between these regions to determine where interregional transmission may provide the greatest resilience benefits for the grid. This report describes the analysis and outlines a methodology, based on time-synchronized load and resource availability, for identifying where the resilience benefits of interregional transmission may be greatest based on where resources are available during periods when individual regions are stressed.

Reliability and Resource Adequacy vs. Resilience

Today's grid planners typically limit their consideration of neighboring resources and grid conditions and model their own system in isolation, or (at best) evaluate their immediate neighbors. However, this misses the value that interregional transmission broadly provides for resource adequacy, reliability, and resilience. Many regions already benefit greatly from the interregional transmission that currently exists, but without a methodology to include it in planning studies, planners are limited in their ability to coordinate at the interregional level or properly consider interregional transmission investments that could specifically enhance resilience.

Without a methodology to include interregional transmission in planning studies, planners are limited in their ability to coordinate at the interregional level or properly consider interregional transmission investments that could specifically enhance resilience.

Since the passage of the Energy Policy Act of 2005 and the establishment of mandatory reliability standards for the bulk electricity system, the concept of grid reliability has become increasingly synonymous with adherence to the North American Electric Reliability Corporation (NERC) operational and planning reliability criteria. NERC's reliability standards define minimum criteria for balancing authorities which are responsible for maintaining system reliability within a region; complying with these standards (along with any additional local reliability standards) indicates that the system is reliable. While some of the NERC standards—most notably the emergency operations planning (EOP) standards—address the need to have procedures to prepare for and to operate during extreme events, in general, the NERC standards define planning and operational requirements for expected grid conditions rather than extreme conditions.

Resource adequacy—the ability of supply-side, demand-side, and transmission resources to meet demand—is not tied to the NERC reliability criteria. Rather, it is the responsibility of the states and delegated market regions to determine the adequacy of resources to meet forecasted customer demand. Although planners are increasingly considering ways to modify resource adequacy criteria to better capture extreme events, these criteria, like reliability standards, are designed to minimize the *occurrence* of events with unserved customer demand. However, the *impact* of the high-impact, low-probability extreme events that do occur has not traditionally been a consideration in establishing a resource adequacy standard.[1] Grid resilience is the system's capability to limit these events' impacts through efforts to prepare for, anticipate, absorb, adapt to, and recover from them. For extreme weather events in particular, interregional transmission may be able to provide benefits that local solutions cannot. Given the weather-sensitivity of electricity demand, variable renewable generation, and fuel supply, connections between regions that have different resources and weather conditions can be more useful than local resources during extreme weather. Interregional transmission can provide resource diversity by allowing a region to access resources that are not subject to the same extreme conditions that local resources are facing.

The Benefits of Interregional Transmission

Resilience benefits are an important component of the range of benefits that interregional transmission can provide. As described in the recently released FERC Order 1920, quantifying the benefits of transmission, including interregional transmission, for mitigating the impacts of extreme weather events and unexpected system conditions is one of seven benefits that will be required in long-range transmission planning assessments (Table 1).[2] Notably, recent examples of extreme weather have highlighted the magnitude of benefits that today's interregional transmission provides and foreshadow the growing importance of enabling more interregional transmission to support the grid under future extreme weather.

TABLE 1
The Seven Required Benefits for Long-Term Regional Transmission Planning Given in FERC Order 1920

FERC Order 1920 Benefit Number	Long-Term Regional Transmission Planning Benefits
1	Avoided or deferred reliability transmission facilities and aging infrastructure replacement
2	A benefit that can be characterized and measured as either reduced loss-of-load probability or reduced planning reserve margin
3	Production cost savings
4	Reduced transmission energy losses
5	Reduced congestion due to transmission outages
6	Mitigation of extreme weather events and unexpected system conditions
7	Capacity cost benefits from reduced peak energy losses

In the two most recent examples, Winter Storm Uri in Texas and the U.S. Midwest in 2021 and Winter Storm Elliott in the Midwest and eastern U.S. in 2022, many local generation resources performed poorly, regardless of their fuel source, across a large swath of the U.S. grid. Interregional transmission, in contrast, exhibited significant benefits during these events, including facilitating around 13,000 MW of imports from PJM and the Southeast into the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) territories during Uri, which greatly reduced stress on the affected systems (FERC, 2021). Regions like ERCOT, which have limited interregional transmission, were exposed to greater damages over multiple days, including loss of life. Resilience, as defined in this study, is the ability

1 Some regions are evaluating the benefits of including an assessment of the severity of extreme events as part of their reserve margin standard development (PUCT, 2023; Tri-State, 2023)

2 Federal Energy Regulatory Commission Order No. 1920: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, Docket No. RM21-17-000. https://www.ferc.gov/media/e1-rm21-17-000.

of the grid to prepare for, anticipate, absorb, adapt to, and recover from disruptions. These examples show how interregional transmission allowed grid operators to absorb, adapt to, and recover from disruptions in a timely and efficient manner by reducing the magnitude and duration of rolling blackouts or avoiding the need to institute them altogether.

In addition to its value during extreme weather events, interregional transmission provides an array of benefits year-round, such as production cost benefits, benefit #3 in Table 1 (p. 3). This contrasts with local resources used solely for emergency or peak conditions. Interregional transmission also provides benefits to regions on both sides of a transfer, in contrast to investment solely in local resources. In fact, recent extreme weather events have indicated that interregional transmission can benefit *more* than just two regions, by allowing power to flow across multiple regions and allowing a neighbor's neighbor to provide support. Grid operations data demonstrate the benefits of transferring power from one region that is not under stress, through another region that is partially affected, and into a region in the center of the event—as we saw as power was transferred from PJM through MISO and into SPP during Winter Storm Uri. Interregional transmission also played a crucial role during Winter Storm Elliott when PJM and the Southeast suffered coincident fuel-supply shortages and plant failures, resulting in 90 GW (or 13% of capacity) in the Eastern Interconnect being unavailable (Howland, 2023). Interregional transmission allowed neighbors not experiencing concurrent power generation outages and extremely high load to transfer power into the region, without which the load shedding would have been greater and would have presented larger risks to maintaining grid stability.

As the electricity grids across the nation see increased integration of renewable resources, the ability of interregional transmission to maximize the availability of diversified renewable resources during extreme events will grow. Interregional transmission as a resilience solution allows the electricity grid to expand in a way that supports the likely future resource mix while increasing its flexibility and adaptability to future extreme weather risks.

Interregional transmission can provide resource diversity during extreme weather by allowing a region to access resources that are not subject to the same conditions that local resources are facing.

A Need for Best Practices for Quantifying Resilience Benefits of Interregional Transmission

Given the variety of options to improve grid resilience, it is important to have robust procedures to assess expected benefits and allow cost/benefit comparisons of solutions. When evaluating and designing interregional transmission projects, one must consider the expected availability of all grid resources able to export power during extreme weather events, based on projected generator outages in each region, compared to neighboring regions: the resource availability of a region's neighbors, and its neighbors' neighbors, needs to be captured in planning studies.

Recent industry studies have begun to incorporate resilience benefits from increased interregional transmission capacity, providing initial methodologies and starting the industry discussion. A study conducted by GE Energy Consulting in 2022 evaluated likely operational outcomes and costs for extreme and normal conditions across the Eastern Interconnection, comparing a case with existing interregional transmission limitations to a case with no interregional transmission limitations (NRDC, 2022). In a more targeted study, MISO quantified certain resilience benefits as part of the justification for its Long Range Transmission Plan Tranche 1 (MTEP21) projects. The Tranche 1 projects' resilience benefits to MISO customers from the avoided risk of load shedding were quantified at $1.2 billion to $11.6 billion in present value benefits (MISO, 2022). Notably, as considered in the MISO study and also described in the ESIG report *Multi-Value Transmission Planning for a Clean Energy Future* (ESIG, 2022), resilience benefits from transmission are one component of the benefits provided by new transmission projects, and interregional projects can provide greater resilience benefits by accessing external resources that may be unaffected by local or regional challenges.

These initial resilience studies present different methodologies to quantify resilience benefits resulting from increased transmission capacity. However, there remain critical gaps in the electricity industry's ability to assess the benefits of interregional transmission. Currently, assessments that include neighboring regions are often too computationally intensive for a utility or region to handle, or they are performed but only consider direct

neighbors, which may face similar extreme weather conditions. To support planners evaluating and designing interregional transmission projects, an assessment is needed of each region in the U.S. in terms of hourly variability in wind and solar resources; the unavailability of thermal generators due to correlated outages and maintenance plans; and regions' ability to import or export power to their neighbors. With this need fulfilled, planners may be able to sufficiently represent the availability of all resources across the entire United States hour by hour under many weather conditions in a way that is not computationally intractable. It is important that these hour-by-hour data also incorporate periods when regions are affected by extreme weather events, and these weather events must represent credible scenarios for how they are distributed, move, and affect the electricity grid across large geographies over time.

A Need for a National-Scale Solution to a Nationwide Risk

Recent extreme weather events have reinforced that these events are often larger than local planning regions and can move across multiple regions as the storms progress, a dynamic that points to the need for a national-scale solution. Congress and the Federal Energy Regulatory Commission (FERC) took notice of the critical role transmission played in maintaining reliability and creating a resilient system during Winter Storms Uri and Elliott. Following these events, legislation was introduced that would direct FERC to coordinate construction of an interregional transmission system. In addition, FERC opened docket AD23-3 to evaluate the current interregional planning processes established in response to FERC Order 1000, which created a framework for regional and interregional transmission planning and cost allocation requirements to promote efficient and competitive electricity transmission projects.

In addition, the Fiscal Responsibility Act of 2023 requires NERC to identify current interregional transfer capabilities and prudent additions to interregional transmission that would demonstrably strengthen reliability. These initiatives focus on the need to identify a minimum amount of interregional transmission to serve as a simple baseline for regions to plan to. Any additional interregional transmission recommended is expected to improve grid performance during events that push grid operations far beyond typical planning and operational criteria, such as the events that occurred during Winter Storms Uri and Elliott.

Most recently, FERC Order 1920 requires regional transmission planners to implement "(1) the sharing of information regarding their respective long-term transmission needs, as well as long-term regional transmission facilities to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address long-term transmission needs."[3] While FERC Order 1920 did not propose a minimum interregional transfer capability, there is an open proceeding (Docket No. AD23-3-000) considering one on reliability grounds.

These initiatives and recent orders represent increasing momentum across the U.S. grid to spur larger-scale assessments of transmission needs. This growing recognition will require new methods for planners to approach large-scale interregional transmission projects and assess which regions may offer the greatest benefits to their constituents by providing access to diverse resources across the U.S. grid.

New methods are needed for planners to approach large-scale interregional transmission projects and assess which regions may offer the greatest benefits to their constituents by providing access to diverse resources across the U.S. grid.

Study Objectives, Analysis, and Case Study

ESIG's Transmission Resilience Task Force was created in December 2022 to provide a forum to discuss a rigorous approach for assessing and quantifying the resilience benefits of increased interregional transmission capacity. This report summarizes the results of this study.

This work provides a starting point methodology that can be adapted to meet individual planning regions' needs and also inform national efforts to assess resilience benefits and the availability of interregional transmission capacity. Both require an evaluation of how much diversity exists in hourly electricity demand and resource availability across multiple weather conditions. Resource availability assessments include wind, solar, thermal resources, storage, and hydroelectric availability, since all of these resources are impacted in some fashion by extreme weather. The existing interregional transfer capabilities also need to be quantified to determine the benefits brought by existing capabilities and to evaluate how much and where additional transmission capacity may best enhance transmission grid resilience.

The task force's work has multiple phases: to complete a national assessment of weather and geographical diversity during extreme events and to perform interregional transmission extreme event stress-testing. Additional phases may be considered that take this planning and incorporate it into transmission power flow analyses. This report covers the first phase, the national assessment of weather and geographical diversity during extreme events, and addresses the following questions:

3 See FERC Order 1920, page 1217, https://www.ferc.gov/media/e1-rm21-17-000.

- How much diversity exists in resource availability and customer demand between regions, and to what degree does this diversity increase as the distance between the regions increases? This is key to understanding whether surplus resources are available in other regions to support a region during extreme weather events, and where specifically those resources are located.
- How much interregional transmission capacity is currently available, and how does this available capacity compare to the expected availability of surplus resources across regions during extreme events determined in the previous question? The answer here can point to interregional pathways where increased capacity could be prioritized to gain the greatest resilience benefit.
- How can a region prioritize potential future increases in interregional transmission capacity? This study, using the assessment of likely availability of surplus resources in other regions during extreme events and the current availability of interregional transmission capacity, outlines a methodology to allow regional planners to identify high-priority paths where increased capacity can be most beneficial.

This work provides a starting point methodology that can be adapted to meet individual planning regions' needs and that can inform national efforts to assess resilience benefits and the availability of interregional transmission capacity.

To answer the first question, we conducted an initial assessment of the diversity of customer demand and resource availability—of both variable generation and thermal units—in regions across the country. This assessment looked at both normal operating conditions and extreme conditions within a set of hourly weather data representing weather from 2007 through 2013 on a future grid, using hourly weather data and resource mixes prepared by the National Renewable Energy Laboratory (NREL) for use in its Regional Energy Deployment System (ReEDS) model framework (NREL, 2023b). The analysis shows the geographical scope of historical extreme weather events like the 2011 Southwest cold weather event, and low renewable production periods and their effects on resource availability. When one

region is affected by extreme conditions such as winter storms or summer heat waves, this analysis indicated the weather impacts on nearby regions and calculated the resources available in unaffected regions to support the affected ones.

The task force evaluated several methods to address the second question about current interregional transmission capacity and expected availability of surplus resources during extreme events in the future. Quantifying interregional transmission capacity requires careful consideration of computational complexity, the impact of input assumptions (most notably, assumptions regarding customer demand and the availability of resources can affect transfer capacity studies that rely on grid simulations), and the fidelity with actual historical operational outcomes. The task force chose to determine interregional transmission capacity using historical transfer data provided by the Energy Information Administration (EIA) Form 930. These data were aggregated into FERC Order 1000 regions, outliers removed, and the 99.9th percentiles of interchanges between regions calculated. Answering this question enables the evaluation of a region's capability to use its surplus resources to export power to external regions during their high-risk periods. If there are plenty of surplus resources in a region but insufficient transmission capability, then expanding a region's transmission capability can unlock important resilience benefits for neighboring grids.

The third question—how a region can prioritize potential increases in interregional transmission capacity—was answered by developing a modeling methodology with which regions can quantify the surplus of resources across every region of the U.S. relative to their own resource fleet and electricity demand. We performed this assessment for all hours of the 2007–2013 weather years available in the NREL dataset used and for a subset of hours when each region has relatively fewer internal resources and may wish look to neighbors for support. This modeling methodology allows a planner to evaluate how often a certain neighboring region (or a neighbor's neighbor) could be relied on to export power both during normal grid conditions and during modeled extreme conditions, although the data used in this analysis did not include more recent extreme conditions that truly stressed the grid. Importantly, this question was answered using a framework that can be expanded to include more years of weather conditions, generator availability, or patterns in electricity demand as the grid changes in the future.

This framework can be used to assess existing resources and interregional transmission capacity and help a region prioritize where to increase interregional transmission to receive the greatest resilience benefits, based on information about the diversity in resource and electricity demand across the entire U.S.

These three questions encompass the task force's phase I goal of developing a method for assessing weather and geographical diversity in resource availability and electricity demand simultaneously across the entire U.S. and in a chronological approach for multiple years of weather, to aid in assessing the resilience value that interregional transmission can provide the grid. These results were then used in a case study to lay out how a region might use this framework to conduct its own interregional transmission assessment with a more comprehensive view of external resource availability. This framework can be used to assess existing resources and interregional transmission capacity and help a region prioritize where to increase interregional transmission to receive the greatest resilience benefits based on information about the diversity in resource and electricity demand across the entire U.S. The case study used the proposed Building Integrated Grids With Inter-Regional Energy Supply (BIG WIRES) Act[4] as a basis for setting a minimum interregional transmission requirement for each FERC Order 1000 region and identifying where new transmission can be prioritized to both meet this requirement and capture the greatest resilience benefit. This large-scale analysis, spanning the entire U.S., provides key information about the value of interregional transmission for use by planners as they consider the range of options for increasing grid resilience.

4 https://www.hickenlooper.senate.gov/press_releases/hickenlooper-peters-introduce-big-wires-act-to-reform-permitting-lower-energy-costs/

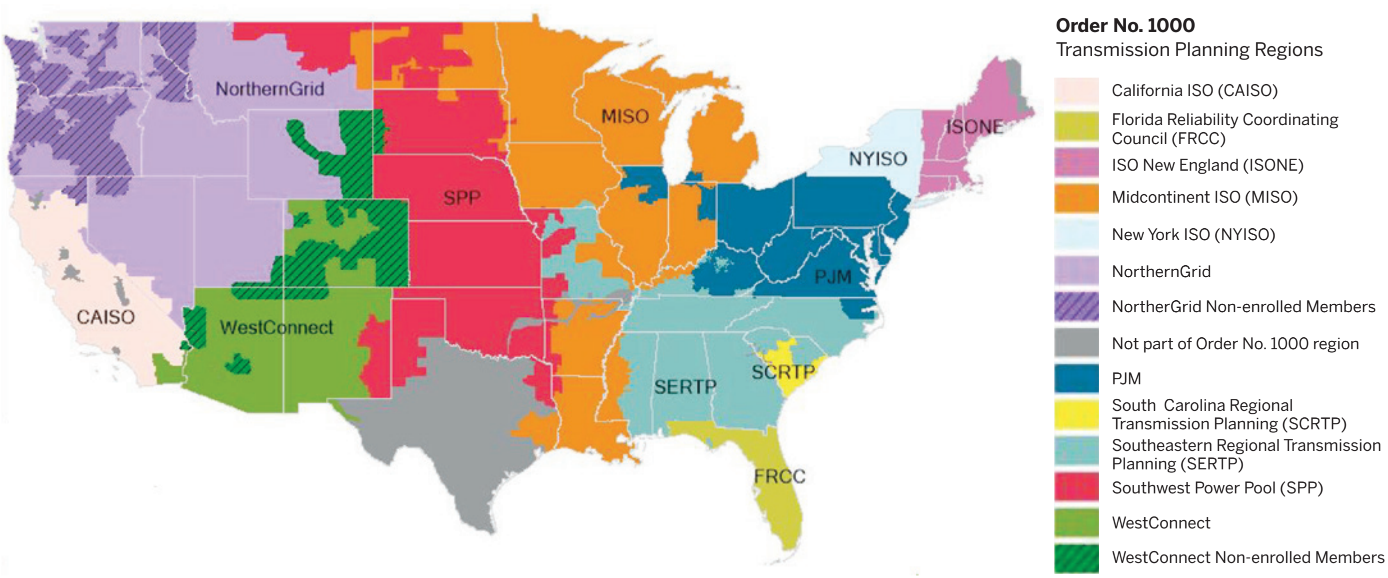
Today's Interregional Transfer Capability

The United States has one of the largest interconnected power systems in the world, consisting of approximately 66 balancing authorities that manage local operations and 12 (including Texas) transmission planning regions. The number and geographical variability of these regions, along with the complexity of the underlying transmission system, make it inherently difficult to determine how much electricity can be transferred between regions. Regions represent administratively different sections of the grid and can be defined by utility territories, balancing authorities, or planning regions, or by grid operator regions like independent system operators and regional transmission organizations (ISOs and RTOs). For this study, we adopted the FERC Order 1000 definition for transmission planning regions and aggregated balancing authorities into these larger regions, with some modifications, including combining the South Carolina Regional Transmission Planning region and the Southeastern Regional Transmission Planning region. The FERC Order 1000 transmission planning regions are shown in Figure 1.

Creating/Selecting a Baseline for Interregional Transmission

To identify where new transfer capability could provide increased grid resilience, we needed a baseline of the interregional transmission that exists today. It should be

FIGURE 1
FERC Order 1000 Transmission Planning Region Map



Notes: The colored areas are intended to approximate the scope and location of the transmission planning region but are for illustrative purposes only.

Source: Federal Energy Regulatory Commission; https://www.ferc.gov/media/regions-map-printable-version-order-no-1000.

noted that the interregional transfer capability is not a single, constant number. It can fluctuate seasonally due to adjusted ratings of transmission lines that can transfer more power in colder weather, daily due to transmission line outages or maintenance, and hourly due to changes in unit commitment and stability considerations driven by the type and location of load and generation. Furthermore, the definition of "interregional" will influence the transfer capability. Using FERC Order 1000 regions, for example, yields different results compared to a topology that considers balancing authorities or any other more granular topology. More granular regions better represent transmission bottlenecks for moving power between regions and better represent regional risks in demand and resource availability, such as during cold weather that greatly affects sub-regions but not the entire region.[5]

Even as no single value can precisely quantify a region's interregional transfer capability, two approaches were considered to estimate the existing amount of interregional transfer capability:

- Calculating regions' capabilities using AC power flow analysis
- Calculating maximum historical flows between regions and using these values as the capability in further analyses

For this study we chose to use historical flows based on publicly available data to determine existing transfer capabilities between regions. Specifically, we used the flow data provided on the U.S. Department of Energy's EIA Form 930 filings (EIA, 2023), as this dataset presents hourly imports and exports between balancing authorities and is reported uniformly across the United States. The data are publicly available, have a long history, and can be analyzed rapidly to review historical performance. This approach does have limitations, as it measures only actual historical flows and not technical capability. Flows may have been limited not by the transmission network but by the lack of resources available, contractual limitations, or other market reasons that affected transfers between regions.[6] However, the approach has advantages for our purposes here, namely, that it is not dependent on assumptions or susceptible to manipulation, and it includes a wider range of generator operating conditions and load levels than could be considered in a simulated environment.

Data Analysis on Historical Flows

The following analysis outlines the steps taken to use historical interchange (flow) data from the EIA Form 930 to determine interregional transmission limits between FERC Order 1000 regions. All results in this report start with this assessment as the baseline transmission capability.

Collection of Hourly Interchange Data

To conduct the analysis of historical, interregional power transfers, the EIA Form 930 hourly interchange data were collected at the balancing area authority level and were aggregated to the FERC Order 1000 planning regions. While there could be transmission-constrained regions internal to a FERC Order 1000 region that would benefit from evaluation at a more granular level, the chosen aggregation method has the benefit of reflecting the current paradigm of regional transmission coordination, which may allow for more immediate and actionable decisions to be made on future transfer capability requirements.

Actual historical flows were quantified on an hourly basis across five years, from 2019 to 2023.[7] The existing interregional transfer capability was defined as the greater of the 99.9th percentiles of imports and exports, after controlling for a small number of outliers due to data quality issues. As an illustrative example, Figure 2 (p. 11) shows the hourly interchange for the California Independent System Operator (CAISO) planning region as a histogram, where positive numbers on the x-axis represent exports out of CAISO to neighboring regions and negative numbers represent imports. The

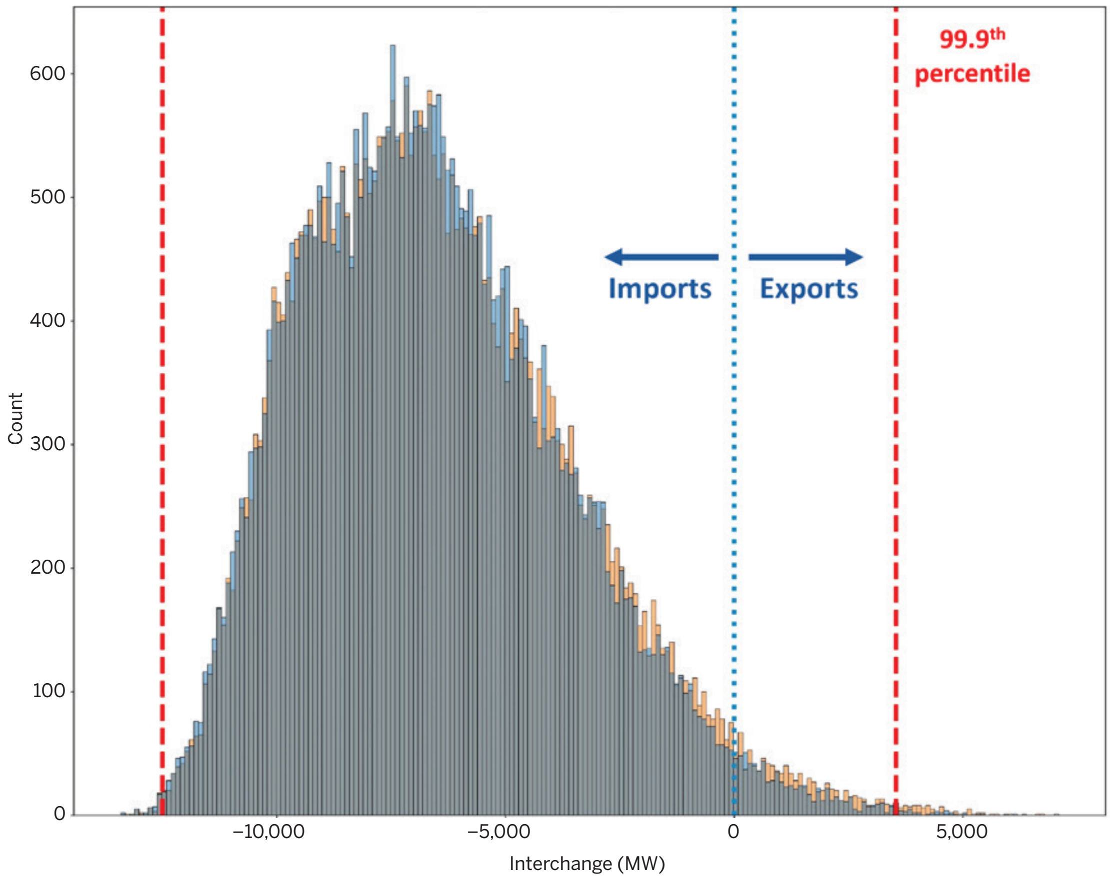
5 FERC Order 1000 regions represent aggregations of transmission providers that must coordinate and develop a regional transmission plan among members and between neighboring regions. Balancing authorities are entities that ensure that power system demand and supply are balanced within their regions while also managing flows between neighboring balancing authorities.

6 Industry recognition of the need for accurately calculating actual capabilities and limitations is reflected in a separate study being conducted by NERC to determine transfer capabilities using detailed AC power flow simulations (NERC, 2024).

7 Only five years of EIA data were used due to data quality issues in earlier time periods.

FIGURE 2

Histogram of Hourly, Coincident Flows Between CAISO and Its Neighbors, 2019–2023



Hourly interchange data for 2019–2023 between the California Independent System Operator and neighboring balancing authorities based on EIA Form 930 interchange.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

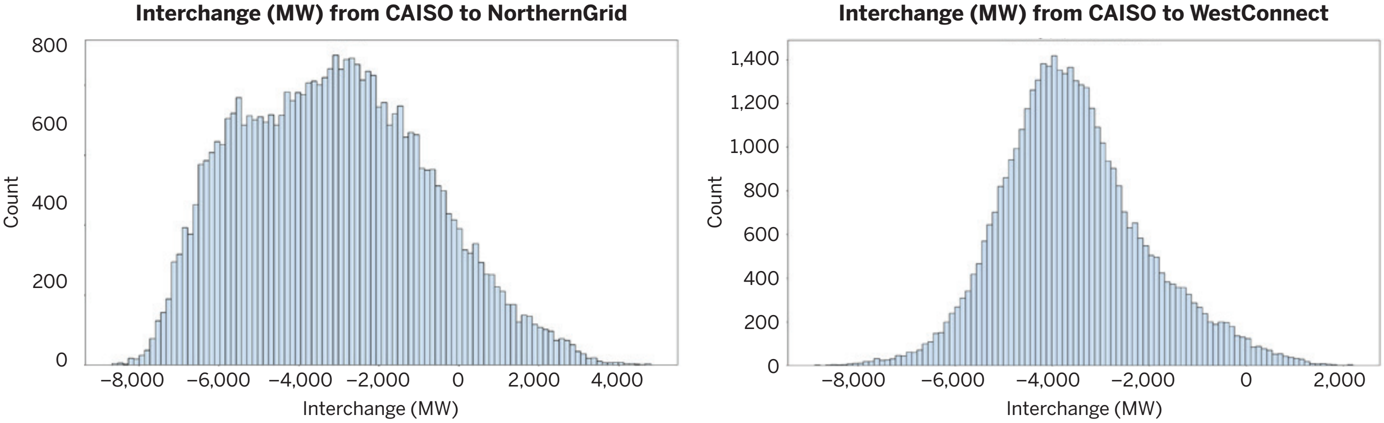
vertical red lines represent the 99.9th percentile of hourly flows in both directions with the magnitude of the coincident transfer capability being 12,551 MW.

Determination of Coincident and Non-coincident Transfer Capabilities

This analysis also calculated both coincident and non-coincident transfer capabilities based on flows to and from each region. Non-coincident transfer capabilities represent the flows between each pair of regions when considered separately; for example, the transfer capabilities between CAISO and NorthernGrid and between CAISO and WestConnect were calculated independently. In contrast, coincident transfer capabilities reflect the total aggregate flows into or out of a region, considering all sources simultaneously. Coincident limits provide a better representation of what a region can import or export instantaneously to all of its neighbors collectively. In comparison, non-coincident flows better illustrate the capacity of the existing infrastructure to handle transfers between specific pairs of regions. Both values were calculated, since planners may use them for different purposes depending on planning requirements. Identifying both limits is important for understanding whether additional benefits could be gained from prioritizing upgrades to one specific connection (non-coincident limits) or whether risks are being driven from the entire region's import limit (coincident limits), and therefore helps planners decide whether transmission grid resilience improved by focusing on enhancing individual transfer

FIGURE 3

Example of Non-coincident Interchange Flows Between CAISO, NorthernGrid, and WestConnect



This figure illustrates how the non-coincident flows between the California Independent System Operator and its neighbors can be larger than the coincident flows in Figure 2 (p. 11). Negative values represent imports into CAISO.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

paths or improving overall regional transfer capacity depending on which limits are driving risks.

An example of these two calculations is shown in Figure 3. In this case, the individual connections between CAISO and its two neighbors are 8,026 MW (NorthernGrid) and 7,908 MW (WestConnect) of non-coincident transfer capability. The sum of these is 15,934 MW, or 27% above the coincident transfer 99.9th percentile value of 12,551 MW. The difference in these numbers is significant when considering how much additional transfer capability will be required. It has yet to be determined whether coincident or non-coincident transfer limits will be the starting point for assessing how much additional transfer capability is needed to ensure a resilient grid. The appendix shows histograms of the coincident hourly flows for each FERC Order 1000 planning region.

In regions with several interregional ties and more bi-directional flows, the differences between coincident and non-coincident flows can be larger, which means the region may have reduced import or export capability to receive or give support via certain individual ties. This study defined the transfer capability for a region based on the magnitude historical flows between FERC Order 1000 regions (choosing the larger of the values for observed exports or imports) based on what each region had reported for the EIA Form 930. Both coincident and non-coincident values are reported in Table 2 (p. 13).

Due to limitations in data availability and the focus on FERC Order 1000 regions, interregional transfer capability between U.S. regions and neighboring regions in Canada or Mexico were not included in the estimates.

For this report, a decision was made to present both non-coincident and coincident transfer limits from the EIA Form 930 data but to base the increase in transfer capabilities needed on the non-coincident limits between each pair of regions. This was chosen in part because historical maximums observed do not necessarily represent maximum capabilities for either coincident

or non-coincident values. In this case, the sum of the observed non-coincident maximum transfers is higher than the observed coincident maximum. In reality, the interregional transfer capability may be somewhere in between these values or potentially above them with the region not having experienced an event that actually pushes import limits to the extreme. While the exact limits are not well defined in the industry today, efforts are ongoing to identify both non-coincident and coincident limits so that both can be assessed to facilitate better interregional transmission planning.

Results show that MISO, PJM, and CAISO have the highest non-coincident interregional transfer capability on a MW basis. However, as a percentage of load, WestConnect, CAISO, and NorthernGrid have the highest interregional transfer capability.

Results of the historical data analysis are provided in Table 2, which shows the total interregional transfer capability for each FERC Order 1000 region in terms of its total import capability. These values are based on the 99.9th percentile of EIA Form 930 data reported as flowing into each region. (The existing transfer capability for each pair of regions (e.g., WestConnect and CAISO) that makes up the total import capability is provided in the appendix.) Also included is an estimate of peak demand, based on a median peak demand across the seven weather years evaluated. This table gives us a starting point from which to view how much interregional transmission each FERC Order 1000 region has and how large this capability is relative to the peak demand modeled in this study.

Results show that MISO, PJM, and CAISO have the highest non-coincident interregional transfer capability on a MW basis, each exceeding 15,000 MW of interregional transfer capability when evaluating historical

TABLE 2

Historical Interregional Transfer Capability by Region, from West to East

FERC Order 1000 Region	Non-coincident Interregional Transfer Capability (MW)	Coincident Interregional Transfer Capability (MW)	Peak Demand (MW)	Non-coincident Capability as % of Peak Load	Coincident Capability as % of Peak Load
CAISO	15,900	12,600	59,900	27%	21%
NorthernGrid	9,900	8,800	48,200	21%	18%
WestConnect	10,700	7,300	38,700	28%	19%
ERCOT	800	800	83,900	1%	1%
SPP	6,700	4,000	54,500	12%	7%
MISO	17,500	16,100	131,000	14%	12%
SERTP	14,000	9,000	128,000	11%	7%
FRCC	2,900	2,900	51,100	6%	6%
PJM	16,900	11,800	150,400	11%	8%
NYISO	5,600	5,000	32,300	17%	15%
ISONE	1,800	1,800	25,700	7%	7%

This table shows the total interregional transfer capability for each FERC Order 1000 region in terms of its import capability as defined by the magnitude of the 99.9th percentile imports observed in hourly EIA 930 interchange data from 2019 through 2023. Data are provided alongside the peak demand for each region simulated for this report. Values are rounded to the nearest 100 MW.

Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; FRCC = Florida Reliability Coordinating Council; ISONE = Independent System Operator of New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; SERTP = Southeastern Regional Transmission Planning; SPP = Southwest Power Pool.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

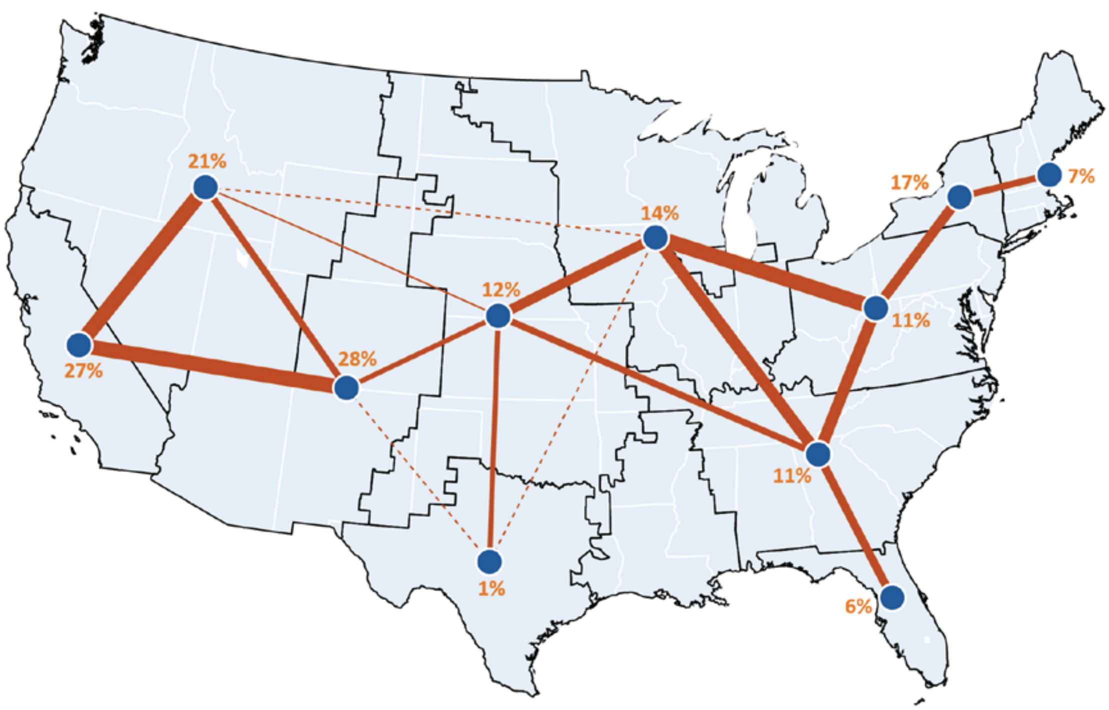
flows. As a percentage of load, WestConnect (28%), CAISO (27%), and NorthernGrid (21%) have the highest interregional transfer capability and are the only regions exceeding 20%. This is significant in the context of existing proposals for boosting interregional transmission capacity to levels specified relative to a region's peak electricity demand. For example, if passed, the BIG WIRES Act would set a minimum transfer capability value at 30% of peak load. Given today's limits and peak load, every region in the U.S. would require substantial additions of interregional transmission to meet this requirement, regardless of whether non-coincident or coincident transfer limits were used.

If passed, the BIG WIRES Act would set a minimum transfer capability value at 30% of peak load. Given today's limits and peak load, every region in the U.S. would require substantial additions of interregional transmission to meet this requirement.

ERCOT, which is not synchronously connected with the rest of the Eastern or Western Interconnection, has the least amount of interregional transfer capability in terms of both MW and percentage of load. It is followed by the Florida Reliability Coordinating Council (FRCC) (6%) and the Independent System Operator of New England (ISONE) (7%), regions at the periphery of the U.S. grid and that have connections with only a single neighboring FERC Order 1000 region.[8] Figures 4 and 5 show the historical interregional transfer capability between FERC

FIGURE 4

Existing Interregional Transmission Paths Across the U.S., by FERC Order 1000 Region



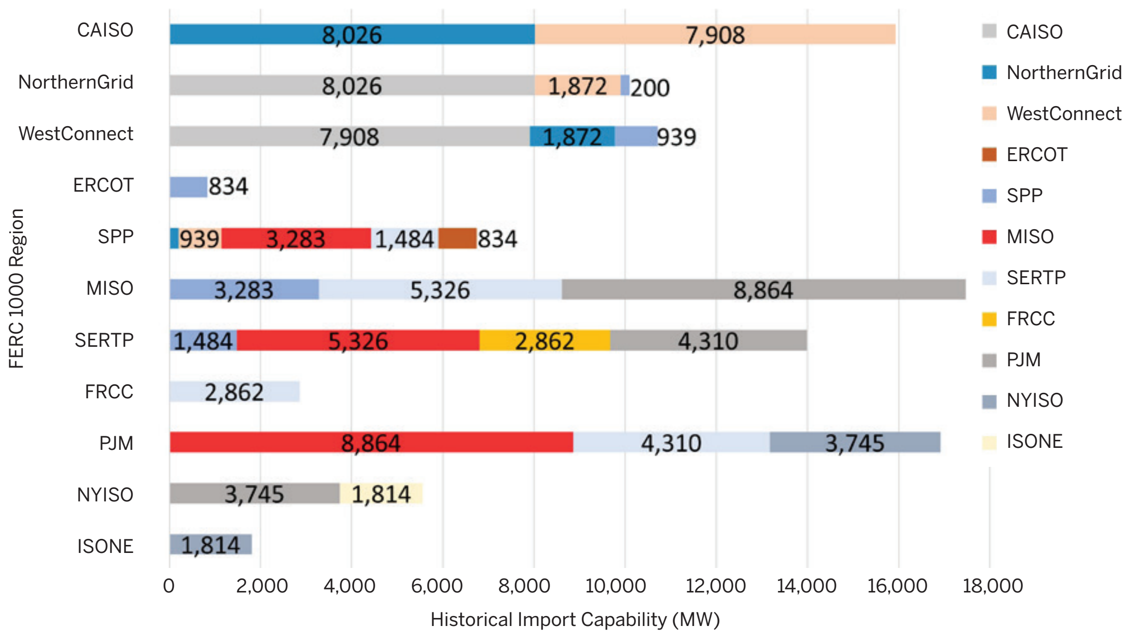
The blue dots represent the FERC Order 1000 regions, with orange lines showing the magnitude of the transfer capability between each pair of regions. Dotted lines represent no existing transfer capability, but the potential for immediate neighbors to create transfer capability. The thickness of the solid lines indicates the relative amount of transfer capability in each case. Note, transfer capabilities for U.S. regions with connections to Canadian regions are not included in these values.

Source: Energy Systems Integration Group; data from Energy Information Administration 930 Hourly Electric Grid Monitor.

8 While not evaluated in this study, ISONE has interconnections with both Quebec and New Brunswick that would approximately double its interregional transmission capability if Canadian provinces were included in this study.

FIGURE 5

Existing Interregional Import Capability, by FERC Order 1000 Region



The figure shows the historical import capability between each FERC Order 1000 region and its directly connected neighbors based on EIA Form 930 data.

Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; FRCC = Florida Reliability Coordinating Council; ISONE = Independent System Operator of New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; SERTP = Southeastern Regional Transmission Planning; SPP = Southwest Power Pool.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

Order 1000 regions, illustrating the size and locations of today's interregional transmission connections.

Before any analysis can effectively be done on how well current interregional transmission enables a resilient and reliable grid—and therefore what additional transfer capacity would best increase the resilience benefits for interregional transmission—it is first necessary to determine the existing transfer capability that today's system can support. No nationwide AC power flow analysis using a consistent dataset exists that shows the transfer capabilities between specific planning regions. Most regions largely focus only on their own internal transmission capabilities while taking different approaches on how to define transfer capabilities between themselves and their neighbors.

This study performed a nationwide analysis, based on a single consistent dataset drawn from actual historical operating conditions across the entire U.S. grid, and provides a starting point for assessing how well existing transfer capability enables transmission grid resilience today and where expansion may be necessary.

This report provides an alternative analysis to conducting a nationwide AC power flow study, which estimates existing transfer capabilities based on data drawn from actual historical operation conditions across the entire U.S. grid to provide a starting point for assessing how well existing transfer capability enables transmission grid resilience today and where expansion may be necessary.

Nationwide Assessment of Regions' Energy Margins During Extreme Events

An estimate of current interregional transfer capability between FERC 1000 regions is needed to evaluate where expanding transfer capability would provide the greatest resilience benefits for the grid. To assess these benefits, it is important to evaluate the impacts of extreme weather conditions on resource availability and load across multiple regions. Since it is uncertain whether typical periods of high risk today (winter and summer peak loads) will be the same under a future resource mix driven by variable renewable energy and energy storage resources, hourly chronological operations for all hours are needed to inform whether new risks emerge as the grid evolves. This national assessment allows for both analyses since data were developed for assessment at an hourly level across multiple weather years. It is particularly important to understand the correlated risks and/or uncorrelated risks due to weather, load diversity, and resource availability at a regional level—as the variation in risk between regions determines when and where additional resources are available to support the wider system, particularly during periods of extreme weather or low renewable energy output.

Importance of Correlated Risks Within a Region

Today, resource adequacy studies often do not attempt to model the entire interconnection, let alone the three interconnections of the U.S. power system. Instead, regions often either model their own system in isolation or evaluate only their immediate neighbors, due to computational intractability and the effort required to build models of sufficient detail. In addition, even if transfers between neighbors are represented, the actual technical limitation of the grid may not be represented, which can understate the benefits of today's system and blind planners to additional benefits that may be realized by expanding their analyses. These assessments to quantify transfer capability are often only conducted for the annual or seasonal peak period; however, as the resource mix changes and electrification of new loads proceeds, the timing of risk is changing and becoming increasingly correlated with specific characteristics of the weather.

New methods are needed that consider correlated *hourly, weather-dependent* inputs on loads and resource availability to better understand how interregional transmission can be best leveraged to mitigate these risks. The hourly energy margin analysis described in this report incorporates consideration of weather-dependence of both renewable energy production and outages for thermal power plants. (The latter is a notable development seeing traction across many regions where thermal plants are being evaluated on their weather performance just as renewables are.) In addition, the approach outlined here mitigates the need to perform detailed production-cost or resource adequacy assessments for evaluating the potential benefits for transmission grid resilience and assessing where to prioritize the expansion of transmission capability. This is because the analysis is based on expected resource availability on a fleet-wide basis versus modeling individual generators. This analysis can be used to complement a region's production-cost and resource adequacy assessments by enabling modeling of import availability depending on weather, grid conditions, and changing resource mixes without modeling every external generator in detail.

When the correlated load, wind and solar output, and thermal generator outages are evaluated together, system planners can quantify the potential available supply of resources, calculate the surplus or deficit of reserves, and consider opportunities for interregional transmission to mitigate risk by transferring power from one region to another.

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Importance of Uncorrelated Risks Between Regions

Improving grid resilience specifically involves regions' ability to access other regions with uncorrelated risks. If a region is considering interregional transmission to improve resilience, it will want to make investments in new or upgraded transmission that helps access regions least likely to be experiencing the same weather-related stressors. Planners will need to quantify the potential benefits that greater transfer capability between regions of uncorrelated risk can provide for system resilience, as well as the types of weather or grid-related events during which they can be expected to provide assistance.

Need for a Simplified, High-Level View of Available Capacity and Hourly Reserves at a National Scale

There is a critical need for an alternative to simulating a full production-cost or resource adequacy model of the U.S. power system to evaluate the transmission grid resilience benefits of interregional transmission. Planners need access to a simplified, high-level view of available capacity and hourly reserves at a national scale across many years of hourly weather data. They also need a consistent dataset showing the expected resource availability across the power system during different types of extreme events—for example, a Southeast cold snap or a Western heat dome—to better show which regions have uncorrelated risks and therefore which transmission paths can provide a resilience hedge during extreme weather conditions or extended periods of low renewable production. In this report we define a metric for reporting hourly changes in a region's resources relative to its electricity demand to establish a consistent dataset to evaluate the resilience benefits of interregional transmission. In doing so, the availability of all regions' resources on an hourly basis for multiple weather years is calculated to quantify how each receives or provides support during periods of low surplus resources using existing interregional transmission capability and to assess where future capacity could be built to enhance transmission grid resilience.

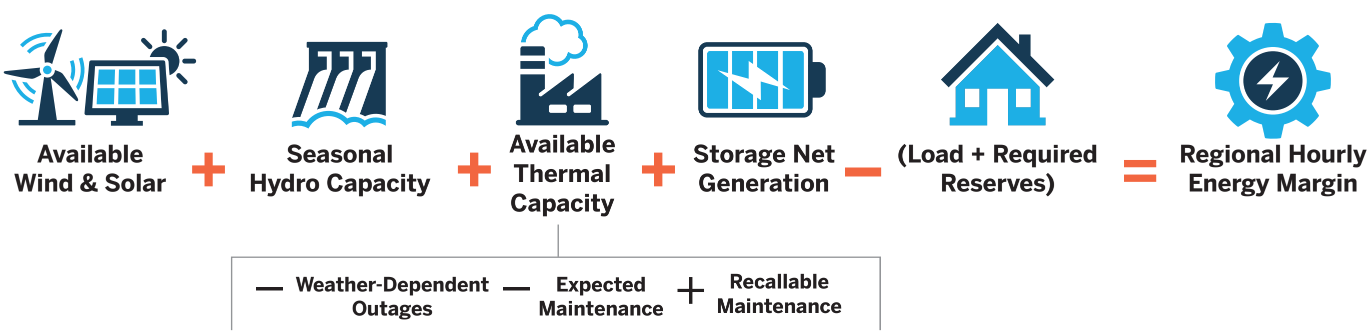
Planners need access to a simplified, high-level view of available capacity and hourly reserves at a national scale across many years of hourly weather data.

Evaluating Hourly Energy Margins Across Multiple Weather Years

This study developed an hourly energy margin assessment using multiple weather years of time-synchronized wind, solar, load, and weather-dependent generator outages. This methodology results in a set of deterministic hourly reserve levels for specific weather years across the U.S. power system. (The evaluation is deterministic because the availability of resources and electricity load is predetermined for each weather year assessed based on historical solar irradiance, wind speed, and temperature data, similar to most planning model approaches.) The hourly energy margin analysis allows planning assessments to look beyond a region's primary neighbors and consider energy availability across larger geographical regions. The deterministic reserve value for a region was calculated on an hourly basis using the formula described in Figure 6.

Using the inputs described in the following section, a margin for every hour of a given weather year was calculated and used as an input to a region's planning model to serve as an approximation for hourly resource availability in external regions without conducting detailed modeling. Advantages and limitations of this approach are described in Table 3 (p. 19).

FIGURE 6
Regional Hourly Energy Margin Formula Used in This Study



Source: Energy Systems Integration Group.

TABLE 3

Pros and Cons of the Hourly Energy Margin Analysis Developed in this Study

Method Pros	Method Cons
✓ Allows for quick regional assessments of expected resource availability ✓ Captures hourly variability in wind and solar output against thermal availability ✓ Incorporates multiple weather years of temperature data into resource availability ✓ Allows for easy variation for levels of reserve requirements to assess more conservative operations	x Does not assess actual system dispatch of economic transfers x Hydro uses a simplified availability based on seasonal capacity ratings, which does not capture energy limitations of hydro x Storage resources are dispatched to net load within a 24-hour period as an aggregated capacity/energy pool

Source: Energy Systems Integration Group.

This methodology can be readily expanded to include additional weather years and consider the distributions of imports available for planning studies such as probabilistic resource adequacy assessments.

The main benefit of this approach is to provide a time series of data showing the relative conditions of all the regions in the U.S. during a given extreme event. Both historical and synthetic data can be fed into the hourly energy margin formula and provide a deterministic assessment of the regions where surplus resources are likely available to support regions in deficit. This level of external awareness is critical for assessing the value that increasing interregional transmission capabilities can provide a region in terms of resilience. The methodology can be readily expanded to include additional weather years and consider the distributions of imports available for planning studies such as probabilistic resource adequacy assessments.

Components of the Hourly Energy Margin

We developed the hourly energy margin by leveraging publicly available data in the NREL Cambium and ReEDS datasets for the weather years 2007–2013 and modified these data with additional analysis where necessary to align peak load forecasts with recent industry trends (Gagnon, Cowiestoll, and Schwarz, 2023; NREL, 2023a). Using data such as hourly load, wind, and solar for granular regions like those used in the ReEDS model allows for results to be aggregated into larger planning regions while maintaining internal geographical differences in resource availability. Table 4 (p. 20) provides the major input categories, their source, and a short description of what the data represent. For this analysis, much of the data were based on the NREL Cambium standard scenarios, which are based on results from the ReEDS capacity expansion model.

Installed Capacity by Region

Developing the hourly energy margin requires a summary of each region's capacity by technology and fuel type. Technology types were treated differently when determining availability based on outage rates or expected production profiles depending on whether they were dispatchable resources, like thermal power plants or battery storage, or non-dispatchable, like solar and wind resources. Thermal resources were derated by the expected weather-dependent outage rate for each day, renewables used hourly weather-specific production profiles, and storage resources were dispatched against net load with no flexibility assumed for their charging/discharging profiles. For regional studies such as this, any regional aggregation of power plants can be used to suit a study's needs. In this analysis, the NREL ReEDS balancing authorities were used since they provide a granular breakdown of U.S. electricity infrastructure that allowed for aggregation into larger regions like the FERC Order 1000 regions for reporting purposes. Figure 7 (p. 21) shows the installed capacity by region and type as a percentage of total capacity for each FERC Order 1000 region using the NREL case identified in Table 4.

TABLE 4

Summary of Study Inputs and Assumptions

Input Category	Data Source	Data Description
Region topology	NREL ReEDS[a] / FERC	The geographical distribution of load and resources was based on the National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) model balancing areas for the 2022 Cambium scenarios. Areas were aggregated into Federal Energy Regulatory Commission (FERC) Order 1000 regions with slight modifications.
Transmission capability	EIA Form 930[b]	The transfer capability between FERC Order 1000 regions was based on the existing transmission system and historical power flows between FERC Order 1000 regions. Data are based on the 99.9th percentile or observed maximum of historical transfers between balancing authorities aggregated into FERC Order 1000 regions based on the Energy Information Administration's Form 930.
Installed capacity by region	NREL Cambium 2022[b]	The future capacity build for each ReEDS balancing area was based on the NREL Cambium 2022 low-cost renewable standard scenario results. The resource mix assumed was the scenario's 2024 results but is intended to represent a late 2020s system with greater renewable resource expansion and thermal retirements.
Wind and solar profiles	NREL ReEDS[a]	The electricity production profiles for wind and solar for the 2007–2013 weather years were developed by NREL for use in its ReEDS capacity expansion model. The datasets use historical meteorological data to produce geographically diverse solar and wind production profiles using the WIND Toolkit and National Solar Radiation Database (NSRDB) datasets. Profiles were available directly from the NREL ReEDS GitHub repository for each ReEDS region.
Weather-year load profiles	NREL Cambium 2022[c]	The load profiles for each ReEDS region were developed by NREL based on historical weather and load patterns for the 2007–2013 weather years. The profiles were used to turn future electricity demand due to economic growth into weather-varying profiles as if historical weather occurred in a future system. Additional load scaling was done based on near-term peak and energy forecasts by independent system operators, regional transmission organizations, and utilities to match the median weather year peak forecasts with industry expectations at the time.
Weather-dependent outages	Murphy, Sowell, and Apt (2019)[d] & Telos Energy	The correlated temperature and outage rate probability curves by prime mover (steam turbine, gas turbine, etc.) were developed by Sinnott Murphy for PJM in 2019. The PJM curves for each FERC Order 1000 region were shifted in the present analysis based on climate zone differences to reflect where asset owners are likely to have more experience mitigating plant outages during extreme heat or cold. The temperature data used to calculate outage rates were based on historical daily minimum/maximum temperature observations for 1981–2023 across many weather stations in each FERC Order 1000 region. Temperature profiles from weather stations were given a weight based on nearby power plant capacity.
Planned outages	Telos Energy	Annual expected maintenance rates as a percentage of a unit type across the generator fleet were calculated using historical fleet-wide data from the North American Electric Reliability Corporation's (NERC's) Generating Availability Data System (GADS). The occurrence of planned outage and maintenance by month was based on published monthly maintenance data (if available) at a regional level. Regions with limited or no monthly data available were assumed to have similar monthly profiles as their closest neighbor.
Hydro availability	NREL Cambium 2022[c]	The availability of hydropower resources was based on seasonal maximum capacity ratings for each ReEDS region in the hourly data from the low-cost renewable scenario developed by NREL. The maximum rating does not capture energy limitations for hydropower units but does reflect maximum generating capability by season (capacity limitations).

(CONTINUED)

TABLE 4

Summary of Study Inputs and Assumptions (CONTINUED)

Input Category	Data Source	Data Description
Storage dispatch	Telos Energy	Battery storage and pumped hydro storage units were aggregated into a single capacity and energy pool for each region. These resources were scheduled based on net load (load – renewable production) for each region for 24-hour periods for every day of the seven weather years used.

a NREL ReEDS, https://github.com/NREL/ReEDS-2.0/tree/main/inputs

b EIA Form 930, https://www.eia.gov/electricity/gridmonitor/about

c NREL Cambium 2022, https://scenarioviewer.nrel.gov/

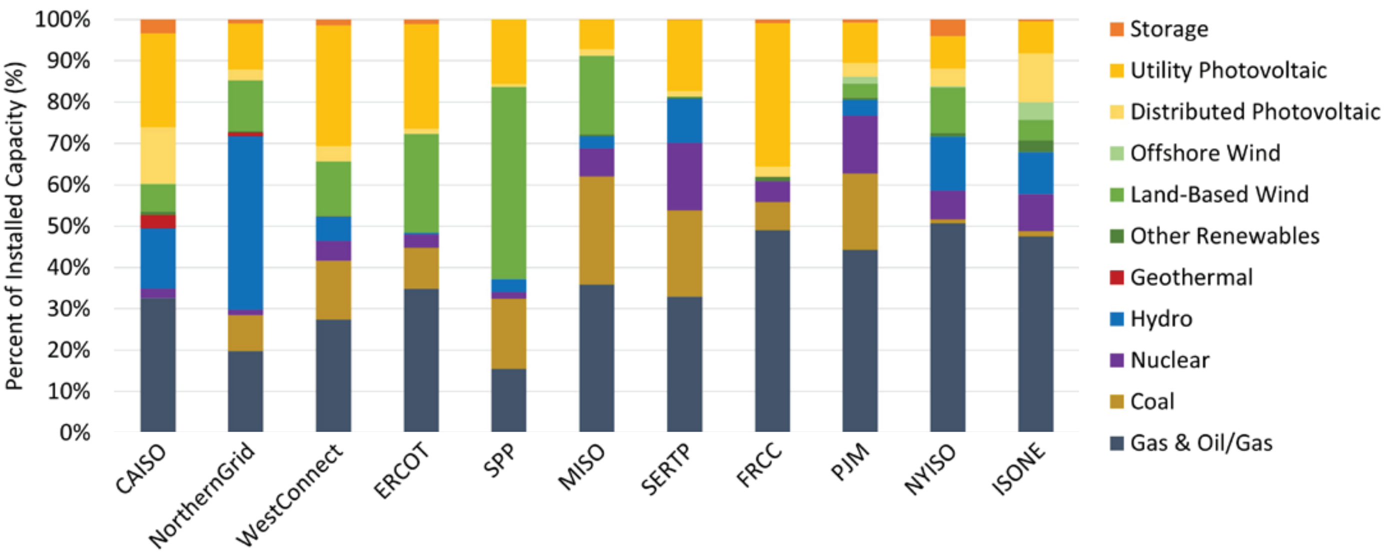
d Murphy, Sowell, and Apt (2019), https://doi.org/10.1016/j.apenergy.2019.113513

These are the major components used to calculate the hourly energy margin for this analysis, along with the data source for each and an explanation of what data were used.

Source: Energy Systems Integration Group.

FIGURE 7

Percentage of Installed Capacity by Type by FERC Order 1000 Region for the NREL Cambium Low-Cost Renewable Scenario in 2024



Source: Energy Systems Integration Group; data from the NREL Cambium low renewable cost scenario for 2024.

Wind and Solar Profiles

We used the wind and solar hourly production profiles developed by NREL for its ReEDS capacity expansion model for the 2007–2013 weather years. NREL's data are based on modeling renewable production with the lab's Wind Integration National Dataset (WIND) Toolkit, National Solar Radiation Database (NSRDB), and PVWatts model.[9] Additional information on the types of renewable resource classes modeled (low-quality versus higher-quality resources) is available in the ReEDS documentation (Ho et al., 2021). The use of the NREL production profiles allowed for seven years

9 National Solar Radiation Database is at https://nsrdb.nrel.gov/ and WIND Toolkit is at https://www.nrel.gov/grid/wind-toolkit.html.

of hourly weather-correlated wind and solar output to be included in the energy margin calculations. Including weather-varying renewable energy production alongside electricity load is a key input to represent weather-induced risks due to low renewable energy availability and to capture the distribution of excess energy when renewable energy output is high.

Weather-Year Load Profiles

As discussed above, it is just as important to capture variation in electricity load due to weather as it is to represent the availability of renewable energy. An additional aspect of this representation is to have a time-synchronized dataset where wind, solar, and electricity load are built on the same time series of weather data. This allows one to quantify how much additional load must be met by existing thermal, hydropower, and energy storage resources within each region or via energy imports from neighbors, a key component for assessing the value of interregional transmission. In this study we used the weather-year load profiles for 2007–2013 provided within the NREL ReEDS modeling framework used for its 2022 Cambium scenarios. These profiles are publicly available and time-synchronized to the renewable energy production profiles. The resulting load forecasts represent NREL's base assumption on electrification and economic growth for each ReEDS region based on regional economic growth projections from the EIA's *2022 Annual Energy Outlook* (EIA, 2022) and NREL's medium electrification future, described in more detail in the NREL Cambium documentation under the "Demand Growth and Flexibility" section (Gagnon, Cowiestoll, and Schwarz, 2023).

It is important to have a time-synchronized dataset where wind, solar, and electricity load are built on the same time series of weather data. This allows one to quantify how much additional load must be met by existing thermal, hydropower, and energy storage resources within each region or via energy imports from neighbors, a key component for assessing the value of interregional transmission.

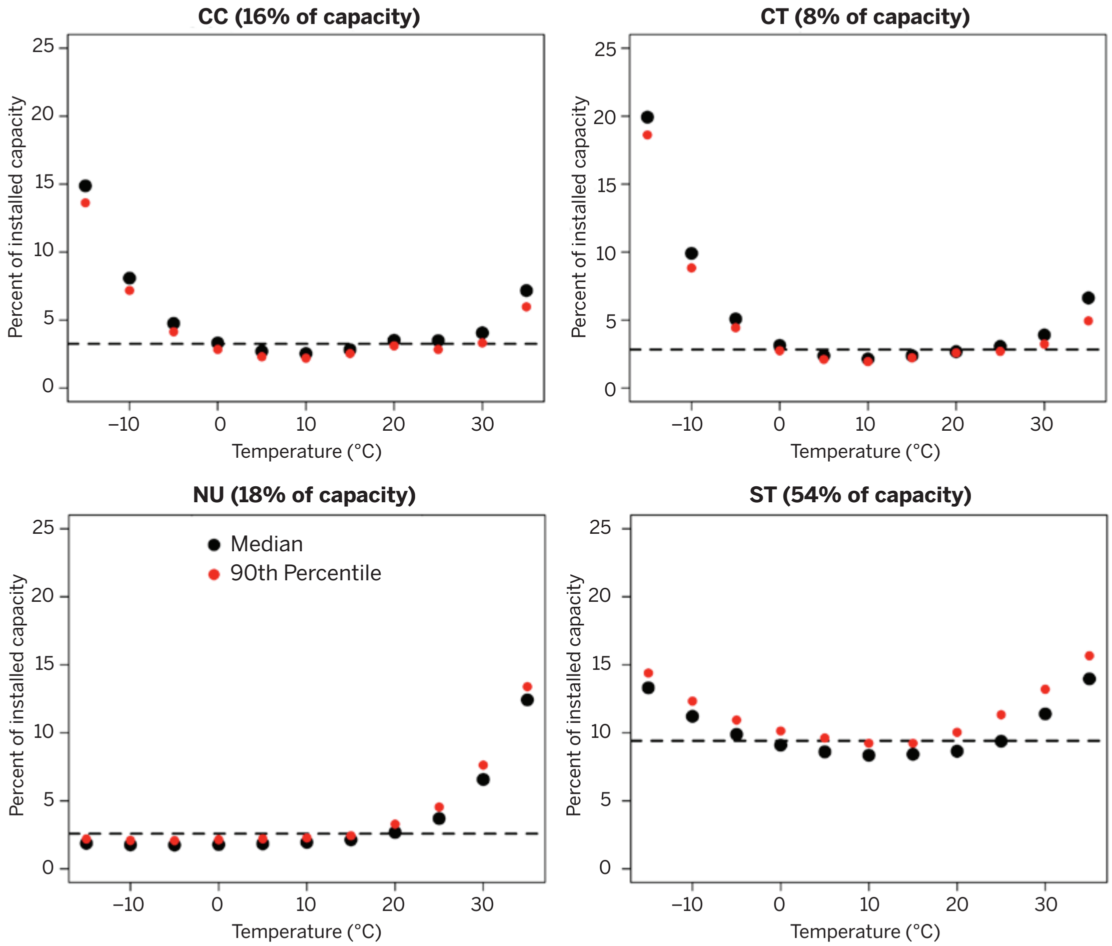
Weather-Dependent Outage Curves for Thermal Generators

Since the extreme grid emergencies posed by Winter Storms Uri and Elliott in 2021 and 2022, greater importance has been placed on determining the correlated risks between all generator technology types and weather. Historically, planners have recognized differences in maximum generating capacity for thermal resource types, which usually results in a seasonal rating since ambient temperature and humidity can both degrade power-generating capabilities. However, little consideration has been given beyond derating maximum output of thermal plants based on typical ambient weather conditions and expected outage rates. To represent the contribution of the thermal generation fleet to correlated risks for each region due to extreme weather, we leveraged existing work that tracks different generator types and their outage risk based on historical outage and temperature data. This effort allowed for modeling regional variation in increased outage risks due to temperature, thereby providing insight into which regions may have surplus thermal generation available during extreme events while other regions suffer increased outage risks due to correlated weather such as what the Southeast faced during Winter Storm Elliott.

Recent work by Murphy, Sowell, and Apt (2019) evaluating thermal generator performance sought to characterize the relationships between resource technology types and correlated forced outages due to temperature and weather (Figure 8, p. 23). The resulting weather-dependent outage curves show the increased probability that generators of a certain type (e.g., combined-cycle gas turbines) may experience a forced outage as temperatures approach extreme values. The importance of including these effects in analyses for risk planning is that, previously, forced outage rates of different units were assumed to be largely independent events, with no correlation between generator outages. However, recent operational data have shown this not to be the case, for both hot and cold temperatures. For example, there are fuel-network interdependencies for natural gas generators as well as cold-weather equipment failures and other temperature and outage correlations across all thermal generator types. An example of weather-dependent forced outage curves for PJM is shown in Figure 8.

FIGURE 8

Weather-Dependent Outage Functions for Thermal Power Plants by Fuel and Generator Type in PJM



The charts represent the increase in the percentage of installed capacity on outage for each type of generation resource in PJM as a function of temperature. Extreme temperatures see an uplift in outage rates relative to the entire fleet. The dotted lines show the annual outage rate and highlight how extreme temperatures exhibit outage rates well above the annual average for all generation types.

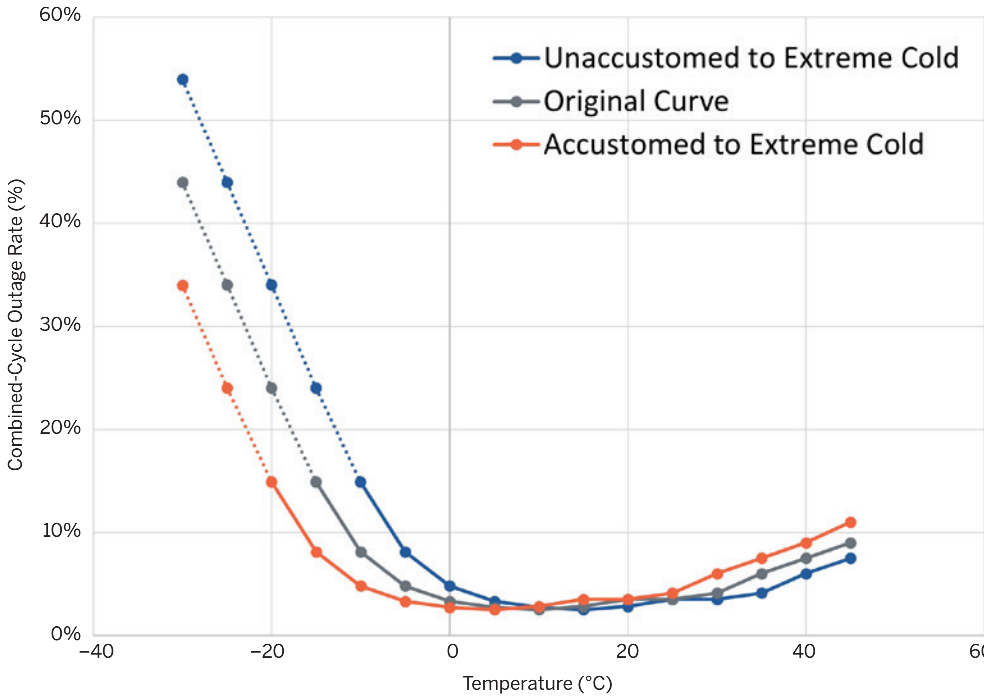
Notes: CC = combined cycle; CT = combustion turbine; NU = nuclear unit; ST = steam turbine.

Source: Murphy, Sowell, and Apt (2019).

The development of weather-dependent outage curves for different regions and climate zones across the United States is an ongoing effort. Some regions, like SPP and PJM, have sought to build on the above work and develop approaches that better capture extreme weather events seen during Winter Storms Uri and Elliott. Since efforts for this report are at the national scale, we made adjustments to the original curves developed for PJM to account for differences in generator performance observed across different regions in the U.S., including shifts to better represent effects on thermal outages for extreme cold conditions experienced during those winter storms (MISO, 2023; PJM, 2023; SPP, 2023). In effect, the curves for regions where extreme cold weather is more common—and generators are better prepared and often have dual-fuel capabilities or better weatherization practices—were shifted to the left, indicating that generators have better performance in winter and slightly underperform in the summer. Curves for regions not accustomed to extreme cold were shifted to the right,

FIGURE 9

Weather-Dependent Outage Rate Curve for Combined-Cycle Units, with Regional Shifts and Adjustments for Winter Storms Uri and Elliott



The weather-dependent outage curves for regions where extreme cold weather is more common (and generators are better prepared) shift to the left, indicating that generators have better performance in winter and slightly underperform in the summer. Curves for regions not accustomed to extreme cold shift to the right, which indicates worse winter performance but slightly better performance during extreme heat.

Source: Energy Systems Integration Group; data adapted from Murphy, Sowell, and Apt (2019).

which indicates worse winter performance and slightly better performance during extreme heat. Figure 9 shows an example of the degree-shifting performed for combined-cycle units.

The chosen degree shifts for the FERC 1000 regions are listed in Table 5 (p. 25). Some regions, like SPP and MISO, span different climate zones; therefore, we used a north-versus-south split to adjust the curves in each subregion. The 5-degree shift was implemented consistently across regions to approximate different generator performances in different regions since the only available data were for PJM. Future analysis from Murphy, Sowell, and Apt is expected to produce region-specific curves.

Weather-dependent outages for the energy margin analysis were calculated based on daily historical temperature observations using weather stations across the United States. Station temperature data were weighted by capacity based on the proximity of generators to stations. The maximum or minimum weighted observed temperature for each day in the region (whichever temperature resulted in greater outage risks) set the percentage of capacity expected on forced outage by unit type (gas combined-cycle, coal steam turbine, etc.) for weather events. This expected outage rate was applied as a derate to the installed capacity of the regional resources for that day on a fleet-wide basis. It is worth noting that this is not a simulated outage rate of individual generators, but rather a derate applied to all generators of a particular unit type representing an expected amount of capacity on outage for that day given temperature data.

TABLE 5

Weather-Dependent Outage Curve Shift for All FERC 1000 Regions

FERC 1000 Region	Weather-Dependent Outage Degree Shift
CAISO	Original curve
NorthernGrid	5°C shift left
WestConnect	5°C shift right
ERCOT	5°C shift right
SPP	SPP North: 5°C shift left SPP South: 5°C shift right
MISO	MISO North: 5°C shift left MISO South: 5°C shift right
SERTP	5°C shift right
FRCC	5°C shift right
PJM	Original curve
NYISO	5°C shift left
ISONE	5°C shift left

Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; FRCC = Florida Reliability Coordinating Council; ISONE = Independent System Operator of New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; SERTP = Southeastern Regional Transmission Planning; SPP = Southwest Power Pool.

Source: Energy Systems Integration Group.

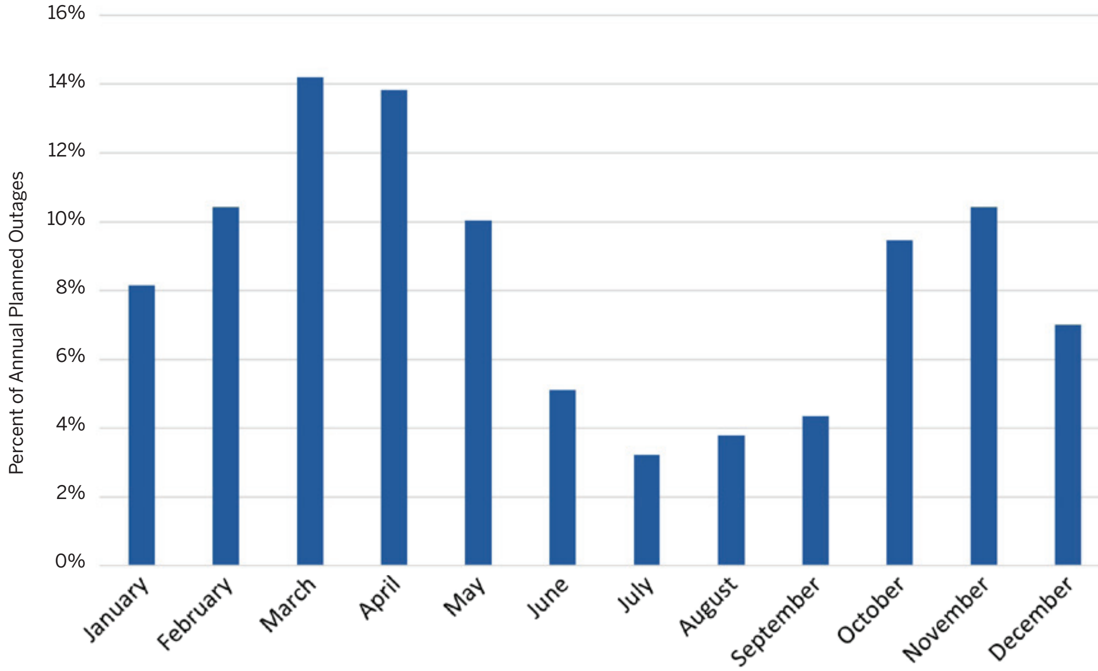
Planned Outages for Thermal Generators

Using publicly available data from utilities and ISOs/RTOs on the occurrence of maintenance across the generation fleet for each month, we created an annual maintenance shape to distribute fleet-wide maintenance outages by resource type over each month of the year by technology type (NERC, 2023). If maintenance information was not available, we used neighboring region profiles and scaled them based on a percentage of total capacity.

Annual maintenance outages were calculated using the NERC Generating Availability Data System (GADS) fleet-wide dataset to develop planned outage factors and maintenance outage factors for different generator types. Annual maintenance was then distributed by month for each generator type using the maintenance shapes. Figure 10 (p. 26) shows an example of a maintenance shape and typical distribution of planned MW on outage for CAISO. It was assumed that the MW of planned outages was constant for every day in a month. In addition, when calculating the energy margin, we reduced the expected capacity on planned outage by 20% to account for some maintenance being recallable if an emergency is expected.

FIGURE 10

Calculation of the Allocation of Annual Planned Outages by Month, California Independent System Operator (CAISO)



Source: Energy Systems Integration Group; allocation of annual maintenance is based on data on monthly average maximum daily generation outage by outage type given in CAISO (2022) and NERC (2023).

Hydropower Availability

Existing hydropower availability was taken directly from the NREL ReEDS model for each ReEDS region. In general, assumptions around the existing hydropower fleet were based on historical performance developed by NREL or referenced in the ReEDS documentation. Based on this documentation, we modeled resources in the Western Interconnection using seasonal capacity adjustments available from the Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee 2024 Common Case, which derated potential hydropower output relative to installed capacity. Non-WECC hydropower units were modeled based on historical performance reported by the National Hydropower Asset Assessment Program referred to in the NREL ReEDS documentation, resulting in historical seasonal capacity factors (Ho et. al, 2021; Hydrosource, 2023). The seasonal capacity availability was not adjusted for different weather years but could be changed for sensitivities around drought conditions and hydropower availability.

For modeling hydropower performance in the energy margin analysis, it was assumed that: (1) the maximum seasonal capacity rating could be available in any hour of the season, and (2) the seasonal derate reflected resource availability due to water levels and unit outages, as the derate was based on historical performance. Since the analysis was not concerned with economic dispatch, no assumptions were made on when or how hydropower plants would be dispatched, only that if required, the capacity would be available at a varying level by season. Table 6 (p. 27) shows the seasonal capacity ratings as a percentage of hydropower capacity for each FERC 1000 region. No variation in seasonal capacity ratings was available for hydropower based on weather years, but future work could evaluate drought or high hydro conditions with similar methods.

TABLE 6

Seasonal Maximum Capacity Rating for Hydropower Units, by FERC 1000 Region

FERC 1000 Region	Spring Rating (% of ICAP)	Summer Rating (% of ICAP)	Fall Rating (% of ICAP)	Winter Rating (% of ICAP)
CAISO	61%	64%	52%	50%
NorthernGrid	80%	76%	70%	76%
WestConnect	95%	95%	94%	94%
ERCOT	34%	33%	30%	30%
SPP	80%	81%	77%	78%
MISO	79%	78%	73%	74%
SERTP	71%	68%	67%	74%
FRCC	86%	85%	84%	86%
PJM	62%	48%	44%	55%
NYISO	75%	74%	71%	77%
ISONE	70%	54%	50%	61%

Note: ICAP = installed capacity.

Source: Energy Systems Integration Group; data from NREL Cambium 2022 Scenario (low renewable cost scenario) Hourly Data.

Storage Dispatch

Multiple methods could be used to model storage dispatch in the energy margin analysis. To avoid reliance on a production cost model to calculate the energy margin, we used an alternative method assuming that storage assets are dispatched heuristically to arbitrage net load within a single day. This approach is not effective at dispatching longer-duration storage, and so it would require modifications to accommodate multi-day storage dispatch in the future.

To create the storage dispatch profile, each region's storage assets—pumped hydropower storage and batteries—were aggregated into a capacity and energy pool dispatched in equal increments. Storage charging for each region was assumed to occur during the lowest net-load hours of a day. Storage discharging was assumed to occur during the highest net-load hours, assuming perfect foresight within a day. This process was conducted iteratively until all the storage capacity was used. An example of this is shown in Figure 11 (p. 28) for a 48-hour period in CAISO to illustrate the dispatch of storage against net load. Charging efficiency was accounted for on the discharge profile (positive values) and assumes 85% for batteries and 70% for pumped storage hydro.

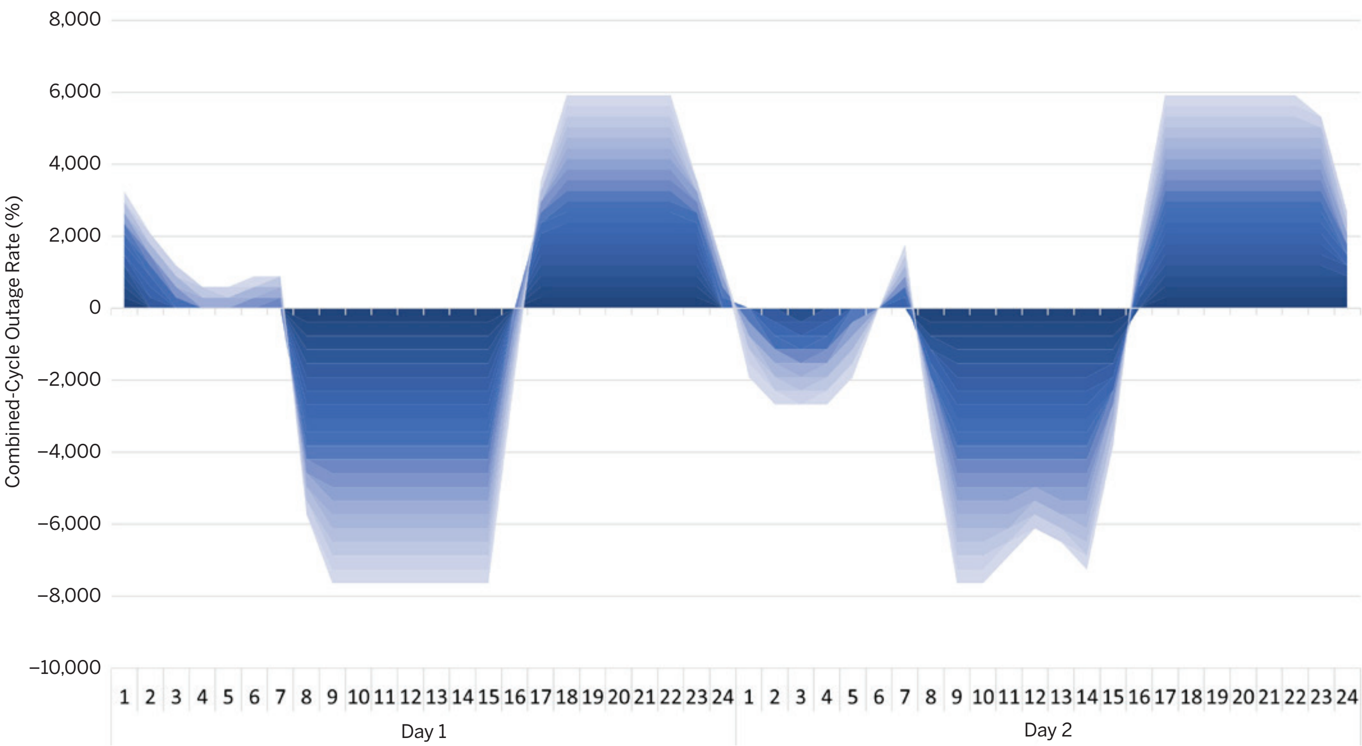
Using this method, we developed an 8,760-hour net-load dispatch profile for each FERC 1000 region and every weather year. Storage charging represented additional load to serve, and discharging reduced the load needing to be served by thermal or hydro resources. This method inherently reduced the flexibility of storage resources within the system in favor of simplicity. Accounting for storage operations and resource availability based on historical performance is expected to improve as more large-scale assets are brought online across the country.

Results of the Hourly Energy Margin Analysis

Often, there is reluctance in planning processes to consider external resources and how they may support a region to meet load during times of extreme weather or other unforeseen events. Here we present planners with some ways to visualize the potential of external resources from neighboring regions to provide support to a region.

FIGURE 11

Example of a 48-Hour Aggregated Storage Net-Load Dispatch Profile for CAISO



The figure shows an example 48-hour period of aggregated storage resources dispatched against the California Independent System Operator's net load (load minus renewable output). The shades of blue represent different blocks of storage resources that are dispatched together as net load changes.

Sources: Energy Systems Integration Group; data from NREL ReEDS Load and Renewable Profiles and NREL Cambium 2022 Scenario (low renewable cost scenario).

This method provides a high-level approach to view where and when resource availability exists so that interregional transmission can be leveraged to improve system resilience.

Having a full U.S. time-synchronized dataset of load, wind, solar, and weather-dependent outages allows one to determine the expected variability in regional energy margins across large geographical regions. The result is the ability to view the entire U.S. power grid at once in terms of an hourly margin—the amount of excess MW available every hour—expressed as a percentage of the hourly load. This information shows the state of energy margin surplus or deficit in all regions at the same time to inform when and where regions can provide or receive support during all hours assessed, including periods when grid stress conditions affect some but not all regions.

This method provides planners with a high-level approach to view where and when resource availability exists to inform how regions can provide or receive support, including periods when grid stress conditions affect some but not all regions.

The use of synthetic historical weather data allows planners to analyze known extreme events under potential future grid conditions. For example, events like the 2011 Southwest Cold Weather Event can be reassessed assuming different grid resources and load, allowing one to identify where surplus capacity and energy would be available in future years relative to existing interregional transfer capabilities. This is similar to how weather-year data are used in resource adequacy studies but has been simplified by using an expected availability approach and single simulations of weather years (compared to thousands) to enable viewing the entire U.S. grid at scale. While this study uses only the 2007–2013 weather-year data, the approach can be readily expanded with additional weather data as available.

The following section discusses the visuals and analysis used in this report to investigate the relationships between regions' energy margins to aid in understanding where and when surplus resources may be available across the entire grid. These figures are not meant to provide specific recommendations, but rather to show some methods for visualizing trends to build understanding of the larger regional risks that are important for planners to act on. Planners could use such a review, for example, to identify regions of uncorrelated risks where additional interregional transmission could provide mitigation for extreme weather events, as well as identify regions where *not* to invest heavily in interregional transmission due to correlated risks—as ties between regions experiencing similar weather patterns won't be as likely to provide resilience benefits.

Planners could use this type of review to identify regions of uncorrelated risks where additional interregional transmission could provide mitigation for extreme weather events, as well as identify regions where not to invest heavily in interregional transmission due to correlated risks.

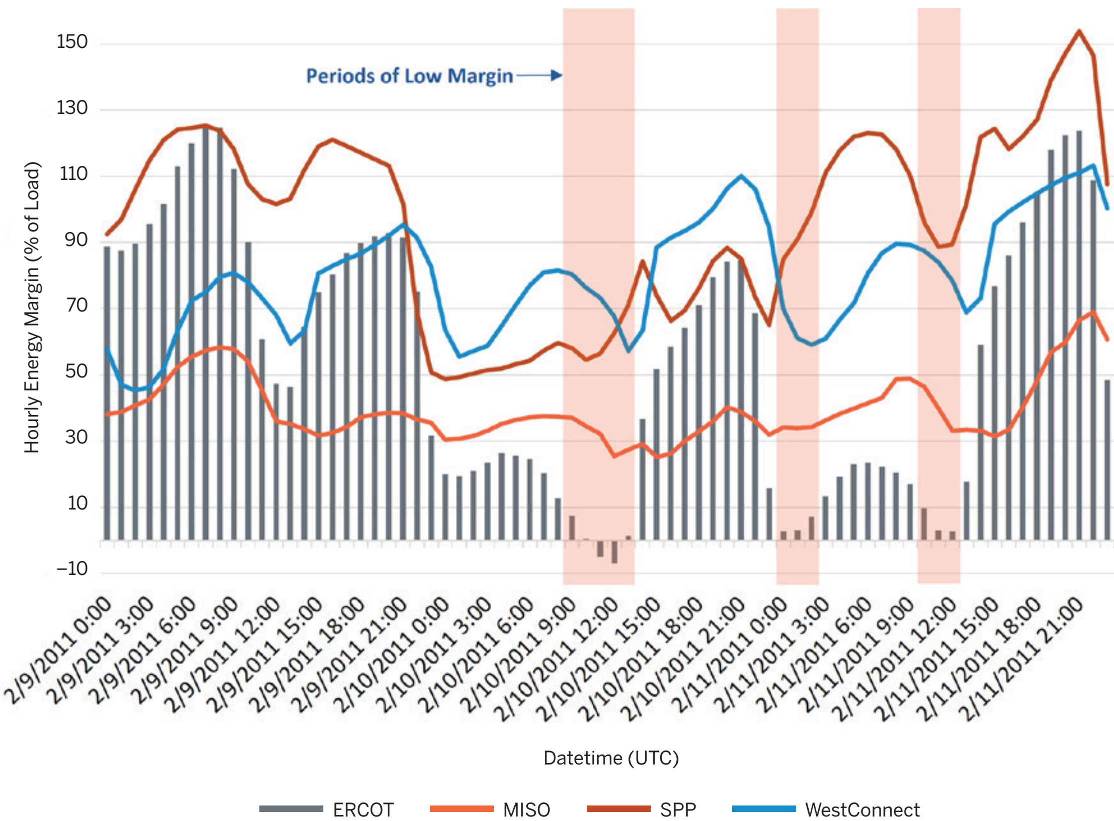
Examining Regional Energy Margins for Specific Extreme Events

One benefit of this approach is that it uses synthetic historical hourly weather data representative of actual weather conditions that have occurred. This allows one to investigate known stressful periods within the weather dataset and zoom in on specific regions to identify where resources are available to alleviate the stress if interregional transmission capacity were available. Additionally, by simulating all hours of a weather year, one can screen for additional stressful periods that may occur because of the changing resource mix or increasing electricity demand, helping to identify future potential risks that neighbors could help alleviate.

Figure 12 (p. 30) shows a snapshot of hourly energy margin results for all FERC Order 1000 regions for a three-day period during the recreated 2011 Southwest-Cold Weather Event available in the weather-year data. While SPP and MISO show relatively high hourly energy margins, ERCOT's margins drop to a minimum of 3% relative to load, showing that ERCOT has high risk and may need imports to support its grid if the transmission capacity is available.

FIGURE 12

Hourly Energy Margin for ERCOT, SPP, MISO, and WestConnect for 2/9/2011– 2/11/2011 Weather Data



The figure shows the hourly energy margin for ERCOT, MISO, SPP, and WestConnect during the recreated 2011 Southwest Cold Weather Event available in the weather-year data. ERCOT's energy margins are shown as vertical gray bars, with orange shading highlighting periods where its energy margin is low (below 10%), which indicates high-risk periods where imports may be needed. Horizontal lines show MISO, SPP, and WestConnect's energy margins (their surplus energy in each hour) to show availability of resources to neighboring regions, including ERCOT, if sufficient interregional transmission is available.

Notes: ERCOT = Electric Reliability Council of Texas; MISO = Midcontinent Independent System Operator; SPP = Southwest Power Pool.

Source: Energy Systems Integration Group.

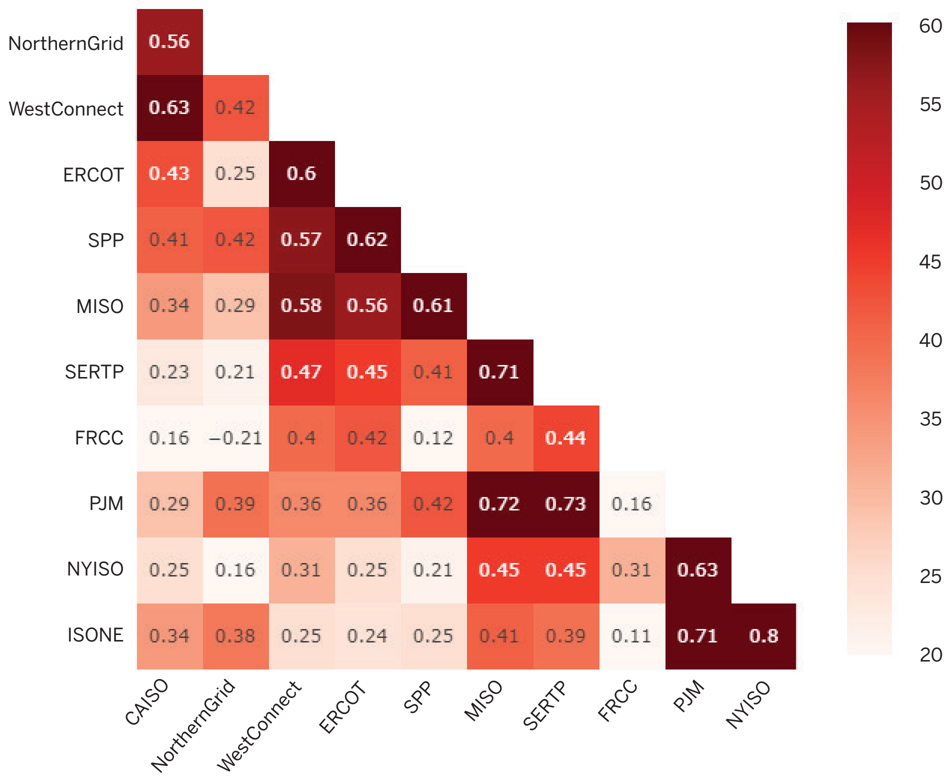
Calculating Regional Correlations in Energy Margin

Beyond analyzing time series data, we can also compute the correlations between regional energy margins to quantify the degree of alignment between different regions. These correlations can help planners identify whether regions track each other closely (a high positive correlation), show no alignment (uncorrelated), or even inversely align. Regions with lower correlations suggest greater geographical diversity in energy margins. Strategically, interregional transmission initiatives may want to focus on linking these less correlated regions to enhance system robustness and resource sharing.

Figures 13 (p. 31) and 14 (p. 33) show two approaches to determining correlations. Figure 13 shows the hourly energy margin correlations by comparing the levels of energy margin surplus or deficit on an hourly basis between each pair of regions using data for the entire period, in this case seven years or more than 61,000 hours. Correlations are calculated to determine how much one region's changing surplus or deficit can explain another region's: when one region has a surplus, does its neighbor also

FIGURE 13

Minimum Daily Energy Margin Correlations Between FERC 1000 Regions for 2007–2013, All Hours



Correlation (r value) in hourly energy margin between every FERC Order 1000 region using 2007–2013 weather data for load, renewable energy, and thermal outage rates.

Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; FRCC = Florida Reliability Coordinating Council; ISONE = Independent System Operator of New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; SERTP = Southeastern Regional Transmission Planning; SPP = Southwest Power Pool.

Source: Energy Systems Integration Group.

have a surplus or does it have a deficit? In general, regions concentrated in a smaller geographical area show higher correlations in energy margins (due to less weather, resource, and geographical diversity), whereas regions with greater distance between one another or more diversity in terms of resource mix or weather have lower correlations in terms of risk periods. Figure 13 shows the correlation in energy margin between each region across the 2007–2013 weather years. Here, darker cells (higher values) indicate a higher correlation (r value in statistical terms) between the energy margin in each region as a percentage of region load. Lighter cells (lower values) indicate weak or no correlation. Regions are ordered (top to bottom and left to right) going west to east across the country.

Regions with lower correlations suggest greater geographical diversity in energy margins. Strategically, interregional transmission initiatives may want to focus on linking these less-correlated regions to enhance system robustness and resource sharing.

The energy margins in ISONE, for example, are most highly correlated with those in NYISO and, to a lesser extent, PJM—ISONE's close neighbors. When ISONE has surplus capacity available, it is likely that PJM and NYISO also have surplus. The same is true for periods

of deficits or tight energy margins. In this example, adding interregional transmission capability between immediate neighbors will be less valuable than transmission that can access regions farther away—one needs insight into the availability of neighbors' neighbors' resources and whether they can be accessed in order to make the most beneficial investments. However, with increased distance comes increased cost of transmission.

Expressing correlations across all hours of the analysis shows that there are geographical concentrations of correlated energy margins. There are clearly regions with higher correlations due to similar weather patterns or resource availability in terms of both outage rates and wind and solar availability. Notably, some regions, like those that border one another along the seam between the Eastern and Western Interconnections (such as SPP and NorthernGrid or the Northeast and the Southeast) exhibit lower correlations, indicating potential for support from regions farther away than immediate neighbors.

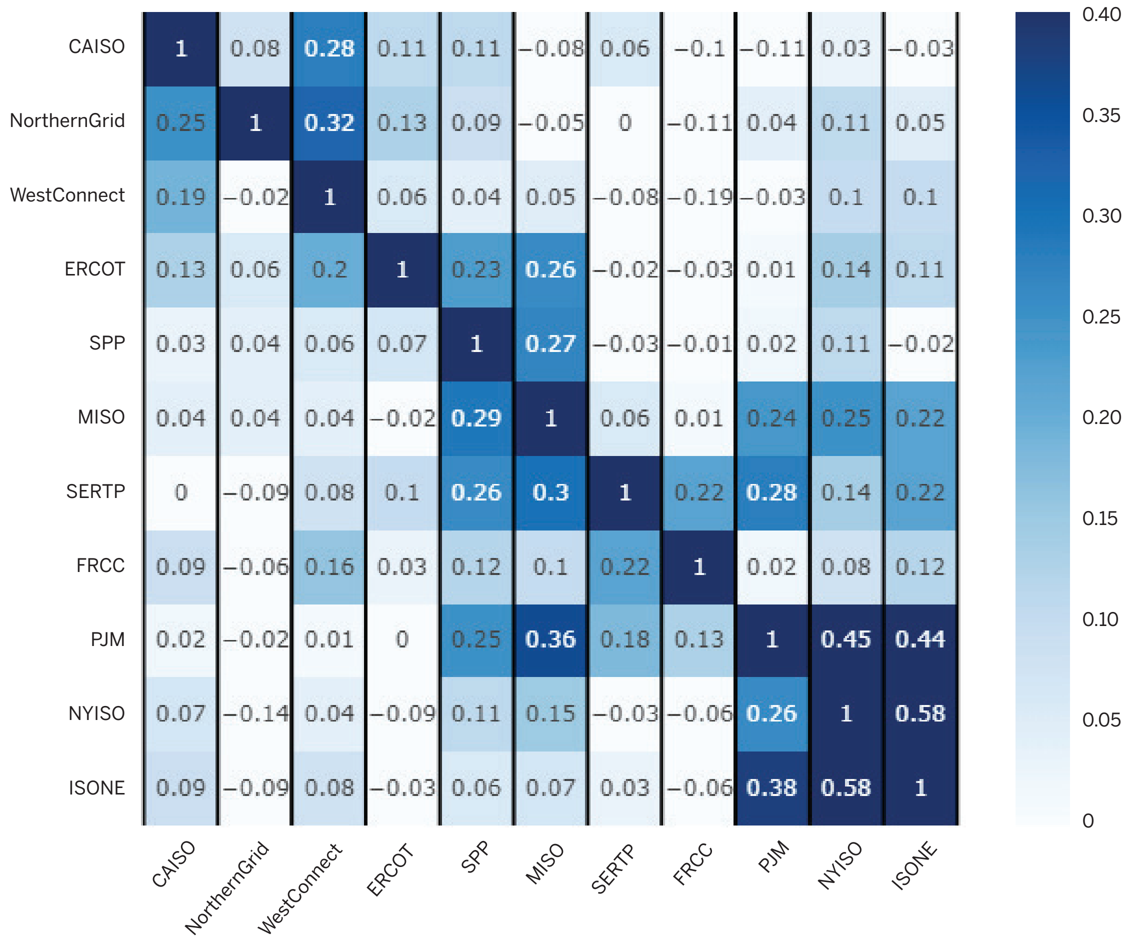
For resilience purposes, it is less important to capture the correlation in energy margins across all hours than to evaluate the hours when there is a risk to the system. To better show how risk periods are correlated, or uncorrelated, specifically during extreme weather events and high-risk conditions, Figure 14 (p. 33) uses the lowest 1,400 hours of energy margin (2.2% of hours) for each region over the weather years and expresses the correlation with the energy margins of each of the other FERC 1000 regions.

Data in Figure 14 are read by column. For example, the column of cells for MISO shows that when MISO has the lowest (tightest) energy margins, it is most correlated to low energy margins in PJM (0.36) and the Southeastern Regional Transmission Planning (SERTP) region (0.30) (the darkest cells) and least correlated to WestConnect

A region may increase its grid resilience through more or larger interconnections with regions that have low or no correlation in energy margins during all hours as well as during risk periods.

FIGURE 14

Correlation Between FERC 1000 Regions During Hours with Low Margin (Lowest 1,400 Hours)



To show how risk periods are correlated, or uncorrelated, specifically during extreme weather events and high-risk conditions, this figure uses the lowest 1,400 hours of energy margin (2.2% of hours) for each region over the weather years in the 2007–2013 period and expresses the correlation with the energy margins of each of the other FERC 1000 regions. Data in this figure are read by columns.

Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; FRCC = Florida Reliability Coordinating Council; ISONE = Independent System Operator of New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; SERTP = Southeastern Regional Transmission Planning; SPP = Southwest Power Pool.

Source: Energy Systems Integration Group.

and NorthernGrid (the lightest cells). This format shows the regional concentrations in correlated risks, with the greatest correlation between regions in the Mid-Atlantic and Northeast.

The r values presented in Figure 13 (p. 31) and Figure 14 are useful for describing variations in surpluses or deficits between regions during all hours of the year and during a subset of higher-risk hours. While this information alone does not provide a specific recommendation for planners considering building interregional transmission, it describes where resilience benefits may be greatest: a region may increase its grid resilience through more or larger interconnections with regions that have low or no correlation in energy margins both during all hours and during risk periods.

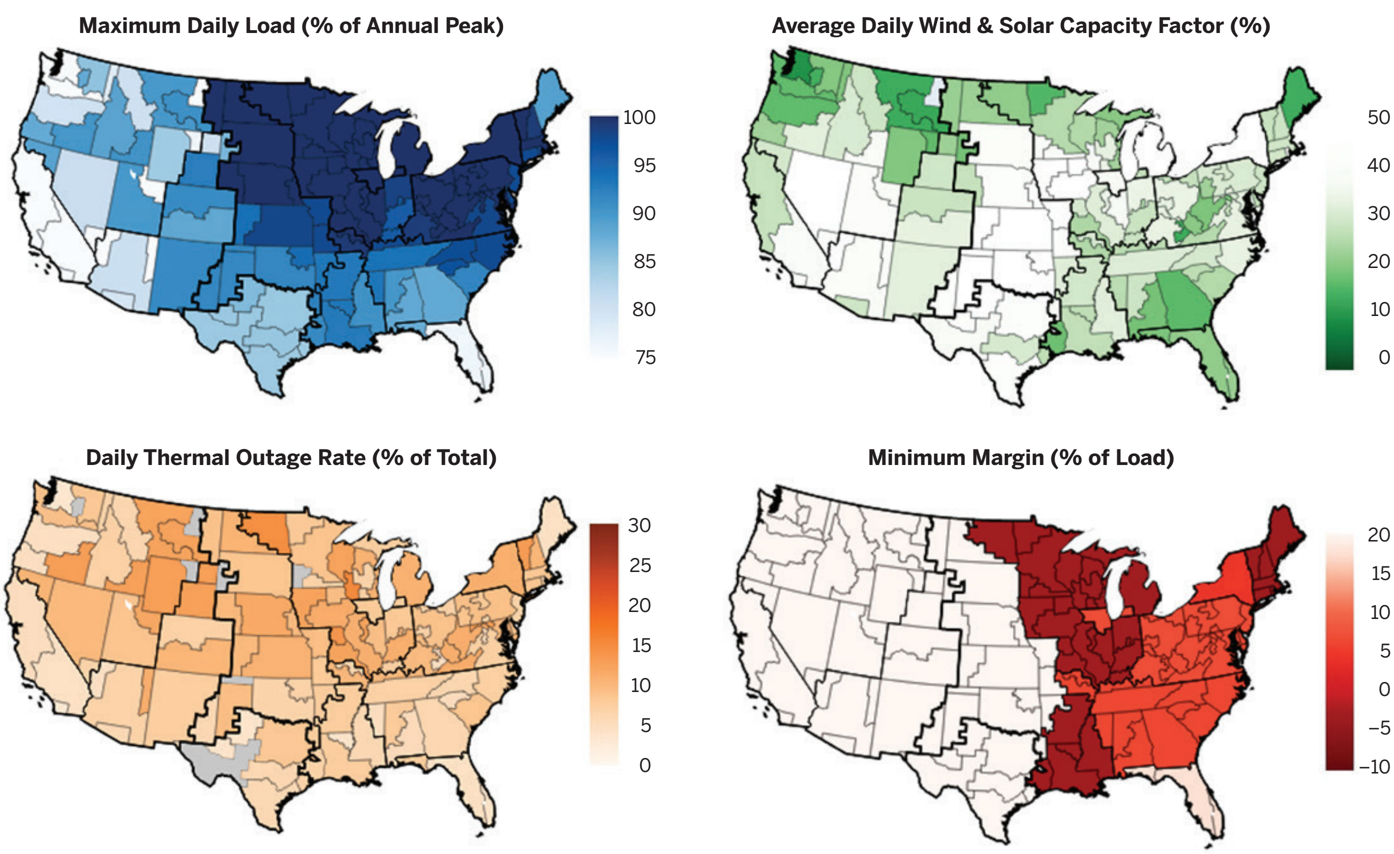
Visualizing Energy Margins Across Time and Space

Figure 15 offers another way to visualize variations between regions. It uses maps to summarize the margin calculations for each major driver for one high-load day during a summer weather scenario and to show the minimum daily energy margin experienced by each region. The key drivers are load levels relative to peak, renewable output, and weather-dependent forced outages on the thermal fleet. This visualization can be developed for each hour in which an energy margin is calculated. Figure 15 shows summarized results for a single day for brevity (using July 17, 2012, weather data). Visuals like these maps can be used to quickly convey the state of a planner's region and all of its neighbors during critical hours or days of low energy margin identified in the energy margin calculations. It is recommended that visual aids like these be used to enhance understanding of how weather events progress across the U.S. grid and how that affects resource availability when assessing interregional transmission for resilience.

High-level visualizations such as Figure 15 show that while some regions experience elevated outage rates or are at their peak load during a given extreme weather

FIGURE 15

Maps Summarizing Major Factors in the Hourly Energy Margin for FERC 1000 Regions for July 17, 2012, Weather Data



Multiple maps like those shown in this figure are used to depict the variations in key drivers of risk for the energy margin analysis across every region in the U.S. Data are shown for a summer day based on weather data for July 17, 2012. The maps depict daily values such as maximum daily load, average daily wind and solar generation, daily thermal outage rates, and the minimum daily margin for each FERC Order 1000 region. This visual aids in identifying which regions are in surplus and which are in deficit and thus require imports via interregional transmission. In each map, a darker shade of the color represents higher grid stress.

Note: Daily values are shown.

Source: Energy Systems Integration Group.

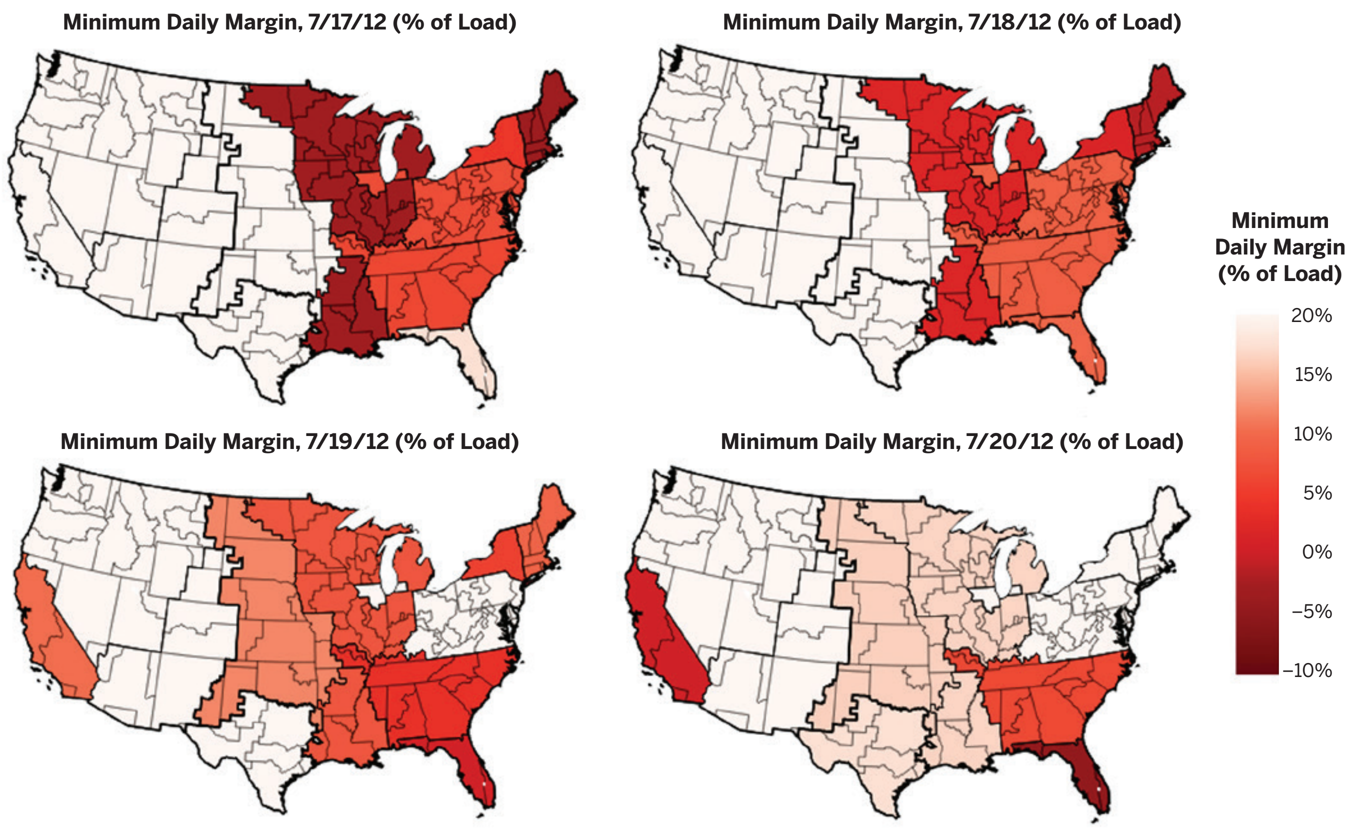
event, other regions can provide support as they are in sufficient surplus. For this visualization, no interregional transmission is included in the calculations of hourly energy margin. These visuals show only where imports would be required to maintain adequate margin levels and where margin levels are high to potentially provide this support.

The maps on p. 34 show different grid stressors for the north-central and northeast U.S., while neighboring regions (and regions farther away) are not experiencing stress and would be in a position to offer support. In each map, a darker shade of the color represents higher grid stress. The upper left panel shows that regions in the north-central and northeast hit their annual peak load on this day (dark blue shading), while regions in the south-central and southeast were somewhat lower, and those in the west were far below peak load. The renewable output map in the upper right shows that renewable energy was relatively low in the north-central (MISO) and northeast (PJM and ISONE) regions, and the thermal outage map in the lower left shows that areas in those regions had an expected outage rate of 5% to 15%. The bottom right map presents the lowest energy margin value for each region during that day. Values for the north-central and northeast regions approach 0% margin (or negative), indicating that the regions had reached their minimum reserve levels (specified as 6% in the study) and would start shedding load in the absence of any support via interregional transmission. Representations in these maps do not include the effect of existing transfer capability between regions to meet regional energy requirements, but rather show where transfers would be needed to meet the required reserve levels.

Visualizing these patterns between regions is important for understanding what is available across the power grid and how regions may benefit each other. To illustrate an example of how an event progresses over time, Figure 16 (p. 36) shows Figure 15's bottom right map describing regions' minimum daily energy margin for the weather on July 17 through 20, 2012.

FIGURE 16

Progression of Minimum Daily Energy Margin for FERC 1000 Regions for July 17–20, 2012, Weather Data



These daily minimum energy margin maps for 7/17/2012 through 7/20/2012 show how the areas of low margin change over time as different regions across the grid face tight conditions at different times, indicating there may be resources available via interregional transmission. Transfers using existing transfer capabilities are not shown.

Note: Daily values are shown.

Source: Energy Systems Integration Group.

While visualizing the variations in hourly and daily energy margin values across all FERC 1000 regions is important to understand where surpluses and deficits may exist and how weather events impact their geographical location, there remains a need to turn these data into actionable results. Next, we discuss how to use the energy margin framework to quantify how much and where additional interregional transmission should be prioritized if a concerted effort is made to increase interregional transmission capabilities to improve resilience in the power grid.

While visualizing the variations in hourly and daily energy margin values across all FERC 1000 regions is important to understand where surpluses and deficits may exist and how weather events impact their geographical location, there remains a need to turn these data into actionable results.

Priorities for New Interregional Transmission Capability

Assessing the differences in energy availability across regions can show where resilience benefits from interregional transmission can be realized. Existing interregional transmission capacity detailed in Table 2 (p. 13) can serve as the starting point for determining where and how much additional transfer capability could be expanded between FERC 1000 regions based on the depth of resources available in each region when they may require imports to meet the specified energy margin target of 6% of their hourly load. This report provides details on how the hourly energy margin is calculated and offers an example case study implementing it. Individual regions can develop their own datasets to calculate hourly energy margins between their own regions and other regions across the grid. The hourly energy margin allows planners to assess resource availability across many hours of system conditions and give specific focus to extreme events if they are included in the weather datasets. This can enable planners to decide where it might make sense to increase interregional transmission capacity to provide resilience benefits.

An individual region can develop its own dataset to calculate hourly energy margins between it and other regions across the grid. The hourly energy margin allows planners to assess resource availability across many hours of system conditions, enabling them to decide where it might make sense to increase interregional transmission capacity to provide resilience benefits.

The case study outlined in this section uses the U.S. Senate proposal in September 2023 of the BIG WIRES Act that seeks to set a minimum interregional transfer capability of 30% of a region's peak load.[10] Our analysis of interregional transmission capacity presented here indicates that, to meet such a requirement, every FERC Order 1000 region in the U.S. would be required to increase transfer capability through new lines or upgrading existing lines. We used the hourly energy margin approach detailed above to determine the best locations to expand transfer capabilities to meet the proposed standard of the BIG WIRES Act and ensure that expansion was targeted toward connecting areas with low or uncorrelated energy margins.

10 See https://www.hickenlooper.senate.gov/wp-content/uploads/2023/09/BIG-WIRES-One-Pager-Sep.-20231.pdf and *Building Integrated Grids With Inter-Regional Energy Supply Act* (BIG WIRES Act), S. 1, 118th Cong. (2023) at https://www.hickenlooper.senate.gov/wp-content/uploads/2023/09/PAT23853.pdf.

A Method for Prioritizing New Transmission for Resilience

The objective of this prioritization of additional interregional transmission capability was to enhance resilience for each region during potential shortfall events due to high load, high generator outages, or low renewable output, and combinations of these factors. The methodology intentionally did *not* assess other power system objectives such as relieving congestion, accessing low-cost renewables, or achieving policy goals.

This approach will help planners, regulators, and others identify where interregional transmission is most needed based on hourly energy margins for all regions, and thus determine which transmission connections should be given priority.

The case study adapted the goal from the proposed BIG WIRES Act of establishing a minimum interregional transmission capability equal to 30% of a region's peak load. Here, we assessed additional import capabilities for each FERC Order 1000 region and the additional capability needed to ensure that each region can import up to 10%, 20%, and 30% of its peak load. This incremental approach was chosen so that additions could be reviewed at different levels and potentially highlight which regions should be given greater priority to initially increase capabilities form existing levels to 10%, and so on. We determined the location and magnitude of increased interregional transmission capacity for each region to meet these levels using the hourly energy margin analysis (e.g., should PJM build more capability with MISO, SERTP, or NYISO?).[11] It's important to note that this method does not seek to determine an optimal or economic level of interregional transmission, nor is it meant to replace existing planning frameworks designed to achieve a 1-day-in-10-year loss-of-load expectation. Rather, this approach will help planners, regulators, and others identify where interregional transmission is most needed based on hourly energy margins for all regions, and thus determine which transmission connections should be given priority.

Four Key Practices for Interregional Transmission Planning

The methodology for prioritizing interregional transmission upgrades outlined in this report has four primary planning practices (Table 7, p. 39).

- **Prioritize regions with less existing interregional transfer capability.** This approach identifies regions with interregional transmission capacity that do not meet the targeted transmission capability as a percentage of their peak load and prioritizes increasing their transfer capability.
- **Prioritize transfer capability that increases imports from regions that tend to have surplus resources when other regions are tight.** The methodology prioritizes transmission from regions that are likely to have a surplus during times of tight supply conditions elsewhere. This is assessed on an hourly basis using the hourly energy margin analysis.
- **Focus on immediate neighbors.** Increasing interregional transmission should focus on connections with geographically closer regions to minimize costs. For example, while transmission lines from ISONE to the Southwest would have the most benefit of weather diversity (and span multiple time zones, which increases diversity in the timing of peak load), it would be prohibitively expensive. Increasing connections with immediate neighbors is much less expensive while still bringing significant resilience benefits when prioritized using data-driven approaches.
- **Allow for power to flow from a neighbor's neighbor.** While the previous objective focuses on immediate neighbors, the analysis does allow for flows across the network and for a region to access geographical diversity beyond its immediate neighbor, accommodating the movement of power from adjacent regions and establishing a more interconnected and supportive network.

11 The Building Integrated Grids With Inter-Regional Energy Supply Act (BIG WIRES) bill seeks to set a minimum level of transfer capability for a region (import or export) at 30%. This was adapted for our study to assess only import capabilities and at incremental levels.

TABLE 7

Four Key Practices for Interregional Transmission Planning

Prioritize regions with less existing interregional transfer capability	Regions with interregional transmission capacity that does not meet the targeted transmission capability as a percentage of their peak load would be prioritized for increasing transfer capability.
Prioritize transfer capability that increases imports from regions with uncorrelated risks	Transmission would be prioritized from regions likely to have a surplus during times of tight supply conditions elsewhere. This requires assessing hourly variations in surpluses and deficits for all regions.
Focus on immediate neighbors	Efforts to increase interregional transmission would focus on connections between geographically closer regions in order to minimize costs.
Allow for power to flow from a neighbor's neighbor	To evaluate interregional transmission, one needs to adequately represent a region's access to load and resource diversity beyond its immediate neighbors and accommodate the movement of power from adjacent regions, establishing a more interconnected and supportive network.

Source: Energy Systems Integration Group.

The Methodology

First, we created a reliability-focused model that prompts regions to prioritize nearby resources over resources that are farther (and even farther) away, by setting a relative cost for each region based on its reserve levels. Here, "relative cost" refers to a proxy price, based not on traditional economic models but on a comparison of reserve resources across regions. This means that regions with similar reserve percentages were treated as having equivalent internal prices. A region's relative electricity cost increased as its reserves depleted, influencing the flow of power from areas with lower costs (indicative of higher reserves) to areas with higher costs (indicative of potential shortfalls). Power flowing between regions was limited to periods when a region could not meet its own demand, and imports to a region could only occur if a region's margin was below 10%. In this case, power could flow from regions where it is available. An additional cost increase was applied to power when it had to flow between regions, to ensure that a region first used its own resources to maintain reserves before calling upon the wider grid, with increasing costs for imports from regions farther away than direct neighbors.

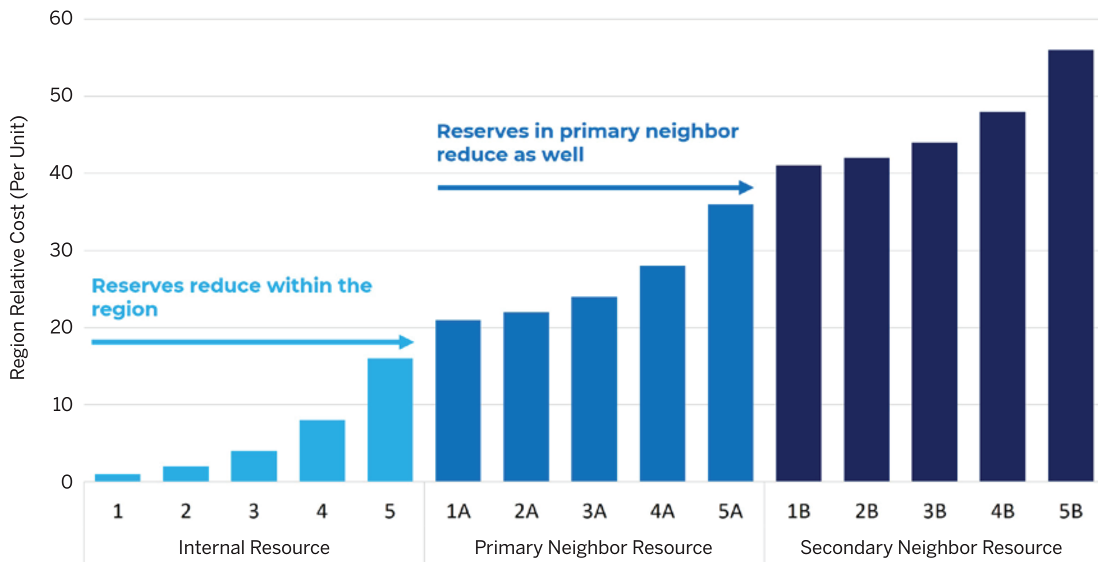
A pipe and bubble model was used to optimize the hourly energy margin for all regions and allow transfers based on historical transfer capabilities. Regardless of fuel costs or production costs that are resource-dependent, the regional shadow cost was a function of the hourly reserve margin—analogous to the operating reserve demand curve (ORDC) constructed in ERCOT that increases prices during periods of tight supply, regardless of the underlying location-based marginal price. As a region's reserves decline, the price rises exponentially. When combined with an additional cost to transport power between regions, a clear priority of resources was developed.

This relative pricing method satisfies the goals of prioritizing regions using surplus and deficit information from the hourly energy margin, focusing on immediate neighbors first, and allowing for power to flow from a neighbors' neighbor.

A region's priority was to serve its load with its own resources, which tightened its reserves to the minimum level. This was followed by the region importing energy from its neighbors. As the neighboring region's reserves also got closer to their minimum level, the price of energy in both these regions was higher than that of their neighbors. Now both regions had a reduced ability to export power. Once an immediate neighbor is not able to export power, or a more distant neighbor has far

FIGURE 17

Illustrative Example of the Regional Relative Cost Approach Based on Reserve Levels (Single Region and Import Example)



The figure illustrates, from an importing region's perspective, how internal resources and neighbors' resources are priced in the model. The x-axis represents different resources being dispatched from various regions from the perspective of a single receiving region. The relative prices result in internal resources being used to meet load and reserves first, then the region's immediate neighbor may support it, and finally its secondary neighbor could support it if additional resources were needed and that neighbor had a surplus.

Source: Energy Systems Integration Group.

greater reserves, then the model would dictate that power would be delivered from a neighbor's neighbor, and so on, until either transmission constraints were met or resources were exhausted. This approach satisfies the goals of prioritizing regions using surplus and deficit information from the hourly energy margin, focusing on immediate neighbors first, and allowing for power to flow from a neighbors' neighbor.

Figure 17 illustrates this relative pricing method. The x-axis represents different resources being dispatched from various regions from the perspective of a single receiving region. The relative prices assigned in the model result in internal resources being used to meet load and reserves first, then the region's immediate neighbor may support it, and finally its secondary neighbor could support it if additional resources were needed and that neighbor had a surplus.

This method was employed across all hours of the year and all weather years, evaluating more than 61,000 hourly energy margins (7 weather years x 8,760 hours per year). In each hour, the regional price was set by the relative hourly reserve margin and available resources. Any power that flowed between regions required the receiving region to first exhaust all of its own resources. This requirement allowed us to isolate the transfers necessary to resolve resource shortfalls in a region, identifying periods when a region could not meet its own load and reserve requirements. If an existing transmission connection, such as SPP to MISO, reached its maximum transfer capability but MISO was in deficit while SPP's reserve levels were still high, then the pathway was identified as constrained and targeted for consideration of additional transfer capability. This assessment was performed across all regions simultaneously considering each region as a receiver (needing power) and a provider (having excess reserves to export) depending on its reserve levels.

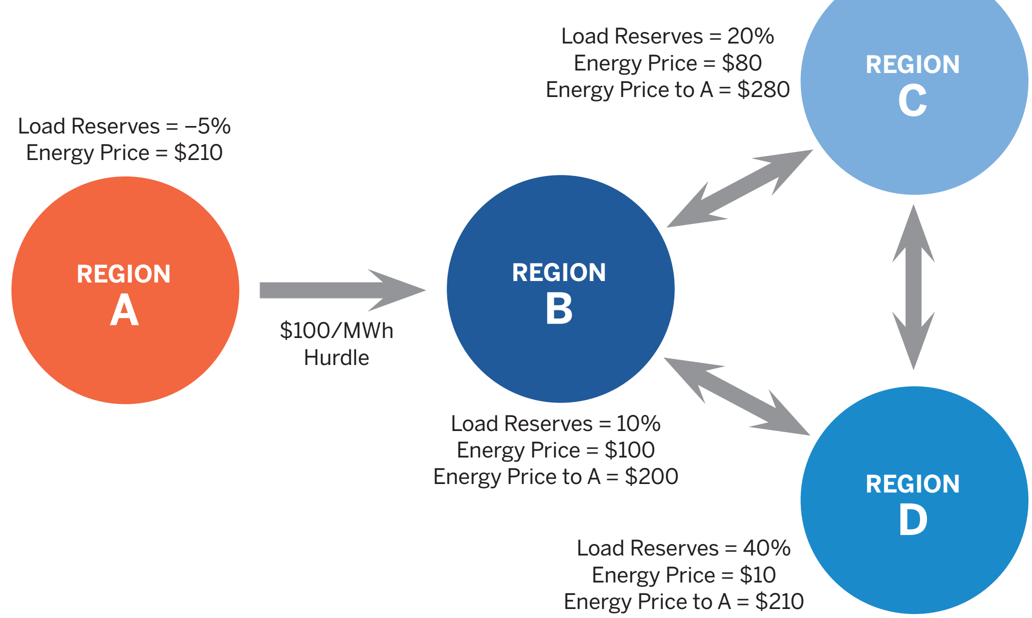
An illustration of this assessment is shown in Figure 18. Values shown in the figure are only illustrative and intended to showcase how flows would occur given the relative pricing curve used. In this case, Region A has deficient supply (negative reserves), has a high price due to the negative reserves, and requires imports. Neighboring Region B is unwilling to support Region A directly, as it also has tight reserves and a relatively high price—it has reserves equal to only 10% of its current load, which is the minimum constraint used, so it cannot reduce its reserves to export to Region A. Region C and Region D have surplus. In this example, transfer capability would be prioritized from Region D to Region B and then to Region A, because Region D had more surplus (in terms of load reserves) than Region C.

To take this example one step further, if power flow from Region D to Region B is constrained because existing transfer capabilities are insufficient, then power would flow on an unpreferred path going from Region C to B to A. If a planner in Region A wanted to facilitate more interregional transfer capability, they would identify Region D to Region B as the preferred path because it has deeper reserves and offers more consistent support. Coordinated planning between Regions A, B, and D would then be pursued to enable more transfers along this preferred path. This type of assessment and cross-regional planning is not conducted in current industry transmission planning activities.

In summary, this approach to expanding interregional transmission infrastructure is designed to bolster system resilience by strategically enhancing connectivity, especially in regions that are currently under-served in terms of interregional transfer capabilities. By prioritizing transfers based on surplus resources and geographical

FIGURE 18

An Illustrative Example Prioritizing Interregional Transmission Based on Resilience Value

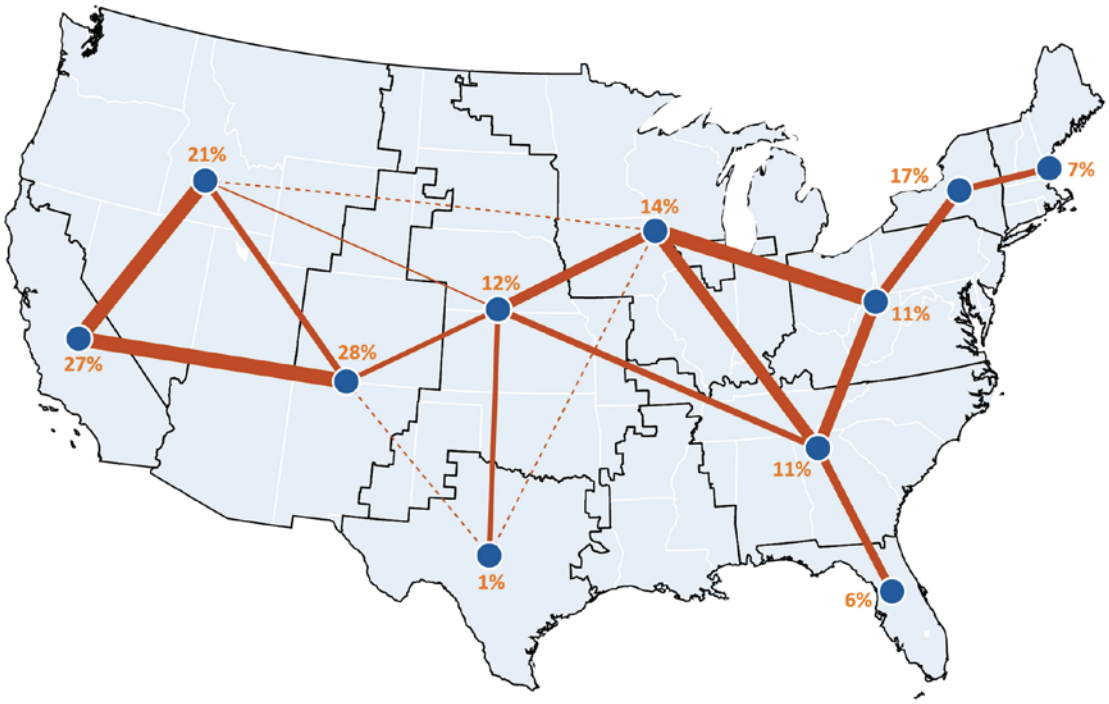


An illustrative example of a pipe and bubble model showing how, when Region A is in deficit and an immediate neighbor, Region B, is at its minimum reserve constraint, support for Region A would come from Region D or Region C due to their having sufficient levels of load reserves (above the minimum 10% constraint used). Region D would be prioritized for imports into Region A due to its having a higher level of load reserves than Region C. This transfer is contingent on there being sufficient transmission capability to allow power to flow from Region D to Region B to Region A.

Source: Energy Systems Integration Group.

FIGURE 19

Existing Interregional Transmission Paths Across the U.S., by FERC Order 1000 Region



The blue dots represent the FERC Order 1000 regions, with orange lines showing the magnitude of the transfer capability between each pair of regions. Dotted lines represent no existing transfer capability, but the potential for immediate neighbors to create transfer capability. The thickness of the solid lines indicates the relative amount of transfer capability in each case. Note, transfer capabilities for U.S. regions with connections to Canadian regions are not included in these values.

Source: Energy Systems Integration Group; data from Energy Information Administration 930 Hourly Electric Grid Monitor.

By prioritizing transfers based on surplus resources and geographical proximity, this method provides a robust framework for guiding future transmission expansion decisions.

proximity, this method provides a robust framework for guiding future transmission expansion decisions.

Prioritizing the Addition of Interregional Transmission for Resilience

Results of the analysis prioritized which regions should increase interregional transfer capability to meet resilience objectives. Existing connections between regions are shown in Figure 19 (identical to Figure 4 above) as solid lines of different thicknesses. Dotted lines indicate connections that do not exist today.

Table 8 (p. 43) shows the current interregional transfer capability between each pair of neighboring regions in the third column—discussed in the section "Today's Interregional Transfer Capability"—based on the highest observed flows between FERC Order 1000 regions. There is no existing transfer capability between MISO and NorthernGrid, between ERCOT and WestConnect, or between MISO and ERCOT, and only limited transfer capability between the Western and Eastern Interconnections (SPP to NorthernGrid and WestConnect and ERCOT to SPP). Each successive column of Table 8 shows the additional transfer capability needed across each path to have each region achieve an interregional transfer capability equal to 10%, 20%, or 30% of its annual peak electricity demand. Results show the transfer capability between pairs of regions. For example, ERCOT, FRCC, and ISONE would need to increase transfer capability to meet the requirement of being able to import up to 10% of their peak load via interregional transmission.[12] To meet this requirement, ERCOT would need to increase transfer capability in roughly equal amounts to WestConnect, MISO, and SPP. ISONE and FRCC, however, would increase transfer capability to only the adjacent FERC Order 1000 regions, given that they are located on the periphery of the U.S. grid.

The results show that to enhance grid resilience, many regions require transmission expansion to/from neighbors. In the 20% case, in which regions are required to have sufficient transmission capacity to import 20% of their peak load, graphically shown in Figure 20 (p. 45), additional transfer capability was added across 9 out of 11 FERC Order 1000 regions. Increases in transfer capability were particularly seen into and out of the Southeast and between the Eastern and Western Interconnections. This trend continued in the 30% case. The final column of Table 8 shows the relative increase for each path from existing capabilities to the 30% of peak load level and specifically calls out new interregional transfer capabilities that do not exist today.

It should be noted that, based on the weather data assessed in this report, for all regions except PJM, additional transmission capability is driven by deficiencies in maintaining the target energy margin via imports. In the 2007–2013 years assessed, PJM had sufficient resources to meet its load and reserve targets. This points to the need for additional weather years to be assessed

TABLE 8

Interregional Transfer Capability Needed for Each FERC 1000 Region Based on Meeting a Hypothetical Required Import Capability up to a Minimum 30% of Peak Load Capability

Importing Region	Export -> Import Path	Base Transmission Capability (MW)	Incremental Transmission to Reach 10% Import Capability (MW)	Incremental Transmission to Reach 20% Import Capability (MW)	Incremental Transmission to Reach 30% Import Capability (MW)	Percentage Increase to Reach 30% Import Capability
CAISO	NorthernGrid -> CAISO	8,026	0	0	2,237	28%
	WestConnect -> CAISO	7,908	0	0	479	6%
Northern-Grid	CAISO -> NorthernGrid	8,026	0	0	0	0%
	MISO -> NorthernGrid	0	0	46	2,593	New capability
	SPP -> NorthernGrid	200	0	46	2,593	1,296%
	WestConnect -> NorthernGrid	1,872	0	0	0	0%
West-Connect	CAISO -> WestConnect	7,908	0	0	0	0%
	ERCOT -> WestConnect	0	0	0	542	New capability
	NorthernGrid -> WestConnect	1,872	0	0	0	0%
	SPP -> WestConnect	939	0	0	433	46%
ERCOT	MISO -> ERCOT	0	2,467	6,351	6,351	New capability
	SPP -> ERCOT	834	2,420	4,538	4,538	544%
	WestConnect -> ERCOT	0	2,752	5,223	13,696	New capability

(CONTINUED)

Small increases needed in transfer capability · Moderate increases · Largest increases

New transfer capabilities between systems that are not connected today

12 Note that the interregional transfer capability only considers interconnections to FERC Order 1000 regions in the United States. ISONE, however, does have interconnections to Quebec and New Brunswick that, if counted, would allow it to meet the 10% minimum criteria.

TABLE 8

Interregional Transfer Capability Needed for Each FERC 1000 Region Based on Meeting a Hypothetical Required Import Capability up to a Minimum 30% of Peak Load Capability (CONTINUED)

Importing Region	Export -> Import Path	Base Transmission Capability (MW)	Incremental Transmission to Reach 10% Import Capability (MW)	Incremental Transmission to Reach 20% Import Capability (MW)	Incremental Transmission to Reach 30% Import Capability (MW)	Percentage Increase to Reach 30% Import Capability
SPP	ERCOT -> SPP	834	0	0	0	0%
	MISO -> SPP	3,283	0	593	593	18%
	NorthernGrid -> SPP	200	0	2,372	7,967	3,983%
	SERTP -> SPP	1,484	0	0	0	0%
	WestConnect -> SPP	939	0	1,483	1,483	158%
MISO	ERCOT -> MISO	0	0	3,573	7,362	New capability
	NorthernGrid -> MISO	0	0	4,764	13,857	New capability
	PJM -> MISO	8,864	0	0	0	0%
	SERTP -> MISO	5,326	0	0	0	0%
	SPP -> MISO	3,283	0	1,469	2,227	68%
SERTP	FRCC -> SERTP	2,862	0	453	791	28%
	MISO -> SERTP	5,326	0	1,848	3,286	62%
	PJM -> SERTP	4,310	0	3,153	7,297	169%
	SPP -> SERTP	1,484	0	7,121	14,480	976%
FRCC	SERTP -> FRCC	2,862	2,833	8,528	14,224	497%
PJM	MISO -> PJM	8,864	0	5,042	10,383	117%
	NYISO -> PJM	3,745	0	5,042	10,383	277%
	SERTP -> PJM	4,310	0	5,042	10,383	241%
NYISO	ISONE -> NYISO	1,814	0	0	0	0%
	PJM -> NYISO	3,745	0	1,148	4,502	120%
ISONE	NYISO -> ISONE	1,814	897	3,607	6,318	348%

Small increases needed in transfer capability; Moderate increases; Largest increases
New transfer capabilities between systems that are not connected today

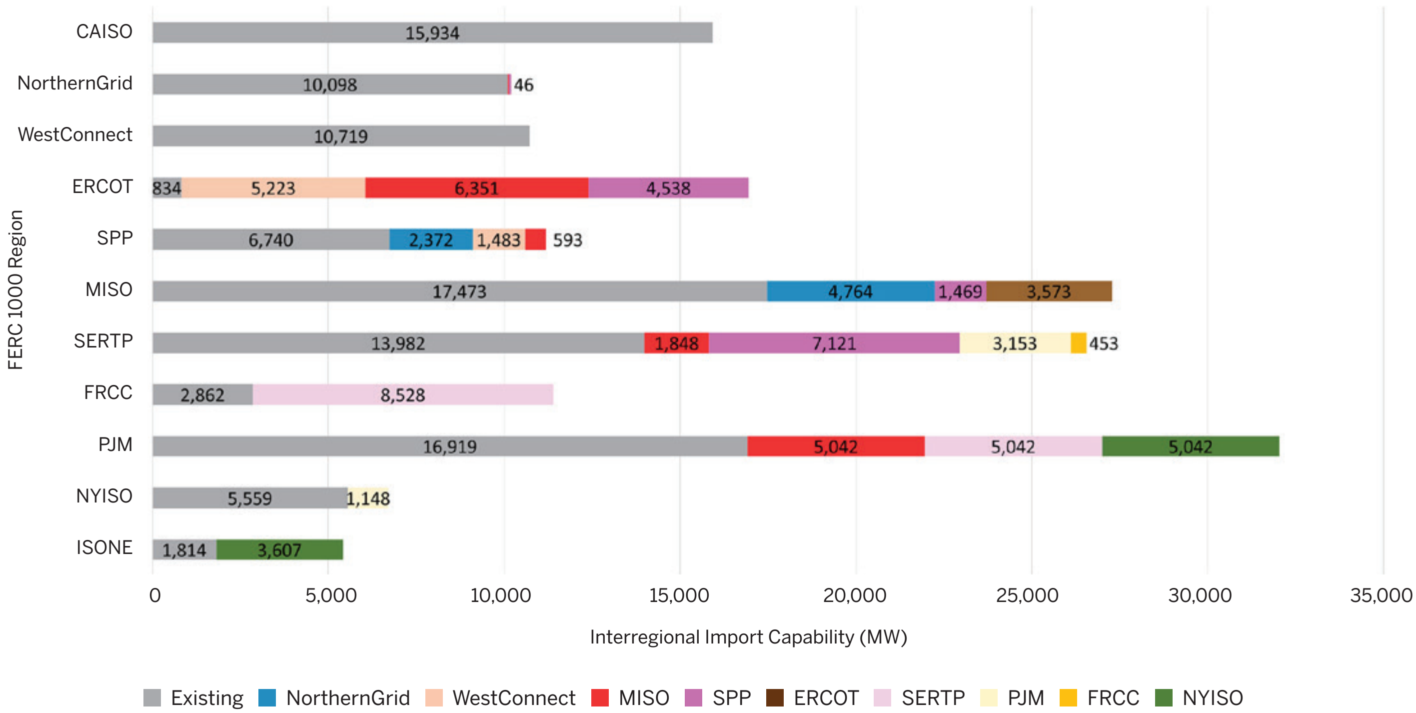
Cell colors indicate the magnitude of the transfer capability needed, with light yellow indicating small increases needed in transfer capability, orange indicating moderate increases, and darker red indicating the largest increases. Gray indicates new transfer capabilities between systems that are not connected today. Transfer capabilities presented are based on the import direction identified in the left-most column. The second column shows the direction from which import capability is coming. The incremental transmission columns show how many additional MW of transfer capability are needed to ensure that each FERC Order 1000 region can import up to 10%, 20%, and 30% of peak load. Allocation of increased transfer capability is based on the prioritization method outlined in the previous section.

Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; FRCC = Florida Reliability Coordinating Council; ISONE = Independent System Operator of New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; SERTP = Southeastern Regional Transmission Planning; SPP = Southwest Power Pool.

Source: Energy Systems Integration Group.

FIGURE 20

Interregional Non-Coincident Import Capability Added by the Model, by FERC Order 1000 Region, to Allow Each Region to Import 20% of Its Peak Load



The figure shows the additional interregional transmission capability that would be needed between FERC Order 1000 regions to enable them to import 20% of their peak load, and where the additional capability is coming from. Gray areas of bars represent each region's existing transfer capability. Colored areas of bars represent transfer capability needed between that region and the respective other region(s).

Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; FRCC = Florida Reliability Coordinating Council; ISONE = Independent System Operator of New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; SERTP = Southeastern Regional Transmission Planning; SPP = Southwest Power Pool.

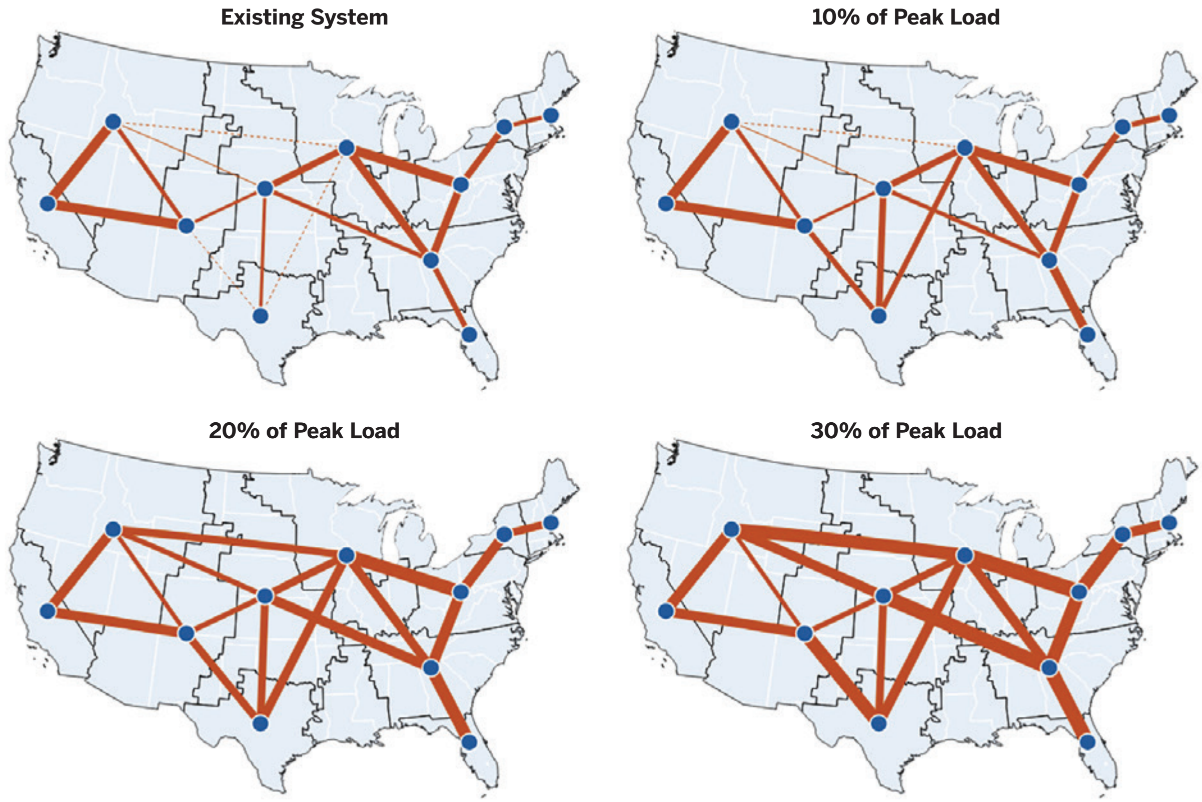
Source: Energy Systems Integration Group.

that include extreme weather events for all regions to capture a wider range of events. Since this case study focused on how much additional capability is required to meet a specified import level, the additional transfer capability for PJM to reach 30% of its peak load was spread evenly between its neighbors in lieu of being proportional to the flows required to maintain its reserve levels. The even distribution of additional capacity was informed by PJM's correlation between SERTP, NYISO, and MISO during low margin hours (see Figure 14, p. 33), indicating similar levels of benefits offered by these three regions.

Figure 21 (p. 46) shows the existing transfer capability between regions and the increase in transfer capability that would constitute 10%, 20%, and 30% of each region's peak loads based on Table 8 (p. 43). For simplicity, the lines represent the maximum transfer capability between regions in the import or export direction. (Requirements for some regions to increase import capabilities, like MISO, mean that import capabilities may be larger than export capabilities, and only the larger of import vs. export capability is shown in the figure.) Relative to the existing system in the upper left quadrant of Figure 21, the 10%, 20%, and 30% transfer capability requirements would lead to increased resilience benefits, as transfer capabilities between inter-connections today are relatively small. In addition to increasing transfer capability between the Western and Eastern Interconnections, there is also significant expansion of transfer capability into and out of ERCOT and into and out of the southeastern U.S.

FIGURE 21

Existing U.S. Interregional Transfer Capability Between FERC 1000 Regions, and the Size of Connections Needed for 10%, 20%, and 30% Minimum Transfer Capability



At the top left (existing system), lines connect the center of FERC Order 1000 regions and show where existing interregional transmission connections (solid lines) exist today. Dotted lines represent connections that do not exist today, but where regions are geographical neighbors and connections could be established. The other three maps show modeled increases in transfer capability according to whether a region needed to have sufficient transfer capability to import 10%, 20%, or 30% of its peak load. Lines increase in thickness to show increased transfer capabilities as regions achieve different levels of import capability relative to their peak load. By the 20% scenario, all modeled potential connections exist, and the transfer capability increases steadily as the percentage-of-peak-load requirement goes up.

Source: Energy Systems Integration Group.

While this study focused only on power flows for resilience reasons—to mitigate periods of tight energy margins—the methodology can be expanded or modified to include other factors that planners might want to incorporate. For example, the methodology can readily accommodate changes to the structure by altering the relative cost levels for a region, the additional costs for flowing power between regions, or adjusted resource mixes in different regions based on future resource portfolios. Additionally, the minimum reserve requirement for each region could be modified to make some regions more or less willing to share resources when neighbors are in deficit.

This analysis implemented an hourly energy margin for the 2007–2013 weather years to identify where and how much interregional transmission capability can be expanded for each FERC Order 1000 region to meet a minimum transfer capability level based on a future load and resource mix. The results prioritize transfer capability expansion based on the relative surplus and deficits between FERC 1000 regions for the 2007–2013 weather years, with a focus on increasing transfer capabilities between regions that have diverse load and energy availability patterns as a resilience hedge.

Key Findings, Suggested Practices, and Next Steps

Recent extreme weather events across the U.S. have prompted increased attention to the resilience of the U.S. power grid, with a focus centered around how the transmission network can be leveraged to enhance system-wide resilience. Today's transmission network already provides critical support for regions when extreme weather or unforeseen power plant outages require imports from another region to meet electricity load, and interregional transmission provides numerous other benefits such as reducing congestion cost, increasing access to renewables, and improving market efficiency. However, traditionally, planners have been reluctant to plan to rely on resources external to their system during extreme events, even though historical records show the importance of external resources for ensuring the system is resilient. This study aimed to quantify the amount of existing transfer capability between regions and assess whether current capabilities can provide sufficient power transfer during extreme events when a system has low levels of reserves.

The hourly energy margin method outlined in this report offers a method for planners to determine how well external regions could provide support during realistic weather events on an hourly basis. This analytical framework can be used by planners to gain familiarity with and confidence in assessing resource availability outside their own systems.

The hourly energy margin method outlined in this report offers a method for planners to determine how well external regions could provide support during realistic weather events on an hourly basis. This analytical framework can be used by planners to gain familiarity with and confidence in assessing resource availability outside their own systems. The method is intended to facilitate efforts to build interregional transmission that mitigates risks and is intelligently identified to bridge regions having uncorrelated risk periods, and to inform the market on potential high-value transmission projects that may garner greater support from operators, regulators, and the public to ensure a safe and resilient grid of the future.

This report outlines an approach to prioritize which regions a given region should increase its transfer capabilities to and from, based on regions' relative reserve levels (how much spare capacity a region has relative to its electricity load) and a requirement to reach a target level of interregional transfer capability (in this case the target level was defined by the proposed BIG WIRES Act at 30% of a region's peak load).

Key Findings

The results of this study show that the energy margin analysis can be used to calculate hourly resource availability across many different weather conditions in many different regions at a national level. This methodology can be used and adapted by planners in multiple ways. By performing their own assessments of hourly energy margins for their own systems and external systems, planners can assess the expected availability of resources across many regions and learn where surplus capacity and energy may be, under many weather conditions. This assessment can be developed by each region individually or by larger planning coordinators such as those defined by FERC Order 1000. Through the use of synthetic historical weather data and potentially future projections of extreme weather risks, regional extreme weather can be evaluated using multiple scenarios of different grid resources and load to identify where surplus capacity and energy may be available in future years, relative to existing interregional transfer capabilities. This methodology's focus on evaluating hourly energy margins across many hours in a chronological, hour-by-hour fashion allows

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Weather-Correlated Electricity Grid Data

A cornerstone of the energy margin analysis described in this report is the availability of time-synchronized load, solar, and wind output and weather-dependent outage rates for the thermal generation fleet. While the analytical period was limited to 2007–2013 due to data availability, it would be beneficial to expand the analysis to a larger set of weather years to capture more extreme weather events. The need for a national dataset for weather, renewables, and load was identified in another ESIG report, *Weather Dataset Needs for Planning and Analyzing Modern Power Systems* (ESIG, 2023); a consistent national dataset for many weather years would be an ideal data source to assist planners in addressing resilience goals and using the energy margin analysis described in this report, although existing weather-dependent load and renewable generation datasets are widely available from resource adequacy analyses. Efforts are also ongoing to develop a consistent dataset for weather-dependent outages of thermal power plants that builds on the information used by this report, which adapted weather dependent outage data from Murphy, Sowell, and Apt (2019).

A National-Scale Assessment Identifies Today's Priority Transfer Capability Needs

By assessing hourly expected energy availability using time- and weather-synchronized load, wind, solar and weather-dependent plant outages, planners can determine the correlation between every planning region's energy margins and use that knowledge to assess where future transmission improvements might be most valuable. Once it can be determined whether an external region can offer support during a planning region's periods of high risk—that is, whether an external region's periods of high risk (such as extreme winter or summer events) do not tend to overlap those of the planning region—this can inform whether additional transmission capacity through upgrading existing capabilities or building new lines can provide resilience benefits during those extreme events. In doing so, priority transfer paths can be identified.

Results of the case study showed that greater diversity in surplus resource availability could be provided by developing greater transfer capability between the Eastern and Western Interconnections as well as between the center of the country and some of the more isolated areas of the U.S. grid (the Northeast, the Southeast, ERCOT). For example, for SPP to achieve an import capability of 20% and 30% of its peak load, it would seek to increase interregional transfer capabilities with NorthernGrid and WestConnect based on resource and load diversity.

System-wide Increases in Transfer Capability

Taking a system-wide view of increased transfer capabilities, the results of using the hourly energy margin analysis to achieve 10%, 20%, and 30% import capability for all FERC Order 1000 regions requires 11.4 GW, 71.4 GW, and 149 GW of additional transfer capability, respectively. This increase in transfer capability is based on the existing non-coincident import capabilities shown in Table 2 (p. 13). To achieve lower transfer capability levels (the 10% requirement), only ERCOT, FRCC, and ISONE require increased capabilities. To achieve the 20% and 30% levels, additional transfer capability is required, and growth in transfer capability needs is seen primarily in ERCOT, MISO, SERTP, FRCC, and PJM, which collectively account for 119 GW (80%) of increased import capability to reach the 30% level.

The Need for Granular Regions

Lastly, how transmission regions are defined is important for effectively determining where resources are available and whether they can be adequately transferred from areas of surplus to deficit. Our results indicate that using FERC Order 1000 regions may overstate resource availability within a region because internal transmission constraints are not fully represented. It will be important to maintain consistency with current planning practices, which are often conducted across existing transmission planning regions, when coordinating future projects at a large regional or national scale, but internal transmission limitations need to be accounted for when assessing both energy margin surpluses, deficits, and transfer capabilities. It may be necessary to use regions smaller than the FERC Order 1000 regions used here in order to better account for the locations of surpluses and deficits and determine where transmission can provide the greatest resilience benefits.

Suggested Practices

Based on the key findings of this analysis, the ESIG Transmission Resilience Task Force suggests the following practices for planners to better assess regional resource availability and better evaluate how existing and future interregional transmission connections would benefit system resilience during real weather events. Planners can:

- **Consider transmission as a resilience asset.** Transmission can enable a region's access to resources in other regions that typically experience different weather, fuel supply, or demand patterns. Such exchange of energy can reduce the impact of localized weather events by allowing the region to benefit from geographical diversity. Planners can also consider that transmission can serve as an alternative to local resources by providing access to external resources that are not challenged by the same correlated risks faced by local resources.
- **Use the energy margin method when performing regional resource adequacy or production cost studies.** This method provides an hourly energy margin for neighboring regions and neighbors' neighbors—how much spare capacity relative to electricity demand is available within a region. The hourly energy margin can be used to model external resource availability for resilience and reliability purposes, rather than assuming the planning region is an island. This will provide a more accurate and realistic picture of the resource availability and demand across the U.S.
- **Recognize that the transfer capability between regions is dependent on grid conditions and is not static.** As discussed in the section "Today's Interregional Transfer Capability," the available transfer capability between regions is not static. The growing importance of assessing system resilience and reliability during specific extreme weather events requires scenario modeling that (1) departs from traditional transfer capability studies that focus on a few snapshot conditions (such as spring light load, winter peak, and summer peak), and (2) quantifies transfer capability during other extreme events that may not be the peak load conditions. It is important to quantify risks to maintaining transfer capabilities during critical extreme events, like a polar vortex in the Northeast, and include these in assessments of what is required to build and maintain transfer capabilities.

- **Keep in mind that results will be affected by the definition of a relevant study region.** Planners will need to use a sufficiently granular set of sub-regions for analysis which can be aggregated into different larger regions depending on the study need. This report focused on using the NREL ReEDS regions as a starting point, which allows for aggregations into the FERC Order 1000 regions, but it also allows aggregation into states or NERC regions. Providing this kind of flexibility in how regions can be defined ensures that the analysis is robust and results can be evaluated with respect to different planning regions. If more granular information on transfer capability and resource availability is available for a planner using the energy margin method, this enables energy margin results to provide more information on areas of risk and actual deliverability of surplus resources.

Next Steps

Continuing efforts are needed to evaluate what level of interregional transmission is prudent for ensuring that the U.S. bulk power system is resilient. While the hourly energy margin assessment presented in this report can serve regions by providing a national view of resource availability during specific weather events, it represents only one component for better representing interregional transmission and its benefits in planning efforts. Additional work is needed to generate a national-scale view of resource availability provided by the energy margin assessment.

Several next steps were outlined by the Transmission Resilience Task Force, some of which it will be undertaking in its next phase of work:

- Extend the analysis to include recent extreme weather conditions and broaden the dataset used beyond the 2007–2013 weather years
- Enhance the representation of weather-dependent outages using updated analyses forthcoming from the industry based on recent real-world extreme weather events
- Expand the analysis to consider future extreme weather conditions that may result from changing climate trends
- Incorporate assessments of more aggressive resource mix changes and electrification futures
- Develop more granular views of energy margins to pick up on important variations in resource locations and availability within large planning areas
- Implement the energy margin analysis alongside typical resource adequacy loss-of-load analyses in an extreme weather stress-testing assessment
- Implement a view of resource availability and hourly dispatch conditions from resource adequacy models and the energy margin analysis across many hours of extreme weather events for a transmission power flow analysis, moving away from single-hour snapshot assessments

Interregional transmission not only facilitates a more resilient grid by diversifying energy sources and balancing load during critical periods, but also underscores the importance of strategic planning and investment in infrastructure that can withstand and adapt to the evolving demands of our climate and societal needs.

As the industry faces significant uncertainty around future load growth, a changing resource mix, and a changing climate, there is a growing need to ensure that electricity systems remain robust and adaptable. Interregional transmission not only facilitates a more resilient grid by diversifying energy sources and balancing load during critical periods, but also underscores the importance of strategic planning and investment in infrastructure that can withstand and adapt to the evolving demands of our climate and societal needs. By prioritizing the expansion and enhancement of interregional connections, we can ensure that the grid remains capable of meeting the diverse challenges of tomorrow.

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PHOTOS

Appendix

Data shown here report the individual paths between FERC Order 1000 regions and the magnitude of the 99.9th percentile of interchanges between each FERC Order 1000 region and its neighbors based on hourly data from the EIA Form 930 for 2019–2023. Data show the individual maximum between each region, non-coincident, which was used in the analysis as the basis for existing interregional transmission capabilities between FERC Order 1000 regions. Connections to Canadian regions were not assessed.

TABLE A-1

Detailed Non-Coincident Transfer Limits by Pairs of FERC Order 1000 Regions

FERC 1000 Region	Path Name	Source	Sink	Base Transmission (MW)
CAISO	NorthernGrid to CAISO	NorthernGrid	CAISO	8,026
	WestConnect to CAISO	WestConnect	CAISO	7,908
NorthernGrid	CAISO to NorthernGrid	CAISO	NorthernGrid	8,026
	MISO to NorthernGrid	MISO	NorthernGrid	0
	SPP to NorthernGrid	SPP	NorthernGrid	200
	WestConnect to NorthernGrid	WestConnect	NorthernGrid	1,872
WestConnect	CAISO to WestConnect	CAISO	WestConnect	7,908
	ERCOT to WestConnect	ERCOT	WestConnect	0
	NorthernGrid to WestConnect	NorthernGrid	WestConnect	1,872
	SPP to WestConnect	SPP	WestConnect	939
ERCOT	MISO to ERCOT	MISO	ERCOT	0
	SPP to ERCOT	SPP	ERCOT	834
	WestConnect to ERCOT	WestConnect	ERCOT	0
SPP	ERCOT to SPP	ERCOT	SPP	834
	MISO to SPP	MISO	SPP	3,283
	NorthernGrid to SPP	NorthernGrid	SPP	200
	SERTP to SPP	SERTP	SPP	1,484
	WestConnect to SPP	WestConnect	SPP	939

(CONTINUED)

TABLE A-1

Detailed Non-Coincident Transfer Limits by Pairs of FERC Order 1000 Regions (CONTINUED)

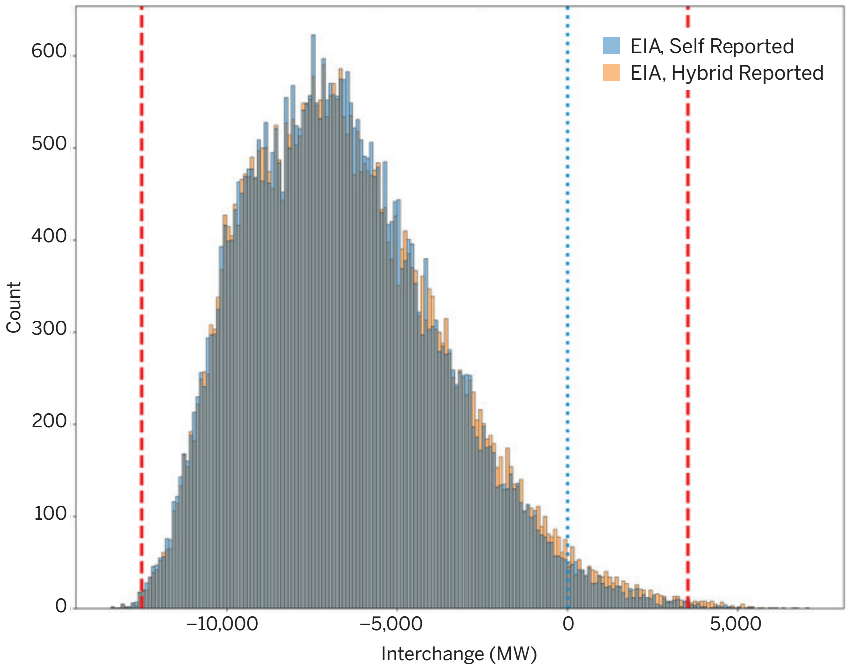
FERC 1000 Region	Path Name	Source	Sink	Base Transmission (MW)
MISO	ERCOT to MISO	ERCOT	MISO	0
	NorthernGrid to MISO	NorthernGrid	MISO	0
	PJM to MISO	PJM	MISO	8,864
	SERTP to MISO	SERTP	MISO	5,326
	SPP to MISO	SPP	MISO	3,283
SERTP	FRCC to SERTP	FRCC	SERTP	2,862
	MISO to SERTP	MISO	SERTP	5,326
	PJM to SERTP	PJM	SERTP	4,310
	SPP to SERTP	SPP	SERTP	1,484
FRCC	SERTP to FRCC	SERTP	FRCC	2,862
PJM	MISO to PJM	MISO	PJM	8,864
	NYISO to PJM	NYISO	PJM	3,745
	SERTP to PJM	SERTP	PJM	4,310
NYISO	ISONE to NYISO	ISONE	NYISO	1,814
	PJM to NYISO	PJM	NYISO	3,745
ISONE	NYISO to ISONE	NYISO	ISONE	1,814

Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; FRCC = Florida Reliability Coordinating Council; ISONE = Independent System Operator of New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; SERTP = Southeastern Regional Transmission Planning; SPP = Southwest Power Pool.

Source: Energy Systems Integration Group.

FIGURE A-1

Comparison of Interchange Flow for the California Independent System Operator

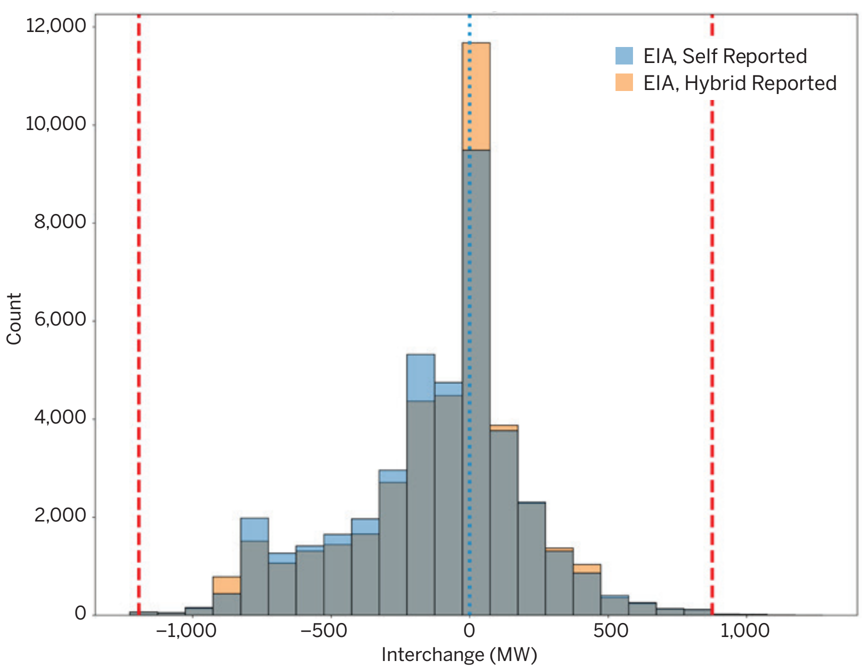


Data show the hourly interchange for the California Independent System Operator FERC Order 1000 region showing both self-reported (blue) and hybrid-reported (orange) interchange with the region. Hybrid data are aggregated based on the neighboring regions' reported data for their interchanges with the region. Red lines mark the 99.9th percentile of interchange values, and the blue line marks 0 MW interchange. Positive values indicate exports, negative values indicate imports.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

FIGURE A-2

Comparison of Interchange Flow for the Electric Reliability Council of Texas

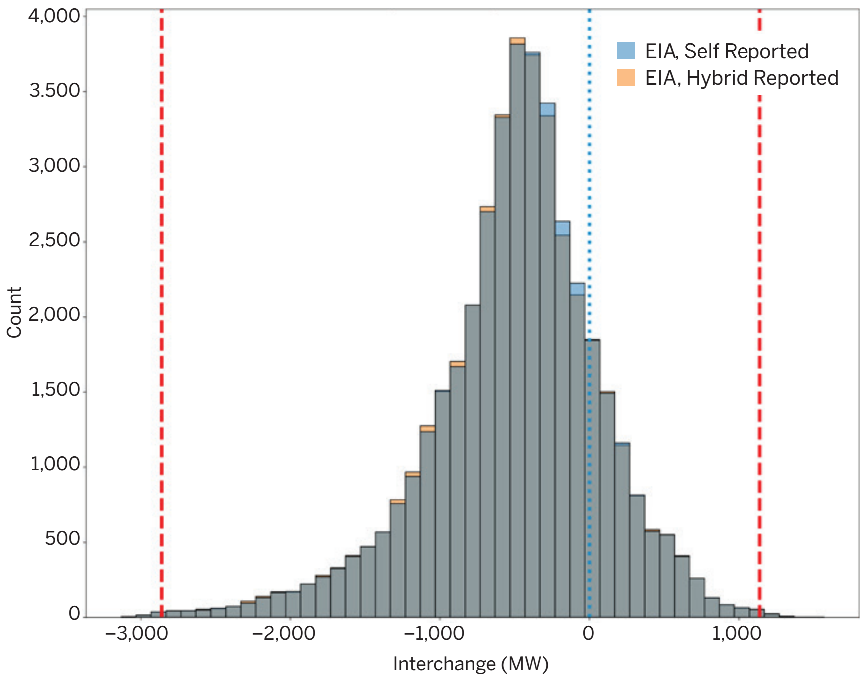


Data show the hourly interchange for the Electric Reliability Council of Texas FERC Order 1000 region showing both self-reported (blue) and hybrid-reported (orange) interchange with the region. Hybrid data are aggregated based on the neighboring regions' reported data for their interchanges with the region. Red lines mark the 99.9th percentile of interchange values, and the blue line marks 0 MW interchange. Positive values indicate exports, negative values indicate imports.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

FIGURE A-3

Comparison of Interchange Flow for the Florida Reliability Coordinating Council

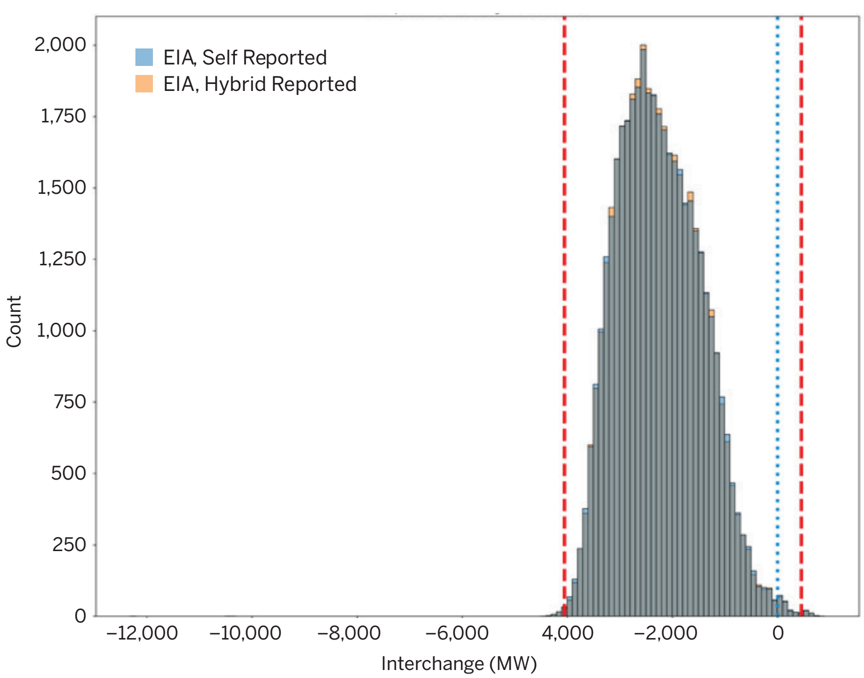


Data show the hourly interchange for the Florida Reliability Coordinating Council FERC Order 1000 region showing both self-reported (blue) and hybrid-reported (orange) interchange with the region. Hybrid data are aggregated based on the neighboring regions' reported data for their interchanges with the region. Red lines mark the 99.9th percentile of interchange values, and the blue line marks 0 MW interchange. Positive values indicate exports, negative values indicate imports.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

FIGURE A-4

Comparison of Interchange Flow for the Independent System Operator of New England

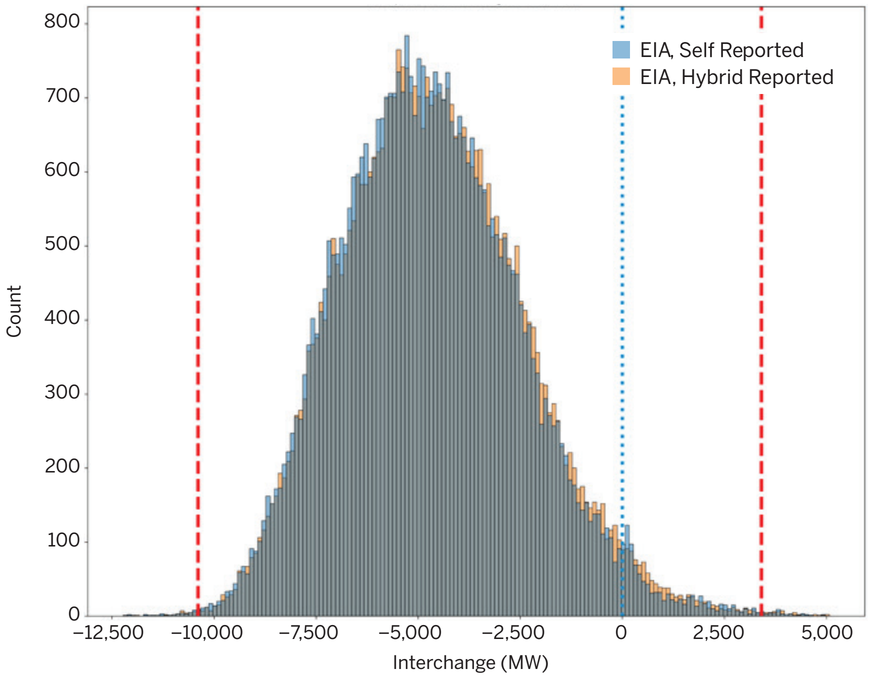


Data show the hourly interchange for the Independent System Operator of New England FERC Order 1000 region showing both self-reported (blue) and hybrid-reported (orange) interchange with the region. Hybrid data are aggregated based on the neighboring regions' reported data for their interchanges with the region. Red lines mark the 99.9th percentile of interchange values, and the blue line marks 0 MW interchange. Positive values indicate exports, negative values indicate imports.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

FIGURE A-5

Comparison of Interchange Flow for the Midcontinent Independent System Operator

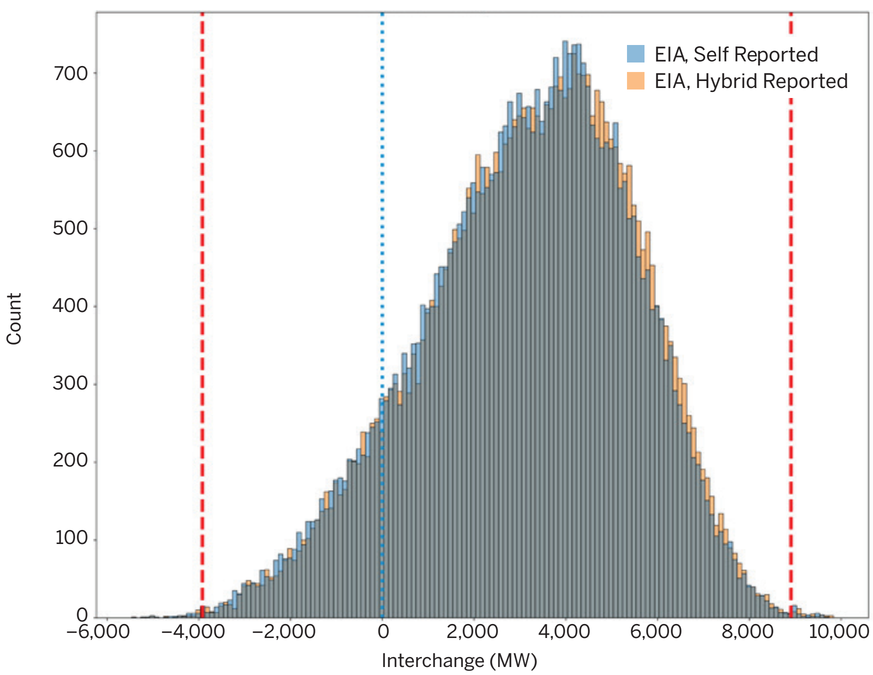


Data show the hourly interchange for the Mid-continent Independent System Operator FERC Order 1000 region showing both self-reported (blue) and hybrid-reported (orange) interchange with the region. Hybrid data are aggregated based on the neighboring regions' reported data for their interchanges with the region. Red lines mark the 99.9th percentile of interchange values, and the blue line marks 0 MW interchange. Positive values indicate exports, negative values indicate imports.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

FIGURE A-6

Comparison of Interchange Flow for NorthernGrid

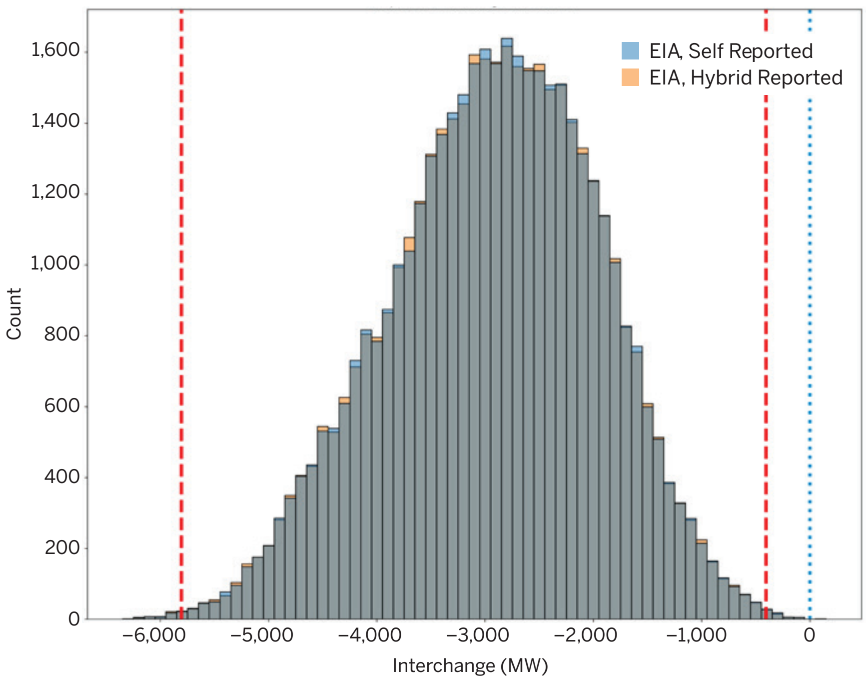


Data show the hourly interchange for the NorthernGrid FERC Order 1000 region showing both self-reported (blue) and hybrid-reported (orange) interchange with the region. Hybrid data are aggregated based on the neighboring regions' reported data for their interchanges with the region. Red lines mark the 99.9th percentile of interchange values, and the blue line marks 0 MW interchange. Positive values indicate exports, negative values indicate imports.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

FIGURE A-7

Comparison of Interchange Flow for the New York Independent System Operator

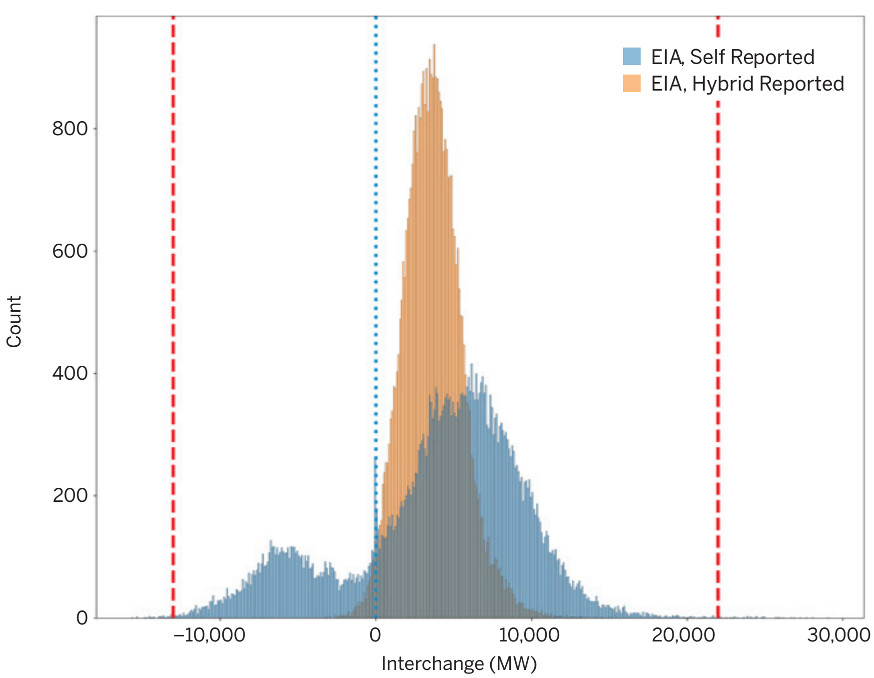


Data show the hourly interchange for the New York Independent System Operator FERC Order 1000 region showing both self-reported (blue) and hybrid-reported (orange) interchange with the region. Hybrid data are aggregated based on the neighboring regions' reported data for their interchanges with the region. Red lines mark the 99.9th percentile of interchange values, and the blue line marks 0 MW interchange. Positive values indicate exports, negative values indicate imports.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

FIGURE A-8

Comparison of Interchange Flow for PJM

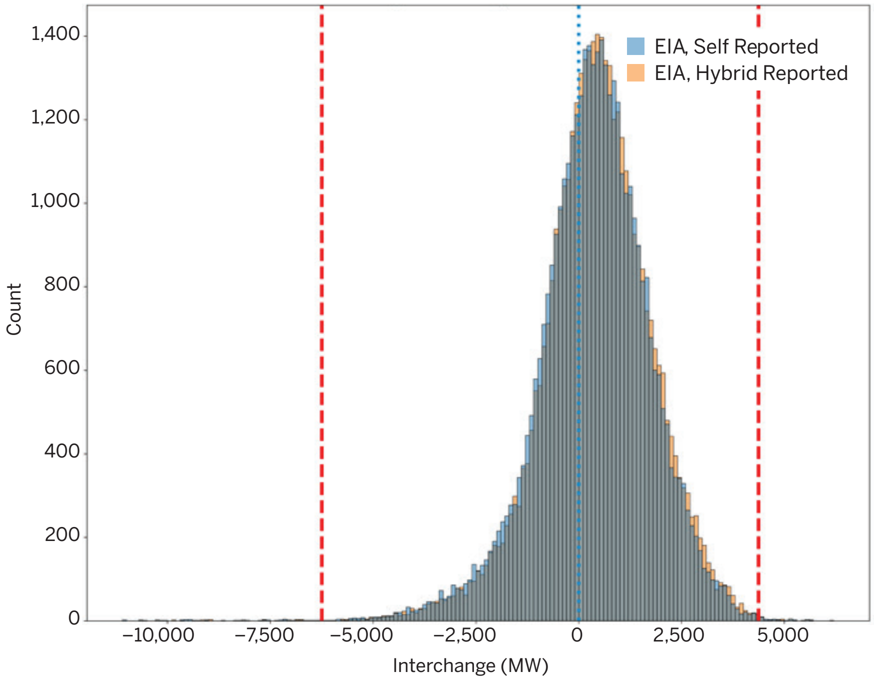


Data show the hourly interchange for the PJM FERC Order 1000 region showing both self-reported (blue) and hybrid-reported (orange) interchange with the region. Hybrid data are aggregated based on the neighboring regions' reported data for their interchanges with the region. Red lines mark the 99.9th percentile of interchange values, and the blue line marks 0 MW interchange. Positive values indicate exports, negative values indicate imports.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

FIGURE A-9

Comparison of Interchange Flow for the Southeastern Electric Reliability Council

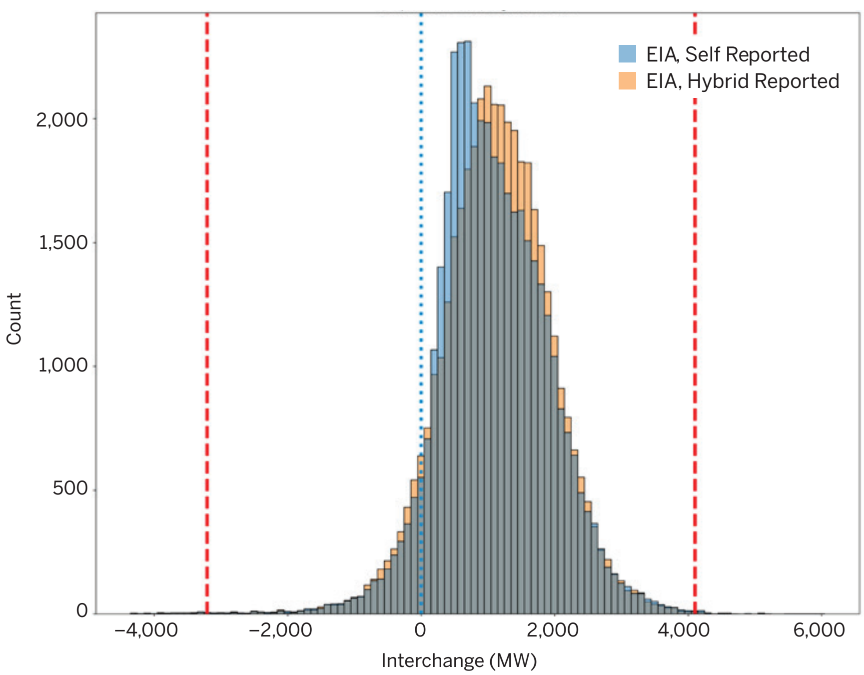


Data show the hourly interchange for the Southeastern Electric Reliability Council FERC Order 1000 region showing both self-reported (blue) and hybrid-reported (orange) interchange with the region. Hybrid data are aggregated based on the neighboring regions' reported data for their interchanges with the region. Red lines mark the 99.9th percentile of interchange values, and the blue line marks 0 MW interchange. Positive values indicate exports, negative values indicate imports.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

FIGURE A-10

Comparison of Interchange Flow for the Southwest Power Pool

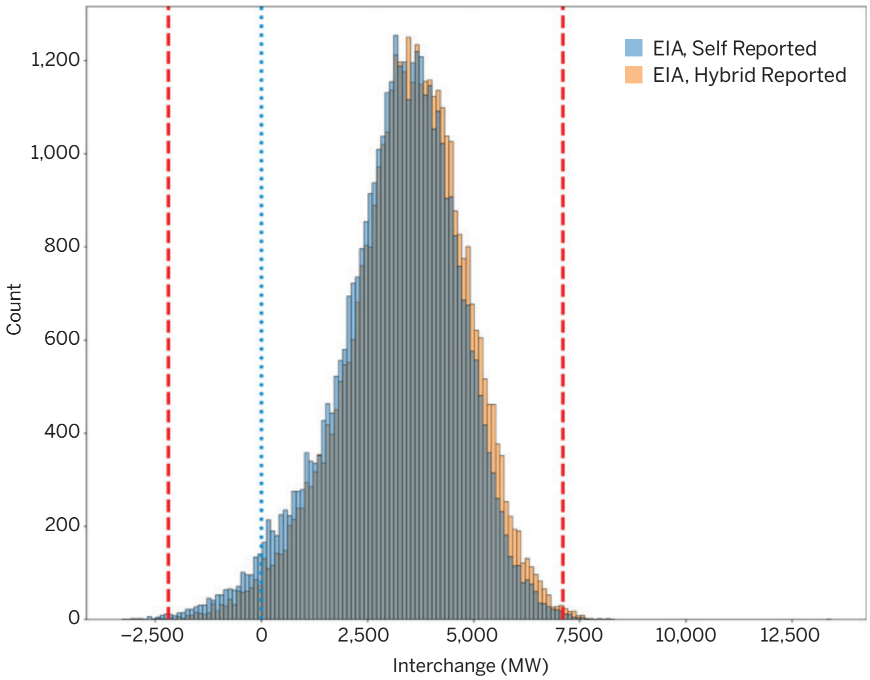


Data show the hourly interchange for the Southwest Power Pool FERC Order 1000 region showing both self-reported (blue) and hybrid-reported (orange) interchange with the region. Hybrid data are aggregated based on the neighboring regions' reported data for their interchanges with the region. Red lines mark the 99.9th percentile of interchange values, and the blue line marks 0 MW interchange. Positive values indicate exports, negative values indicate imports.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

FIGURE A-11

Comparison of Interchange Flow for WestConnect



Data show the hourly interchange for the WestConnect FERC Order 1000 region showing both self-reported (blue) and hybrid-reported (orange) interchange with the region. Hybrid data are aggregated based on the neighboring regions' reported data for their interchanges with the region. Red lines mark the 99.9th percentile of interchange values, and the blue line marks 0 MW interchange. Positive values indicate exports, negative values indicate imports.

Source: Energy Systems Integration Group; data from Energy Information Administration Form 930.

Interregional Transmission for Resilience: Using Regional Diversity to Prioritize Additional Interregional Transmission

A Report by the Energy Systems Integration Group's Transmission Resilience Task Force

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The report is available at https://www.esig.energy/interregional-transmission-for-resilience.

To learn more about ESIG's work on this topic, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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