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Interregional transmission and resource adequacy: an empirical analysis of peak demand coincidence and power flows in the United States, 2016–2024

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Abstract

There is growing interest in leveraging interregional transmission as a resource adequacy (RA) asset as the U.S. electric grid faces challenges from extreme weather, load growth, and a changing generation mix. However, empirical evidence of how transmission functions during periods of system stress remains limited. This paper addresses that gap by analyzing nine years of historical peak demand patterns and interregional power flows across 18 continental U.S. transmission planning regions from 2016–2024. We identify RA-critical periods based on peak net load and assess when regions experience these peaks at simultaneous or opposite times. We then analyze actual power flows during these high-stress periods to evaluate how effectively interregional transmission was used to support stressed regions. Our results show substantial geographic variation in the theoretical potential for transmission to provide RA support. Furthermore, realization of this potential is often poor: approximately half of examined region pairs show transmission flows that support the high-need region 50%–60% of the time during non-coincident peaks, barely better than random. Several pairs exhibit counter-supportive flow patterns, and benefits are often asymmetric between neighboring regions. These findings suggest that operational, market, institutional, or other barriers are constraining the reliability value of interregional transmission.

Acronyms

BA	Balancing Authority
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
HRRR	High-Resolution Rapid Refresh
ISO	Independent System Operator
MW	megawatt
NERC	North American Electric Reliability Corporation
NSRDB	National Solar Radiation Database
RA	Resource Adequacy
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Operator

1. Introduction

The reliability of the U.S. electric grid faces mounting challenges. Recent years have witnessed extreme weather events, such as polar vortex conditions and extreme heat, that have stressed power systems across regions. Meanwhile, rapid load growth from data centers, industrial facilities, and electrification is poised to outpace generation additions in some regions, with interconnection queues to connect new generation stretching years into the future (North American Electric Reliability Corporation 2024, Rand *et al* 2024, U.S. Department of Energy 2025, Wilson *et al* 2025). Grids are also becoming increasingly complex to operate, as growing shares of weather-dependent generation and distributed energy resources make system states harder to predict (Hawker *et al* 2024). These converging pressures have put RA—ensuring sufficient capacity to meet electricity demand under stressed conditions—into the national policy conversation.

RA in the U.S. has traditionally been addressed through localized planning within individual regions. ISOs/RTOs and BAs typically plan generation capacity within their own boundaries, with limited consideration of potential support from neighboring regions. Assessments of RA often focus on generator-side reliability attributes, such as fuel availability, on-site storage, and weather resilience when evaluating reliability challenges (Ramirez-Meyers *et al* 2021). While many entities do include some firm capacity available through certain transmission corridors in their planning processes, they typically treat this external capacity as a fixed resource assumption rather than dynamically modeling the full RA implications across regions (Pfeifenberger *et al* 2021, Brooks *et al* 2025). This siloed approach reflects both institutional boundaries and the complexity of coordinating across regions with different market designs, reliability standards, and governance structures.

However, this fragmented approach comes at a cost. Recent research demonstrates that siloed planning processes lead to higher total system costs compared to integrated interregional planning. Bloom *et al* (2022) found value from increased transmission capacity between the Eastern and Western U.S. interconnections, while Kassel *et al* (2026) found that connecting ERCOT to neighboring grids could reduce costs and carbon emissions. Brown and Botterud (2021), Sergi *et al* (2024), and Senga *et al* (2025) showed that interregional coordination could significantly reduce system costs of a future grid. Empirical analysis of historical wholesale energy markets corroborates these modeled findings: Kemp *et al* (2025) found that additional interregional transfer capacity had substantial market value. These energy market benefits complement the RA value that interregional transmission could provide in regions with organized capacity markets.

Recent policy developments have attempted to motivate or require more integrated planning processes between regions. In 2022, the FERC convened a technical workshop to address interregional transfer capability and transmission cost allocation (Federal Energy Regulatory Commission 2022); in 2024, FERC issued Order No. 1920, requiring transmission providers to conduct long-term regional transmission planning that explicitly evaluates benefits including reduced loss-of-load probability, effectively mandating consideration of transmission's RA value (Federal Energy Regulatory Commission 2024). Recent legislation proposed in Congress has proposed to mandate increasing interregional transfer capabilities (Sen. Hickenlooper 2023, Rep. Casten 2025). Additionally, Congress passed legislation directing the NERC to conduct a study to identify current interregional transfer capabilities and propose interregional transmission additions (Rep. McHenry 2023). These policies reflect growing recognition that transmission infrastructure can serve as a shared reliability resource, in addition to a means of facilitating energy trade.

This recognition has spurred research into quantifying transmission's RA contribution. Deyoe *et al* (2024) developed methods for calculating regional hourly energy margins using modeled weather data to prioritize transmission investments needed to achieve target interregional transfer capabilities. NERC's congressionally mandated Interregional Transfer Capability Study extended this work by identifying constrained interfaces and, importantly, establishing the first unified methodology for defining existing interregional transfer capability across the U.S. (NERC 2024). Goggin *et al* (2023) proposed setting a minimum interregional transfer capability requirement based on geographic diversity between regions. Brooks *et al* (2025) have argued for accrediting transmission with a capacity credit, analogous to generation resources. More broadly, other researchers have advocated for wide-area, probabilistic RA assessments across multiple regions under shared assumptions about load, weather, and transmission to better capture the value of interregional coordination and identify system-wide risk (Stenclik and Schwartz 2025).

While existing research has examined the theoretical potential for transmission to support RA through modeling future scenarios or defining transfer capabilities, they lack empirical evidence about how interregional transmission is actually utilized during periods of system stress. Recent analysis by

Safavi *et al* (2025) found that interregional transmission is often operated uneconomically and remains under-utilized even when price signals in wholesale energy markets suggest valuable trading opportunities. Whether similar patterns exist during reliability-critical periods remains underexplored in the literature.

This paper addresses that gap through an empirical analysis of interregional transmission utilization during RA-critical periods across the entire U.S. First, we identify periods of RA risk across 18 transmission planning regions using historical net load (demand minus variable renewable generation) patterns from 2016–2024, examining which regions experience peak demand simultaneously and which have complementary timing that could enable mutual support. Second, we analyze actual power flows on interregional transmission during these high-risk periods to determine whether, and how effectively, interregional transmission was utilized to support stressed regions. Third, we evaluate whether interregional transmission provides symmetric benefits, or whether operational patterns systematically favor some regions over others. These three contributions add new empirical evidence about both the potential and challenges of using interregional transmission to provide RA in the U.S.

While the empirical scope of this paper is constrained to the U.S., RA challenges are a global problem. European countries are facing increased adequacy challenges due to a rapidly changing grid mix, with transmission system operators documenting increasing reliance on cross-border imports during peak periods (Larsen and van Ackere 2023). Central and South America currently have limited capacity for cross-border electricity trade due to institutional barriers and coordination challenges; a 2021 report found that allowing unrestricted transmission without increasing generation capacity in 20 Latin American countries would save the region nearly \$2 billion annually (Timilsina *et al* 2021). The empirical insights from the U.S. experience documented in this paper may help inform international efforts to better integrate transmission into RA planning.

Our analysis shows substantial geographic variation in both the potential and realization of transmission's RA value. We find that while some region pairs demonstrate strong complementary peak timing and responsive transmission operations that effectively leverage this potential, many others show transmission flows that are largely unresponsive or even counter-productive during periods of greatest need. These findings have important implications for both transmission planning and for operational reforms needed to realize the full reliability value of existing and future Interregional transmission infrastructure.

2. Methods

Our analysis proceeds in three steps. First, we define 18 transmission planning regions and compile historical data on electricity demand and renewable generation for each region from 2016–2024. Next, we identify periods of RA risk using net load and examine the temporal coincidence of peak periods across regions. Finally, we analyze actual power flows on interregional transmission interfaces during these high-risk periods to assess how effectively transmission was utilized to support stressed regions.

2.1. Regional definition and study period

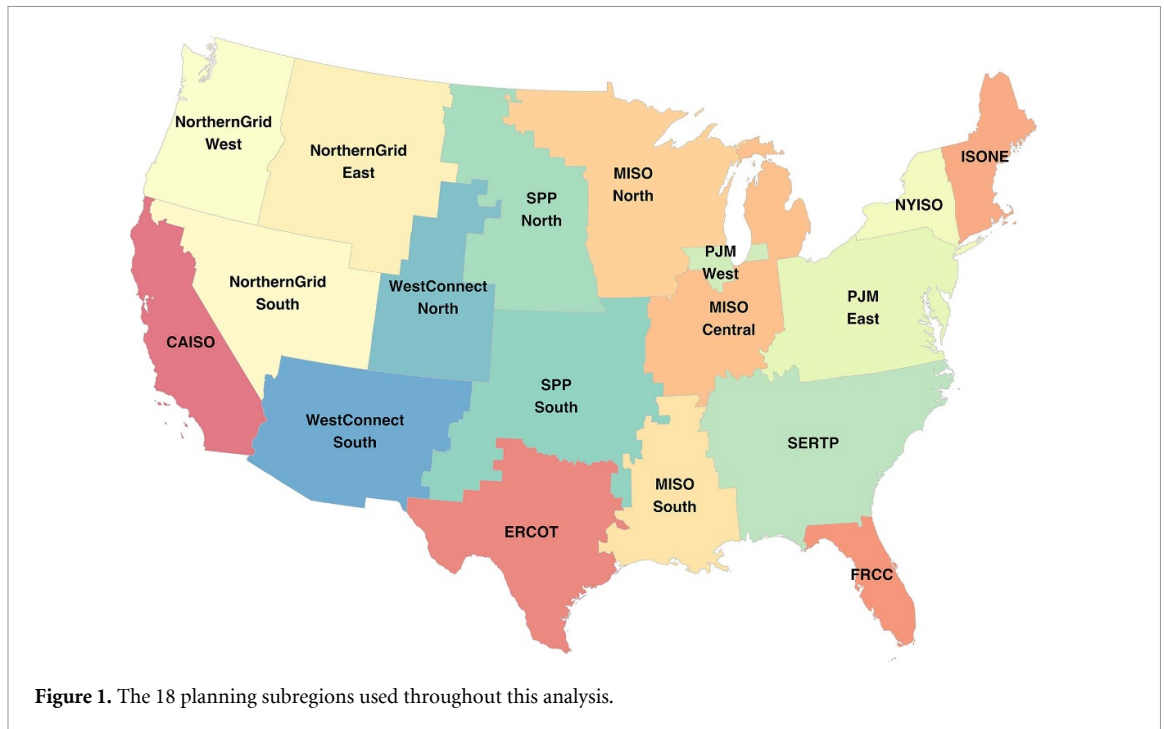
We analyze 18 transmission planning regions (figure 1) defined for the (U.S. Department of Energy's 2026) National Transmission Needs Study; these are also the planning subregions used in NREL's ReEDS model (Brown *et al* 2020, U.S. Department of Energy 2026). This regional framework provides greater granularity than the 11 FERC Order No. 1000 regions commonly used in transmission planning discussions, allowing us to better capture sub-regional variations in weather patterns, demand profiles, and generation mix that affect RA risk. Our analysis covers the period from January 2016 through December 2024, encompassing nine years of historical operations across diverse weather conditions and system configurations.

2.2. Data Sources and Processing

2.2.1. Load data

We compiled hourly electricity demand data at the BA and ISO/RTO level from a data provider, Velocity Suite, which aggregates publicly available data from Form EIA-930 and from PJM, MISO, and SPP zonal reporting. We assigned each BA or ISO to one of the 18 planning subregions shown in figure 1 based on geographic boundaries. A table showing the assignments of BAs to planning subregions can be found in appendix table 1.

The demand data reflect actual electricity delivered and thus exclude unserved energy during emergency events. To capture total system demand including periods when supply fell short, we incorporated firm load shedding events of 100 MW or greater reported through DOE Form OE-417



(U.S. Department of Energy Office of Cybersecurity, Energy Security, and Emergency Response n.d.).

We note that OE-417 reporting is limited to large outage events and has historically been underreported, meaning our reconstruction of demand during stressed periods may understate the true extent of unserved energy (Stevens *et al* 2025). These load shedding events were added to reported demand to reconstruct what demand would have been absent curtailments. See appendix A.1.5 to see how these load shedding events impact the net load profiles.

2.2.2. Renewable generation data

We compiled hourly wind and solar generation using a hybrid approach combining empirical and modeled data, necessitated by limitations in empirical data availability:

- *ISO regions (2016–2024)*: we sourced empirical generation data for ISO regions during our whole study period from Velocity Suite, data which are also publicly available from ISO data portals. These data were cleaned for use in the Renewables and Wholesale Electricity Prices (ReWEP) tool and used here (Millstein *et al* 2024).
- *Non-ISO regions (July 2018–2024)*: we obtained empirical generation data for non-ISO regions beginning in July 2018, when Form EIA-930 began reporting resource-level generation data. We again obtained these data from Velocity Suite.
- *Non-ISO regions (2016–June 2018)*: we modeled plant-level generation data for non-ISO regions prior to July 2018, as EIA-930 did not require resource-type-specific reporting at the BA level during this period. For solar, we used NREL’s System Advisor Model with site-specific meteorological data from NREL’s NSRDB or NOAA’s HRRR dataset, except in ERCOT where plant-level data are publicly available (Sengupta *et al* 2018, Dowell *et al* 2022, System Advisor Model Version 2024.12.12 2024). For wind, we modeled generation using HRRR wind speed data combined with turbine-specific power curves configured to each plant’s characteristics, following the methodology in Wiser *et al* (2024a).

We aggregated all plant-level and BA-level renewable generation data into the 18 planning subregions. Detailed data cleaning and aggregation procedures are provided in appendix A.1.

2.3. Identifying RA risk periods

2.3.1. Net load as a proxy for system stress

There are several methods for measuring system risk that vary by system across the U.S. and globally. Probabilistic measures, such as loss-of-load expectation or expected unserved energy, are commonly used in planning models to estimate the likelihood or magnitude of load shedding events over a specified

timeframe. These metrics provide a rigorous, risk-based picture of adequacy, but require computationally intensive simulations and careful interpretation. Their outputs are also model-based expected values rather than directly observable quantities, which makes them well-suited to forward-looking planning but less suited to empirical analysis of realized system behavior.

Many traditional, time-period based RA metrics in the U.S. have focused on peak gross demand. However, with increasing penetrations of variable renewable energy, peak net load (demand minus variable renewable generation) has emerged as a more appropriate indicator of system stress (Zhou *et al* 2018, Cole *et al* 2020, Redefining Resource Adequacy Task Force 2021). Peak net load identifies periods when dispatchable resources face the greatest challenge meeting demand, which may occur at different times than peak gross demand. For example, California's August 2020 rotating outages occurred during the evening net load peak, after the gross load peak and as solar generation declined. Net load offers a transparent and directly observable proxy for these stress periods; indeed, peak net load hours are increasingly used within probabilistic frameworks themselves to define the at-risk periods over which resource contributions are evaluated (de Mijolla *et al* 2022).

We calculate hourly net load for each region as:

Equation (1): net load in hour h for region x .

$$NetLoad_h^x = GrossLoad_h^x + LoadShed_h^x - (WindGeneration_h^x + SolarGeneration_h^x). \quad (1)$$

Net load is nonetheless an incomplete measure of system stress: it captures variation in demand and variable renewable output but treats dispatchable supply as fixed. Several major recent reliability events, including Winter Storm Uri (which occurred in 2021) and Elliot (which occurred in 2022), were driven as much by generator unavailability as by demand. Because such conditions cluster in winter while net load peaks in most of our study regions occur in summer (see appendix B.2 (figure 15) for the distribution of peak hours by season), our risk periods are weighted toward demand-driven rather than supply-driven scarcity. A supply-inclusive metric such as hourly energy margin would capture additional stressed hours, but consistent hourly generator availability data are not published across all 18 planning subregions. High net load hours remain periods of elevated stress; our results characterize a subset of RA-critical hours rather than all of them.

2.3.2. Defining peak periods

Following the findings in Stephen *et al* (2020) and Mills and Rodriguez (2020), we define each region's RA risk periods as the top 100 net load hours per year. This research showed that resource performance during these hours provides a good approximation of the firm capacity contribution of the resource, making these hours an established proxy for the periods of greatest system stress. While the 'top 100' criterion is, of course, a somewhat arbitrary cutoff, the results in appendix B.3 demonstrate that comparisons of net load coincidence and utilization rates during peak hours are not highly sensitive to the specific threshold (e.g., 50 or 200 h).

Equation (2): top net load hours for region x in year y . $H_{x,y}$ represents all hours in year y for region x . $NetLoad_h^{x,y}$ is the net load for hour h in year y . $NetLoad_{100}^{x,y}$ is the 100th largest net load value for region x in year y .

$$Peak\ net\ load\ hours_{x,y} = \{h \in H_{x,y} | NetLoad_h^{x,y} \geq NetLoad_{100}^{x,y}\}. \quad (2)$$

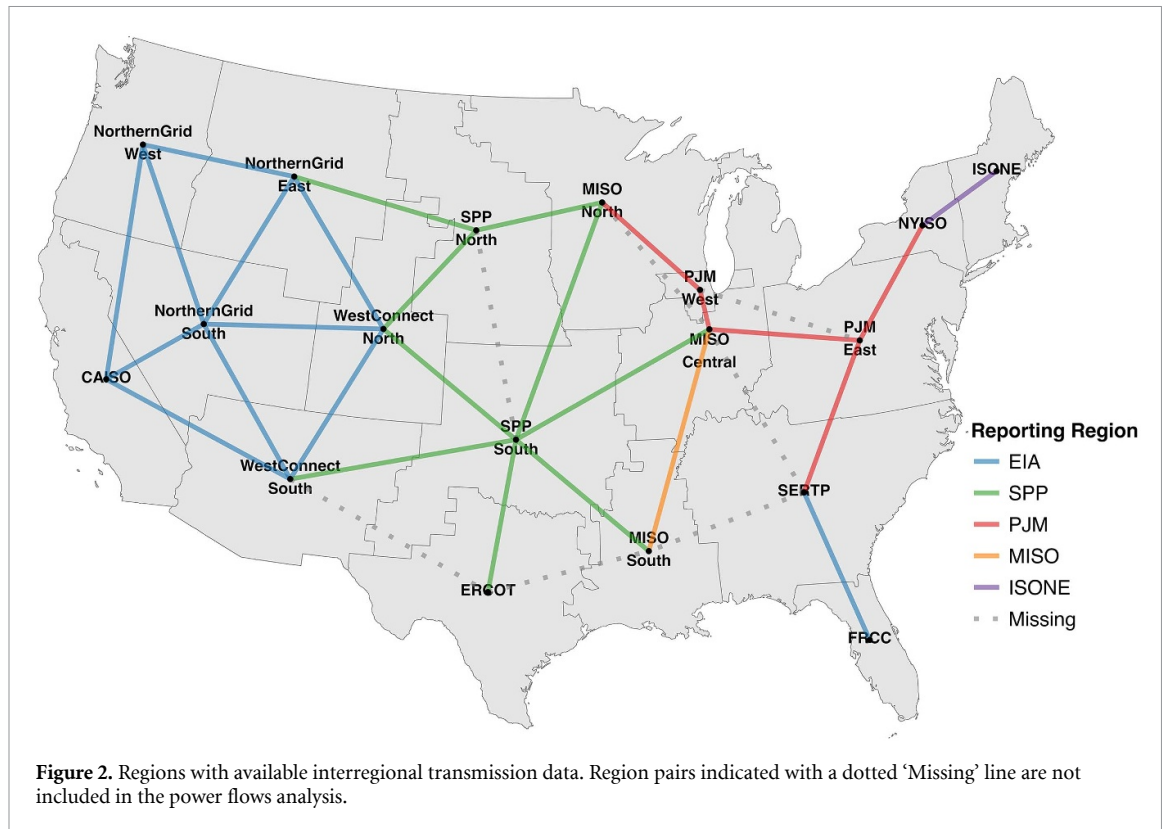
2.3.3. Net load coincidence factor

To quantify the degree to which regions experience peak conditions simultaneously, we calculate a net load coincidence factor between region pairs using equation (3).

Equation (3): $Netload\ coincidence_{A,B}$ represents the annual average percentage of region A's maximum net demand that occurs during region B's peak hours. The equation calculates this by averaging across Y years, taking region A's net load during each of the top 100 net load hours in region B per year ($h \in Top100_{B,y}$) and expressing these as a percentage of region A's maximum net load hour for that year. is region A's net load during hour h of year y . $Max\ Net\ Load_{A,y}$ is the maximum net load for region A in year y . The result provides insight into how stressed neighboring regions are when each region is experiencing peak demand.

$$Netload\ coincidence_{A,B} = \frac{1}{Y \times 100} \sum_{y=1}^Y \sum_{h \in Top100_{B,y}} \left(\frac{NetLoad_{A,h,y}}{MaxNetLoad_{A,y}} \times 100 \right). \quad (3)$$

This metric captures the magnitude of Region A's demand during Region B's most stressful hours. Specifically, it identifies when Region B experiences its peak demand (top 100 annual net load hours)



and measures Region A's net load during those same hours, expressed as a percentage of Region A's maximum net demand. For example, a value of 90% means that when Region B is peaking, Region A is simultaneously operating at 90% of its own maximum. Lower values indicate greater potential for inter-regional resource sharing.

2.4. Analyzing interregional power flows

2.4.1. Transmission path data collection

To evaluate how transmission was actually utilized during RA risk periods, we collected hourly power flow data on interregional interfaces. We obtained real-time net interchange data from two sources: system operator reports or data portals for the seven ISOs and Form EIA-930 reported metered interchange for BAs. We purchased the compiled data from Velocity Suite to expedite data collection.

2.4.2. Matching transmission paths to regions

We mapped each reported transmission interface to pairs of the 18 planning subregions. However, complete mapping was not always possible. Some ISOs do not report sub-regional flows (e.g. between PJM West and PJM East), and some interfaces span more than two regions. Figure 2 shows the region pairs for which we successfully obtained and geographically matched power flow data. Paths that could not be unambiguously assigned to a single region pair were excluded from the power flow analysis.

For each interface between regions, we use hourly net flow data. When multiple transmission lines connect two regions, we aggregate flows to calculate total net interregional transfer. To minimize inconsistencies from different regional reporting practices, we select one region's reported flow for each interface. We preferentially use scheduled real-time flows where available, to minimize the impact of loop flows (unscheduled flows following the path of least resistance); when unavailable, we use metered actual flows. A complete list of transmission paths, their regional assignments, and flow type (scheduled or actual) appears in appendix A.1.4.

2.4.3. Transmission utilization rates

To assess how intensively transmission capacity was used, we calculated hourly utilization rates as the ratio of actual flow to effective capacity. Transfer capacity between regions varies over time due to factors including transmission expansion and decommissioning, outages, and weather. It is also complex to measure for large networked systems, as demonstrated in the NERC Interregional Transfer Capability

Study (NERC 2024). Following Safavi *et al* (2025) and Deyoe *et al* (2024) we proxy effective capacity using the seasonal 99th percentile of observed flows, calculated separately for the import direction (positive flows) and export direction (negative flows). We define seasons as six-month periods (April–September and October–March) to capture typical summer and winter peak patterns. Using the 99th percentile rather than the absolute maximum provides robustness against outliers and data errors. An advantage of basing effective capacity on observed flows is that all operational and contingency constraints are implicitly captured. However, this approach underestimates capacity during seasons in which the true effective capacity was used less than 1% of the time.

Equation (4): transmission interface utilization rate in hour h and season s . *Effective Capacity_s* is proxied by the seasonal 99th percentile of observed flows, calculated separately for imports (positive flows) and exports (negative flows). Each season is defined as a six-month period from April–September or October–March.

$$UtilizationRate_{h,s} = \frac{NetFlow_h}{EffectiveCapacity_s}. \quad (4)$$

This approach inherently allows utilization rates exceeding $\pm 100\%$ for the 1% of hours exceeding the ± 99 th percentile threshold. To prevent extreme outliers from skewing our analysis, we exclude the 0.1% of observations with utilization rates exceeding approximately $\pm 120\%$ (specifically, hours beyond the 90th percentile of observations already above 100% utilization or below -100%).

2.4.4. Categorizing flow patterns

To assess whether transmission flows support RA, we categorize energy transfers during high net load periods based on flow direction and demand coincidence:

- *Supportive flows*: energy flows from the lower-need region toward the higher-need region (the region experiencing its top 100 annual net load hours).
- *Counter-supportive flows*: energy flows away from the high-need region toward a region not experiencing elevated demand.
- *Mutually high-need hours*: both regions simultaneously experience top 100 annual net load hours, making the ‘correct’ flow direction ambiguous.

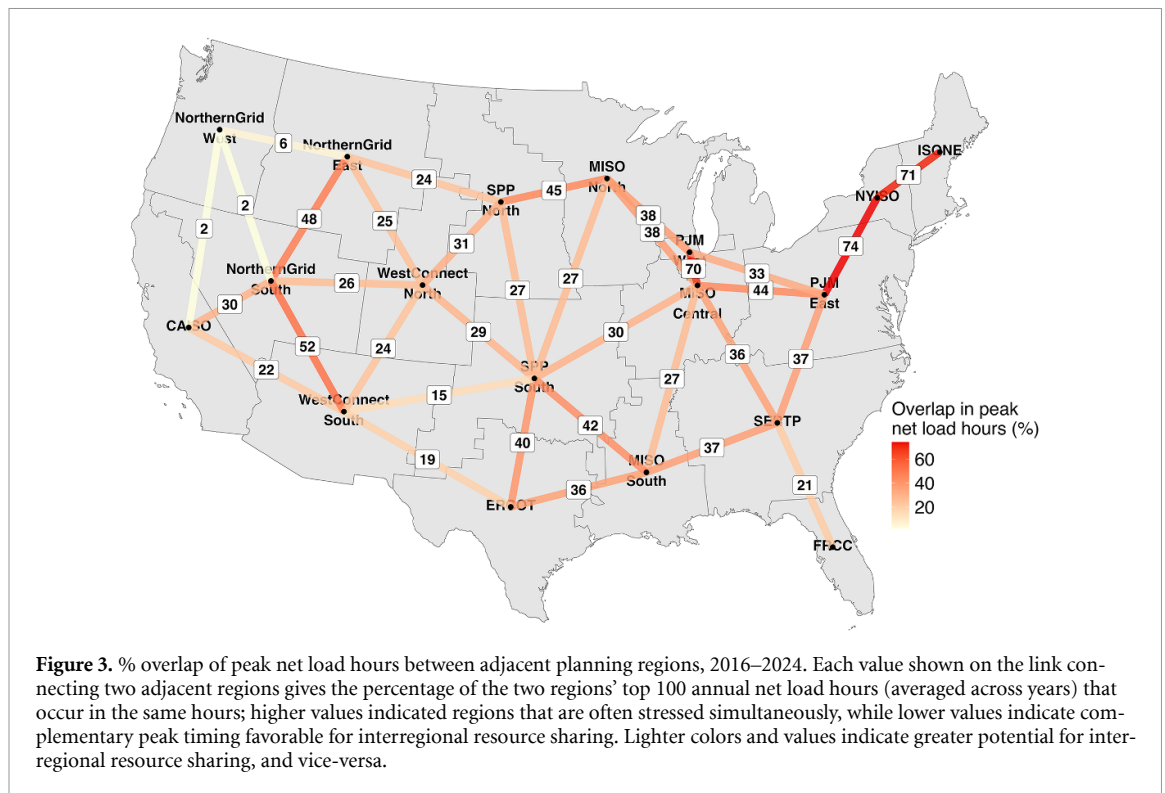
For each region pair, we calculate the percentage of total energy transferred during single-peak periods (hours that are not ‘mutually high-need,’ when only one region is stressed) that flowed in the supportive direction. This metric, defined in equation (5), shows how responsive transmission operations are to relative RA need.

Equation (5): RA support rate between region pair (A,B). $H_{support}$ represents hours when energy flowed toward the high-need region during single-peak periods (when region A peaked and B did not with flow B→A or when B peaked and A did not with flow A→B). $H_{counter}$ represents hours when energy flowed away from the high-need region during single-peak periods. $Flow_h$ is the net power flow (MW) in hour h . The metric represents the percentage of total energy transferred (MWh) that supported the high-need region, excluding hours when both regions simultaneously experienced top 100 annual net load.

$$RA\ Support\ Rate_{A,B} = \frac{\sum_{h \in H_{support}} |Flow_h|}{\sum_{h \in H_{support}} |Flow_h| + \sum_{h \in H_{counter}} |Flow_h|} \times 100. \quad (5)$$

We further examine utilization patterns by comparing mean utilization rates across different operating conditions: all hours versus hours when one region experiences peak demand and its neighbor does not. In theory, if transmission were responding only to RA, transmission would flow toward (or at minimum not away from) the stressed region during these asymmetric peak hours. Deviations from this pattern indicate operational practices, market design issues, security or operational constraints, or technical barriers that may prevent transmission from realizing its full RA potential.

Our analysis of transmission flow patterns is focused on aggregated metrics over the full sample period, but we did perform limited case studies of transmission use during known extreme RA event periods (appendix B.5, figures 19, 20, 21, and 22) and computed the RA Support Rate over time (appendix B.6, figure 23).



3. Results

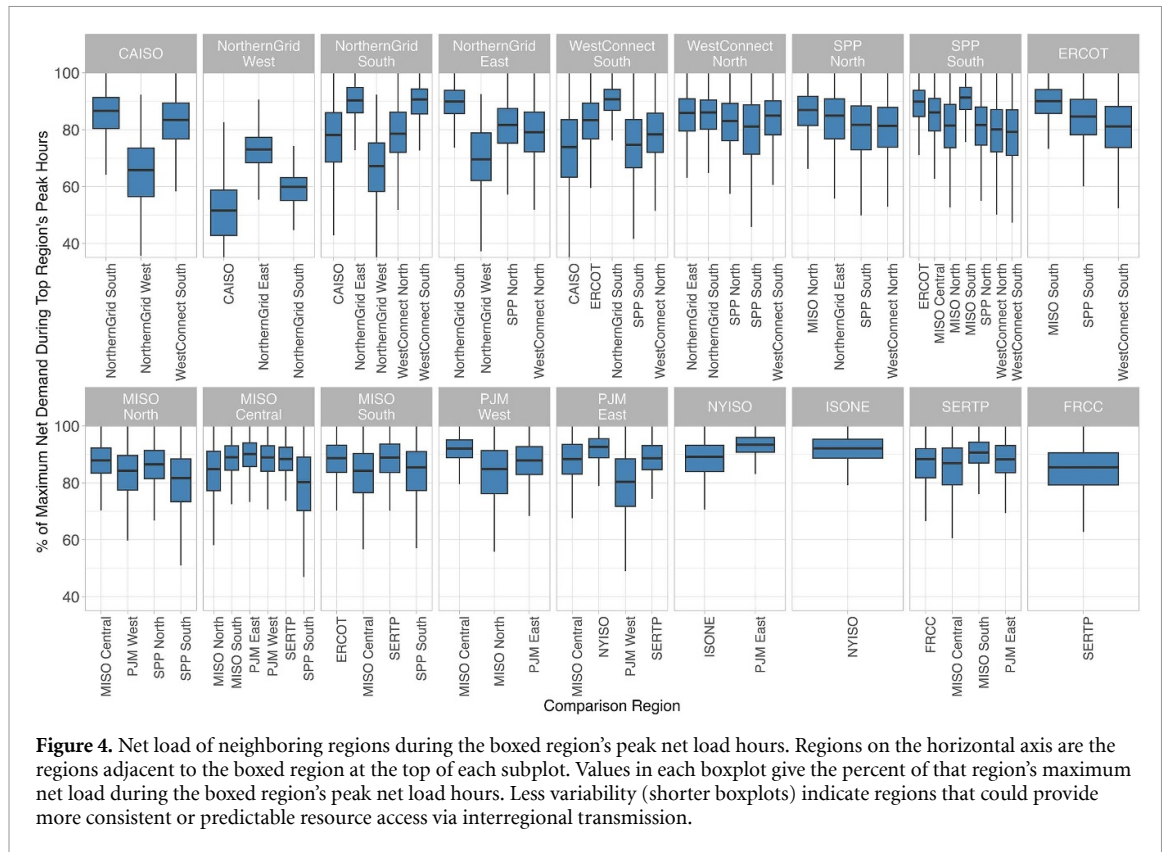
The results section is organized as follows. Section 3.1. analyzes *idealized potential* for RA contributions between neighboring regions. Section 3.2. analyzes *actual recorded flows* across existing infrastructure to answer the question of how effectively existing interregional transmission is utilized to provide RA support.

3.1. Geographic variation in RA risk coincidence

The potential for interregional transmission to serve as an RA asset depends on whether neighboring regions experience peak demand simultaneously or at different times. If two regions consistently peak together, neither can provide reliable support to the other. Conversely, regions with complementary peak timing can potentially share capacity, effectively increasing the collective resource base available to address local stress. Figure 3 shows the percent overlap in the annual top 100 net load hours for adjacent planning subregions. Notably, NorthernGrid West, which includes Oregon and Washington, has the lowest peak period overlap between adjacent regions, with an overlap of just 2% with CAISO and NorthernGrid South (which includes Nevada and Utah) and 6% with NorthernGrid East (which includes Idaho and western Montana and Wyoming). NorthernGrid West is a predominantly winter peaking region, due to both widespread electric heat and mild summers (Davis 2023). Neighboring regions have less electric heating and often have higher air conditioning loads during summers, leading to the typical summer peaking pattern we observe in most other regions.

Other areas of the U.S. have more overlap in peak periods. The central U.S. ranges from about 20% to 60% overlap, with the exception of PJM West and MISO Central's 70% peak hour overlap. The Northeast has the greatest overlap at 71% (between ISONE and NYISO) and 74% (between NYISO and PJM East). This means that three out of every four high-stress hours are shared between PJM East and NYISO. These high overlap rates in the Northeast likely reflect similar weather patterns, comparable seasonal load profiles, and geographic proximity that result in highly synchronized demand peaks.

Beyond these averages, a neighbor's demand distribution offers richer insight into how consistently a neighboring region might be able to provide capacity. If a region has significant variability in its own net load profile during another region's peak hours, it may be a lower quality candidate to provide RA than a region with a less variable, more predictable net load distribution. Figure 4 shows the distribution of the hourly net load data during each region's peak hours to examine how *consistently* a neighboring region might be able to provide capacity during peak periods.



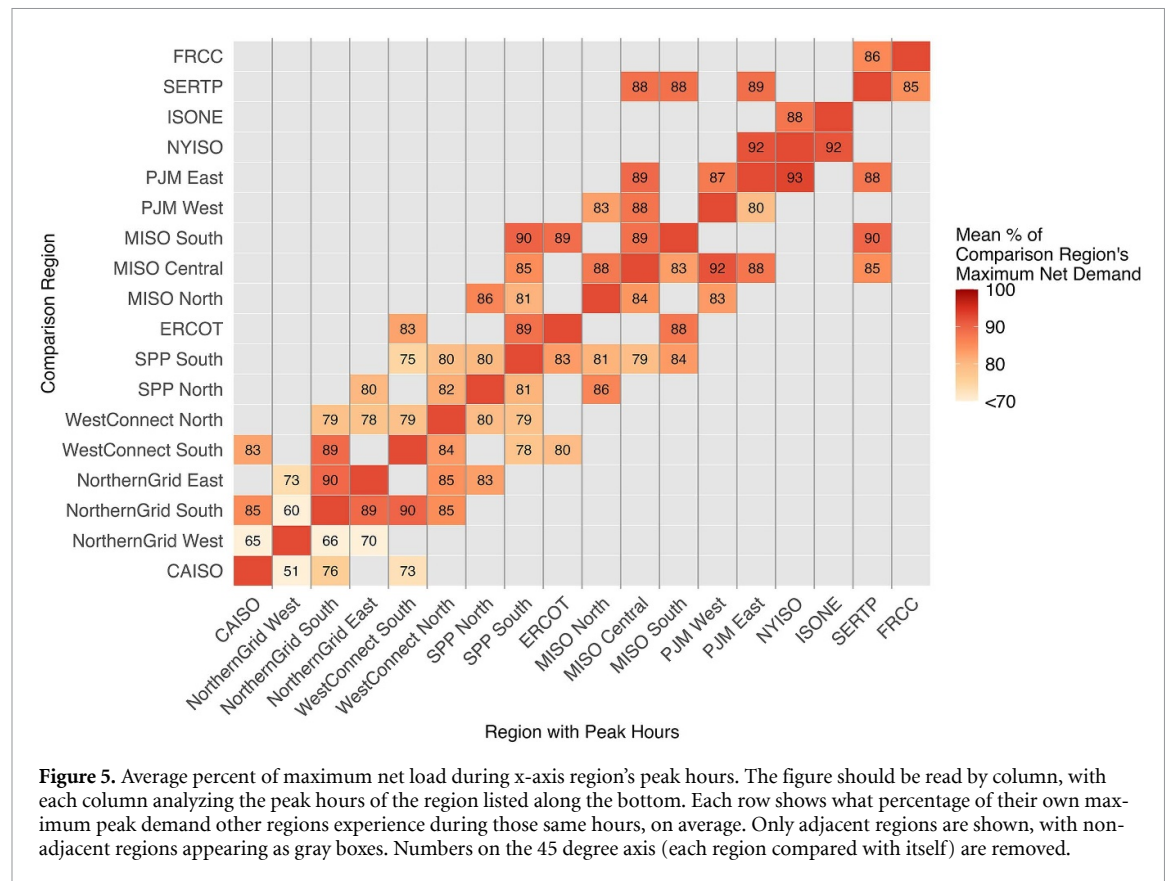
Consider CAISO's panel in figure 4 as an illustrative example. During CAISO's top 100 net load hours, WestConnect South typically operates at 77%–89% of its own maximum net load (median 84%). The height of the box and whiskers show the variability across each region's peak hours. Two neighboring regions might have the same median value, but have different reliability implications: one with a shorter boxplot would be a more predictable capacity resource than one with a wider distribution (with a taller boxplot). From a transmission planning perspective, this variability affects how planners might assess firm capacity contributions: conservative planners might base their assessments on lower percentiles rather than averages to ensure reliability during peak events.

The net load coincidence factor (equation (3)) for each region pair provides further insight into where transmission would be most valuable. The net load coincidence factor (shown in figure 5) shows what percentage of their maximum net demand neighboring regions experience during each region's peak hours. In figure 5, each column represents a region's top 100 h, and the cells show what percentage of their maximum net demand neighboring regions were experiencing during those same hours. Darker colors indicate higher coincidence (regions peaking together), while lighter colors identify complementary patterns favorable for resource sharing. Gray boxes indicate non-adjacent regions and numbers are removed from the 45 degree axis, which compares each region with itself and is thus not a useful metric. See appendix B.1 (figure 14) for a comparison plot with non-adjacent regions included.

Figure 5 confirms and extends the patterns observed in figures 3 and 4. NorthernGrid West shows the strongest potential for bidirectional resource sharing, with neighboring regions typically experiencing only 50%–70% of their own peak demand during NorthernGrid West's stress hours, and vice versa. The Northeast Corridor (PJM East, NYISO, ISONE) shows consistently high coincidence in all directions, with regions typically around 85%–95% of their maximum demand during neighbors' peaks. This mutual stress limits the reliable capacity contribution that transmission can provide in this region.

3.2. Realized RA benefits from interregional transmission

RA benefits from interregional transmission depend on more than non-coincident peak demand: they require that power actually flows toward regions experiencing stress when their neighbors are not similarly constrained. In practice, interregional coordination faces numerous challenges: bilateral contracts may lock in transmission flows regardless of real-time system conditions; differing market designs across regions can create conflicting price signals; technical constraints may limit the direction or magnitude of power flows; physical power flows (on AC ties) are governed by network physics rather than being



independently controllable; security constraints may require flows to be curtailed to maintain reliability in the event of an outage; and operational practices may prioritize other objectives over RA support. We explore whether and to what extent these or other factors prevent transmission from realizing its theoretical RA potential in the following section. We analyze observed power flows to quantify the degree to which actual operations align with patterns of transmission flows that are optimized to solely support RA.

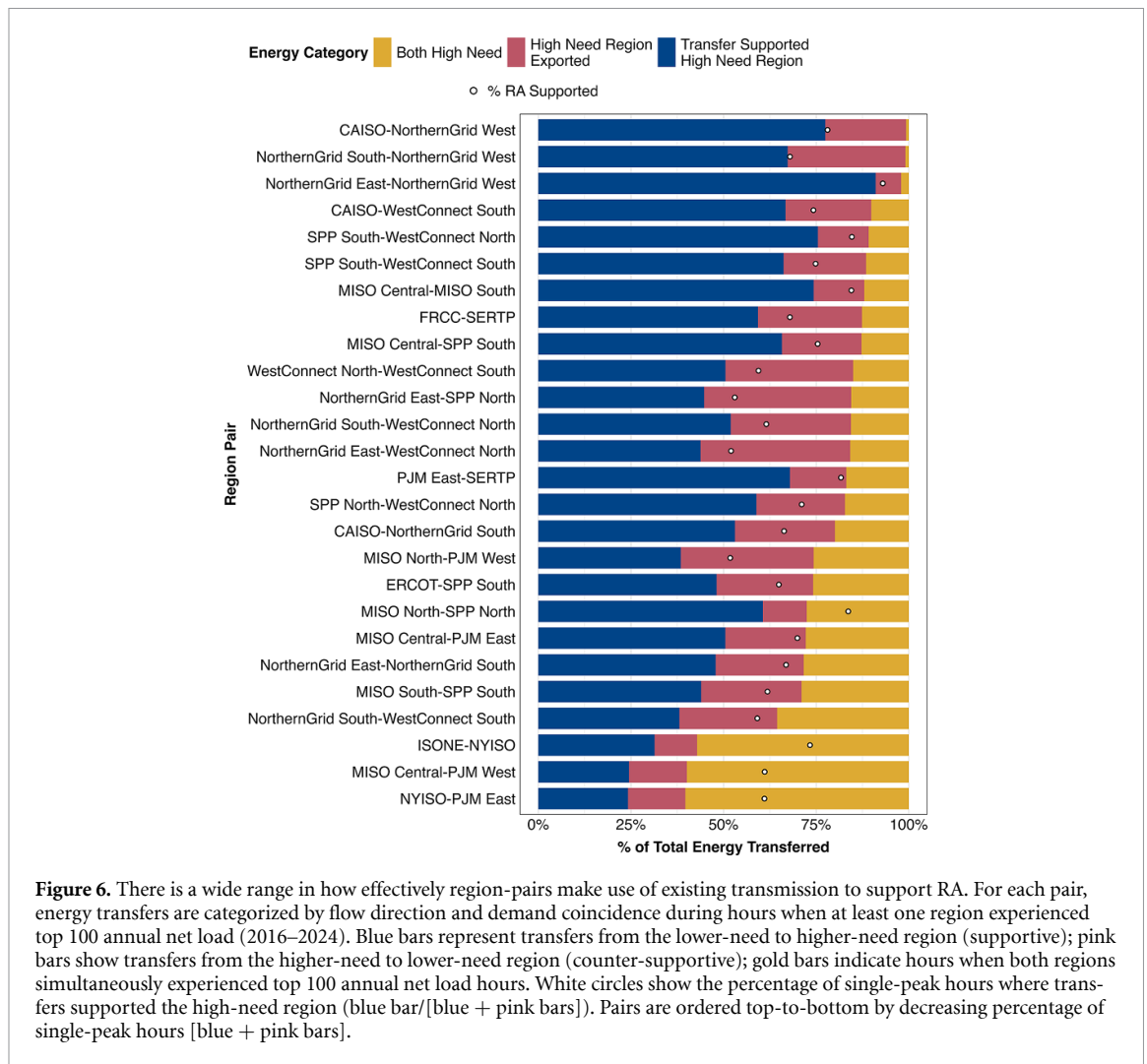
3.2.1. Directional patterns of power flows during peak periods

During periods when one region experiences peak demand and its neighbor does not, transmission that flows toward the stressed region provides RA support. To assess whether this occurs in practice, we examined energy transfers between region pairs during all hours when at least one region experiences its top 100 annual net load hours (up to 200 h per year, depending on the degree of overlap). Figure 6 presents these patterns, categorizing transfers based on whether they supported or opposed the high-need region's RA requirements.

Transfers were classified as: (1) supporting the high-need region (blue), where energy flowed from the lower-need region toward the peaking region; (2) counter-supportive (pink), where the high-need region exported energy despite elevated demand; or (3) mutually high-need (gold), where both regions simultaneously experienced top 100 net load hours, making the direction of 'support' ambiguous. The % RA Supported (white circles), defined in equation (5), indicate the percentage of hours when only one region faced peak demand in the top 100 h and transfers supported the high-need region. Ideally, the % RA Supported would be close to 100%, which would occur if a region pair saw zero counter-supportive hours.

As we saw in the previous section, western region pairs (on the top of the plot) show the highest RA support *potential* (short gold bars). The % RA Supported (white circles) show *how well in practice* interregional transmission was used to support RA during the non-coincident hours (the blue and pink bars). Several regions have >80% of single-peak energy transfers supporting the high-need region, such as NorthernGrid East–NorthernGrid West and SPP South–WestConnect North.

Interestingly, some pairs with moderate or high coincidence factors show strong operational alignment during non-coincident hours. MISO North–SPP North and ISONE–NYISO both have high coincidence (wide gold bars) and show high support rates in non-coincident hours (high white circles), indicating that when peaks do diverge, transmission flows effectively to support the high-need region. This



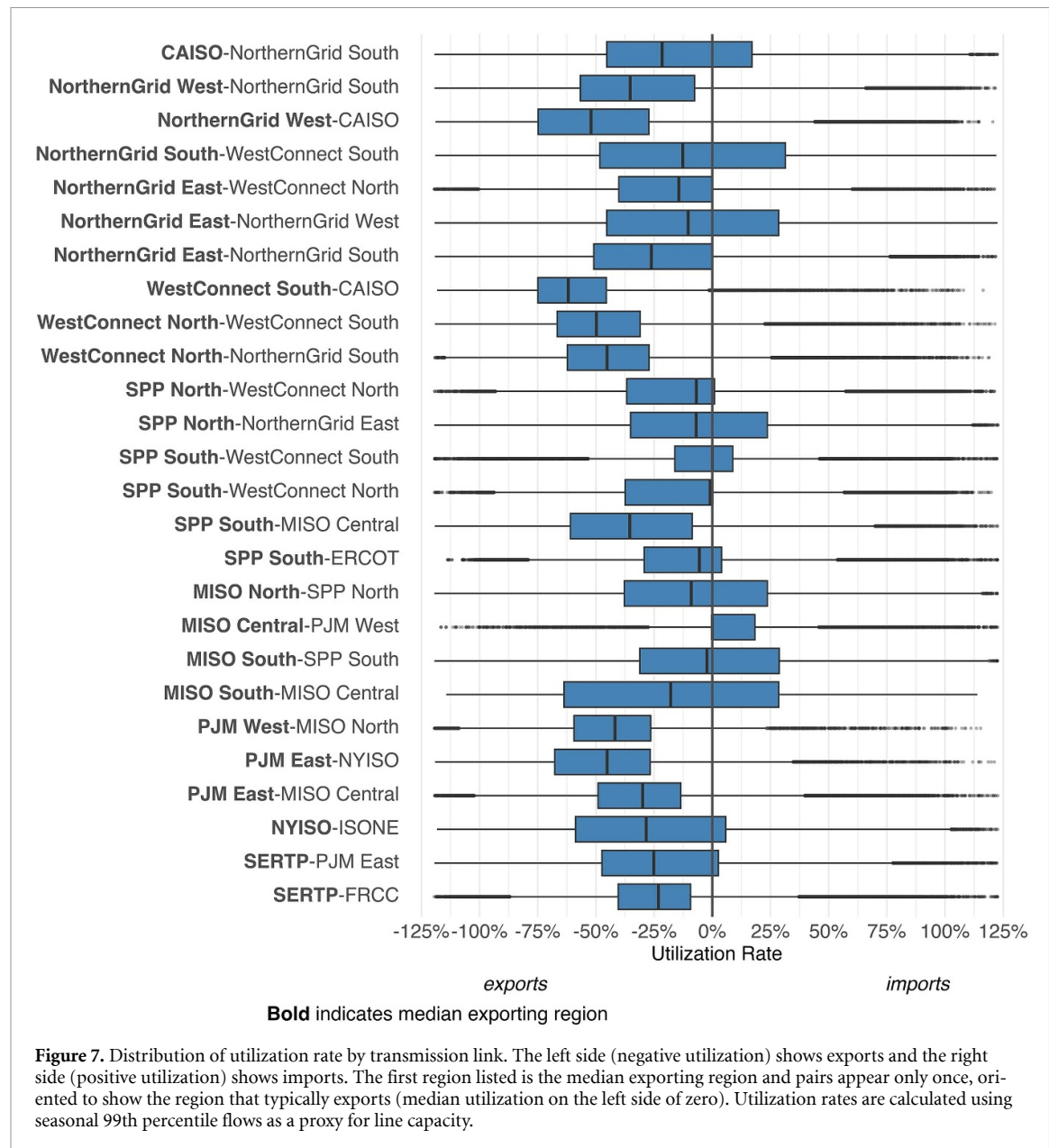
suggests that even regions with significant temporal peak overlap can provide meaningful RA value during the subset of hours when demand patterns diverge.

However, a substantial number of region pairs have % RA Supported near 50%. This raises questions about the possibility for more effective transmission utilization patterns because it means that 50% of the time a region with high need is exporting to a region with lower need. A 50% support rate could indicate either: (1) transmission flows consistently in one direction regardless of relative demand conditions or (2) flows change direction frequently but not in systematic response to peak net load conditions. To investigate this further, we examine the distribution of transmission utilization rates and how they vary between high need and typical periods.

3.2.2. Transmission utilization during peak and non-peak periods

Understanding whether transmission consistently flows in one direction or responds dynamically to changing conditions requires examining utilization patterns across all hours. Figure 7 shows the distribution of hourly transmission utilization rates for each region pair across all hours in the study period, providing insight into whether low support rates stem from unidirectional flows or from bidirectional but unresponsive operations. Pairs appear only once, oriented to show the region that typically exports (median utilization on the left side of zero). Utilization rates are calculated as a percentage of seasonal 99th percentile flows, separately for the import (positive) and export (negative) directions, providing a proxy for transmission capacity usage. If the available transmission capacity was underutilized historically, the true absolute utilization rates may be lower than indicated by this proxy.

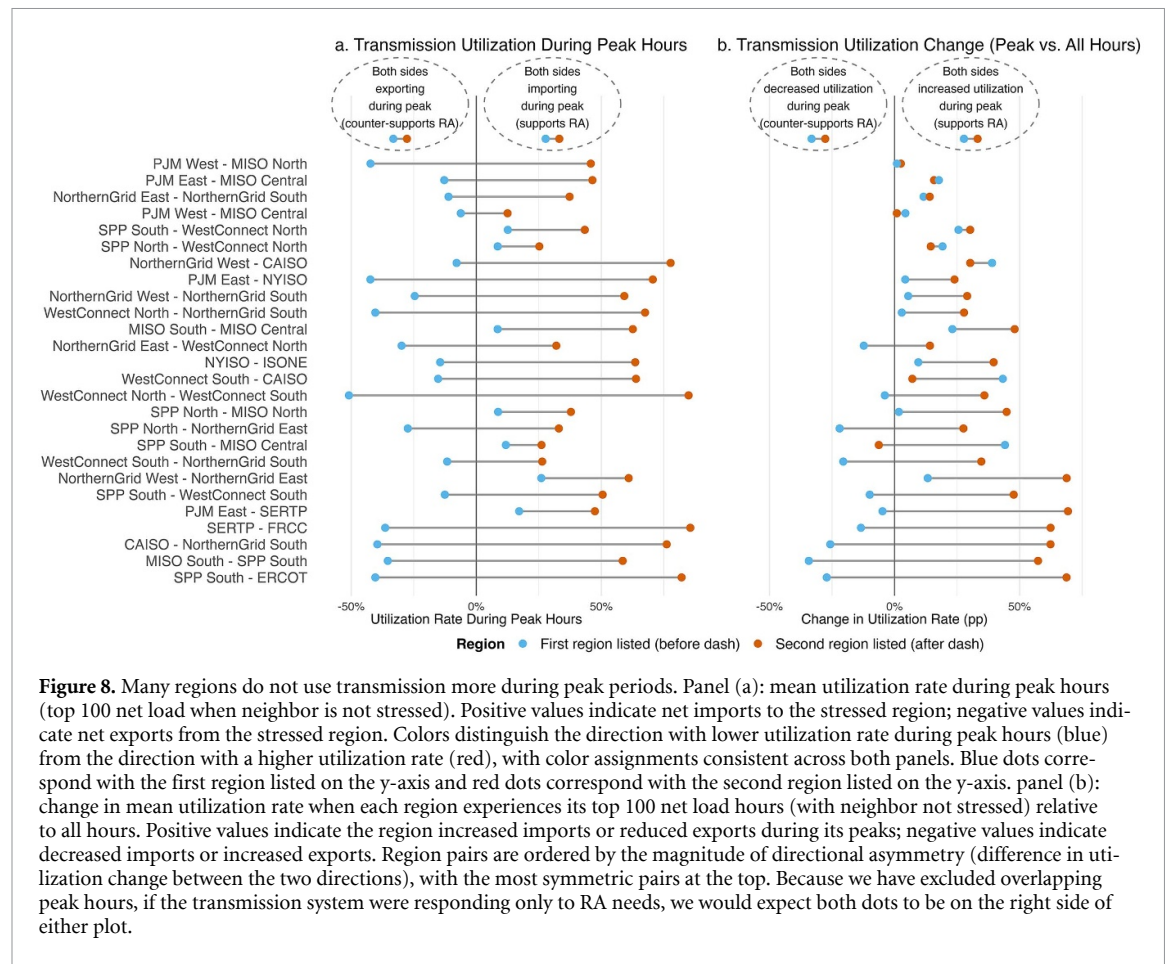
The distributions show variation in how region pairs utilize their interregional transmission. Many region pairs show relatively low median utilization. Thirteen region pairs have median utilization rates below $\pm 25\%$, and several (e.g. MISO Central–PJM West and SPP South–WestConnect South) have narrow distributions centered around zero, suggesting their interregional transmission is lightly utilized in either direction during most hours.



The width of the distributions also varies widely. Pairs like NorthernGrid South-WestConnect South and MISO South-MISO Central show wide distributions extending to high utilization in both directions, indicating bidirectional utilization. However, only MISO South-MISO Central has a high % RA Supported from figure 6, indicating the bidirectional utilization between NorthernGrid South and WestConnect South may be responding to factors other than RA need. In contrast, pairs like WestConnect South-CAISO or PJM West-MISO North show narrower distributions away from 0, suggesting unidirectional flow patterns (e.g. one region mostly exports).

While figure 7 shows overall utilization patterns, it does not reveal whether transmission responds to RA needs specifically. If transmission effectively supports RA, we should observe different utilization patterns during peak periods: stressed regions should increase imports (or reduce exports) when their neighbors are not similarly constrained. To test this, we compare mean utilization rates during all hours against utilization during each region's peak demand hours—specifically, hours when a region experienced its top 100 annual net load while its neighbor did not. In an unconstrained system that is responding to RA, transmission during these high-need hours should flow toward (or at a minimum not away from) the stressed region.

The results show heterogeneity in operational responsiveness across region pairs (see appendix B.4, figure 18 for corresponding figure). Several pairs demonstrate strong alignment between need and utilization; for example NorthernGrid East imports substantially more from NorthernGrid West during its



peak hours than it does on average. Other pairs, however, exhibit counter-supportive utilization, whereby the stressed region increases net exports during high-demand hours. When NYISO experiences peak demand and ISONE does not, for instance, NYISO exports more to ISONE despite its own elevated stress.

Notably, a given transmission interface is often more responsive to one side's need than the other's. In the case of ERCOT and SPP South, ERCOT benefits from increased imports from SPP South during ERCOT's peak hours, while SPP South increases exports to ERCOT during SPP South's own peak hours. This asymmetry in responsiveness to RA need is explored further in the following section.

3.2.3. Asymmetry in transmission's RA benefits

One region per pair in a link often benefits more from interregional transmission during peak periods than the opposite region in the pair. Figure 8 examines whether transmission provides symmetric RA benefits to interconnected regions. Panel a shows absolute utilization rates during peak hours when the neighbor is not stressed, providing context for interpreting the changes shown in panel b. For example, looking at the first row in panel a, we see that PJM West consistently exports to MISO North at 42% of line capacity during its own peak hours while MISO North is not also peaking. On the other hand, MISO North consistently imports from PJM West at 46% of line capacity during its own peak hours while PJM West is not also peaking. Panel b shows the change in the utilization rate when each region experiences peak demand (with the neighbor not stressed) relative to all hours. A dot on the right side of panel b indicates that a region increases imports from the neighboring region when it is stressed and its neighbor is not; a dot on the left side indicates that it exports more when the region is stressed and its neighbor is not. Pairs are ordered vertically by their 'spread,' the absolute difference between the two directional changes, and as shown in Panel b, with symmetric pairs (small spread) at the top and asymmetric pairs (large spread) at the bottom.

Figure 8 shows that the operational benefits of transmission for RA are often highly asymmetric between connected regions. In the top of panel b, there are a few regions with short, positive values for both regions. If transmission were highly responsive to demand, we would see both dots over to the far-right side of the panel—both regions would increase imports (or decrease exports) from (or to)

their neighbor when they are stressed and their neighbor is not. Instead, we see many regions with large spreads, indicating that one region in a pair receives responsive transmission changes during its peak hours while the other experiences unresponsive or counter-supportive changes in flow direction during its own peaks.

Consider the bottom pairs in panel b with the largest spreads. Transmission between SPP South and ERCOT shows a dramatic asymmetry: ERCOT increases utilization with SPP South by approximately 60 percentage points during its peak hours (importing substantially more from SPP South), while SPP South decreases utilization with ERCOT by over 25 percentage points during its peak hours (exporting more to ERCOT when SPP South itself is stressed and ERCOT is not). This pattern repeats across most region pairs in our sample.

Another interesting case is PJM West and MISO North, at the top of figure 8. Utilization rates between these regions change very little during each region's peak periods, giving them the least amount of 'spread' in panel b. In addition, panel a shows that MISO North has a high positive utilization rate from PJM West during its peak hours, while PJM West has a high negative utilization (i.e. exports to MISO North) during its own peak hours. This pattern shows a lack of responsiveness to relative need: PJM West exports to MISO North regardless of whether PJM West is experiencing high demand.

4. Conclusion and future work

This study provides an empirical assessment of how interregional transmission functions as an RA asset across the U.S. Using nine years of historical data on net load patterns and power flows (2016–2024), we evaluated both the theoretical potential for transmission to support RA, based on the overlap in peak demand periods, and the extent to which existing transmission infrastructure realizes this potential during actual system stress events. Our analysis reveals several findings with implications for transmission planning and operations.

We find substantial geographic variation in the potential for interregional transmission to support RA. Regions with complementary peak timing, such as many region pairs in the West, have strong theoretical potential for mutual RA support, with peak-hour overlaps as low as 2%–6%. In contrast, region pairs in the Northeast show peak hour overlaps of 71%–74%, possibly limiting the opportunities for bidirectional RA support, regardless of transmission capacity. Most region pairs across the central U.S. fall between these extremes, with 20%–60% peak period overlap, suggesting moderate potential for interregional RA contributions during the subset of hours when peak demands diverge.

Actual transmission utilization patterns during peak periods often fail to realize their theoretical potential. Many region pairs show transmission flows that are largely unresponsive to relative demand conditions: approximately half of the examined pairs support the high-need region in only 50%–60% of hours when one region peaks and the other does not, barely better than random. Furthermore, several pairs exhibit systematic counter-supportive patterns, with stressed regions reducing imports or increasing exports to neighbors even when those neighbors are not experiencing elevated demand. These patterns suggest that factors beyond real-time system conditions, such as bilateral contracts, market structure differences, constraints due to network physics, security constraints, or other technical constraints may dominate transmission utilization decisions, preventing transmission from realizing its full RA potential.

Finally, we document significant asymmetries in the RA benefit that interregional transmission provides to different regions. While transmission could ideally provide reciprocal support, with each region pair in a link importing during its own peak demand periods (when its neighbor is not similarly peaking) and exporting during its neighbor's peaks, we find that many interconnections systematically provide support for one region more than the other.

These findings have implications for the active area of U.S. policymaking related to transmission planning. Policymakers increasingly recognize transmission infrastructure as a shared reliability resource, in addition to a means of facilitating energy trade. Recent federal initiatives have sought to promote integrated interregional planning and establish minimum transfer capability requirements between regions. Our analysis suggests that building additional transmission capacity alone may not fully realize the anticipated RA benefits. Equally important are operational reforms that ensure existing and future transmission infrastructure responds effectively to system stress between interconnected regions, when physical operating constraints allow.

Our finding that peak coincidence varies significantly across the country indicates that not all interregional transmission provides equal RA value. Maximal RA benefits from transmission may be found between regions with complementary peak timing, where the RA value proposition is strongest. Policies

that mandate a single minimum interregional transfer capability relative to peak load represent a one-size-fits-all approach that may be inefficient between some regions from an RA perspective. While many ISO planning models can distinguish differing peak timing across neighboring regions, transmission infrastructure often receives no capacity credit for RA unless paired with firm generator supply contracts or deliverability rights (Pfeifenberger *et al* 2013, Carvallo *et al* 2023); explicitly crediting transmission itself with RA value based on geographic and weather diversity could better capture the reliability benefits it provides.

Perhaps more importantly, our findings also show that significant existing transmission capacity is not utilized to support RA during periods of greatest RA need. Several others have noted that inefficient use of interregional transmission leads to significant economic losses (Pfeifenberger *et al* 2023, Potomac Economics 2023a, 2023b, 2023c, Safavi *et al* 2025); our work runs in parallel to these findings, indicating that counter-supportive flows during periods of high RA need can reduce the potential RA value of interregional transmission. Simply building more transmission will not solve this problem. Prior work has proposed options that policymakers and system operators could pursue to improve market outcomes. Simeone and Rose (2024) propose establishing interregional RA sharing frameworks and Stencik and Schwartz (2025) propose conducting wide-area RA assessments to harmonize RA planning between regions. Brooks *et al* (2025) propose creating capacity markets that explicitly value and compensate cross-border transmission capacity contributions, which could provide economic incentives to align operational decisions with reliability needs. Similarly, improving intertie optimization to ensure power flows effectively respond to price signals, discussed in Pfeifenberger *et al* (2023), would likely improve RA outcomes as well, since high prices are likely correlated with RA events.

Several limitations of our analysis suggest directions for future research. Our regional aggregation approach provides a broad overview of interregional dynamics but obscures potentially important variations at finer geographic scales and between individual transmission lines. In addition, our study documents these patterns without identifying the underlying drivers. Future work could therefore investigate the causal mechanisms behind the observed phenomena to support more targeted interventions. For example, it could examine the characteristics of specific transmission corridors that perform better or worse in supporting RA, including comparisons between DC and AC interties or assessments of how ownership structures and operational agreements affect utilization patterns.

Additionally, while net load provides a reasonable proxy for system stress, it represents an imperfect indicator of actual RA risk. We do not account for transmission constraints within regions, operating reserve requirements, outages, or dynamic stability limits that may prevent flows from responding to RA needs even when economically or operationally desirable. A future analysis could evaluate periods of low energy margin (when available generation is small relative to demand) rather than net load alone. Net load captures periods of high demand net of variable renewable output, which tend to occur in summer (shown in appendix B.3), but it does not reflect reduction in the available supply that characterize many winter reliability events. As a result, our metric is biased toward summer risk periods and may understate winter risk, when reliability shortfalls are driven by generation unavailability rather than demand.

The nine-year study period, while capturing diverse empirical operating conditions including several extreme weather events, represents a relatively short timeframe for RA analysis. Some probabilistic RA assessments examine modeled multi-decade periods to capture rare but consequential events. Future work should extend this analysis across longer timeframes to assess whether historical patterns of peak coincidence and transmission utilization remain valid planning assumptions. Finally, our analysis takes transmission capacity and operational patterns as given, documenting what has occurred rather than what could occur under different institutional arrangements. Modeling studies that simulate how transmission flows might respond under alternative market designs, operating procedures, or regulatory frameworks would complement our empirical findings and help identify the most promising pathways to realize transmission's full RA potential.

Acknowledgment

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Data availability statement

The data cannot be made publicly available upon publication because they are owned by a third party and the terms of use prevent public distribution. The data that support the findings of this study are available upon reasonable request from the authors.

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Appendix A. Supplementary information

A.1. Data sources and processing

A.1.1. Load data aggregation

We proceed with the following process in order to gather load data for the continental U.S., clean outliers, and split it into the requisite planning subregions. See figure 1 for a map of regions used in this analysis. These regions are derived from NREL's ReEDS planning subregions. The ReEDS *GitHub* site provides a mapping between 134 zones, 31 BAs, and 18 planning subregions¹.

We use load data that comes primarily at the BA- or ISO-level, from Form EIA-930. For most BAs and ISOs, we can use the mapping from table 1 to assign it to one of the 18 planning subregions. However, ReEDS zones do not always map perfectly to BA boundaries. There are three BAs that we must split into multiple planning subregions: Avista Corp., PacifiCorp East, and PacifiCorp West, described further below. Additionally, we gather data at the ISO load-zone level from the three ISO regions that are split into multiple planning subregions (SPP to SPP North and SPP South; MISO to MISO North, MISO Central, and MISO South; and PJM to PJM East and PJM West) to enable us to split the data by assigning the zonal data to planning subregions. For any BA that is fully surrounded by an ISO, we group these with the surrounding ISO (e.g., LADWP is grouped with CAISO).

A.1.1.1. Avista, PacifiCorp East, and PacifiCorp West

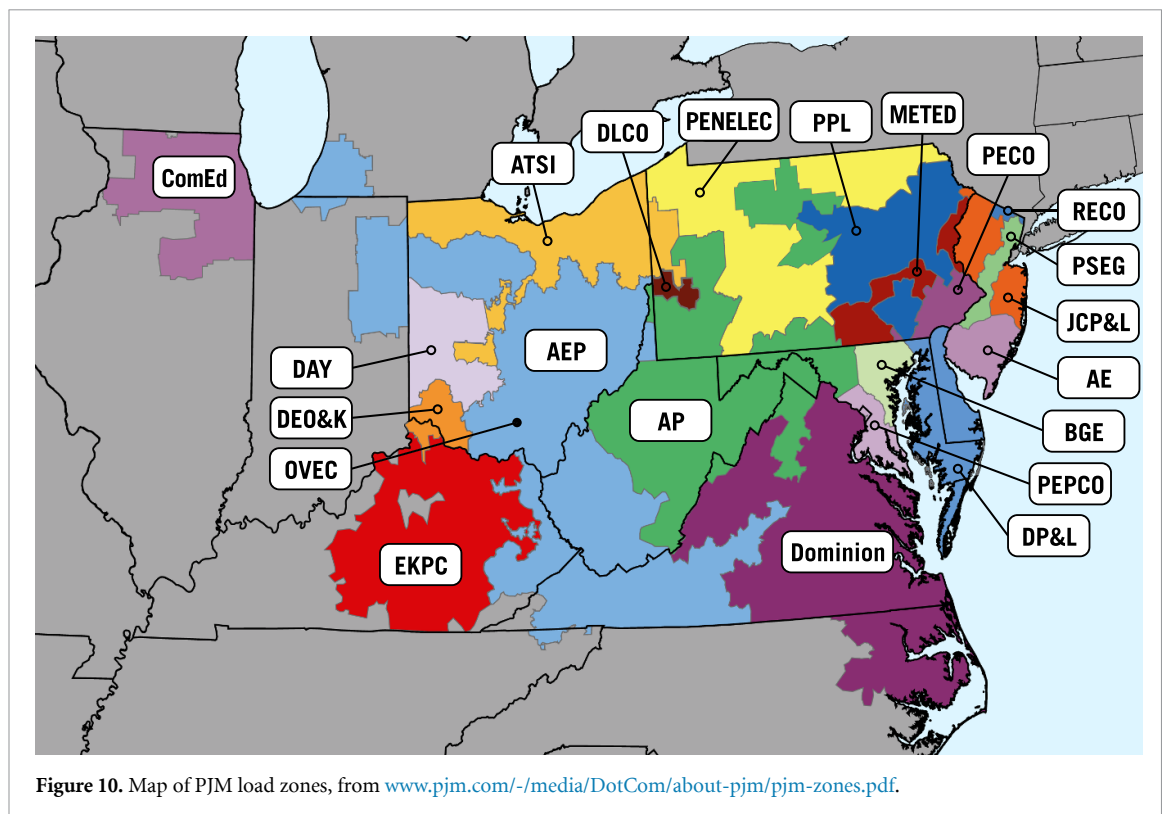
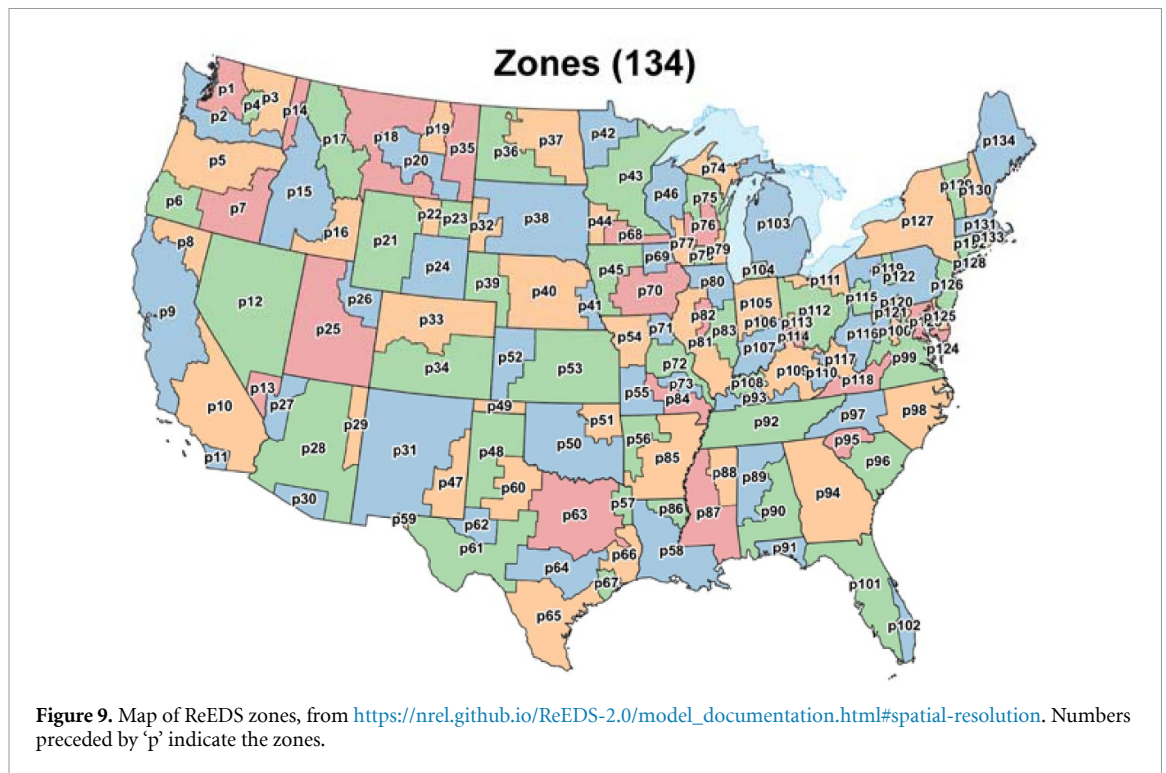
For Avista, PacifiCorp East, and PacifiCorp West, we split the load data proportionally into planning subregions using synthetic load data available publicly on the ReEDS *GitHub* repository². These data include ReEDS zone-level synthetic load for 2013 through 2022, using weather years 2007–2013. Because we know the zone values for each BA, we are able to proportionally divide the load between the BA and the planning subregion (See Footnote 1). For example, we know that Avista belongs to zones p3 and p14; p3 belongs to NorthernGrid West and p14 belongs to NorthernGrid East, so we identify the proportion of Avista's synthetic load belonging to each of these two regions, then split the empirical load according to these weights. Figure 9 shows a map of zones used in ReEDS.

¹ See crosswalk here: <https://github.com/NREL/ReEDS-2.0/blob/main/inputs/hierarchy.csv>. Columns *ba* and *transgrp* define the zones and planning subregions. Zone shapefiles can be found here: https://github.com/NREL/ReEDS-2.0/tree/main/inputs/shapefiles/US_PCA.

² NREL ReEDS-2.0. See 'EER_Baseline_AEO2022_load_hourly.h5': <https://github.com/NREL/ReEDS-2.0/tree/main/inputs/load>

Table 1. Balancing authority to region crosswalk. Where multiple planning regions are listed, the BA is split proportionally between the regions as described below. Table derived from ReEDS: <https://github.com/NREL/ReEDS-2.0/blob/main/inputs/hierarchy.csv>.

Balancing authority name	EIA BA Code	Planning subregion
Alcoa Power Generating, Inc.—Yadkin Division	YAD	SERTP
Arizona Public Service Company	AZPS	WestConnect South
Associated Electric Cooperative, Inc.	AECI	SERTP
Avista Corporation	AVA	NorthernGrid West and NorthernGrid East
Balancing Authority of Northern California	BANC	CAISO
Bonneville Power Administration	BPAT	NorthernGrid West
California Independent System Operator	CISO	CAISO
City of Homestead	HST	FRCC
City of Tacoma, Department of Public Utilities, Light Division	TPWR	NorthernGrid West
City of Tallahassee	TAL	FRCC
Duke Energy Carolinas	DUK	SERTP
Duke Energy Florida, Inc.	FPC	FRCC
Duke Energy Progress East	CPLE	SERTP
Duke Energy Progress West	CPLW	SERTP
El Paso Electric Company	EPE	WestConnect South
Electric Energy, Inc.	EEI	SERTP
Electric Reliability Council of Texas, Inc.	ERCO	ERCOT
Florida Municipal Power Pool	FMPP	FRCC
Florida Power & Light Co.	FPL	FRCC
Gainesville Regional Utilities	GVL	FRCC
Idaho Power Company	IPCO	NorthernGrid East
Imperial Irrigation District	IID	CAISO
ISO New England	ISNE	ISONE
JEA	JEA	FRCC
Los Angeles Department of Water and Power	LDWP	CAISO
Louisville Gas and Electric Company and Kentucky Utilities Company	LGEE	SERTP
Midcontinent Independent System Operator, Inc.	MISO	MISO North, MISO Central, and MISO South
Nevada Power Company	NEVP	NorthernGrid South
Utilities Commission of New Smyrna Beach	NSB	FRCC
New York Independent System Operator	NYIS	NYISO
NorthWestern Corporation	NWMT	NorthernGrid East
Ohio Valley Electric Corporation	OVEC	PJM East
PacifiCorp East	PACE	NorthernGrid South and NorthernGrid East
PacifiCorp West	PACW	NorthernGrid West and NorthernGrid South
PJM Interconnection, LLC	PJM	PJM East and PJM West
Portland General Electric Company	PGE	NorthernGrid West
PowerSouth Energy Cooperative	AEC	SERTP
Public Service Company of Colorado	PSCO	WestConnect North
Public Service Company of New Mexico	PNM	WestConnect South
Public Utility District No. 1 of Chelan County	CHPD	NorthernGrid West
Public Utility District No. 2 of Grant County, Washington	GCPD	NorthernGrid West
PUD No. 1 of Douglas County	DOPD	NorthernGrid West
Puget Sound Energy, Inc.	PSEI	NorthernGrid West
Salt River Project Agricultural Improvement and Power District	SRP	WestConnect South
Seattle City Light	SCL	NorthernGrid West
Seminole Electric Cooperative	SEC	FRCC
Dominion Energy South Carolina, Inc.	SCEG	SERTP
South Carolina Public Service Authority	SC	SERTP
Southeastern Power Administration	SEPA	SERTP
Southern Company Services, Inc.—Trans	SOCO	SERTP
Southwest Power Pool	SWPP	SPP North and SPP South
Southwestern Power Administration	SPA	MISO South
Tampa Electric Company	TEC	FRCC
Tennessee Valley Authority	TVA	SERTP
Tucson Electric Power	TEPC	WestConnect South
Turlock Irrigation District	TIDC	CAISO
Western Area Power Administration—Desert Southwest Region	WALC	WestConnect South
Western Area Power Administration—Rocky Mountain Region	WACM	WestConnect North
Western Area Power Administration—Upper Great Plains West	WAUW	NorthernGrid East



A.1.1.2. PJM

In PJM, MISO, and SPP, we use zonal load published by the ISOs to split into the corresponding planning regions. In PJM, we assign COMED to PJM West and all other zones to PJM East. Figure 10 shows a map of PJM load zones and table 2 provides a crosswalk of PJM zones to BAs and planning subregions used in this analysis.

Table 2. Mapping of PJM load zones to EIA balancing authority subregions and planning subregions.

PJM zone	EIA BA name	Planning region
AEP	American Electric Power	PJM East
AP	Allegheny Power	PJM East
ATSI	American Transmission Systems, Inc.	PJM East
COMED	Commonwealth Edison	PJM West
DAY	Dayton Power & Light	PJM East
DEOK	Duke Energy Ohio/Kentucky	PJM East
DOM	Dominion Virginia Power	PJM East
DUQ	Duquesne Lighting Company	PJM East
EKPC	East Kentucky Power Cooperative	PJM East
PJM EAST	Atlantic Electric, Baltimore Gas & Electric, Delmarva Power & Light, Jersey Central Power & Light, Ohio Valley Electric Corp., Metropolitan Edison, PECO Energy, Potomac Electric Power, Pennsylvania Power & Light, Pennsylvania Electric, Public Service Electric & Gas, Rockland Electric (East)	PJM East

Table 3. Mapping of SPP load zones to EIA BA subregions and planning subregions.

SPP load zone	EIA BA subregion name	Planning subregion
AEPW_CSWS	AEPW American Electric Power West	SPP South
EDE_EDE	Empire District Electric Company	SPP South
GRDA_GRDA	Grand River Dam Authority	SPP South
INDN_INDN	Independence Power & Light	SPP South
KACY_KACY	Kansas City Board of Public Utilities	SPP South
KCPL_KCPL	Kansas City Power & Light	SPP South
LES_LES	Lincoln Electric System	SPP North
MPS_MPS	KCP&L Greater Missouri Operations	SPP South
NPPD_NPPD	Nebraska Public Power District	SPP North
OKGE_OKGE	Oklahoma Gas and Electric Co.	SPP South
OPPD_OPPD	Omaha Public Power District	SPP North
SECI_SECI	Sunflower Electric	SPP South
SPRM_SPRM	City of Springfield	SPP South
SPS_SPS	Southwestern Public Service Company	SPP South
WAUE_UGPM	Western Area Power Upper Great Plains East	SPP North
WFEC_WFEC	Western Farmers Electric Cooperative	SPP South
WR_WR	Westar Energy	SPP South

A.1.1.3. SPP

In SPP, we map all zones north of Kansas and Missouri to SPP North and those south of Nebraska to SPP South. An interactive map of SPP load zones can be found at ([EIA n.d.](#)). We do not include the Western Area Power Administration (WAPA)—Rocky Mountain Region or WAPA—Upper Great Plains West Region in SPP. These regions joined SPP in 2021, but are included with WestConnect North and NorthernGrid East, respectively, for the entirety of this analysis. Table 3 provides a crosswalk of SPP load zones to EIA BA and planning subregions.

A.1.1.4. MISO

MISO load zones do not neatly divide into MISO North, Central, and South. Some of MISO's zonal load data is reported jointly, with zones 2 and 7 reported together, zones 3 and 5 reported together, and zones 8, 9, and 10 reported together. We assign zones 1, 2, and 3 to MISO North; zones 4, 5, 6, and 7 to MISO Central; and zones 8, 9, and 10 to MISO South (see figure 11 for a map of these zones). In order to split up the data from zones 2 and 7 and zones 3 and 5, we again rely on a proportional split of ReEDS zones, similar to what we did for Avista, PacifiCorp East, and PacifiCorp West. MISO's zone 7 corresponds with ReEDS zone p103; load zone 2 corresponds with ReEDS zones p74, p75, p76, p78, and p79. Thus, we can assign proportional weights to divide MISO zones 2 and 7 proportionally. This process is detailed in table 4.

A.1.2. Load data cleaning

To clean the load data, we use a peer-reviewed screening and imputation process that screens for anomalous values and imputes them using the Multiple Imputations by Chained Equations (MICE) framework



Figure 11. Map of MISO Local Resource Zones, from www.misostates.org/images/stories/meetings/Cost_Allocation_Principles_Committee/2021/Website_Presentations.pdf.

Table 4. Process to split and aggregate MISO's local resource zones into planning subregions.

MISO NORTH

- Step 1. Calculate MISO North as local resource zones (LRZ) 1, 2, 3.
LRZ2_7 are joined so need to split off 2 from 7; LRZ3_5 are joined so need to split off 3 from 5.
- Step 2. Can calculate LRZ_3 as load from MIDCONTINENT NORTH zone minus load from LRZ1³.
- Step 3. LRZ2 = LRZ2_7 - LRZ7; LRZ7 calculated for MISO Central below.
- Step 4. MISO North = LRZ1 + LRZ2 + LRZ3.

MISO CENTRAL

- Step 1. Calculate MISO Central as local resource zones (LRZ) 4, 5, 6, 7.
LRZ2_7 are joined so need to split off 7 from 2; LRZ3_5 are joined so need to split off 5 from 3.
- Step 2. LRZ5 = LRZ3_5 - LRZ3; LRZ3 calculated for MISO North above.
- Step 3. Get data: 1) MISO local resource zones and 2) NREL ReEDS load by zone.
- Step 4. Split LRZ2_7 proportionally by ReEDS zone as follows (note: ReEDS zone p103 is the same as LRZ7):

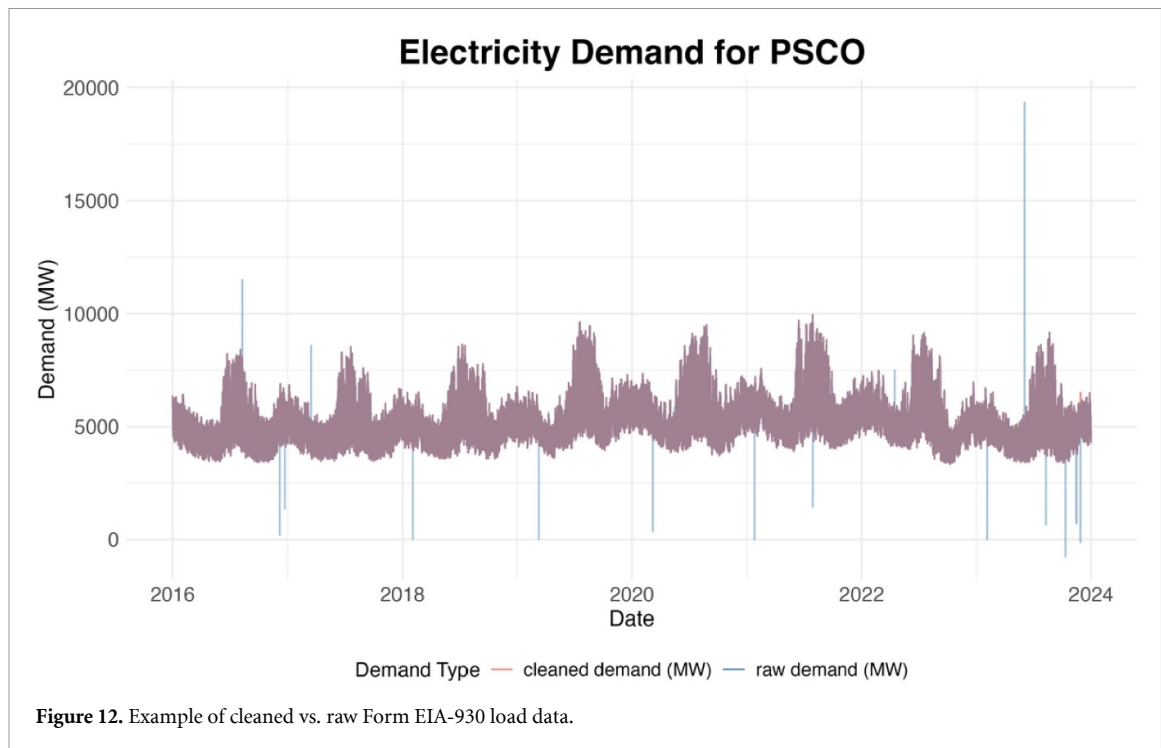
$$LRZ7 = LRZ2_7 \times \frac{p103}{p103 + p74 + p75 + p76 + p78 + p79}$$
- Step 5. MISO Central = LRZ4 + LRZ5 + LRZ6 + LRZ7

MISO SOUTH

- Step 1. Calculate MISO South as LRZ8 + LRZ9 + LRZ10.

(Ruggles *et al* 2020). The screening process identifies values that are very high or low, missing, negative, excessively repeated, or otherwise anomalous. The MICE framework then imputes hourly demand for these regions. See figure 12 for an example of the Public Service Company of Colorado's cleaned demand with its original demand.

³ MIDCONTINENT NORTH is another reported load zone from MISO that roughly encompasses local resource zones 1 and 3.



A.1.3. Wind and solar modeling

We rely on modeled wind and solar data for two reasons: (1) prior to July, 2018, non-ISO BA regions were not required to report source-level generation data to Form EIA-930. Thus, we use modeled wind and solar generation data in these regions from January, 2016, to July, 2018. (2) For the three ISOs that encompass multiple subregions (SPP, PJM, and MISO) and three BAs that span multiple subregions (Avista, PacifiCorp East, and PacifiCorp West), we split their empirical generation data into subregions using proportional allocation from the modeled data. Using modeled generation data at the planning subregion level, we assign hourly weights based on the proportion of generation from each resource (wind or solar) going to each subregion. These derived weights allow us to disaggregate the empirical ISO-level generation data into our defined subregions. For example, an hour of modeled wind data in MISO might be assigned weights of (0.3, 0.3, 0.4) representing the proportion of modeled wind generation from MISO North, Central, and South, respectively. We then use these weights to split the empirical generation data into the desired regions.

The primary modeled wind generation is estimated using meteorological data from NOAA's HRRR and a power curve configured to the characteristics of each plant. We apply a bias correction method to the HRRR-based wind or solar generation after making curtailment adjustments, except for the plants in ERCOT, which provide plant-level recorded generation at a high temporal resolution. Bias correction is an iterative two-step process that linearly adjusts the model estimates using scaling factors. First, the scaling factors are inferred by matching each plant's annual total modeled generation to its expected annual output. The expected annual output is estimated from the modeled annual output, adjusted for performance decline due to aging (Hamilton *et al* 2020) and curtailment. In the second step, we match the sum of hourly modeled generation across all plants within each ISO or BA to the corresponding hourly total of reported wind generation from each ISO or BA. Before performing this matching, we first adjust the reported hourly profiles to align with the updated modeled generation from Step 1 (i.e. the first update output) at the monthly scale. This adjustment ensures that the ISO/BA annual total matches the expected annual output from Step 1 while preserving the original hourly shape of the profile. The iteration continues until the updated (i.e. scaled) model generation matches both the expected annual output and the ISO/BA-level reported generation, with minimal change in root mean squared error (typically around 5 iterations). This same bias correction method is applied to modeled solar generation, which is estimated using HRRR or NSRDB meteorological data.

The bias-corrected wind generation has been implemented for a subset of all wind plants. Where bias-corrected generation is unavailable, we use the raw HRRR-based generation from the PLUSWIND database (years 2018–2021) (Millstein *et al* 2023) or the dataset used for value analysis in the Land-Based

Wind Market Report (LBWMR) (Wiser *et al* 2024b). Although HRRR has shown better hourly correlation with recorded generation compared to ERA5 (Millstein *et al* 2023), the raw modeled wind generation from PLUSWIND or LBWMR is only available from 2018. Therefore, for years prior to 2018, we used wind generation estimated from ERA5, the fifth-generation atmospheric reanalysis of the ECMWF (European Centre for Medium-Range Weather Forecasts). We also used ERA5-based generation for plants where HRRR-based generation was not available in our database. Further details on wind generation using HRRR and ERA5 can be found in (Millstein *et al* 2023).

Similarly, the bias-corrected solar generation has been implemented for a subset of all plants. Where bias-corrected generation is unavailable, we use the raw NSRDB- or HRRR-based modeled generation from NREL's System Advisor Model (System Advisor Model Version 2024.12.12 2024).

A.1.4. Transmission path assignments

To match transmission paths to planning subregions, we rely on a variety of sources, including the ReEDS BA to planning subregion crosswalk, transmission-related reports released by the ISOs, maps of high-voltage transmission lines, and geography (MISO 2023, Monitoring Analytics 2024, U.S. Electric Power Transmission Lines (Archive) 2024, Southwest Power Pool 2025, Blackwater n.d.).

Using the assigned regions, we then evaluated the quality of data from each reporting region (from the seven ISOs and the EIA) by examining data completeness, outliers, and how well two regions reporting the same data matched one another. From this, we selected a final set of transmission paths to use, where we selected one reporting region per link, and inverted the data as needed to represent both imports and exports from both sides of the link. Table 5 shows all transmission paths used, with their assigned planning subregions, and the schedule type, which can be 'actual' metered flows or 'scheduled' real-time flows. Where available, we used scheduled flows to minimize the impact of loop flows, but some reporting regions (such as EIA) report only actual metered flows.

A.1.5. Dropped load data

In order to present a complete picture of net demand, including demand that went unserved, we add dropped load from load shedding events to the net load data. We source dropped load data from DOE Form OE-417 (U.S. Department of Energy Office of Cybersecurity n.d.). These data are available publicly from EIA's Electric Power Monthly for 2002 through 2023 (U.S. Energy Information Administration (EIA) 2025); these data are not yet available for 2024 at the time of writing. It is mandatory for balancing authorities to report this form to DOE after large electric disturbance events.

We merged the downloaded EIA Electric Power Monthly data for 2002–2023 and conducted data quality assessment. We identified suspicious records where MW loss equaled customer counts and those with extreme MW-per-customer ratios. The MW-per-customer ratio was calculated by dividing MW loss by the number of customers, with infinite values (from zero customer counts) removed to retain only valid ratios.

Since the key variable (MW loss) was missing for many dropped load events, we implemented a regression-based imputation framework leveraging the relationship between MW loss and customers affected. Only events with ≥ 1000 customers and complete customer data were eligible (893 training samples, 853 requiring imputation). We evaluated three ordinary linear regression models using 5-fold cross-validation: original scales ($CV R^2 = 0.208$), square-root transformations ($CV R^2 = 0.217$), and logarithmic transformations ($CV R^2 = 0.228$). The logarithmic model performed best ($CV R^2 = 0.228$, $MAE = 529.70$ MW) and was used to predict missing MW values.

After inspection of the remaining data, we determined that many of the reported MW loss values were of poor quality or not representative of load shedding (e.g. representing failure of underlying transmission or distribution equipment). For this reason, we filtered the 'Type of Disturbance' variable to those equal to 'Firm load shedding of 100 MWs or more implemented under emergency.' This resulted in 54 events between 2016 and 2023.

The dropped load data lists the reporting utility/power pool, NERC region, and area affected, which gives the state and sometimes the county. To aggregate or dis-aggregate these locations to the planning subregional level used in this paper, we combine these three pieces of information to infer the planning subregion. For example, if the utility/power pool is MISO and the area affected is Texas, we can infer that the planning subregion is MISO South.

The data list the event start and restoration times. To create timeseries data, we apply the MW loss values to every hour between the start and end times. We then add this value to the net load values to

Table 5. List of all transmission paths used in this analysis, with the reporting region and planning subregions on either end. Schedule type indicates whether actual metered flows or scheduled flows were used. All flows are real-time.

Reporting region name	Transmission path name	Planning subregion A	Planning subregion B	Schedule type
Energy Information Administration	AZPS to CISO	WestConnect South	CAISO	ACTUAL
Energy Information Administration	AZPS to IID	WestConnect South	CAISO	ACTUAL
Energy Information Administration	AZPS to LDWP	WestConnect South	CAISO	ACTUAL
Energy Information Administration	AZPS to PACE	WestConnect South	NorthernGrid South	ACTUAL
Energy Information Administration	AZPS to WACM	WestConnect South	WestConnect North	ACTUAL
Energy Information Administration	BANC to BPAT	CAISO	NorthernGrid West	ACTUAL
Energy Information Administration	BPAT to BANC	NorthernGrid West	CAISO	ACTUAL
Energy Information Administration	BPAT to CISO	NorthernGrid West	CAISO	ACTUAL
Energy Information Administration	BPAT to IPCO	NorthernGrid West	NorthernGrid East	ACTUAL
Energy Information Administration	BPAT to LDWP	NorthernGrid West	CAISO	ACTUAL
Energy Information Administration	BPAT to NEVP	NorthernGrid West	NorthernGrid South	ACTUAL
Energy Information Administration	BPAT to NWMT	NorthernGrid West	NorthernGrid East	ACTUAL
Energy Information Administration	CISO to AZPS	CAISO	WestConnect South	ACTUAL
Energy Information Administration	CISO to BPAT	CAISO	NorthernGrid West	ACTUAL
Energy Information Administration	CISO to NEVP	CAISO	NorthernGrid South	ACTUAL
Energy Information Administration	CISO to PACW	CAISO	NorthernGrid South	ACTUAL
Energy Information Administration	CISO to SRP	CAISO	WestConnect South	ACTUAL
Energy Information Administration	CISO to WALC	CAISO	WestConnect South	ACTUAL
Energy Information Administration	FPC to SOCO	FRCC	SERTP	ACTUAL
Energy Information Administration	FPL to SOCO	FRCC	SERTP	ACTUAL
Energy Information Administration	GWA to BPAT	NorthernGrid East	NorthernGrid West	ACTUAL
Energy Information Administration	IID to AZPS	CAISO	WestConnect South	ACTUAL
Energy Information Administration	IID to WALC	CAISO	WestConnect South	ACTUAL
Energy Information Administration	IPCO to AVA	NorthernGrid East	NorthernGrid West	ACTUAL
Energy Information Administration	IPCO to BPAT	NorthernGrid East	NorthernGrid West	ACTUAL
Energy Information Administration	IPCO to NEVP	NorthernGrid East	NorthernGrid South	ACTUAL
Energy Information Administration	IPCO to PACW	NorthernGrid East	NorthernGrid West	ACTUAL
Energy Information Administration	LDWP to AZPS	CAISO	WestConnect South	ACTUAL
Energy Information Administration	LDWP to BPAT	CAISO	NorthernGrid West	ACTUAL
Energy Information Administration	LDWP to NEVP	CAISO	NorthernGrid South	ACTUAL

(Continued.)

Table 5. (Continued.)

Reporting region name	Transmission path name	Planning subregion A	Planning subregion B	Schedule type
Energy Information Administration	LDWP to PACE	CAISO	NorthernGrid South	ACTUAL
Energy Information Administration	LDWP to WALC	CAISO	WestConnect South	ACTUAL
Energy Information Administration	NEVP to BPAT	NorthernGrid South	NorthernGrid West	ACTUAL
Energy Information Administration	NEVP to CISO	NorthernGrid South	CAISO	ACTUAL
Energy Information Administration	NEVP to IPCO	NorthernGrid South	NorthernGrid East	ACTUAL
Energy Information Administration	NEVP to LDWP	NorthernGrid South	CAISO	ACTUAL
Energy Information Administration	NEVP to WALC	NorthernGrid South	WestConnect South	ACTUAL
Energy Information Administration	NWMT to BPAT	NorthernGrid East	NorthernGrid West	ACTUAL
Energy Information Administration	PACE to AZPS	NorthernGrid South	WestConnect South	ACTUAL
Energy Information Administration	PACE to LDWP	NorthernGrid South	CAISO	ACTUAL
Energy Information Administration	PACE to PACW	NorthernGrid East	NorthernGrid West	ACTUAL
Energy Information Administration	PACE to SRP	NorthernGrid South	WestConnect South	ACTUAL
Energy Information Administration	PACE to WACM	NorthernGrid South	WestConnect North	ACTUAL
Energy Information Administration	PACW to AVA	NorthernGrid West	NorthernGrid East	ACTUAL
Energy Information Administration	PACW to CISO	NorthernGrid South	CAISO	ACTUAL
Energy Information Administration	PACW to IPCO	NorthernGrid West	NorthernGrid East	ACTUAL
Energy Information Administration	PACW to PACE	NorthernGrid West	NorthernGrid East	ACTUAL
Energy Information Administration	PNM to PSCO	WestConnect South	WestConnect North	ACTUAL
Energy Information Administration	PNM to WACM	WestConnect South	WestConnect North	ACTUAL
Energy Information Administration	PSCO to PNM	WestConnect North	WestConnect South	ACTUAL
Energy Information Administration	SOCO to FPC	SERTP	FRCC	ACTUAL
Energy Information Administration	SOCO to FPL	SERTP	FRCC	ACTUAL
Energy Information Administration	SOCO to TAL	SERTP	FRCC	ACTUAL
Energy Information Administration	SRP to CISO	WestConnect South	CAISO	ACTUAL
Energy Information Administration	SRP to PACE	WestConnect South	NorthernGrid South	ACTUAL
Energy Information Administration	TAL to SOCO	FRCC	SERTP	ACTUAL
Energy Information Administration	WACM to AZPS	WestConnect North	WestConnect South	ACTUAL
Energy Information Administration	WACM to PACE	WestConnect North	NorthernGrid South	ACTUAL
Energy Information Administration	WACM to PNM	WestConnect North	WestConnect South	ACTUAL
Energy Information Administration	WACM to SRP	WestConnect North	WestConnect South	ACTUAL

(Continued.)

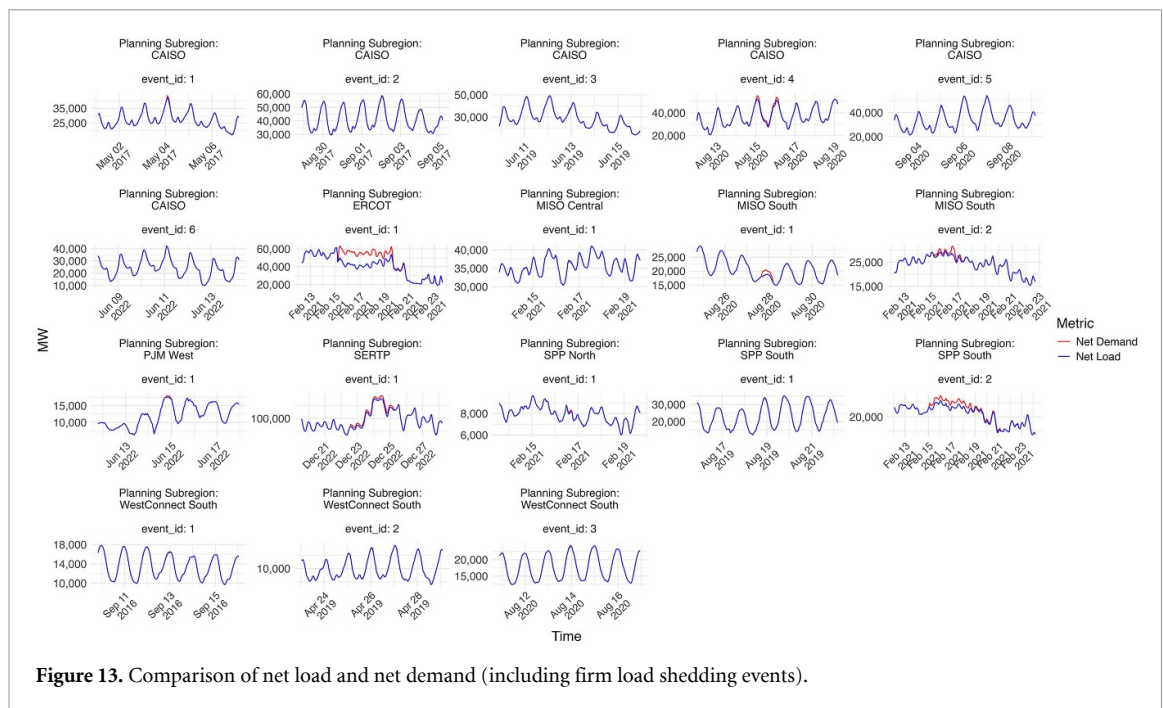
Table 5. (Continued.)

Reporting region name	Transmission path name	Planning subregion A	Planning subregion B	Schedule type
Energy Information Administration	WACM to WALC	WestConnect North	WestConnect South	ACTUAL
Energy Information Administration	WACM to WAUW	WestConnect North	NorthernGrid East	ACTUAL
Energy Information Administration	WALC to CISO	WestConnect South	CAISO	ACTUAL
Energy Information Administration	WALC to IID	WestConnect South	CAISO	ACTUAL
Energy Information Administration	WALC to LDWP	WestConnect South	CAISO	ACTUAL
Energy Information Administration	WALC to NEVP	WestConnect South	NorthernGrid South	ACTUAL
Energy Information Administration	WALC to WACM	WestConnect South	WestConnect North	ACTUAL
Energy Information Administration	WAUW to WACM	NorthernGrid East	WestConnect North	ACTUAL
Midcontinent ISO	MISO_INTRA	MISO Central	MISO South	SCHEDULED
SPP	Aliant Energy West to SPP	MISO North	SPP North	ACTUAL
SPP	Ameren to SPP	MISO Central	SPP South	ACTUAL
SPP	Blackwater DC Tie to SPP	WestConnect South	SPP South	ACTUAL
SPP	Cleco to SPP	MISO South	SPP South	ACTUAL
SPP	Dairyland Power to SPP	MISO North	SPP North	ACTUAL
SPP	EDDY DC Tie to SPP	WestConnect South	SPP South	ACTUAL
SPP	Entergy to SPP	MISO South	SPP South	ACTUAL
SPP	Great River Energy to SPP	MISO North	SPP North	ACTUAL
SPP	LAMAR DC Tie to SPP	WestConnect North	SPP South	ACTUAL
SPP	Midamerican to SPP	MISO North	SPP North	ACTUAL
SPP	Miles City West DC Tie to SPP	NorthernGrid East	SPP North	ACTUAL
SPP	Montana Dakota Utilities to SPP	NorthernGrid East	SPP North	ACTUAL
SPP	Northern States Power to SPP	MISO North	SPP North	ACTUAL
SPP	Otter Tail Power to SPP	MISO North	SPP North	ACTUAL
SPP	Rapid City East DC Tie to SPP	WestConnect North	SPP North	ACTUAL
SPP	Southwestern Power Administration to SPP	MISO South	SPP South	ACTUAL
SPP	Stegall DC Tie to SPP	WestConnect North	SPP North	ACTUAL
SPP	ERCOT East DC Tie to SPP	ERCOT	SPP South	ACTUAL
SPP	ERCOT North DC Tie to SPP	ERCOT	SPP South	ACTUAL
SPP	Sydney DC Tie to SPP	WestConnect North	SPP North	ACTUAL
New England ISO	Cross Sound Cable to ISONE	NYISO	ISONE	SCHEDULED
New England ISO	NY NNC to ISONE	NYISO	ISONE	SCHEDULED
New England ISO	NY Northern AC to ISONE	NYISO	ISONE	SCHEDULED

(Continued.)

Table 5. (Continued.)

Reporting region name	Transmission path name	Planning subregion A	Planning subregion B	Schedule type
PJM ISO	ALTE to PJM	MISO North	PJM West	SCHEDULED
PJM ISO	ALTW to PJM	MISO North	PJM West	SCHEDULED
PJM ISO	AMIL to PJM	MISO Central	PJM West	SCHEDULED
PJM ISO	Cinergy	MISO Central	PJM East	SCHEDULED
PJM ISO	CPLW to PJM	SERTP	PJM East	SCHEDULED
PJM ISO	CPLW to PJM	SERTP	PJM East	SCHEDULED
PJM ISO	CWLP to PJM	MISO Central	PJM West	SCHEDULED
PJM ISO	Duke to PJM	SERTP	PJM East	SCHEDULED
PJM ISO	Hudson Line to PJM	NYISO	PJM East	SCHEDULED
PJM ISO	NYISO to PJM	NYISO	PJM East	SCHEDULED
PJM ISO	IPL to PJM	MISO Central	PJM East	SCHEDULED
PJM ISO	LGE to PJM	SERTP	PJM East	SCHEDULED
PJM ISO	Linden VFT to PJM	NYISO	PJM East	SCHEDULED
PJM ISO	MEC to PJM	MISO North	PJM West	SCHEDULED
PJM ISO	Neptune Line to PJM	NYISO	PJM East	SCHEDULED
PJM ISO	NIPS to PJM	MISO Central	PJM West	SCHEDULED
PJM ISO	TVA to PJM	SERTP	PJM East	SCHEDULED
PJM ISO	WE to PJM	MISO North	PJM West	SCHEDULED



achieve net demand. Figure 13 compares the net load (blue, pre-addition of dropped load) to the net demand (red, post-addition of dropped load) for the events in the OE-417 database. There are fewer than 54 events because many of these events were overlapping, meaning they occurred at the same time or sequentially within one planning subregion. Many of these events are relatively small, except those that occurred during Winter Storm Uri.

Appendix B. Supplemental figures

B.1. Peak hour coincidence with all regions included

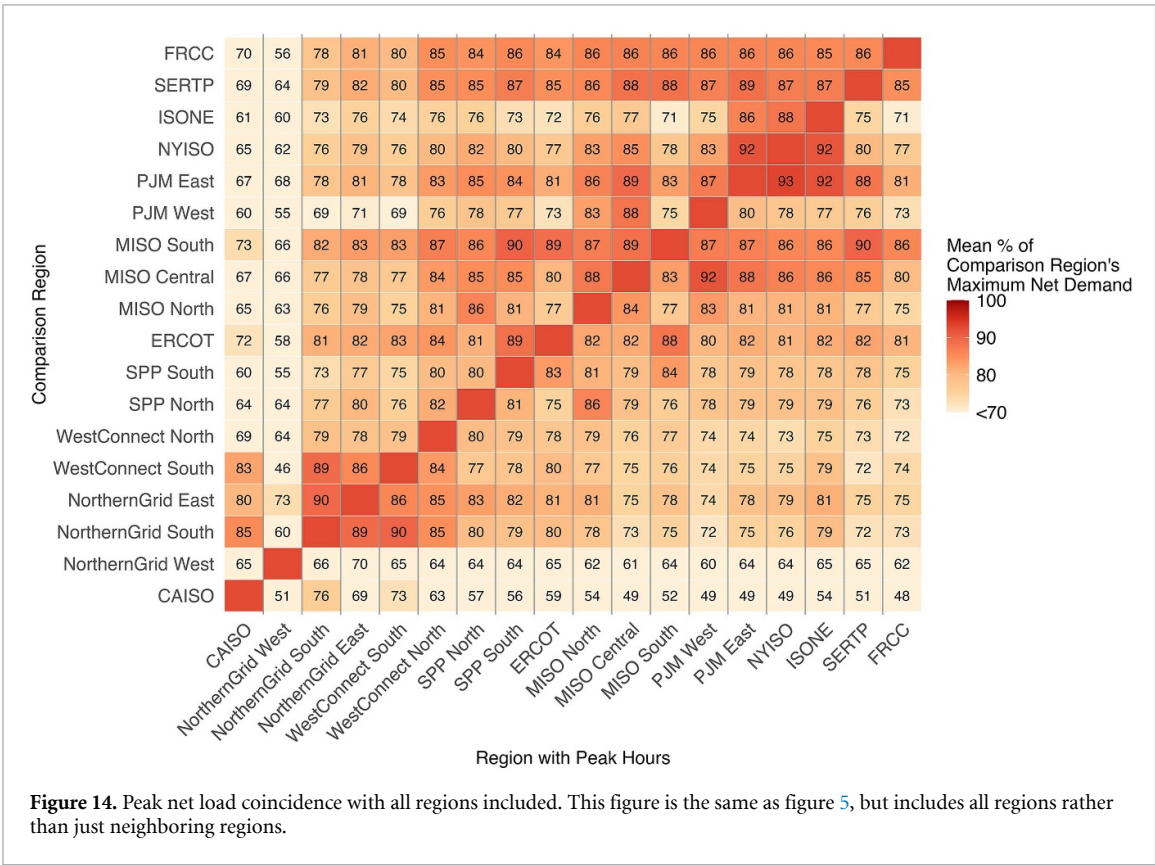


Figure 14. Peak net load coincidence with all regions included. This figure is the same as figure 5, but includes all regions rather than just neighboring regions.

B.2. Seasonality of top net load hours

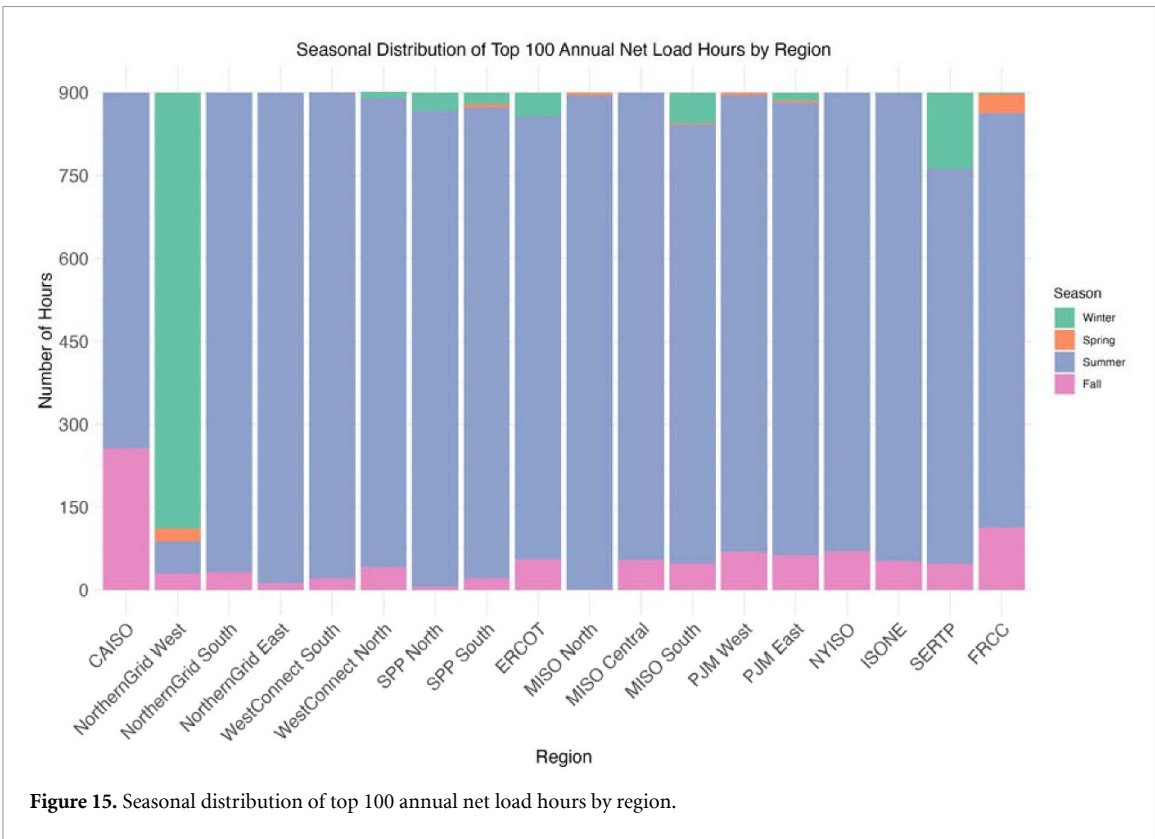


Figure 15. Seasonal distribution of top 100 annual net load hours by region.

B.3. Comparison of different top-hour thresholds

Figure 16 compares how neighboring regions' demand levels vary during the titled region's peak hours, testing sensitivity across varying definitions of 'peak': the top 10, 50, 100, 200, 300, and 500 net load hours. This figure provides a comparison to figure 5, which uses the top 100 net load hours.

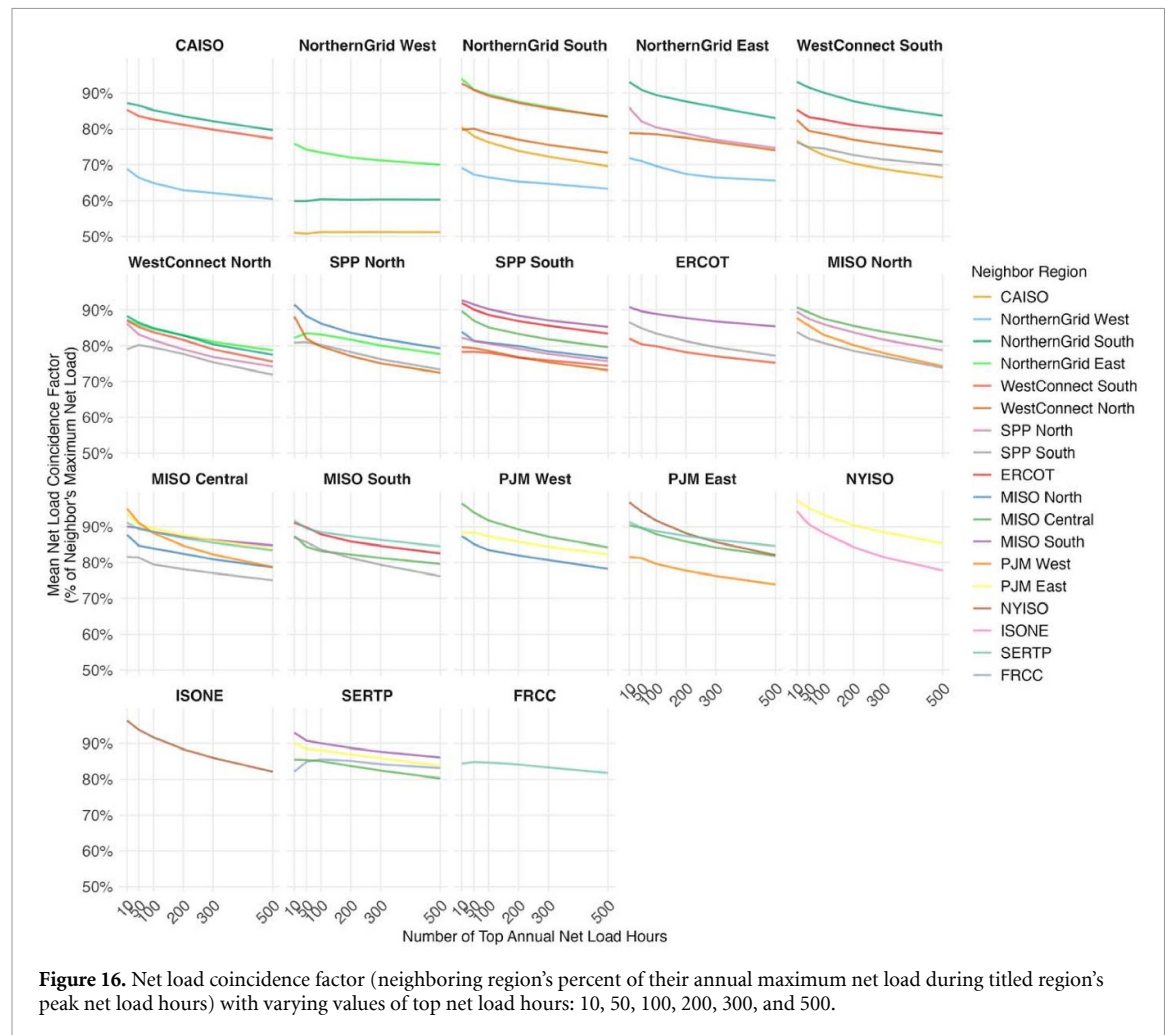


Figure 16. Net load coincidence factor (neighboring region's percent of their annual maximum net load during titled region's peak net load hours) with varying values of top net load hours: 10, 50, 100, 200, 300, and 500.

For each neighboring region, we calculate their average net load during the titled region's top n hours, expressed as a percentage of the neighbor's annual maximum net load. With the annual maximum held constant, each line traces how stressed a neighboring region tends to be during varying numbers of the titled region's peak hours.

As expected, net load coincidence increases slightly as we narrow our focus to fewer, more extreme peak hours. To illustrate one example, in CAISO's plot (the top left corner), NorthernGrid South (teal green line) averages 87.2% of their maximum net load during CAISO's top 10 net load hours. During CAISO's top 50 net load hours, NorthernGrid South averages 86.5% of their maximum net load; top 100 is 85.3%; top 200 is 83.6%; top 300 is 82.2%; and top 500 is 79.7%. For most regions, the metric is fairly stable with varying numbers of peak net load hours, with a gentle downward slope.

Figure 17 examines how transmission utilization patterns change as we vary the definition of 'peak hours' from the most extreme (top 10) to more moderate stress periods (top 500). For regions with high positive utilization rates (indicating net imports to the titled region), we would expect mean utilization rates to decrease with larger numbers of peak hours: regions import less when their stress level goes down. We see this pattern, or a mostly flat utilization rate, in most of these cases. Conversely, for region pairs showing negative utilization during the most extreme peak hours (the titled region exports despite being stressed), many show an increasing utilization pattern as the number of peak hours increases. In most regions, the results are fairly stable to varying top hour thresholds, showing a gently sloping line. Some regions, particularly between ISONE and NYISO, may be more sensitive than others.

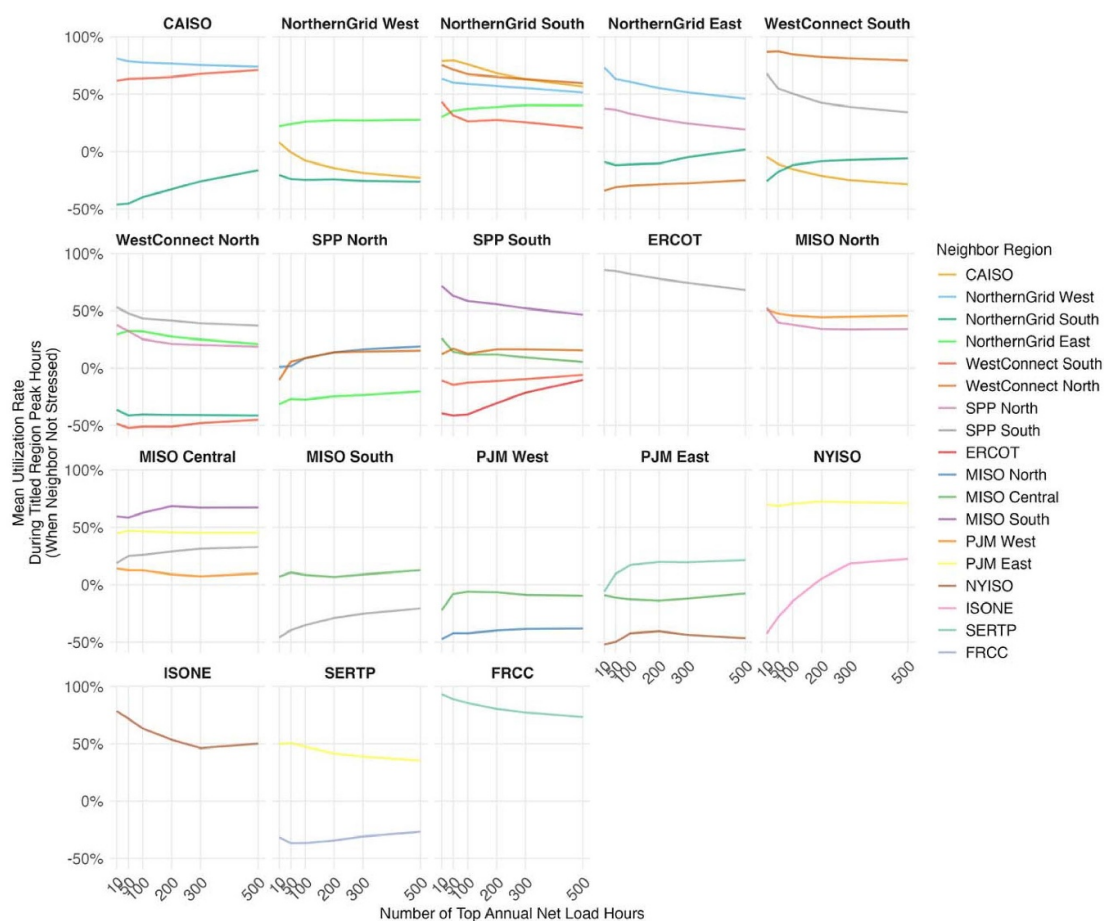


Figure 17. Transmission utilization rate between neighboring regions during 10, 50, 100, 200, 300, and 500 annual top net load hours of the titled region, when the neighboring region is not similarly experiencing their top n net load hours. Positive values indicate net imports to the titled region from the neighboring region; negative values indicate net exports.

B.4. Transmission utilization rates in peak hours vs. all hours

Figure 18 shows the mean utilization rate in all hours (orange bars) versus the top 100 net load hours when the neighboring region is not also stressed (green bars). See section 3.2.2 for further discussion of this figure.

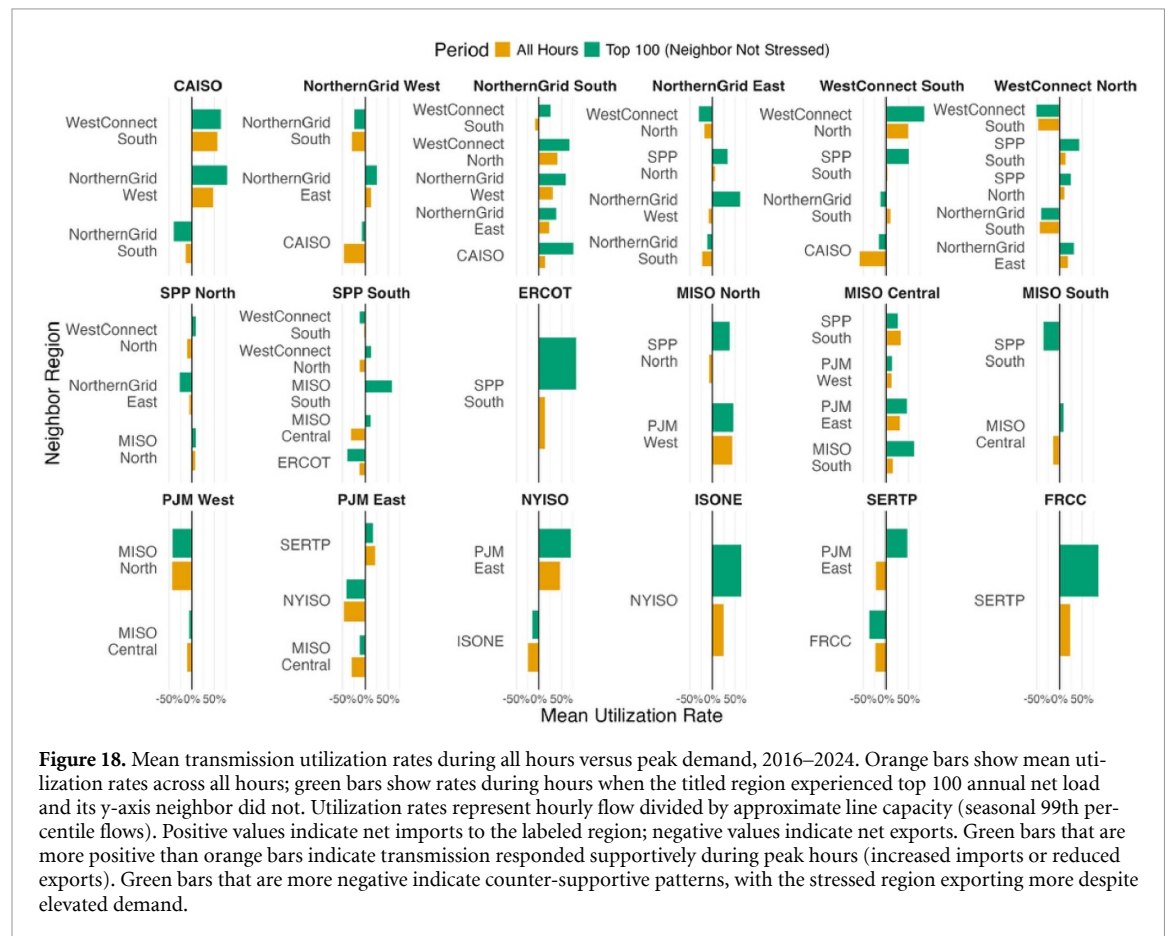
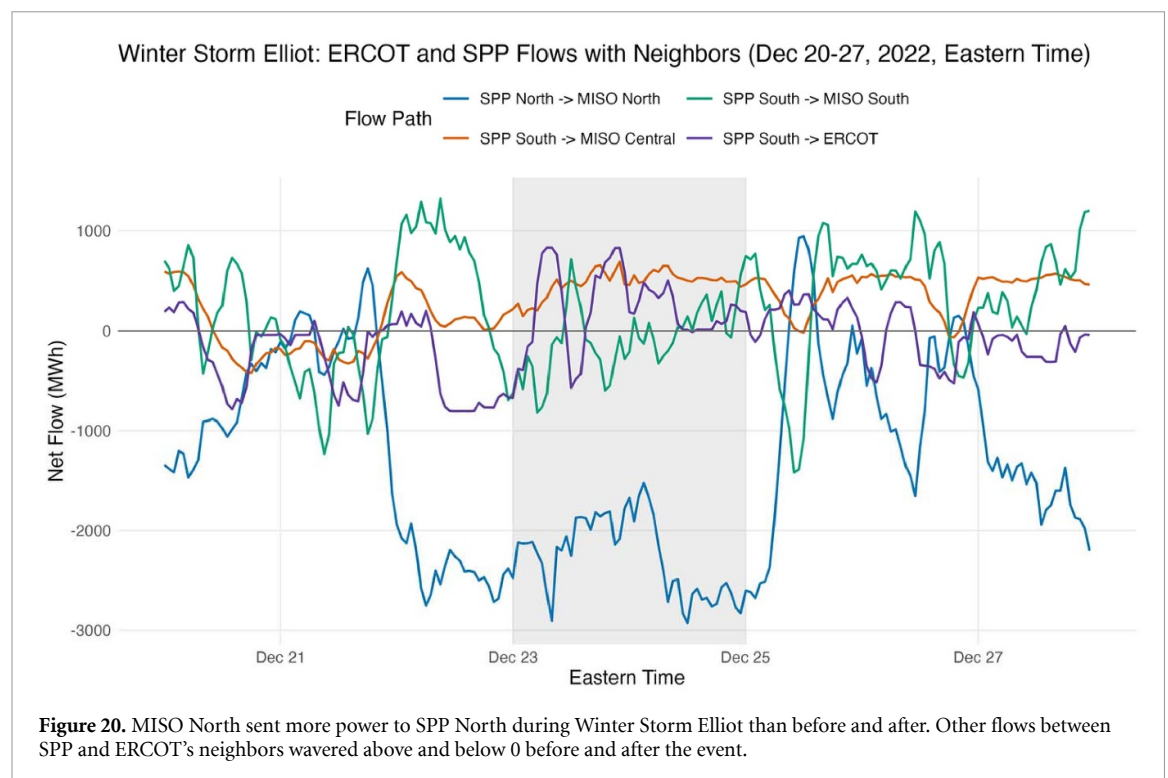
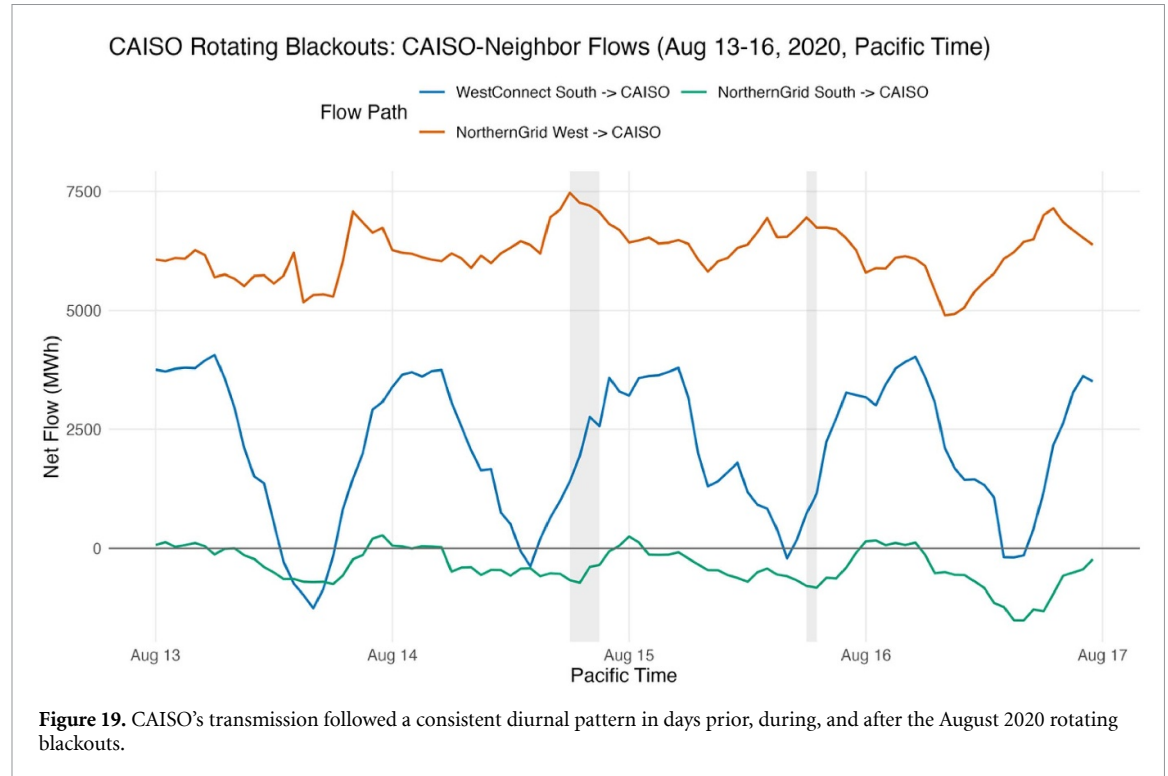
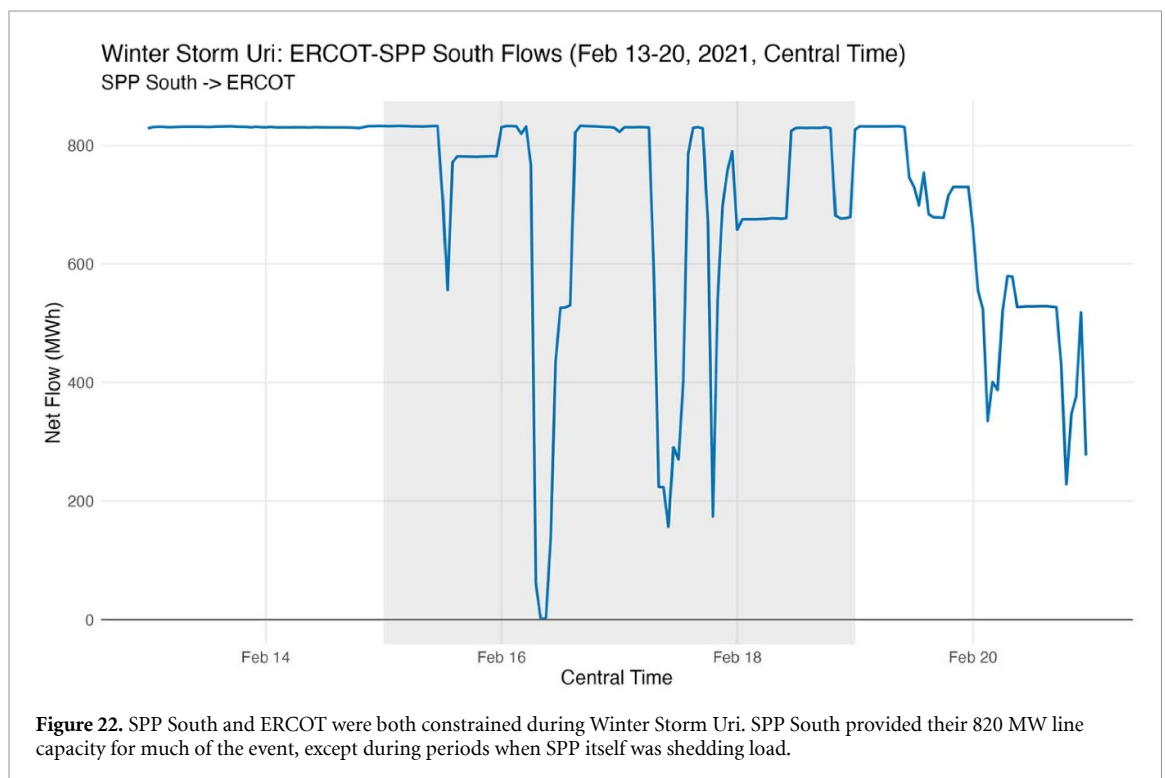
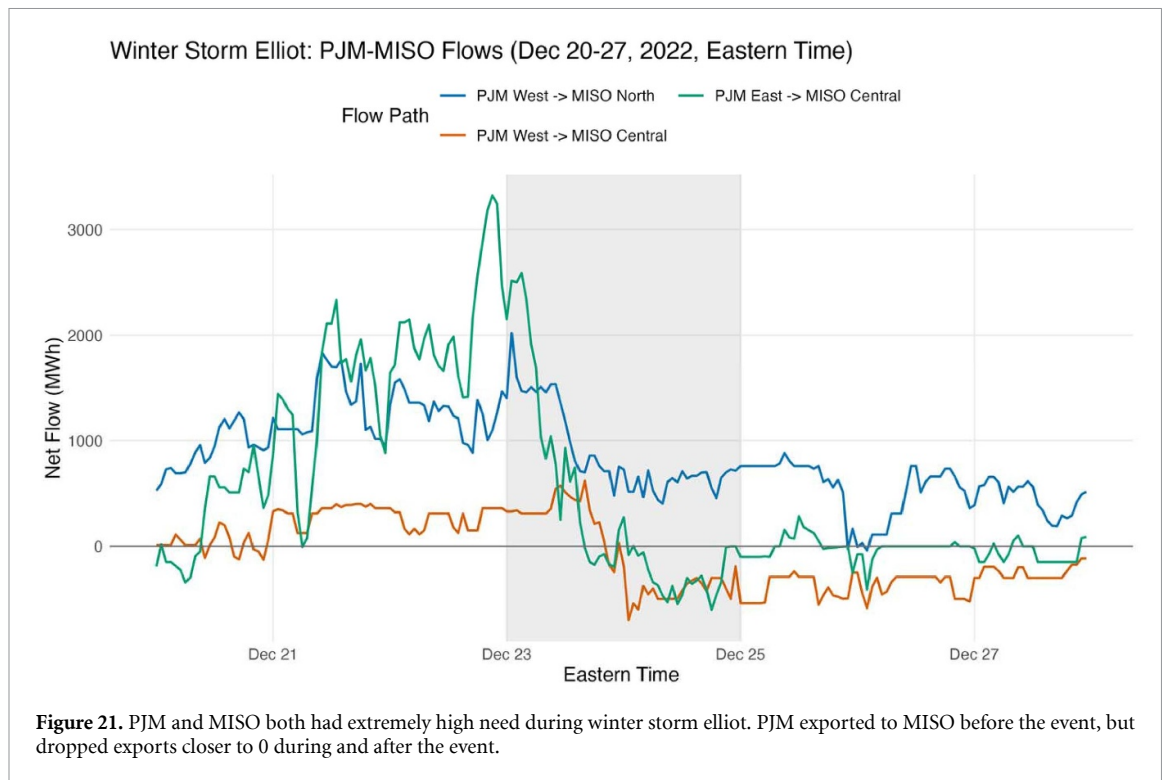


Figure 18. Mean transmission utilization rates during all hours versus peak demand, 2016–2024. Orange bars show mean utilization rates across all hours; green bars show rates during hours when the titled region experienced top 100 annual net load and its y-axis neighbor did not. Utilization rates represent hourly flow divided by approximate line capacity (seasonal 99th percentile flows). Positive values indicate net imports to the labeled region; negative values indicate net exports. Green bars that are more positive than orange bars indicate transmission responded supportively during peak hours (increased imports or reduced exports). Green bars that are more negative indicate counter-supportive patterns, with the stressed region exporting more despite elevated demand.

B.5. Case studies of transmission during extreme RA events

To provide insight into how transmission was used and whether it was responsive to need during known extreme event periods, we present case studies from three events below: CAISO's rotating blackouts in August 2020, Winter Storm Elliot, and Winter Storm Uri. For each event window, we plot hourly net flows on the relevant interregional paths across the event window. The shaded gray shows the most critical periods of the events. Flows on the ERCOT-SPP South ties were already near their import capac-





ity into ERCOT at baseline, with reductions occurring during the period when SPP itself was shedding load, providing limited evidence of adaptive utilization by transmission during the ERCOT emergency window. PJM substantially reduced exports to MISO during Winter Storm Elliot Dec 23, and by Dec 24 flows on multiple paths reversed to imports, consistent with some transmission response to evolving supply-demand tightness. Observed flows between CAISO and neighbors remained on a fairly consistent diurnal cycle in the days before, during, and after the load shedding periods.



Figure 23. RA support rate over time by link. The RA support rate (the white dots from figure 6) equals the percentage of single-peak hours (only one region in the pair is peaking) where the direction of flow along the link supported the high-need region.

B.6. RA support rate over time

To test whether transmission utilization evolves over time, we disaggregated the % RA Supported result from figure 6 by year. Figure 23 reports, for each region pair, the percentage of single-peak hours in which transfers supported the high-need region.

Across most region pairs, we observe year-to-year fluctuation around a relatively stable baseline, with no consistent system-wide trend toward increasing supportive transfer behavior. A small number of pairs

show modest upward trends (notably CAISO-NorthernGrid West, NorthernGrid South-NorthernGrid West, and CAISO-WestConnect South), suggesting gradual improvement in these western corridors. Overall, these patterns indicate that the inefficiencies highlighted in the main analysis are largely persistent rather than transitional over the study period.

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